The ABCs of HVDC Transmission Technologies

An Overview of High Voltage Direct Current Systems and Applications

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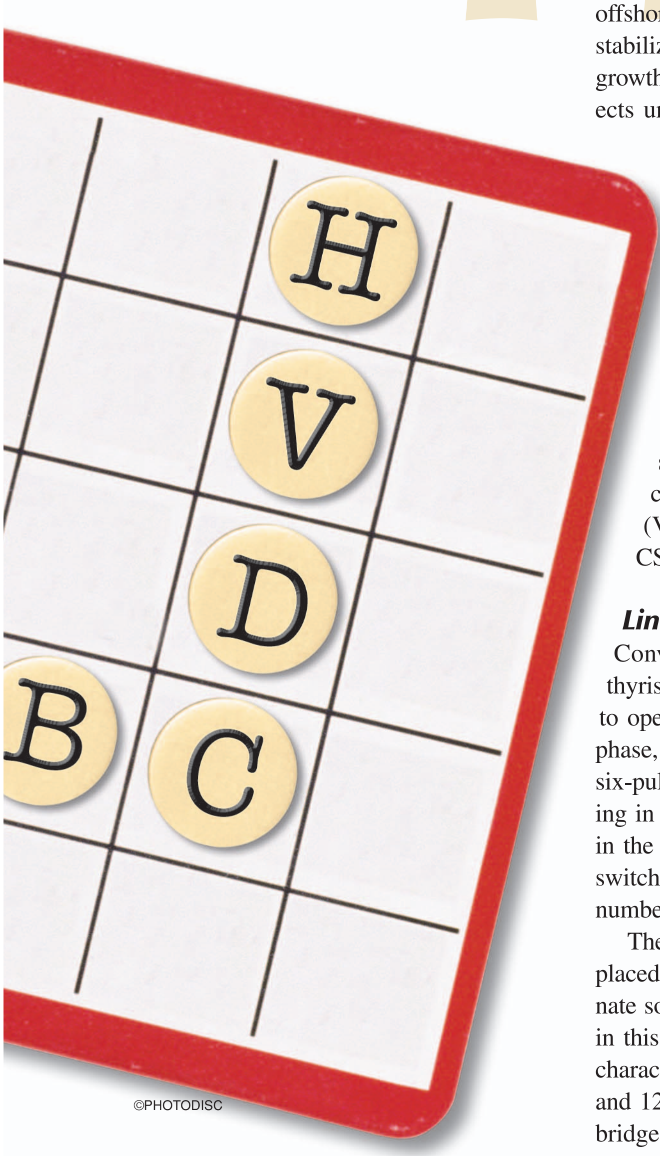
HIGH VOLTAGE DIRECT CURRENT (HVDC) TECHNOLOGY HAS characteristics that make it especially attractive for certain transmission applications. HVDC transmission is widely recognized as being advantageous for long-distance bulk-power delivery, asynchronous interconnections, and long submarine cable crossings. The number of HVDC projects committed or under consideration globally has increased in recent years reflecting a renewed interest in this mature technology. New converter designs have broadened the potential range of HVDC transmission to include applications for underground, offshore, economic replacement of reliability-must-run generation, and voltage stabilization. This broader range of applications has contributed to the recent growth of HVDC transmission. There are approximately ten new HVDC projects under construction or active consideration in North America along with many more projects underway globally. Figure 1 shows the Danish terminal for Skagerrak's pole 3, which is rated 440 MW. Figure 2 shows the ±500-kV HVDC transmission line for the 2,000 MW Intermountain Power Project between Utah and California. This article discusses HVDC technologies, application areas where HVDC is favorable compared to ac transmission, system configuration, station design, and operating principles.



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Core HVDC Technologies

Two basic converter technologies are used in modern HVDC transmission systems. These are conventional line-commutated current source converters (CSCs) and self-commutated voltage source converters (VSCs). Figure 3 shows a conventional HVDC converter station with CSCs while Figure 4 shows a HVDC converter station with VSCs.

Line-Commutated Current Source Converter

Conventional HVDC transmission employs line-commutated CSCs with thyristor valves. Such converters require a synchronous voltage source in order to operate. The basic building block used for HVDC conversion is the three-phase, full-wave bridge referred to as a six-pulse or Graetz bridge. The term six-pulse is due to six commutations or switching operations per period resulting in a characteristic harmonic ripple of six times the fundamental frequency in the dc output voltage. Each six-pulse bridge is comprised of six controlled switching elements or thyristor valves. Each valve is comprised of a suitable number of series-connected thyristors to achieve the desired dc voltage rating.

The dc terminals of two six-pulse bridges with ac voltage sources phase displaced by 30° can be connected in series to increase the dc voltage and eliminate some of the characteristic ac current and dc voltage harmonics. Operation in this manner is referred to as 12-pulse operation. In 12-pulse operation, the characteristic ac current and dc voltage harmonics have frequencies of $12n \pm 1$ and $12n$, respectively. The 30° phase displacement is achieved by feeding one bridge through a transformer with a wye-connected secondary and the other bridge through a transformer with a delta-connected secondary. Most modern HVDC transmission schemes utilize 12-pulse converters to reduce the harmonic filtering requirements required for six-pulse operation; e.g., fifth and seventh on the ac side and sixth on the dc side. This is because, although these harmonic currents still flow through the valves and the transformer windings, they are

180° out of phase and cancel out on the primary side of the converter transformer. Figure 5 shows the thyristor valve arrangement for a 12-pulse converter with three quadruple valves, one for each phase. Each thyristor valve is built up with series-connected thyristor modules.

Line-commutated converters require a relatively strong synchronous voltage source in order to commutate. Commutation is the transfer of current from one phase to another in a synchronized firing sequence of the thyristor valves. The three-phase symmetrical short circuit capacity available from the network at the converter connection point should be at least twice the converter rating for converter operation. Line-commutated CSCs can only operate with the ac current lagging the voltage, so the conversion process demands reactive power. Reactive power is supplied from the ac filters, which look capacitive at the fundamental frequency, shunt banks, or series capacitors that are an integral part of the converter station. Any surplus or deficit in reactive power from these local sources must be accommodated by the ac system. This difference in reactive power needs to be kept within a given band to keep the ac voltage within the desired tolerance. The weaker the ac system or the further the converter is away from generation, the tighter the reactive power exchange must be to stay within the desired voltage tolerance. Figure 6 illustrates the reactive power demand, reactive power compensation, and reactive power exchange with the ac network as a function of dc load current.

figure 1. HVDC converter station with ac filters in the foreground and valve hall in the background.

figure 2. A ±500-kV HVDC transmission line.

Converters with series capacitors connected between the valves and the transformers were introduced in the late 1990s for weak-system, back-to-back applications. These converters are referred to as capacitor-commutated converters (CCCs). The series capacitor provides some of the converter reactive power compensation requirements automatically with load current and provides part of the commutation voltage, improving voltage stability. The overvoltage protection of the series capacitors is simple since the capacitor is not exposed to line faults, and the fault current for internal converter faults is limited by the impedance of the converter transformers. The CCC configuration allows higher power ratings in areas were the ac network is close to its voltage stability limit. The asynchronous Garabi interconnection between Brazil and Argentina consists of 4 × 550 MW parallel CCC links. The Rapid City Tie between the Eastern and Western interconnected systems consists of 2 × 100 MW parallel CCC links (Figure 7). Both installations use a modular design with converter valves located within prefabricated electrical enclosures rather than a conventional valve hall.

