HVDC Transmission

by

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18 March 1998

INTRODUCTION

Electric power transmission was originally developed with direct current. The availability of transformers and the development and improvement of induction motors at the beginning of the 20th Century, led to greater appeal and use of a.c. transmission. Through research and development in Sweden at Allmana Svenska Electriska Aktiebolaget (ASEA), an improved multi-electrode grid controlled mercury arc valve for high powers and voltages was developed from 1929. Experimental plants were set up in the 1930's in Sweden and the USA to investigate the use of mercury arc valves in conversion processes for transmission and frequency changing.

D.c. transmission now became practical when long distances were to be covered or where cables were required. The increase in need for electricity after the Second World War stimulated research, particularly in Sweden and in Russia. In 1950, a 116 km experimental transmission line was commissioned from Moscow to Kasira at 200 kV. The first commercial HVDC line built in 1954 was a 98 km submarine cable with ground return between the island of Gotland and the Swedish mainland.

Thyristors were applied to d.c. transmission in the late 1960's and solid state valves became a reality. In 1969, a contract for the Eel River d.c. link in Canada was awarded as the first application of sold state valves for HVDC transmission. Today, the highest functional d.c. voltage for d.c. transmission is +/- 600 kV for the 785 km transmission line of the Itaipu scheme in Brazil. D.c. transmission is now an integral part of the delivery of electricity in many countries throughout the world.

WHY USE DC TRANSMISSION?

The question is often asked, “Why use d.c. transmission?” One response is that losses are lower, but this is not correct. The level of losses is designed into a transmission system and is regulated by the size of conductor selected. D.c. and a.c. conductors, either as overhead transmission lines or submarine cables can have lower losses but at higher expense since the larger cross-sectional area will generally result in lower losses but cost more.

When converters are used for d.c. transmission in preference to a.c. transmission, it is generally by economic choice driven by one of the following reasons:

1. An overhead d.c. transmission line with its towers can be designed to be less costly per unit of length than an equivalent a.c. line designed to transmit the same level of electric power. However the d.c. converter stations at each end are more costly than the terminating stations of an a.c. line and so there is a breakeven distance above which the total cost of d.c. transmission is less than its a.c. transmission alternative. The d.c. transmission line can have a lower visual profile than an equivalent a.c. line and so contributes to a lower environmental impact. There are other environmental advantages to a d.c. transmission line through the electric and magnetic fields being d.c. instead of ac.
2. If transmission is by submarine or underground cable, the breakeven distance is much less than overhead transmission. It is not practical to consider a.c. cable systems exceeding 50 km but d.c. cable transmission systems are in service whose length is in the hundreds of kilometers and even distances of 600 km or greater have been considered feasible.
3. Some a.c. electric power systems are not synchronized to neighboring networks even though their physical distances between them is quite small. This occurs in Japan where half the country is a 60 hz network and the other is a 50 hz system. It is physically impossible to connect the two together by direct a.c. methods in order to exchange electric power between them. However, if a d.c. converter station is located in each system with an interconnecting d.c. link between them, it is possible to transfer the required power flow even though the a.c. systems so connected remain asynchronous.

CONFIGURATIONS

The integral part of an HVDC power converter is the valve or valve arm. It may be non-controllable if constructed from one or more power diodes in series or controllable if constructed from one or more thyristors in series. Figure 1 depicts the International Electrotechnical Commission (IEC) graphical symbols for valves and bridges (1). The standard bridge or converter connection is defined as a double-way connection comprising six valves or valve arms which are connected as illustrated in Figure 2. Electric power flowing between the HVDC valve group and the a.c. system is three phase. When electric power flows into the d.c. valve group from the a.c. system then it is considered a rectifier. If power flows from the d.c. valve group into the a.c. system, it is an inverter. Each valve consists of many series connected thyristors in thyristor modules. Figure 2 represents the electric circuit network depiction for the six pulse valve group configuration. The six pulse valve group was usual when the valves were mercury arc.

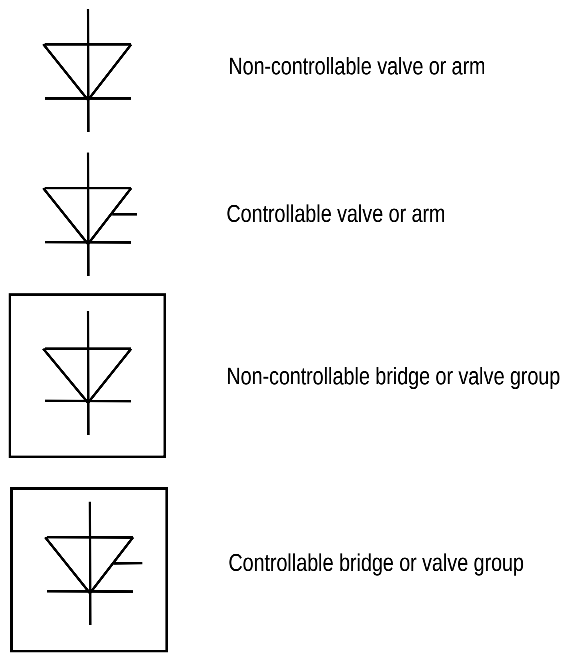

Figure 1. Standard graphical symbols for valves and bridges

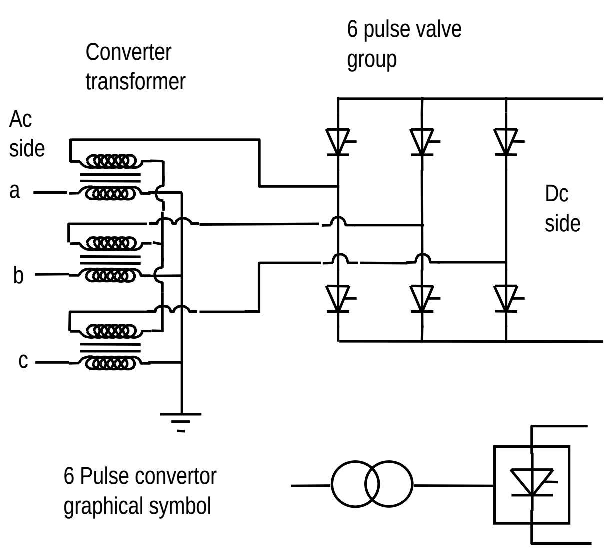

Figure 2. Electric circuit configuration of the basic six pulse valve group with its converter transformer in star-star connection.

Twelve Pulse Valve Group

Nearly all HVDC power converters with thyristor valves are assembled in a converter bridge of twelve pulse configuration. Figure 3 demonstrates the use of two three phase converter transformers with one d.c. side winding as an ungrounded star connection and the other a delta configuration. Consequently the a.c. voltages applied to each six pulse valve group which make up the twelve pulse valve group have a phase difference of 30 degrees which is utilized to cancel the a.c. side 5th and 7th harmonic currents and d.c. side 6th harmonic voltage, thus resulting in a significant saving in harmonic filters. Figure 3 also shows the outline around each of the three groups of four valves in a single vertical stack. These are known as “quadrivalves” and are assembled as one valve structure by stacking four valves in series. Since the voltage rating of thyristors is several kV, a 500 kV quadrivalve may have hundreds of individual thyristors connected in series groups of valve or thyristor modules. A quadrivalve for a high voltage converter is mechanically quite tall and may be suspended from the ceiling of the valve hall, especially in locations susceptible to earthquakes.