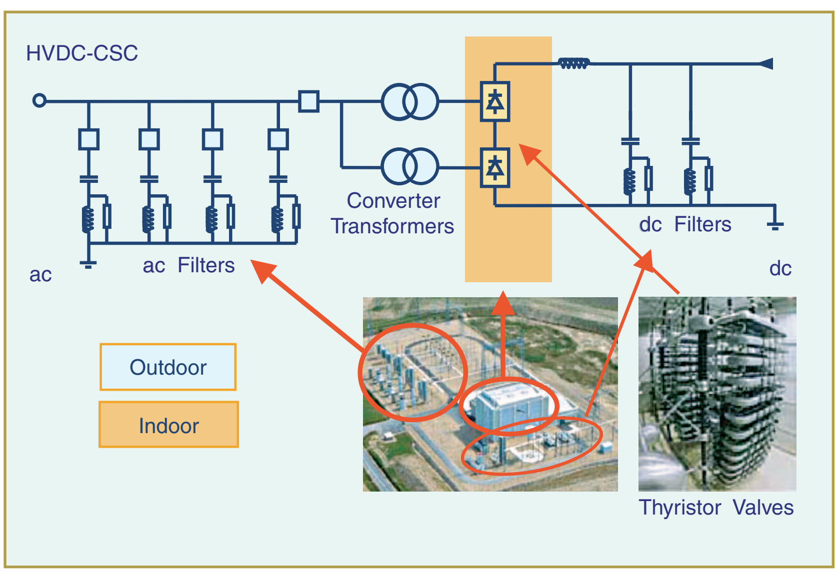

figure 3. Conventional HVDC with current source converters.

Self-Commutated Voltage Source Converter

HVDC transmission using VSCs with pulse-width modulation (PWM), commercially known as HVDC Light, was introduced in the late 1990s. Since then the progression to higher voltage and power ratings for these converters has roughly paralleled that for thyristor valve converters in the 1970s. These VSC-based systems are self-commutated with insulated-gate bipolar transistor (IGBT) valves and solid-dielectric extruded HVDC cables. Figure 8 illustrates solid-state converter development for the two different types of converter technologies using thyristor valves and IGBT valves.

HVDC transmission with VSCs can be beneficial to overall system performance. VSC technology can rapidly control both active and reactive power independently of one another. Reactive power can also be controlled at each terminal independent of the dc transmission voltage level. This control capability gives total flexibility to place converters anywhere in the ac network since there is no restriction on minimum network short-circuit capacity. Self-commutation with VSC even permits black start; i.e., the converter can be used to synthesize a balanced set of three phase voltages like a virtual synchronous generator. The dynamic support of the ac voltage at each converter terminal improves the voltage stability and can increase the transfer capability of the sending- and receiving-end ac systems, thereby leveraging the transfer capability of the dc link. Figure 9 shows the IGBT converter valve arrangement for a VSC station. Figure 10 shows the active and reactive power operating range for a converter station with a VSC. Unlike conventional HVDC transmission, the converters themselves have no reactive power demand and can actually control their reactive power to regulate ac system voltage just like a generator.

HVDC Applications

HVDC transmission applications can be broken down into different basic categories. Although the rationale for selection of HVDC is often economic, there may be other reasons for its selection. HVDC may be the only feasible way to interconnect two asynchronous networks, reduce fault currents, utilize long underground cable circuits, bypass network congestion, share utility rights-of-way without degradation of reliability, and to mitigate environmental concerns. In all of these applications, HVDC nicely complements the ac transmission system.

Long-Distance Bulk Power Transmission

HVDC transmission systems often provide a more economical alternative to ac transmission for long-distance bulk-power delivery from remote resources such as hydroelectric developments, mine-mouth power plants, or large-scale wind farms. Higher power transfers are possible over longer distances using fewer lines with HVDC transmission than with ac transmission. Typical HVDC lines utilize a bipolar configuration with two independent poles, one at a positive voltage and the other at a negative voltage with respect to ground. Bipolar HVDC lines are comparable to a double circuit ac line since they can operate at half power with one pole out of service but require only one-third the number of insulated sets of conductors as a double circuit ac line. Automatic restarts from temporary dc line fault clearing sequences are routine even for generator outlet transmission. No synchro-checking is required as for automatic reclosures following ac line faults since the dc restarts do not expose turbine generator units to high risk of transient torque amplification from closing into faults or across high phase angles. The controllability of HVDC links offer firm transmission capacity

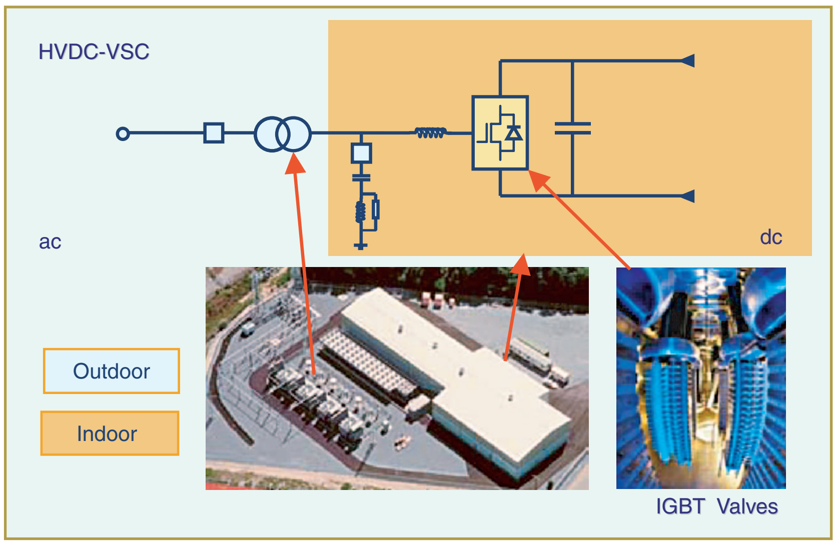

figure 4. HVDC with voltage source converters.

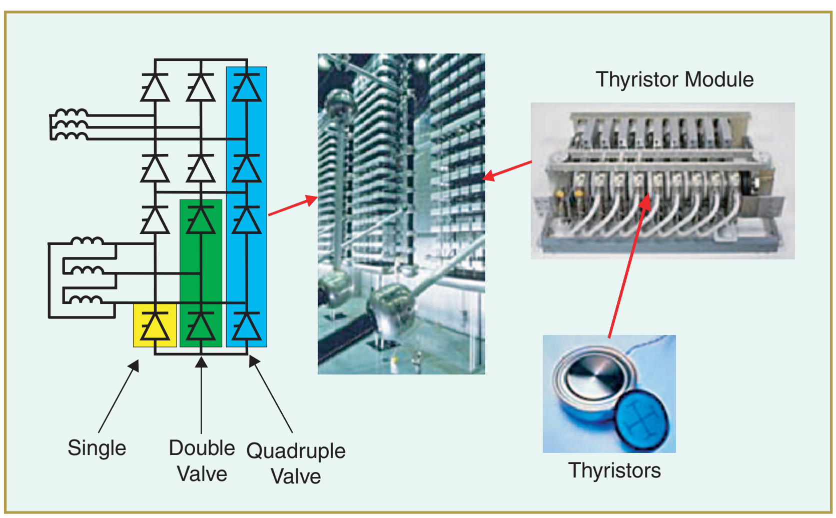

figure 5. Thyristor valve arrangement for a 12-pulse converter with three quadruple valves, one for each phase.