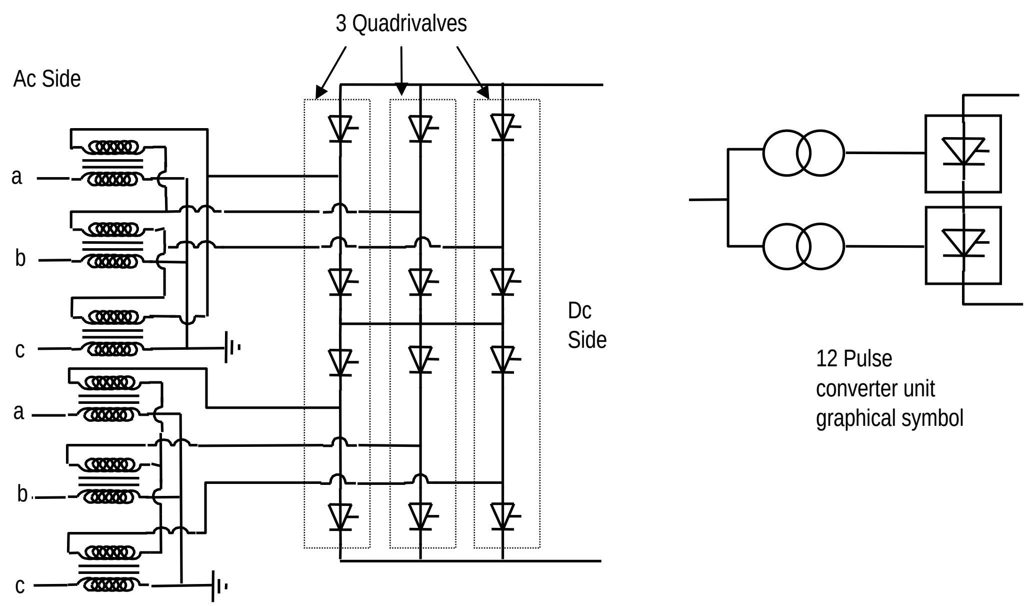

Figure 3. The twelve pulse valve group configuration with two converter transformers. One in star-star connection and the other in star-delta connection.

Thyristor Module

A thyristor or valve module is that part of a valve in a mechanical assembly of series connected thyristors and their immediate auxiliaries including heat sinks cooled by air, water or glycol, damping circuits and valve firing electronics. A thyristor module is usually interchangeable for maintenance purposes and consists of electric components as shown in Figure 4.

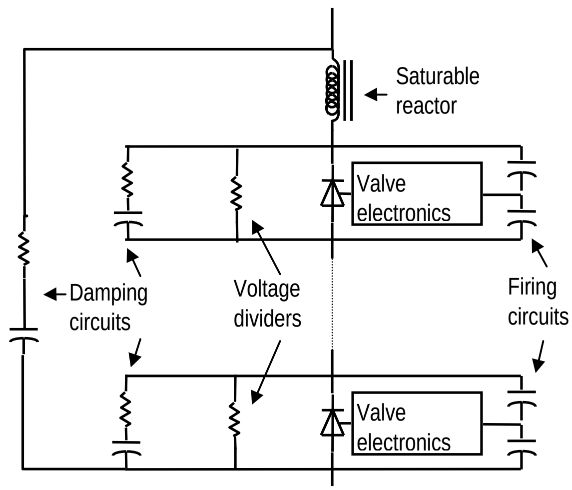

Figure 4. Components of the thyristor modules which make up a valve or quadrivalve.

Substation Configuration

The central equipment of a d.c. substation (2) are the thyristor converters which are usually housed inside a valve hall. Outdoor valves have been applied such as in the Cahora Bassa d.c. transmission line between Mozambique and South Africa. Figure 5 shows an example of the electrical equipment required for a d.c. substation. In this example, two poles are represented which is the usual case and is known as the “bipole” configuration. Some d.c. cable systems only have one pole or “monopole” configuration and may either use the ground as a return path when permitted or use an additional cable to avoid earth currents.

From Figure 5, essential equipment in a d.c. substation in addition to the valve groups include the converter transformers. Their purpose is to transform the a.c. system voltage to which the d.c. system is connected so that the correct d.c. voltage is derived by the converter bridges. For higher rated d.c. substations, converter transformers for 12 pulse operation are usually comprised of single phase units which is a cost effective way to provide spare units for increased reliability.

The secondary or d.c. side windings of the converter transformers are connected to the converter bridges. The converter transformer is located in the switchyard, and if the converter bridges are located in the valve hall, the connection has to be made through its wall. This is accomplished in either of two ways. Firstly, with phase isolated busbars where the bus conductors are housed within insulated bus ducts with oil or SF6 as the insulating medium or secondly, with wall bushings. When applied at d.c. voltages at 400 kV or greater, wall bushings require considerable design and care to avoid external or internal insulation breakdown.

Harmonic filters are required on the a.c. side and usually on the d.c. side. The characteristic a.c. side current harmonics generated by 6 pulse converters are 6n +/- 1 and 12n +/- 1 for 12 pulse converters where n equals all positive integers. A.c. filters are typically tuned to 11th, 13th, 23rd and 25th harmonics for 12 pulse converters. Tuning to the 5th and 7th harmonics is required if the converters can be configured into 6 pulse operation. A.c. side harmonic filters may be switched with circuit breakers or circuit switches to accommodate reactive power requirement strategies since these filters generate reactive power at fundamental frequency. A parallel resonance is naturally created between the capacitance of the a.c. filters and the inductive impedance of the a.c. system. For the special case where such a resonance is lightly damped and tuned to a frequency between the 2nd and 4th harmonic, then a low order harmonic filter at the 2nd or 3rd harmonic may be required, even for 12 pulse converter operation.

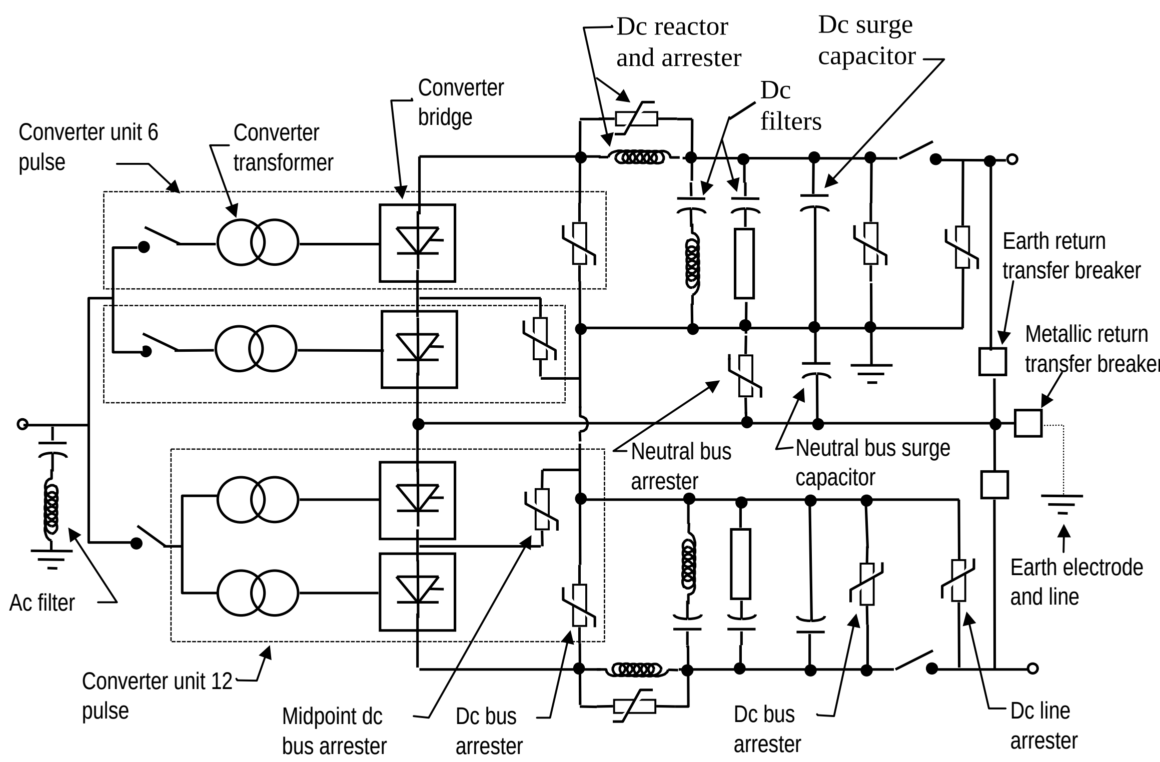

Figure 5. Example of an HVDC substation.

Characteristic d.c. side voltage harmonics generated by a 6 pulse converter are of the order 6n and when generated by a 12 pulse converter, are of the order 12n. D.c. side filters reduce harmonic current flow on d.c. transmission lines to minimize coupling and interference to adjacent voice frequency communication circuits. Where there is no d.c. line such as in the back-to-back configuration, d.c. side filters may not be required.

D.c. reactors are usually included in each pole of a converter station. They assist the d.c. filters in filtering harmonic currents and smooth the d.c. side current so that a discontinuous current mode is not reached at low load current operation. Because rate of change of d.c. side current is limited by the d.c. reactor, the commutation process of the d.c. converter is made more robust.

Surge arresters across each valve in the converter bridge, across each converter bridge and in the d.c. and a.c. switchyard are coordinated to protect the equipment from all overvoltages regardless of their source. They may be used in non-standard applications such as filter protection. Modern HVDC substations use metal-oxide arresters and their rating and selection is made with careful insulation coordination design.

APPLICATIONS OF HVDC CONVERTERS

The first application for HVDC converters was to provide point to point electrical power interconnections between asynchronous a.c. power networks. There are other applications which can be met by HVDC converter transmission which include:

1. Interconnections between asynchronous systems. Some continental electric power systems consist of asynchronous networks such as the East, West, Texas and Quebec networks in North America and island loads such as the Island of Gotland in the Baltic Sea make good use of HVDC interconnections.
2. Deliver energy from remote energy sources. Where generation has been developed at remote sites of available energy, HVDC transmission has been an economical means to bring the electricity to load centers. Gas fired thermal generation can be located close to load centers and may delay development of isolated energy sources in the near term.
3. Import electric energy into congested load areas. In areas where new generation is impossible to bring into service to meet load growth or replace inefficient or decommissioned plant, underground d.c. cable transmission is a viable means to import electricity.
4. Increasing the capacity of existing a.c. transmission by conversion to d.c. transmission. New transmission rights-of-way may be impossible to obtain. Existing overhead a.c. transmission lines if upgraded to or overbuilt with d.c. transmission can substantially increase the power transfer capability on the existing right-of-way.
5. Power flow control. A.c. networks do not easily accommodate desired power flow control. Power marketers and system operators may require the power flow control capability provided by HVDC transmission.

6. Stabilization of electric power networks. Some wide spread a.c. power system networks operate at stability limits well below the thermal capacity of their transmission conductors. HVDC transmission is an option to consider to increase utilization of network conductors along with the various power electronic controllers which can be applied on a.c. transmission.

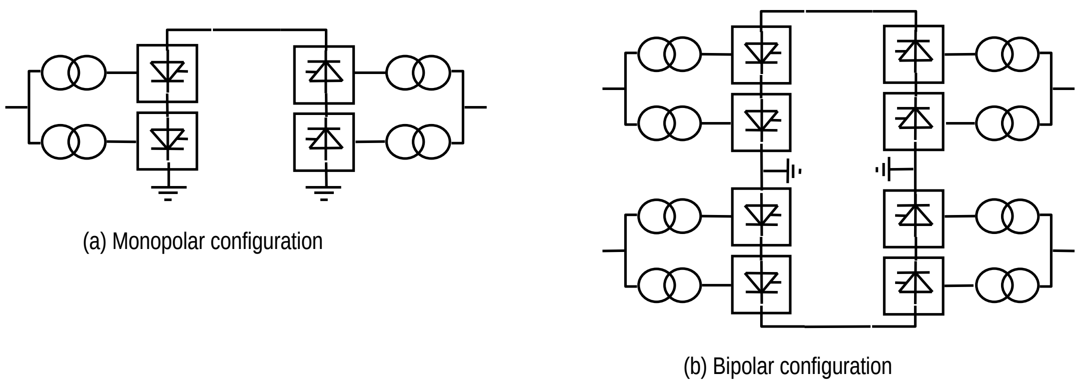

Figure 6. Monopolar and bipolar connection of HVDC converter bridges.

HVDC Converter Arrangements

HVDC converter bridges and lines or cables can be arranged into a number of configurations for effective utilization. Converter bridges may be arranged either monopolar or bipolar as shown in 12 pulse arrangement in Figure 6. Various ways HVDC transmission is used are shown in simplified form in Figure 7 and include the following:

1. Back-to-Back. There are some applications where the two a.c. systems to be interconnected are physically in the same location or substation. No transmission line or cable is required between the converter bridges in this case and the connection may be monopolar or bipolar. Back-to-back d.c. links are used in Japan for interconnections between power system networks of different frequencies (50 and 60 Hz). They are also used as interconnections between adjacent asynchronous networks.
2. Transmission Between Two Substations. When it is economical to transfer electric power through d.c. transmission or cables from one geographical location to another, a two-terminal or point-to-point HVDC transmission is used. In other words, d.c. power from a d.c. rectifier terminal is dedicated to one other terminal operating as an inverter. This is typical of most HVDC transmission systems.
3. Multiterminal HVDC Transmission System. When three or more HVDC substations are geographically separated with interconnecting transmission lines or cables, the HVDC transmission system is multiterminal. If all substations are connected to the

same voltage then the system is parallel multiterminal d.c. If one or more converter bridges are added in series in one or both poles, then the system is series multiterminal d.c. Parallel multiterminal d.c. transmission has been applied when the substation capacity exceeds 10% of the total rectifier substation capacity. It is expected a series multiterminal substation would be applied when its capacity is small (less than 10%) compared to the total rectifier substation capacity. A combination of parallel and series connections of converter bridges is a hybrid multiterminal system. Multiterminal d.c. systems are more difficult to justify economically because of the cost of the additional substations.

4. Unit Connection. When d.c. transmission is applied right at the point of generation, it is possible to connect the converter transformer of the rectifier directly to the generator terminals so the generated power feeds into the d.c. transmission lines. This might be applied with hydro and wind turbine driven generators so that maximum efficiency of the turbine can be achieved with speed control. Regardless of the turbine speed, the power is delivered through the inverter terminal to the a.c. receiving system at its fundamental frequency of 50 or 60 hz.
5. Diode Rectifier. It has been proposed that in some applications where d.c. power transmission is in one direction only, the valves in the rectifier converter bridges can be constructed from diodes instead of thyristors. Power flow control would be achieved at the inverter, and in the case where the unit connection is used, a.c. voltage control by the generator field exciter could be applied to regulate d.c. power. This connection may require high speed a.c. circuit breakers between the generator and the rectifier converter bridges to protect the diodes from overcurrents resulting from a sustained d.c. transmission line short circuit.

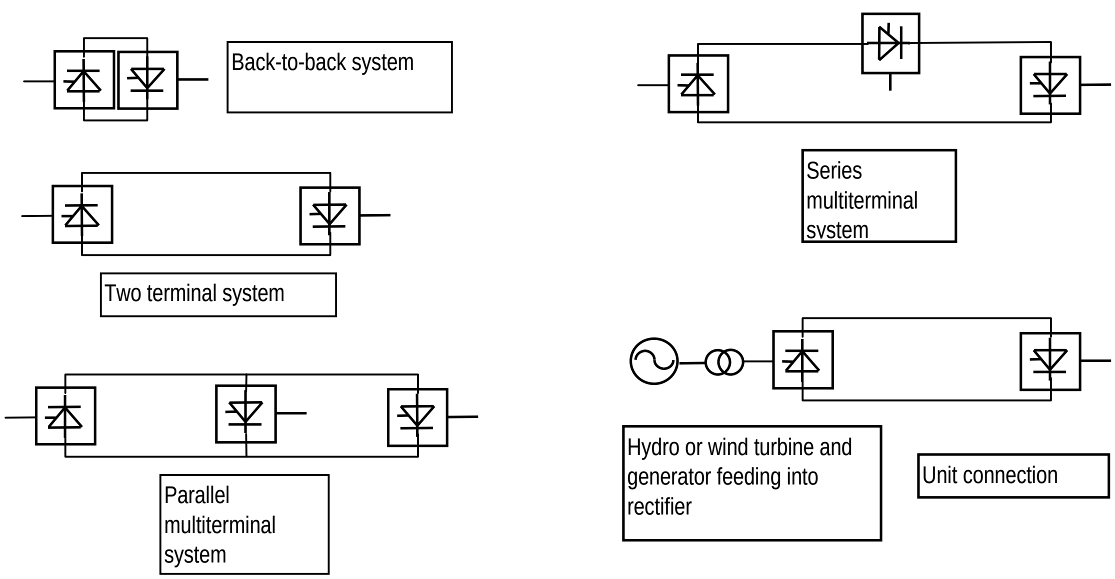

Figure 7. HVDC converter bridge arrangements.