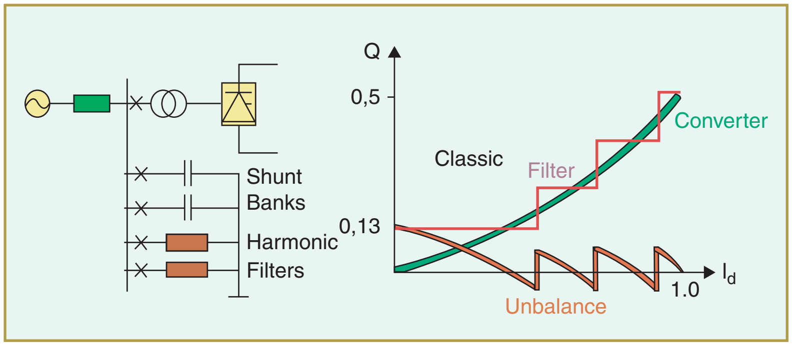

figure 6. Reactive power compensation for conventional HVDC converter station.

Furthermore, the long-distance ac lines usually require intermediate switching stations and reactive power compensation. This can increase the substation costs for ac transmission to the point where it is comparable to that for HVDC transmission.

For example, the generator outlet transmission alternative for the ±250-kV, 500-MW Square Butte Project was two 345-kV series-compensated ac transmission lines. The 12,600-MW Itaipu project has half its power delivered on three 800-kV series-compensated ac lines (three circuits) and the other half delivered on two ±600-kV bipolar HVDC lines (four circuits). Similarly, the ±500-kV, 1,600-MW Intermountain Power Project (IPP) ac alternative comprised two 500-kV ac lines. The IPP takes advantage of the double-circuit nature of the bipolar line and includes a 100% short-term and 50% continuous monopolar overload. The first 6,000-MW stage of the transmission for the Three Gorges Project in China would have required 5 × 500-kV ac lines as opposed to 2 × ±500-kV, 3,000-MW bipolar HVDC lines.

without limitation due to network congestion or loop flow on parallel paths. Controllability allows the HVDC to "leap-frog" multiple "choke-points" or bypass sequential path limits in the ac network. Therefore, the utilization of HVDC links is usually higher than that for extra high voltage ac transmission, lowering the transmission cost per MWh. This controllability can also be very beneficial for the parallel transmission since, by eliminating loop flow, it frees up this transmission capacity for its intended purpose of serving intermediate load and providing an outlet for local generation.

Whenever long-distance transmission is discussed, the concept of "break-even distance" frequently arises. This is where the savings in line costs offset the higher converter station costs. A bipolar HVDC line uses only two insulated sets of conductors rather than three. This results in narrower rights-of-way, smaller transmission towers, and lower line losses than with ac lines of comparable capacity. A rough approximation of the savings in line construction is 30%.

Although break-even distance is influenced by the costs of right-of-way and line construction with a typical value of 500 km, the concept itself is misleading because in many cases more ac lines are needed to deliver the same power over the same distance due to system stability limitations.

Table 1 contains an economic comparison of capital costs and losses for different ac and dc transmission alternatives for a hypothetical 750-mile, 3,000-MW transmission system. The long transmission distance requires intermediate substations or switching stations and shunt reactors for the ac alternatives. The long distance and heavy power transfer, nearly twice the surge-impedance loading on the 500-kV ac alternatives, require a high level of series compensation. These ac station costs are included in the cost estimates for the ac alternatives.

It is interesting to compare the economics for transmission to that of transporting an equivalent amount of energy using other transport methods, in this case using rail transportation of sub-bituminous western coal with a heat content of 8,500 Btu/lb to support a 3,000-MW base load power plant with heat rate of 8,500 Btu/kWh operating at an 85%

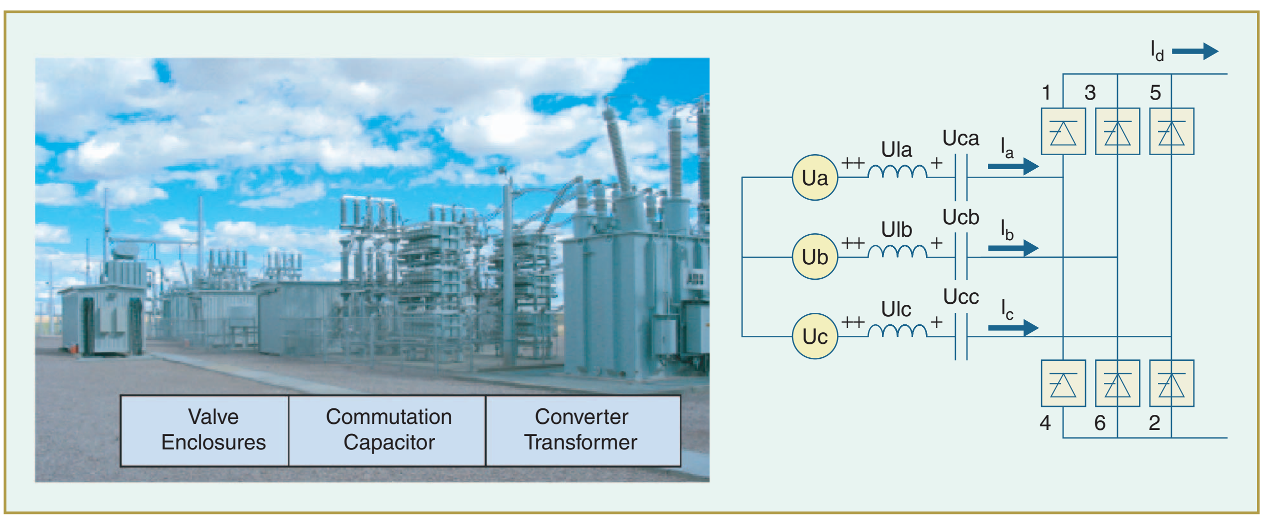

figure 7. Asynchronous back-to-back tie with capacitor-commutated converter near Rapid City, South Dakota.

load factor. The rail route is assumed to be longer than the more direct transmission route; i.e., 900 miles. Each unit train is comprised of 100 cars each carrying 100 tons of coal. The plant requires three unit trains per day. The annual coal transportation costs are about US$560 million per year at an assumed rate of US$50/ton. This works out to be US$186 kW/year and US$25 per MWh. The annual diesel fuel consumed in the process is in excess of 20 million gallons at 500 net ton-miles per gallon. The rail transportation costs are subject to escalation and congestion whereas the transmission costs are fixed. Furthermore, transmission is the only way to deliver remote renewable resources.

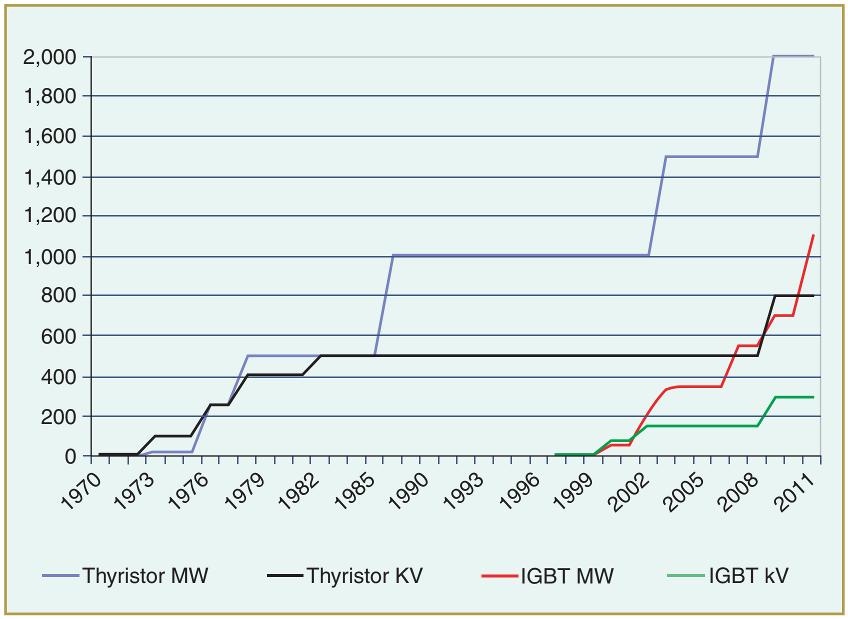

figure 8. Solid-state converter development.

Underground and Submarine Cable Transmission

Unlike the case for ac cables, there is no physical restriction limiting the distance or power level for HVDC underground or submarine cables. Underground cables can be used on shared rights-of-way with other utilities without impacting reliability concerns over use of common corridors. For underground or submarine cable systems there is considerable savings in installed cable costs and cost of losses when using HVDC transmission. Depending on the power level to be transmitted, these savings can offset the higher converter station costs at distances of 40 km or more. Furthermore, there is a drop-off in cable capacity with ac transmission over distance due to its reactive component of charging current since cables have higher capacitances and lower inductances than ac overhead lines. Although this can be compensated by intermediate shunt compensation for underground cables at increased expense, it is not practical to do so for submarine cables.

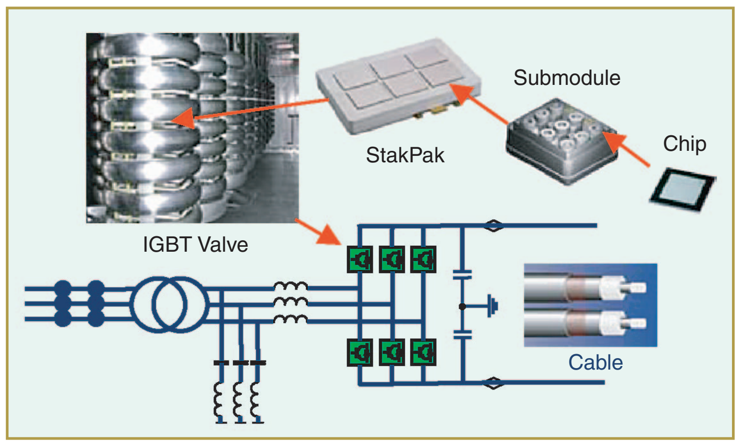

figure 9. HVDC IGBT valve converter arrangement.

For a given cable conductor area, the line losses with HVDC cables can be about half those of ac cables. This is due to ac cables requiring more conductors (three phases), carrying the reactive component of current, skin-effect, and induced currents in the cable sheath and armor.

With a cable system, the need to balance unequal loadings or the risk of postcontingency overloads often necessitates use of a series-connected reactors or phase shifting transformers. These potential problems do not exist with a controlled HVDC cable system.

Extruded HVDC cables with prefabricated joints used with VSC-based transmission are lighter, more flexible, and easier to splice than the mass-impregnated oil-paper cables (MINDs) used for conventional HVDC transmission, thus making them more conducive for land cable applications where transport limitations and extra splicing costs can drive up installation costs. The lower-cost cable installations made possible by the extruded HVDC cables and prefabricated joints makes long-distance underground transmission economically feasible for use in areas with rights-of-way constraints or subject to permitting difficulties or delays with overhead lines.

Asynchronous Ties

With HVDC transmission systems, interconnections can be made between asynchronous networks for more economic or reliable system operation. The asynchronous interconnection allows interconnections of mutual benefit while providing a buffer between the two systems. Often these interconnections use back-to-back converters with no transmission line.

Asynchronous HVDC links act as an effective "firewall" against propagation of cascading outages in one network from passing to another network.

Many asynchronous interconnections exist in North America between the Eastern and Western interconnected systems, between the Electric Reliability Council of Texas (ERCOT) and its neighbors, [e.g., Mexico and the Southwest Power Pool (SPP)], and between Quebec and its neighbors (e.g., New England and the Maritimes). The August 2003 Northeast blackout provides an example of the "firewall" against cascading outages provided by asynchronous interconnections. As the outage expanded and propagated around the lower Great Lakes and through Ontario and New York, it stopped at the asynchronous interface with Quebec. Quebec was unaffected; the weak ac interconnections between New York and New England tripped, but the HVDC links from Quebec continued to deliver power to New England.

Regulators try to eliminate "seams" in electrical networks because of their potential restriction on power markets. Electrical "seams," however, serve as natural points of separation by acting as "shear-pins," thereby reducing the impact of large-scale system disturbances. Asynchronous ties can eliminate market "seams" while retaining natural points of separation.

Interconnections between asynchronous networks are often at the periphery of the respective systems where the networks tend to be weak relative to the desired power transfer. Higher power transfers can be achieved with improved voltage stability in weak system applications using CCCs. The dynamic voltage support and improved voltage stability offered by VSC-based converters permits even higher power transfers without as much need for ac system reinforcement. VSCs do not suffer commutation failures, allowing fast recoveries from nearby ac faults. Economic power schedules that reverse power direction can be made without any restrictions since there is no minimum power or current restrictions.

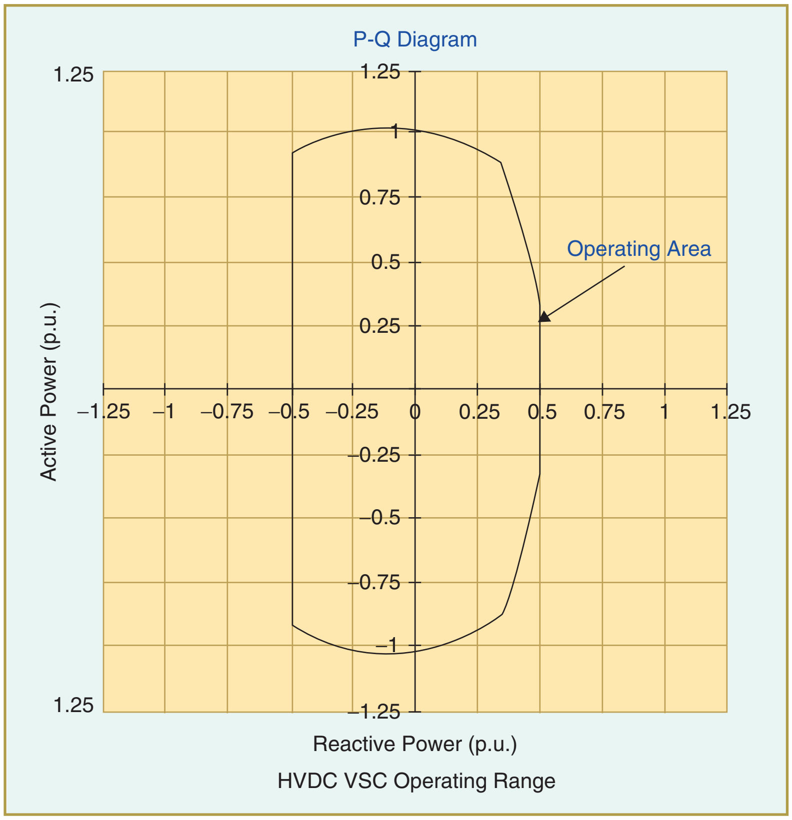

figure 10. Operating range for voltage source converter HVDC transmission.