Economic Considerations

A study for Oak Ridge National Laboratory (3) reported on a survey to 3 suppliers of HVDC equipment for quotations of turnkey costs to supply two bipolar substations for four representative systems. Each substation requires one d.c. electrode and interfaces to an a.c. system with a short circuit capacity four times the rating of the HVDC system. The four representative systems are summarized in Table 1. Table 2 provides a major component breakdown based on average values derived from the responses of the suppliers. The turnkey costs are in 1995/96 US dollars and are for one terminal only with the assumption that both terminals would be provided by the same supplier. The back-to-back d.c. link cost is for the complete installation.

Transmission line costs cannot be so readily defined. Variations depend on the cost of use of the land, the width of the right-of-way required, labor rates for construction, and the difficulty of the terrain to be crossed. A simple rule of thumb may be applied in that the cost of a d.c. transmission line may be 80% to 100% of the cost of an a.c. line whose rated line voltage is the same as the rated pole-to-ground voltage of the d.c. line. The cost advantage of d.c. transmission for traversing long distances is that it may be rated at twice the power flow capacity of an a.c. line of the same voltage.

Table 1. Four representative HVDC systems for substation cost analysis

System No.	D.C. Voltage	Capacity	A.C. Voltage
1	+/- 250 kV	500 MW	230 kV
2	+/- 350 kV	1000 MW	345 kV
3	+/- 500 kV	3000 MW	500 kV
4	Back-to-back	200 MW	230 kV

Table 2. Average breakdown of HVDC turnkey costs from three HVDC suppliers

Item	Project Component	Back-to-back 200 MW	+/-250 kV 500 MW	+/-350 kV 1000 MW	+/-500 kV 3000 MW
1	Converter valves	19.0%	21.0%	21.3%	21.7%
2	Conv. transformers	22.7%	21.3%	21.7%	22.0%
3	D.C. switchyard	3.0%	6.0%	6.0%	6.0%

4	A.C. switchyard	10.7%	9.7%	9.7%	9.3%
5	Control, protection & communication	8.7%	8.0%	8.0%	7.7%
6	Civil works	13.0%	13.7%	13.7%	13.7%
7	Auxiliary power	2.0%	2.3%	2.3%	2.3%
8	Project admin.	21.0%	18.0%	17.3%	17.3%
Total estimated cost $MUS		43.3	145.0	213.7	451.7
Cost - $/kW/Station		**217**	**145**	**107**	**75**

When electricity must be transmitted by underground or undersea cables, a.c. cables become impractical due to their capacitive charging current if longer than a critical length which for undersea applications is less than 50 kM. For distances longer than this critical length with today's technology requires d.c. cables. The choice is system specific, and economic considerations will prevail.

ENVIRONMENTAL CONSIDERATIONS

The electrical environmental effects from HVDC. transmission lines can be characterized by field and ion effects as well as corona effects (4), (5). The electric field arises from both the electrical charge on the conductors and for a HVDC overhead transmission line, from charges on air ions and aerosols surrounding the conductor. These give rise to d.c. electric fields due to the ion current density flowing through the air from or to the conductors as well as due to the ion density in the air. A d.c. magnetic field is produced by d.c. current flowing through the conductors. Air ions produced by HVDC lines form clouds which drift away from the line when blown by the wind and may come in contact with humans, animals and plants outside the transmission line right-of -way or corridor. The corona effects may produce low levels of radio interference, audible noise and ozone generation.

Field and corona effects

The field and corona effects of transmission lines largely favor d.c. transmission over a.c. transmission. The significant considerations are as follows:

1. For a given power transfer requiring extra high voltage transmission, the d.c. transmission line will have a smaller tower profile than the equivalent a.c. tower

carrying the same level of power. This can also lead to less width of right-of-way for the d.c. transmission option.

2. The steady and direct magnetic field of a d.c. transmission line near or at the edge of the transmission right-of-way will be about the same value in magnitude as the earth's naturally occurring magnetic field. For this reason alone, it seems unlikely that this small contribution by HVDC transmission lines to the background geomagnetic field would be a basis for concern.
3. The static and steady electric field from d.c. transmission at the levels experienced beneath lines or at the edge of the right-of-way have no known adverse biological effects. There is no theory or mechanism to explain how a static electric field at the levels produced by d.c. transmission lines could effect human health. The electric field level beneath a HVDC transmission line is of similar magnitude as the naturally occurring static field which exists beneath thunder clouds. Electric fields from a.c. transmission lines have been under more intense scrutiny than fields generated from d.c. transmission lines.
4. The ion and corona effects of d.c. transmission lines lead to a small contribution of ozone production to higher naturally occurring background concentrations. Exacting long term measurements are required to detect such concentrations. The measurements taken at cross-sections across the Nelson River d.c. lines in Canada failed to distinguish background from downwind levels (4). While solar radiation influences the production of ozone even in a rural environment, thereby maintaining its level, any incremental contribution from a d.c. line source is subject to breakdown, leading to a resumption of background levels downwind from the line. Investigations of ozone for indoor conditions indicate that in well mixed air, the half-life of ozone is 1.5 minutes to 7.9 minutes. Increases in temperature and humidity increase the rate of decay (4).
5. If ground return is used with monopolar operation, the resulting d.c. magnetic field can cause error in magnetic compass readings taken in the vicinity of the d.c. line or cable. This impact is minimized by providing a conductor or cable return path (known as metallic return) in close proximity to the main conductor or cable for magnetic field cancellation. Another concern with continuous ground current is that some of the return current may flow in metallic structures such as pipelines and intensify corrosion if cathodic protection is not provided. When pipelines or other continuous metallic grounded structures are in the vicinity of a d.c. link, metallic return may be necessary

D.C CONVERTER OPERATION

The six pulse converter bridge of Figure 2 as the basic converter unit of HVDC transmission is used equally well for rectification where electric power flows from the a.c. side to the d.c. side and inversion where the power flow is from the d.c. side to the a.c. side. Thyristor valves operate as switches which turn on and conduct current when fired on receiving a gate pulse and are forward biased. A thyristor valve will conduct current in one direction and once it conducts, will only turn off when it is reverse biased and the current falls to zero. This process is known as line commutation.

An important property of the thyristor valve is that once its conducting current falls to zero when it is reverse biased and the gate pulse is removed, too rapid an increase in the magnitude of the forward biased voltage will cause the thyristor to inadvertently turn on and conduct. The design of the thyristor valve and converter bridge must ensure such a condition is avoided for useful inverter operation.

Commutation

Rectification or inversion for HVDC converters is accomplished through a process known as line or natural commutation. The valves act as switches so that the a.c. voltage is sequentially switched to always provide a d.c. voltage. With line commutation, the a.c. voltage at both the rectifier and inverter must be provided by the a.c. networks at each end and should be three phase and relatively free of harmonics as depicted in Figure 8. As each valve switches on, it will begin to conduct current while the current begins to fall to zero in the next valve to turn off. Commutation is the process of transfer of current between any two converter valves with both valves carrying current simultaneously during this process.

Consider the rectification process. Each valve will switch on when it receives a firing pulse to its gate and its forward bias voltage becomes more positive than the forward bias voltage of the conducting valve. The current flow through a conducting valve does not change instantaneously as it commutates to another valve because the transfer is through transformer windings. The leakage reactance of the transformer windings is also the commutation reactance so long as the a.c. filters are located on the primary or a.c. side of the converter transformer. The commutation reactance at the rectifier and inverter is shown as an equivalent reactance X_C in Figure 8. The sum of all the valve currents transferred the d.c. side and through the d.c. reactor is the direct current and it is relatively flat because of the inductance of the d.c. reactor and converter transformer.