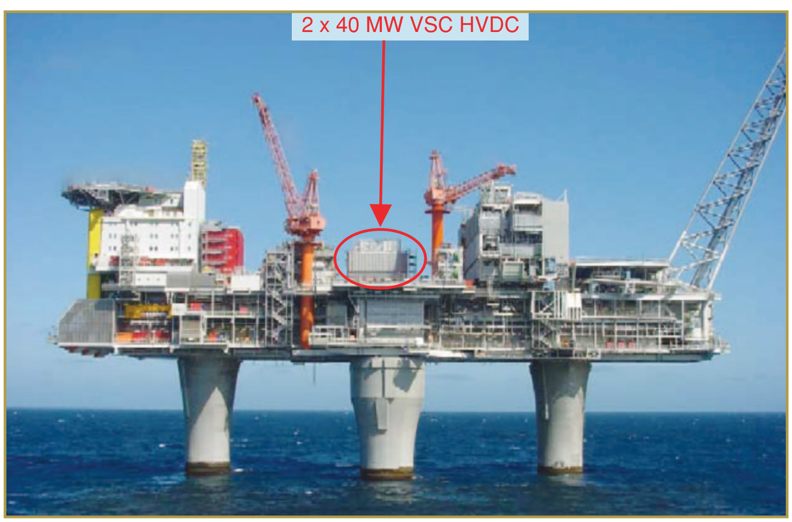

figure 11. VSC power supply to Troll A production platform.

Offshore Transmission

Self-commutation, dynamic voltage control, and black-start capability allow compact VSC HVDC transmission to serve isolated loads on islands or offshore production platforms over long-distance submarine cables. This capability can eliminate the need for running expensive local generation or provide an outlet for offshore generation such as that from wind. The VSCs can operate at variable frequency to more efficiently drive large compressor or pumping loads using high-voltage motors. Figure 11 shows the Troll A production platform in the North Sea where power to drive compressors is delivered from shore to reduce the higher carbon emissions and higher O&M costs associated with less efficient platform-based generation.

Large remote wind generation arrays require a collector system, reactive power support, and outlet transmission. Transmission for wind generation must often traverse scenic or environmentally sensitive areas or bodies of water. Many of the better wind sites with higher capacity factors are located offshore. VSC-based HVDC transmission allows efficient use of long-distance land or submarine cables and provides reactive support to the wind generation complex. Figure 12 shows a design for an offshore converter station designed to transmit power from offshore wind generation.

Multiterminal Systems

Most HVDC systems are for point-to-point transmission with a converter station at each end. The use of intermediate taps is rare. Conventional HVDC transmission uses voltage polarity reversal to reverse the power direction. Polarity reversal requires no special switching arrangement for a two-terminal system where both terminals reverse polarity by control action with no switching to reverse power direction. Special dc-side switching arrangements are needed for polarity reversal in a multiterminal system, however, where it may be desired to reverse the power direction at a tap while maintaining the same power direction on the remaining terminals. For a bipolar system this can be done by connecting the converter to the opposite pole. VSC HVDC transmission, however, reverses power through reversal of the current direction rather than voltage polarity. Thus, power can be reversed at an intermediate tap independently of the main power flow direction without switching to reverse voltage polarity.

Power Delivery to Large Urban Areas

Power supply for large cities depends on local generation and power import capability. Local

table 1. Comparative costs of HVDC and EHV AC transmission alternatives.

Alternative	DC Alternatives + 500 Kv Bipole	2 x + 500 kV 2 bipoles	+ 600 kV Bipole	+800 kV Bipole	AC Alternatives 500 kV 2 Single Ckt	500 kV Double Ckt	765 kV 2 Singl Ckt	Hybrid AC/DC Alternative + 500 kV Bipole	500 kV Single Ckt	Total AC + DC
Capital Cost										
Rated Power (MW)	3000	4000	3000	3000	3000	3000	3000	3000	1500	4500
Station costs including reactive compensation (M$)	$420	$680	$465	$510	$542	$542	$630	$420	$302	$722
Transmission line cost (M$/mile)	$1.60	$1.60	$1.80	$1.95	$2.00	$3.20	$2.80	$1.60	$2.00	
Distance in miles	750	1,500	750	750	1,500	750	1,500	750	750	1,500
Transmission Line Cost (M$)	$1,200	$2,400	$1,350	$1,463	$3,000	$2,400	$4,200	$1,200	$1,500	$2,700
Total Cost (M$)	**$1,620**	**$3,080**	**$1,815**	**$1,973**	**$3,542**	**$2,942**	**$4,830**	**$1,620**	**$1,802**	**$3,422**
Annual Payment, 30 years @ 10%	$172	$327	$193	$209	$376	$312	$512	$172	$191	$363
Cost per kW-Yr	$57.28	$81.68	$64.18	$69.75	$125.24	$104.03	$170.77	$57.28	$127.40	$80.66
Cost per MWh @ 85% Utilization Factor	$7.69	$10.97	$8.62	$9.37	$16.82	$13.97	$22.93	$7.69	$17.11	$10.83
Losses @ full load	193	134	148	103	208	208	139	106	48	154
Losses at full load in %	6.44%	3.35%	4.93%	3.43%	6.93%	6.93%	4.62%	5.29%	4.79%	5.12%
Capitalized cost of losses @ $1500 kW (M$)	$246	$171	$188	$131	$265	$265	$177	$135	$61	$196
Parameters:										
Interest rate %	10%									
Capitalized cost of losses $/kW	$1,500									

Note:
AC current assumes 94% pf
Full load converter station losses = 9.75% per station
Total substation losses (transformers, reactors) assumed = 0.5% of rated power

generation is often older and less efficient than newer units located remotely. Often, however, the older, less-efficient units located near the city center must be dispatched out-of-merit because they must be run for voltage support or reliability due to inadequate transmission. Air quality regulations may limit the availability of these units. New transmission into large cities is difficult to site due to right-of-way limitations and land-use constraints.

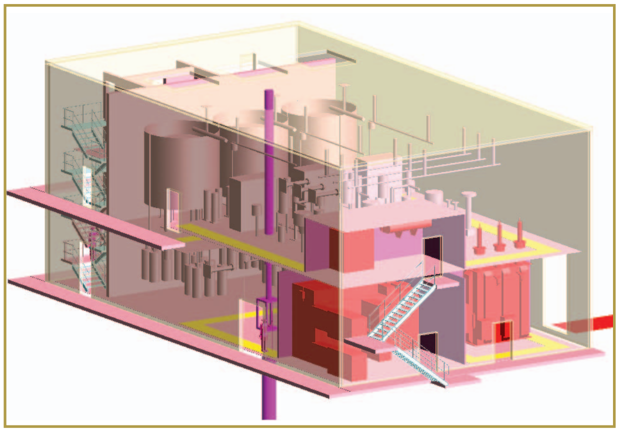

figure 12. VSC converter for offshore wind generation.

Compact VSC-based underground transmission circuits can be placed on existing dual-use rights-of-way to bring in power as well as to provide voltage support, allowing a more economical power supply without compromising reliability. The receiving terminal acts like a virtual generator delivering power and supplying voltage regulation and dynamic reactive power reserve. Stations are compact and housed mainly indoors, making siting in urban areas somewhat easier. Furthermore, the dynamic voltage support offered by the VSC can often increase the capability of the adjacent ac transmission.

System Configurations and Operating Modes

Figure 13 shows the different common system configurations and operating modes used for HVDC transmission. Monopolar systems are the simplest and least expensive systems for moderate power transfers since only two converters and one high-voltage insulated cable or line conductor are required. Such systems have been used with low-voltage electrode lines and sea electrodes to carry the return current in submarine cable crossings.