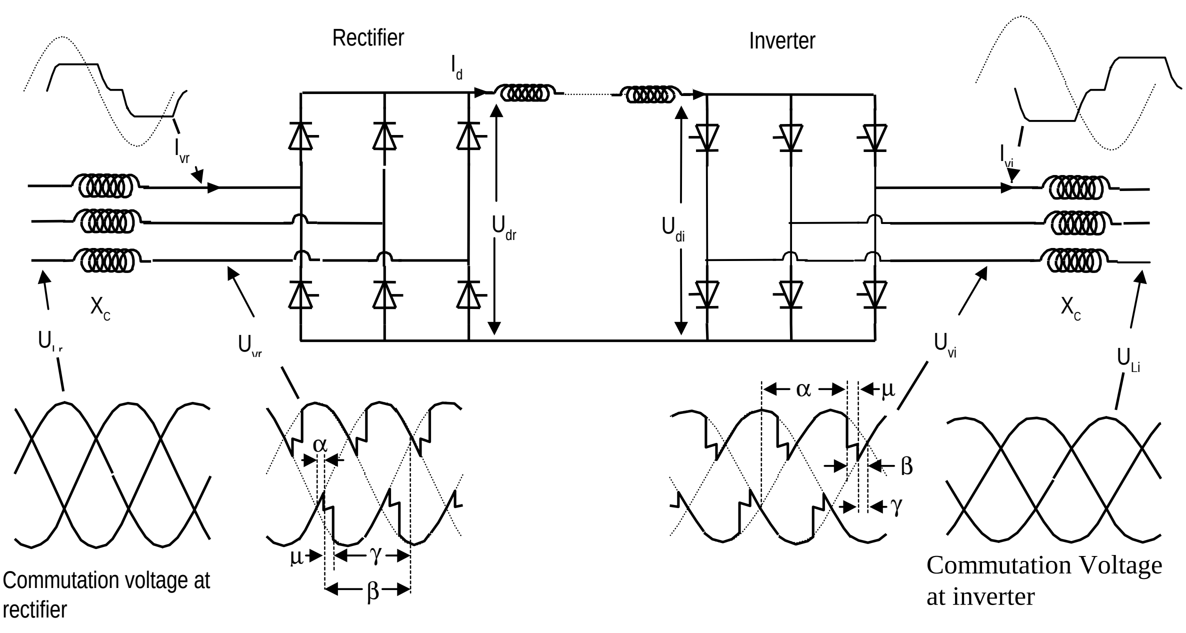

Figure 8. Voltage and current waveshapes associated with d.c. converter bridges.

At the inverter, the three phase a.c. voltage supplied by the a.c. system provides the forward and reverse bias conditions of each valve in the converter bridge to allow commutation of current between valves the same as in the rectifier. The inverter valve can only turn on and conduct when the positive direct voltage from the d.c. line is greater than the back negative voltage derived from the a.c. commutation voltage of the a.c. system at the inverter.

Due to the line commutation valve switching process, a non-sinusoidal current is taken from the a.c. system at the rectifier (I_{vr} in Figure 8) and is delivered to the a.c. system at the inverter (I_{vi} in Figure 8). Both I_{vr} and I_{vi} are lagging to the alternating voltage. This non-sinusoidal current waveform consists of the fundamental frequency a.c. component plus higher harmonics being taken from, and injected into, each a.c. system. The a.c. filters divert the harmonics from entering the a.c. system by offering a low impedance by-pass path allowing the commutation voltage to be relatively harmonic free(U_{Lr} and U_{Li} in Figure 8).

Reversal of power flow in a line commutated d.c. link is not possible by reversing the direction of the direct current. The valves will allow conduction in one direction only. Power flow can only be reversed in line commutated d.c. converter bridges by changing the polarity of the direct voltage. The dual operation of the converter bridges as either a rectifier or inverter is achieved through firing control of the grid pulses.

Converter bridge angles

Figure 8 shows the various electrical angles which define the operation of converter bridges. These angles are measured on the three phase valve side voltages and are based upon steady state conditions with a harmonic free and idealized three phase commutation voltage. They apply to both inverters and rectifiers.

Delay angle α. The time expressed in electrical angular measure from the zero crossing of the idealized sinusoidal commutating voltage to the starting instant of forward current conduction. This angle is controlled by the gate firing pulse and if less than 90 degrees, the converter bridge is a rectifier and if greater than 90 degrees, it is an inverter. This angle is often referred to as the firing angle.

Advance angle β. The time expressed in electrical angular measure from the starting instant of forward current conduction to the next zero crossing of the idealized sinusoidal commutating voltage. The angle of advance β is related in degrees to the angle of delay α by:

$\beta = 180.0 - \alpha$ (1)

Overlap angle μ. The duration of commutation between two converter valve arms expressed in electrical angular measure.

Extinction angle γ. The time expressed in electrical angular measure from the end of current conduction to the next zero crossing of the idealized sinusoidal commutating voltage. γ depends on the angle of advance β and the angle of overlap μ and is determined by the relation:

$\gamma = \beta - \mu$ (2)

Steady state d.c. converter bridge equations

It is useful to express the commutation reactance of a 6 pulse converter bridge in per-unit of the converter transformer rating S_N as follows:

$S_N = \sqrt{2}\, U_{VN}\, I_{dN}$ (3)

where I_{dN} is the rated direct current and U_{VN} is the rated phase-to-phase voltage on the valve or secondary side of the converter transformer. Usually the d.c. converter bridge power rating is known from its rated d.c. current I_{dN} and rated d.c. voltage U_{dN}. The valve and converter bridge design is very dependent upon the commutation reactance X_C and so consequently its value is established and known. In modern HVDC converter bridges it is usually in the range $0.1<X_C<0.15$ in per unit where 1.0 per unit is $(U_{VN})^2/S_N$ ohms.

A reasonably good approximation for the power factor of a converter bridge at the a.c. commutating bus is given by the following expression for a rectifier. Note that the delay angle α is usually known or determined. For example, the normal steady state range of delay angle for a rectifier may be $10^o < \alpha < 18^o$ and the lowest normal operating power factor will be when $\alpha = 18^o$:

Power Factor = $\mathrm{Cos}(\theta) = \mathrm{Cos}(\alpha) - 0.5\, X_C(I_d/I_{dN})$ (4)

and for an inverter:

Power Factor = $\mathrm{Cos}(\theta) = \mathrm{Cos}(\gamma) - 0.5\, X_C(I_d/I_{dN})$ (5)

where I_d is the d.c. load current and I_{dN} is rated d.c. current and θ is the power factor angle. For the inverter, the normal rated extinction angle is established in the converter bridge design, usually at $\gamma = 18^o$. Ignoring the losses in the converter bridge, the power flowing through the bridge P_d is:

$$P_d = I_d U_d \tag{6}$$

where I_d is the operating direct current through the converter bridge and U_d is the operating direct voltage across the converter bridge. Having calculated the power factor angle θ from Equation (4) or (5) and throughput power of the converter bridge from Equation (6), the reactive power Q_L demanded by the converter bridge at the a.c. commutating voltage busbar at either the rectifier or inverter is:

$$Q_L = P_d \operatorname{Tan}(\theta) \tag{7}$$

It may be that the rated phase-to-phase voltage on the valve or secondary side of the converter transformer U_{VN} is not known. It is possible to compute what it should be if the power factor $\operatorname{Cos}(\theta)$ from Equation (4) or (5) is known at the converter bridge rating. Then a good estimate of U_{VN} is:

$$U_{VN} = U_{dN}/[1.35 \operatorname{Cos}(\theta)] \tag{8}$$

Once U_{VN} is known, it is possible to find the converter transformer rating with Equation (3).