In some areas conditions are not conducive to monopolar earth or sea return. This could be the case in heavily congested

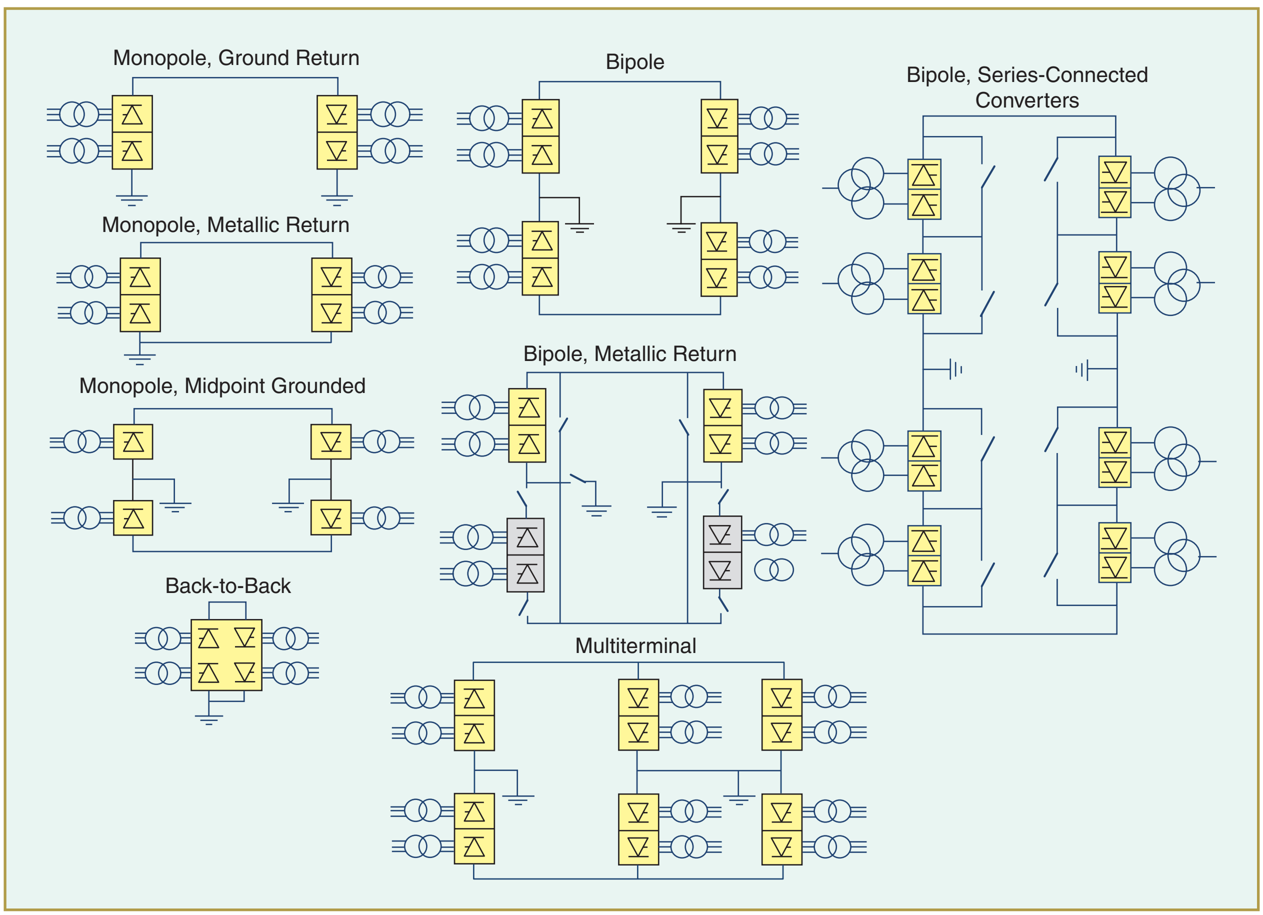

figure 13. HVDC configurations and operating modes.

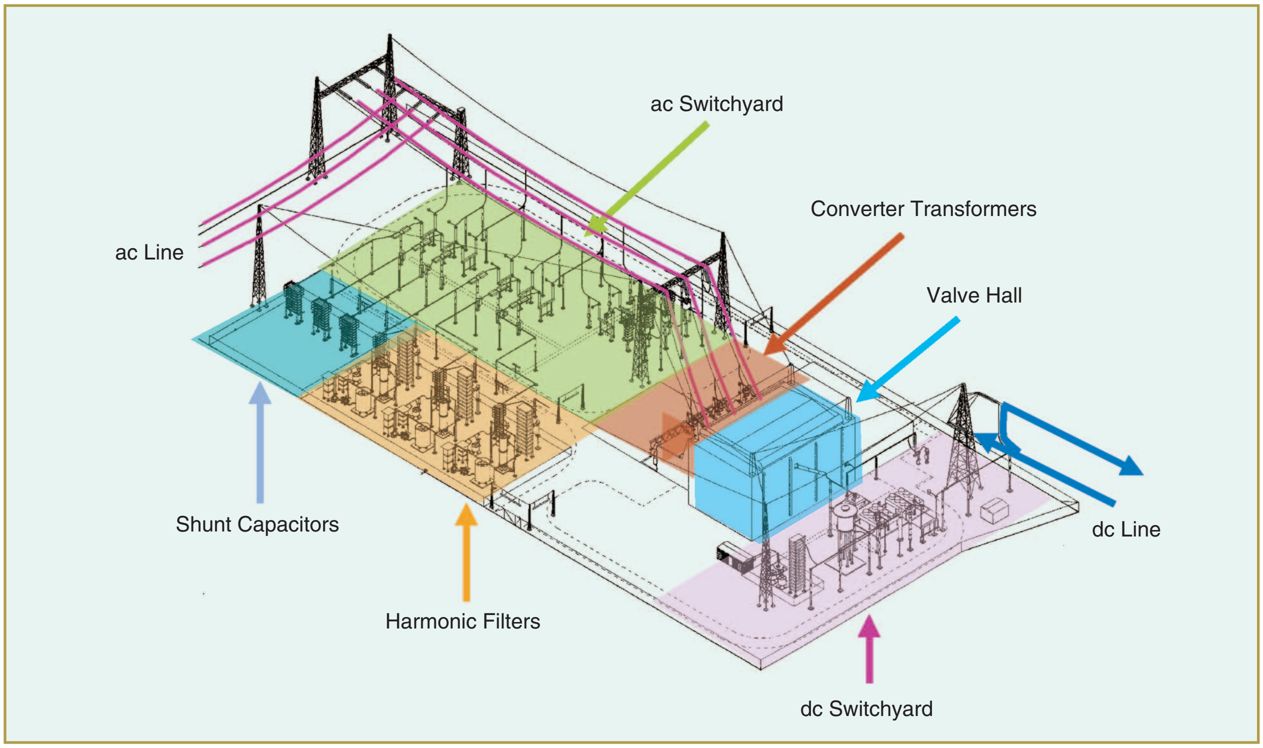

figure 14. Monopolar HVDC converter station.

areas, fresh water cable crossings, or areas with high earth resistivity. In such cases a metallic neutral- or low-voltage cable is used for the return path and the dc circuit uses a simple local ground connection for potential reference only. Back-to-back stations are used for interconnection of asynchronous networks and use ac lines to connect on either side. In such systems power transfer is limited by the relative capacities of the adjacent ac systems at the point of connection.

As an economic alternative to a monopolar system with metallic return, the midpoint of a 12-pulse converter can be connected to earth directly or through an impedance and two half-voltage cables or line conductors can be used. The converter is only operated in 12-pulse mode so there is never any stray earth current.

VSC-based HVDC transmission is usually arranged with a single converter connected pole-to-pole rather than pole-to-ground. The center point of the converter is connected to ground through a high impedance to provide a reference for the dc voltage. Thus, half the converter dc voltage appears across the insulation on each of the two dc cables, one positive the other negative.

The most common configuration for modern overhead HVDC transmission lines is bipolar with a single 12-pulse converter for each pole at each terminal. This gives two independent dc circuits each capable of half capacity. For normal balanced operation there is no earth current. Monopolar earth return operation, often with overload capacity, can be used during outages of the opposite pole.

Earth return operation can be minimized during monopolar outages by using the opposite pole line for metallic return via pole/converter bypass switches at each end. This requires a metallic-return transfer breaker in the ground electrode line at

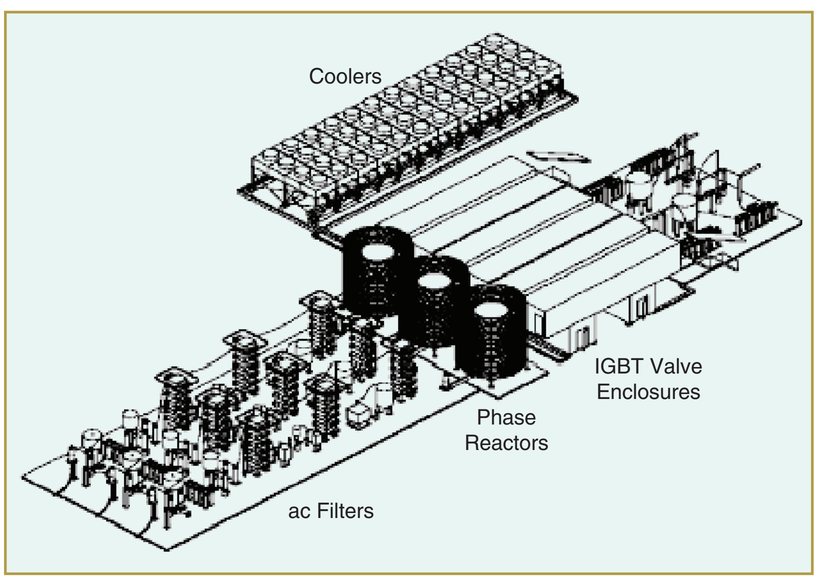

figure 15. VSC HVDC converter station.

one of the dc terminals to commutate the current from the relatively low resistance of the earth into that of the dc line conductor. Metallic return operation capability is provided for most dc transmission systems. This not only is effective during converter outages but also during line insulation failures where the remaining insulation strength is adequate to withstand the low resistive voltage drop in the metallic return path.

For very-high-power HVDC transmission, especially at dc voltages above ±500 kV (i.e., ±600 kV or ±800 kV), series-connected converters can be used to reduce the energy unavailability for individual converter outages or partial line insulation failure. By using two series-connected converters per pole in a bipolar system, only one quarter of the transmission capacity is lost for a converter outage or if the line insulation for the affected pole is degraded to where it can only support half the rated dc line voltage. Operating in this mode also avoids the need to transfer to monopolar metallic return to limit the duration of emergency earth return.

Station Design and Layout

Conventional HVDC

The converter station layout depends on a number of factors such as the dc system configuration (i.e., monopolar, bipolar, or back-to-back), ac filtering, and reactive power compensation requirements. The thyristor valves are air-insulated, water-cooled, and enclosed in a converter building often referred to as a valve hall. For back-to-back ties with their characteristically low dc voltage, thyristor valves can be housed in prefabricated electrical enclosures, in which case a valve hall is not required.

To obtain a more compact station design and reduce the number of insulated high-voltage wall bushings, converter transformers are often placed adjacent to the valve hall with valve winding bushings protruding through the building walls for connection to the valves. Double or quadruple valve structures housing valve modules are used within the valve hall. Valve arresters are located immediately adjacent to the valves. Indoor motor-operated grounding switches are used for personnel safety during maintenance. Closed-loop valve cooling systems are used to circulate the cooling medium, deionized water or water-glycol mix, through the indoor thyristor valves with heat transfer to dry coolers located outdoors. Area requirements for conventional HVDC converter stations are influenced by the ac system voltage and reactive power compensation requirements where each individual bank rating may be limited by such system requirements as reactive power exchange and maximum voltage step on bank switching. The ac yard with filters and shunt compensation can take up as much as three quarters of the total area requirements of the converter station. Figure 14 shows a typical arrangement for an HVDC converter station.

VSC-Based HVDC

The transmission circuit consists of a bipolar two-wire HVDC system with converters connected pole-to-pole. DC capacitors are used to provide a stiff dc voltage source. The dc capacitors are grounded at their electrical center point to establish the earth reference potential for the transmission system. There is no earth return operation. The converters are coupled to the ac system through ac phase reactors and power transformers. Unlike most conventional HVDC systems, harmonic filters are located between the phase reactors and power transformers. Therefore, the transformers are exposed to no dc voltage stresses or harmonic loading, allowing use of ordinary power transformers. Figure 15 shows the station arrangement for a ±150-kV, 350 to 550-MW VSC converter station.

The IGBT valves used in VSC converters are comprised of series-connected IGBT positions. The IGBT is a hybrid device exhibiting the low forward drop of a bipolar transistor as a

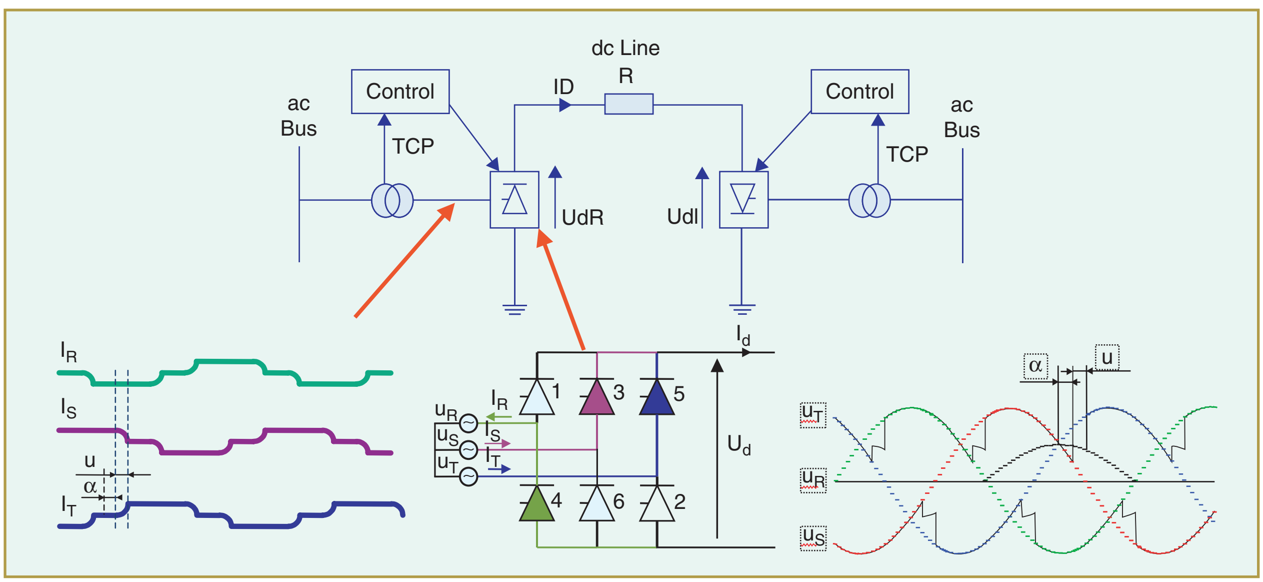

figure 16. Conventional HVDC control.

conducting device. Instead of the regular current-controlled base, the IGBT has a voltage-controlled capacitive gate, as in the MOSFET device.