It may be necessary to determine the overlap angle μ. At the rectifier, the following approximate expression can be applied when delay angle α, per-unit commutating reactance X_C and d.c. load current I_d are known:

$$\operatorname{Cos}(\alpha+\mu) = \operatorname{Cos}(\alpha) - X_C I_d / I_{dN} \tag{10}$$

Similarly at the inverter, the extinction angle γ is usually known for steady state operation so that:

$$\operatorname{Cos}(\gamma+\mu) = \operatorname{Cos}(\gamma) - X_C I_d / I_{dN} \tag{11}$$

The delay angle α at the inverter may not be inherently known but once extinction angle γ and overlap angle μ have been determined, then:

$$\alpha = 180^O - (\gamma + \mu) \tag{12}$$

It is also possible to determine the nominal turns ratio of the converter transformer once the rated secondary (d.c. valve side) voltage U_{VN} is known and if the primary side rated phase-to-phase a.c. bus voltage U_{LN} is also known. Based on phase-to-phase voltages, the nominal turns ratio of the converter transformer TR_N is:

$$TR_N = \frac{\text{Valve side phase-to-phase rated voltage}}{\text{A.c. side phase-to-phase rated voltage}}$$

$$= U_{VN}/U_{LN} \qquad (13)$$

During the operation of a converter bridge, the converter transformer on-line tap changer will adjust to keep the delay angle α at a rectifier at its desired normal operating range. Similarly at the inverter, the on-line tap changer will adjust to maintain the inverter operation at its desired level of d.c. voltage U_d or extinction angle γ. Knowing the desired levels of d.c. voltage (U_d), d.c. current I_d, the nominal turns ratio TR_N of the converter transformer, the operating level of the primary side a.c. voltage U_L, and the extinction angle γ (if an inverter) or delay angle α (if a rectifier), the per-unit turns ratio TR of the converter transformer is found from the expression:

$$TR = \frac{U_d + U_{dN} \dfrac{I_d}{I_{dN}} \dfrac{X_C}{(2\mathrm{Cos}(\varphi) - X_C)}}{1.35\, TR_N\, U_L\, \mathrm{Cos}(\varphi)} \qquad (14)$$

where X_C is the commutating reactance for the converter bridge in per-unit and $\varphi = \alpha$ for a rectifier and $\varphi = \gamma$ if an inverter. I_{dN} is the rated d.c. current for the converter bridge and U_{dN} is its rated d.c. voltage.

Equations 1 to 13 are the steady state and reasonably accurate expressions defining the state of a 6 pulse converter bridge under ideal conditions. More exacting expressions can be found in references (6), (7), (8), (9), (10), (11) and can be used if the network data is known with sufficient accuracy to justify precise mathematical formulation. Defining the performance and operation of a converter bridge under dynamic or transient conditions requires the use of a suitable electromagnetic transients simulation program with the capability of modeling the valves, converter transformer, control system which produces the firing pulses to the valves, and the associated a.c. and d.c. networks.

Short circuit ratio

The strength of the a.c. network at the bus of the HVDC substation can be expressed by the short circuit ratio (SCR), defined as the relation between the short circuit level in MVA at the HVDC substation bus at 1.0 per-unit a.c. voltage and the d.c. power in MW.

The capacitors and a.c. filters connected to the a.c. bus reduce the short circuit level. The expression effective short circuit ratio (ESCR) is used for the ratio between the short circuit level reduced by the reactive power of the shunt capacitor banks and a.c. filters connected to the a.c. bus at 1.0 per-unit voltage and the rated d.c. power.

Lower ESCR or SCR means more pronounced interaction between the HVDC substation and the a.c. network (9), (10). A.c. networks can be classified in the following catagories according to strength:

strong systems with high ESCR: ESCR > 3.0

systems of low ESCR: 3.0 > ESCR > 2.0

weak systems with very low ESCR: ESCR < 2.0

In the case of high ESCR systems, changes in the active/reactive power from the HVDC substation lead to small or moderate a.c. voltage changes. Therefore the additional transient voltage control at the busbar is not normally required. The reactive power balance between the a.c. network and the HVDC substation can be achieved by switched reactive power elements.

In the case of low and very low ESCR systems, the changes in the a.c. network or in the HVDC transmission power could lead to voltage oscillations and a need for special control strategies. Dynamic reactive power control at the a.c. bus at or near the HVDC substation by some form of power electronic reactive power controller such as a static var compensator (SVC) or static synchronous compensator (STATCOM) may be necessary (12). In earlier times, dynamic reactive power control was achieved with synchronous compensators.

Commutation failure

When a converter bridge is operating as an inverter as represented at the receiving end of the d.c. link in Figure 8, a valve will turn off when its forward current commutates to zero and the voltage across the valve remains negative. The period for which the valve stays negatively biased is the extinction angle γ, the duration beyond which the valve then becomes forward biased. Without a firing pulse, the valve will ideally stay non conductive or blocked, even though it experiences a forward bias.

All d.c. valves require removal of the internal stored charges produced during the forward conducting period (defined by period $\alpha + \mu$ at the inverter in Figure 8) before the valve can successfully establish its ability to block a forward bias. The d.c. inverter therefor requires a minimum period of negative bias or minimum extinction angle γ for forward blocking to be successful. If forward blocking fails and conduction is initiated without a firing pulse, commutation failure occurs. This also results in an immediate failure to maintain current in the succeeding converter arm as the d.c. line current returns to the valve which was previously conducting and which has failed to sustain forward blocking (13).

Commutation failure at a converter bridge operating as an inverter is caused by any of the following reasons:

1. When the d.c. current entering the inverter experiences an increase in magnitude which causes the overlap angle μ to increase, the extinction angle γ is reduced and may reach the point where the valve is unable to maintain forward blocking. Increasing the inductance of the d.c. current path through the converter by means of the d.c. smoothing reactor and commutating reactance reduces the rate of change of d.c. current. This has the greatest effect on commutation failure onset.
2. When the magnitude of the a.c. side voltage on one or more phases reduces or is distorted causing the extinction angle to be inadequate as commutation is attempted.
3. A phase angle shift in the a.c. commutating voltage can cause commutation failure. However, the a.c. voltage magnitude reduction and not the corresponding phase shift is the most dominant factor determining the onset of commutation failures for single phase faults.
4. The value of the pre-disturbance steady state extinction angle γ also effects the sensitivity of the inverter to commutation failure. A value of $\gamma = 18^{O}$ is usual for most inverters. Increasing γ to values of 25^{O}, 30^{O} or higher will reduce the possibility of commutation failure (at the expense of increasing the reactive power demand of the inverter).
5. The value of valve current prior to the commutation failure also effects the conditions at which a commutation failure may occur. A commutation failure may more readily happen if the pre-disturbance current is at full load compared to light load current operation.

In general, the more rigid the a.c. voltage to which the inverter feeds into and with an absence of a.c. system disturbances, the less likelihood there will be commutation failures.

Series capacitors with d.c. converter substations

HVDC transmission systems with long d.c. cables are prone to commutation failure when there is a drop in d.c. voltage U_d at the inverter. The d.c. cable has very large capacitance which will discharge current towards the voltage drop at the inverter. The discharge current is limited by the d.c. voltage derived from the a.c. voltage of the commutating bus as well as the d.c. smoothing reactor and the commutating reactance. If the discharge current of the cable increases too quickly, commutation failure will occur causing complete discharge of the cable. To recharge the cable back to its normal operating voltage will delay recovery.

The converter bridge firing controls can be designed to increase the delay angle α when an increase in d.c. current is detected. This may be effective until the limit of the minimum allowable extinction angle γ is reached.

Another way to limit the cable discharge current is to operate the inverter bridge with a three phase series capacitor located in the a.c. system on either side of the converter transformer. Any discharge current from the d.c. cable will pass into the a.c. system through the normally functioning converter bridge and in doing so, will pass through the series capacitor and add charge to it. As a consequence, the voltage of the series capacitor will increase to oppose the cable discharge and be reflected through the converter bridge as an increase in d.c. voltage U_d. This will act as a back emf and limit the discharge current of the cable, thereby avoiding the commutation failure.

The proposed locations of the series capacitor are shown in Figure 9 in single line diagram form (14), (15). With the capacitor located between the converter transformer and the valve group, it is known as a capacitor commutated converter (CCC). With the capacitor located on the a.c. system side of the converter transformer, it is known as a controlled series capacitor converter (CSCC). Each configuration will improve commutation performance of the inverter but the CSCC requires design features to eliminate ferroresonance between the series capacitor and the converter transformer if it should be instigated.

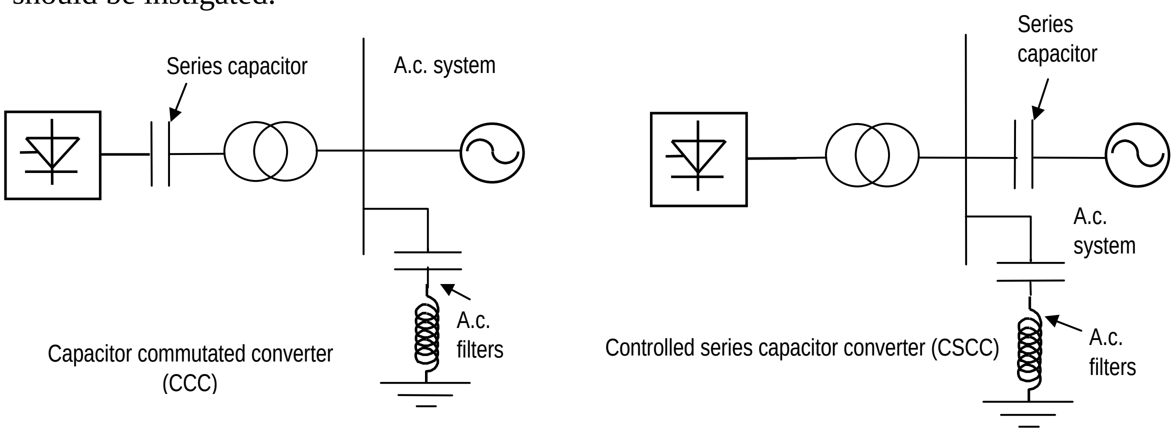

Figure 9. Configurations for applying series capacitors at HVDC substations

CONTROL AND PROTECTION

HVDC transmission systems must transport very large amounts of electric power which can only be accomplished under tightly controlled conditions. D.c. current and voltage is precisely controlled to effect the desired power transfer. It is necessary therefor to continuously and precisely measure system quantities which include at each converter bridge, the d.c. current, its d.c. side voltage, the delay angle α and for an inverter, its extinction angle γ.

Two terminal d.c. transmission systems are the more usual and they have in common a preferred mode of control during normal operation. Under steady state conditions, the inverter is assigned the task of controlling the d.c. voltage. This it may do by maintaining a constant extinction angle γ which causes the d.c. voltage U_d to droop with increasing d.c. current I_d as shown in the minimum constant extinction angle γ characteristic A-B-C-D in Figure 10. The weaker the a.c. system at the inverter, the steeper the droop.

Alternatively, the inverter may normally operate in a d.c. voltage controlling mode which is the constant U_d characteristic B-H-E in Figure 10. This means that the extinction angle γ must increase beyond its minimum setting depicted in Figure 10 as 18^O.

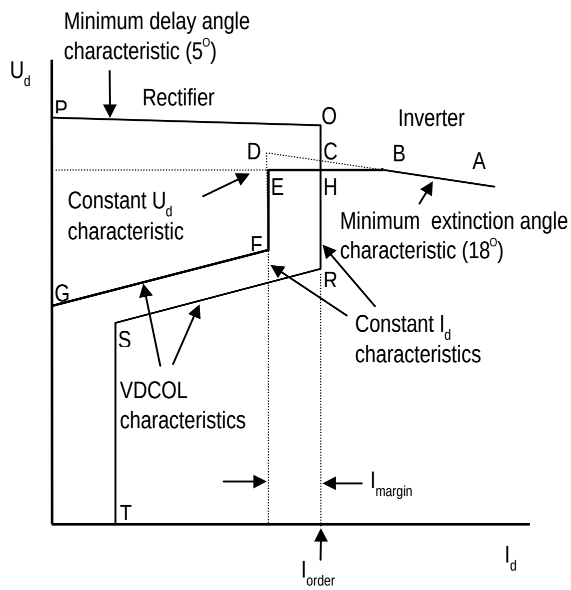

Figure 10. Steady state U_d-I_d characteristics for a two terminal HVDC system.

If the inverter is operating in a minimum constant γ or constant U_d characteristic, than the rectifier must control the d.c. current I_d. This it can do so long as the delay angle α is not at its minimum limit (usually 5^O). The steady state constant current characteristic of the rectifier is shown in Figure 10 as the vertical section Q-C-H-R. Where the rectifier and inverter characteristic intersect, either at points C or H, is the operating point of the HVDC system.

The operating point is reached by action of the on-line tap changers of the converter transformers. The inverter must establish the d.c. voltage U_d by adjusting its on-line tap changer to achieve the desired operating level if it is in constant minimum γ control. If in constant U_d control, the on-line tap changer must adjust its tap to allow the controlled level of U_d be achieved with an extinction angle equal to or slightly larger than its minimum setting of 18^O in this case.

The on-line tap changers on the converter transformers of the rectifier are controlled to adjust their tap settings so that the delay angle α has a working range at a level between approximately 10^O and $15^O$for maintaining the constant current setting I_{order} (see Figure 10). If the inverter is operating in constant d.c. voltage control at the operating point H, and if the d.c. current order I_{order} is increased so that the operating point H moves towards and beyond point B, the inverter mode of control will revert to constant extinction angle γ control and operate on characteristic A-B. D.c. voltage U_d will be less than the desired value, and so the converter transformer on-line tap changer at the inverter will boost its d.c. side voltage until d.c. voltage control is resumed.

Not all HVDC transmission system controls have a constant d.c. voltage control such as is depicted by the horizontal characteristic B-H-E in Figure 10. Instead, the constant extinction angle γ control of characteristic A-B-C-D and the tap changer will provide the d.c. voltage control.

Current margin

The d.c. current order I_{order} is sent to both the rectifier and inverter. It is usual to subtract a small value of current order from the I_{order} sent to the inverter. This is known as the current margin I_{margin} and is depicted in Figure 10. The inverter also has a current controller and it attempts to control the d.c. current I_d to the value I_{order} - I_{margin} but the current controller at the rectifier normally overrides it to maintain the d.c. current at I_{order}. This discrepancy is resolved at the inverter in normal steady state operation as its current controller is not able to keep the d.c. current to the desired value of I_{order} - I_{margin} and is forced out of action. The current control at the inverter becomes active only when the current control at the rectifier ceases when its delay angle α is pegged against its minimum delay angle limit. This is readily observed in the operating characteristics of Figure 10 where the minimum delay angle limit at the rectifier is characteristic P-Q. If for some reason or other such as a low a.c. commutating voltage at the rectifier end, the P-Q characteristic falls below points D or E, the operating point will shift from point H to somewhere on the vertical characteristic D-E-F where it is intersected by the lowered P-Q characteristic. The inverter reverts to current control, controlling the d.c. current I_d to the value I_{order} - I_{margin} and the rectifier is effectively controlling d.c. voltage so long as it is operating at its minimum delay angle characteristic P-Q. The controls can be designed such that the transition from the rectifier controlling current to the inverter controlling current is automatic and smooth.

Voltage dependent current order limit (VDCOL)

During disturbances where the a.c. voltage at the rectifier or inverter is depressed, it will not be helpful to a weak a.c. system if the HVDC transmission system attempts to maintain full load current. A sag in a.c. voltage at either end will result in a lowered d.c. voltage too. The d.c. control characteristics shown in Figure 10 indicates the d.c. current order is reduced if the d.c. voltage is lowered. This can be observed in the rectifier characteristic R-S-T and in the inverter characteristic F-G in Figure 10. The controller which reduces the maximum current order is known as a voltage dependent current order limit or VDCOL (sometimes referred to as a VDCL). The VDCOL control, if invoked by an a.c. system disturbance will keep the d.c. current I_d to the lowered limit during recovery which aids the corresponding recovery of the d.c. system. Only when d.c. voltage U_d has recovered sufficiently will the d.c. current return to its original I_{order} level.

Figure 11 is a schematic diagram of how d.c. transmission system controls are usually implemented.

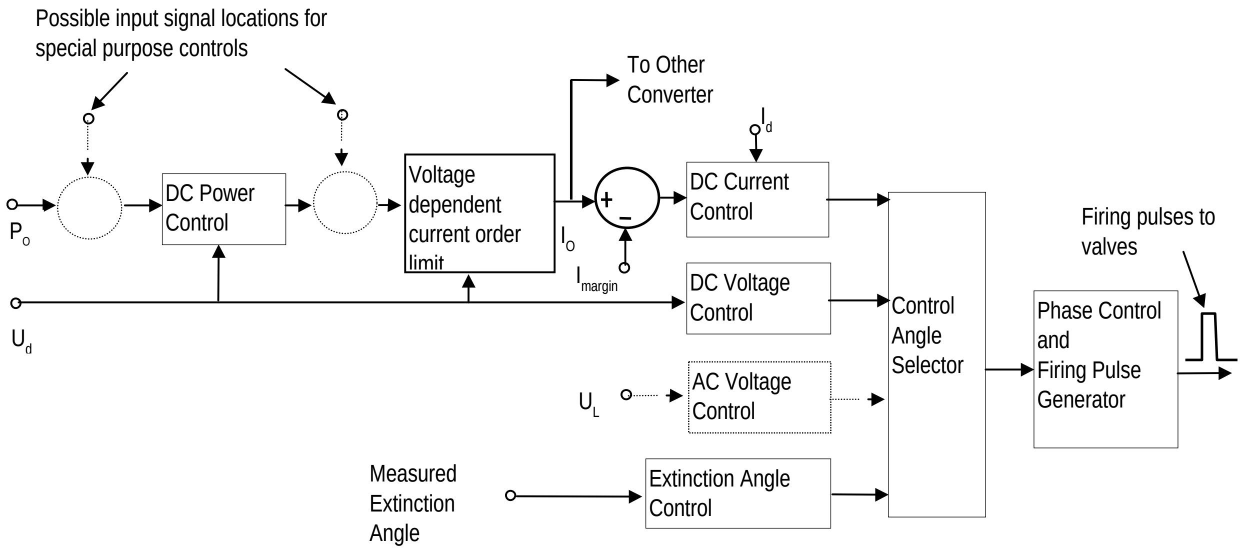

Figure 11. HVDC control system layout

A.c. voltage control

It is desirable to rigidly maintain the a.c. system and commutating bus voltage to a constant value for best operation of the HVDC transmission system. This is more easily achieved when the short circuit ratio is high. With low or very low short circuit ratio systems, difficulties may arise following load changes. With fast load variation, there can be an excess or deficiency of reactive power at the a.c. commutating bus which results in over and undervoltages respectively. When the a.c. system is weak, the changes in converter a.c. bus voltage following a disturbance may be beyond permissible limits. In such cases, an a.c. voltage controller is required for the following reasons:

1. To limit dynamic and transient overvoltage to within permissible limits defined by substation equipment specifications and standards.
2. To prevent a.c. voltage flicker and commutation failure due to a.c. voltage fluctuations when load and filter switching occurs.
3. To enhance HVDC transmission system recovery following severe a.c. system disturbances.
4. To avoid control system instability, particularly when operating in the extinction angle control mode at the inverter.

The synchronous compensator has been the preferred means of a.c. voltage control as it increases the short circuit ratio and serves as a variable reactive power source. Its disadvantages include high losses and maintenance which add to its overall cost. Additional a.c. voltage controllers are available and include:

1. Static compensators which utilize thyristors to control current through inductors and switch in or out various levels of capacitors. By this means, fast control of reactive power is possible to maintain a.c. voltage within desired limits. The main disadvantage is that it does not add to the short circuit ratio.
2. Converter control through delay angle control is possible to regulate the reactive power demand of the converter bridges. This requires that the measured a.c. voltage be used as a feedback signal in the d.c. controls, and delay angle α is transiently modulated to regulate the a.c. commutating bus voltage. This form of control is limited in its effectiveness, particularly when there is little or no d.c. current in the converter when voltage control is required.
3. Use of specially cooled metal oxide varistors together with fast mechanical switching of shunt reactors, capacitors and filters. The metal oxide varistors will protect the HVDC substation equipment against the transient overvoltages, and the switchings of reactive power components will achieve the reactive power balance. Its disadvantage is that voltage control is not continuous, reactive power control is delayed by the slowness of mechanical switching, and short circuit ratio is not increased.
4. Saturated reactors have been applied to limit overvoltages and achieve reactive power balance. Shunt capacitors and filters are required to maintain the reactors in saturation. A.c. voltage control is achieved without controls on a droop characteristic. Short circuit ratio is not increased.
5. Series capacitors in the form of CCC or CSCC can increase the short circuit ratio and improve the regulation of a.c. commutating bus voltage.
6. The static compensator or STATCOM makes use of gate turn-off thyristors in the configuration of the voltage source converter bridge. This is the fastest responding voltage controller available and may offer limited capability for increased short circuit ratio.

Since each a.c. system with its HVDC application is unique, the voltage control method applied is subject to study and design.

Special purpose controls

There are a number of special purpose controllers which can be added to HVDC controls to take advantage of the fast response of a d.c. link and help the performance of the a.c. system. These include:

A.c. system damping controls. An a.c. system is subject to power swings due to electromechanical oscillations. A controller can be added to modulate the d.c. power order or d.c. current order to add damping. The frequency or voltage phase angle of the a.c. system is measured at one or both ends of the d.c. link, and the controller is designed to adjust the power of the d.c. link accordingly.

A.c. system frequency control. A slow responding controller can also adjust the power of the d.c. link to help regulate power system frequency. If the rectifier and inverter are in asynchronous power systems, the d.c. controller can draw power from one system to the other to assist in frequency stabilization of each.

Step change power adjustment. A non-continuous power adjustment can be implemented to take advantage of the ability of a HVDC transmission system to rapidly reduce or increase power. If a.c. system protection determines that a generator or a.c. transmission line is to be tripped, a signal can be sent to the d.c. controls to change its power or current order by an amount which will compensate the loss. This feature is useful in helping maintain a.c. system stability and to ease the shock of a disturbance over a wider area.

A.c. undervoltage compensation. Some portions of an electric power system are prone to a.c. voltage collapse. If a HVDC transmission system is in such an area, a control can be implemented which on detecting the a.c. voltage drop and the rate at which it is dropping, a fast power or current order reduction of the d.c. link can be affected. The reduction in power and reactive power can remove the undervoltage stress on the a.c. system and restore its voltage to normal.

Subsynchronous oscillation damping. A steam turbine and electric generator can have mechanical subsynchronous oscillation modes between the various turbine stages and the generator. If such a generator feeds into the rectifier of a d.c. link, supplementary control may be required on the d.c. link to ensure the subsynchronous oscillation modes of concern are positively damped to limit torsional stresses on the turbine shaft.

AREAS FOR DEVELOPMENT IN HVDC CONVERTERS

The thyristor as the key component of a converter bridge continues to be developed so that its voltage and current rating is increasing. Gate-turn-off thyristors (GTOs) and insulated gate bipole transistors (IGBTs) are required for the voltage source converter (VSC) converter bridge configuration. It is the VSC converter bridge which is being applied in new developments (12). Its special properties include the ability to independently control real and reactive power at the connection bus to the a.c. system. Reactive power can be either capacitive or inductive and can be controlled to quickly change from one to the other.

A voltage source converter as in inverter does not require an active a.c. voltage source to commutate into as does the conventional line commutated converter. The VSC inverter can generate an a.c. three phase voltage and supply electricity to a load as the only source of power. It does require harmonic filtering, harmonic cancellation or pulse width modulation to provide an acceptable a.c. voltage waveshape.

Two applications are now available for the voltage source converter. The first is for low voltage d.c. converters applied to d.c. distribution systems. The first application of a d.c.

distribution system in 1997 was developed in Sweden and known as “HVDC Light.” Other applications for a d.c. distribution system may be (1) in a d.c. feeder to remote or isolated loads, particularly if underwater or underground cable is necessary and (2) for a collector system of a wind farm where cable delivery and optimum and individual speed control of the wind turbines is desired for peak turbine efficiency.

The second immediate application for the VSC converter bridges is in back-to-back configuration. The back-to-back VSC link is the ultimate transmission and power flow controller. It can control and reverse power flow easily, and control reactive power independently on each side. With a suitable control system, it can control power to enhance and preserve a.c. system synchronism, and act as a rapid phase angle power flow regulator with 360 degree range of control.

There is considerable flexibility in the configuration of the VSC converter bridges. Many two level converter bridges can be assembled with appropriate harmonic cancellation properties in order to generate acceptable a.c. system voltage waveshapes. Another option is to use multilevel converter bridges to provide harmonic cancellation. Additionally, both two level and multilevel converter bridges can utilize pulse width modulation to eliminate low order harmonics. With pulse width modulation, high pass filters may still be required since PWM adds to the higher order harmonics.

As VSC converter bridge technology develops for higher d.c. voltage applications, it will be possible to eliminate converter transformers. This is possible with the low voltage applications in use today. It is expected the exciting developments in power electronics will continue to provide exciting new configurations and applications for HVDC converters.

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