A complete IGBT position consists of an IGBT, an antiparallel diode, a gate unit, a voltage divider, and a water-cooled heat sink. Each gate unit includes gate-driving circuits, surveillance circuits, and optical interface. The gate-driving electronics control the gate voltage and current at turn-on and turn-off to achieve optimal turn-on and turn-off processes of the IGBTs.

To be able to switch voltages higher than the rated voltage of one IGBT, many positions are connected in series in each valve similar to thyristors in conventional HVDC valves. All IGBTs must turn on and off at the same moment to achieve an evenly distributed voltage across the valve. Higher currents are handled by paralleling IGBT components or press packs.

The primary objective of the valve dc-side capacitor is to provide a stiff voltage source and a low-inductance path for the turn-off switching currents and to provide energy storage. The capacitor also reduces the harmonic ripple on the dc voltage. Disturbances in the system (e.g., ac faults) will cause dc voltage variations. The ability to limit these voltage variations depends on the size of the dc-side capacitor. Since the dc capacitors are used indoors, dry capacitors are used.

AC filters for VSC HVDC converters have smaller ratings than those for conventional converters and are not required for reactive power compensation. Therefore, these filters are always connected to the converter bus and not switched with transmission loading. All equipment for VSC-based HVDC converter stations, except the transformer, high-side breaker, and valve coolers, is located indoors.

HVDC Control and Operating Principles

Conventional HVDC

The fundamental objectives of an HVDC control system are as follows:

1) to control basic system quantities such as dc line current, dc voltage, and transmitted power accurately and with sufficient speed of response
2) to maintain adequate commutation margin in inverter operation so that the valves can recover their forward blocking capability after conduction before their voltage polarity reverses
3) to control higher-level quantities such as frequency in isolated mode or provide power oscillation damping to help stabilize the ac network
4) to compensate for loss of a pole, a generator, or an ac transmission circuit by rapid readjustment of power
5) to ensure stable operation with reliable commutation in the presence of system disturbances
6) to minimize system losses and converter reactive power consumption
7) to ensure proper operation with fast and stable recoveries during ac system faults and disturbances.

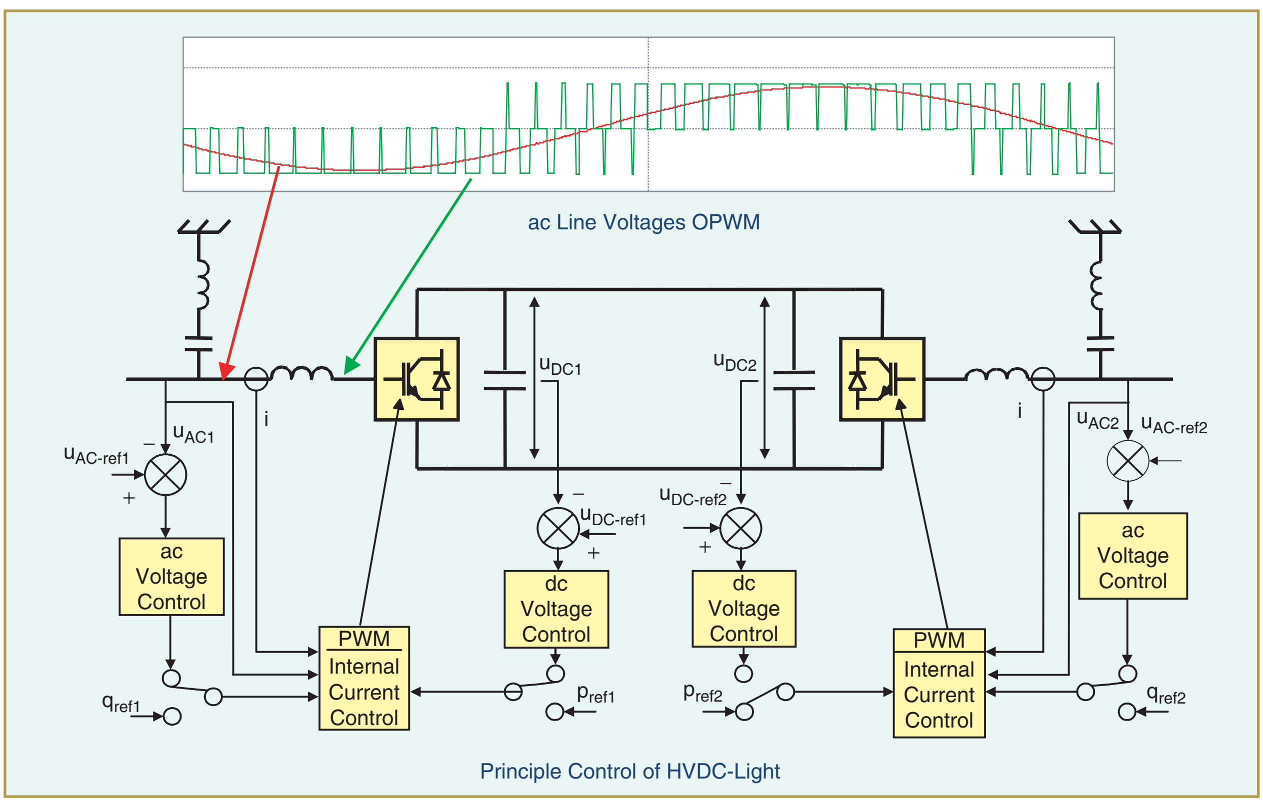

figure 17. Control of VSC HVDC transmission.

For conventional HVDC transmission, one terminal sets the dc voltage level while the other terminal(s) regulates the (its) dc current by controlling its output voltage relative to that maintained by the voltage-setting terminal. Since the dc line resistance is low, large changes in current and hence power can be made with relatively small changes in firing angle (alpha). Two independent methods exist for controlling the converter dc output voltage. These are 1) by changing the ratio between the direct voltage and the ac voltage by varying the delay angle or 2) by changing the converter ac voltage via load tap changers (LTCs) on the converter transformer. Whereas the former method is rapid the latter method is slow due to the limited speed of response of the LTC. Use of high delay angles to achieve a larger dynamic range, however, increases the converter reactive power consumption. To minimize the reactive power demand while still providing adequate dynamic control range and commutation margin, the LTC is used at the rectifier terminal to keep the delay angle within its desired steady-state range (e.g., 13–18°) and at the inverter to keep the extinction angle within its desired range (e.g., 17–20°), if the angle is used for dc voltage control or to maintain rated dc voltage if operating in minimum commutation margin control mode. Figure 16 shows the characteristic transformer current and dc bridge voltage waveforms along with the controlled items Ud, Id, and tap changer position (TCP).

VSC-Based HVDC

Power can be controlled by changing the phase angle of the converter ac voltage with respect to the filter bus voltage, whereas the reactive power can be controlled by changing the magnitude of the fundamental component of the converter ac voltage with respect to the filter bus voltage. By controlling these two aspects of the converter voltage, operation in all four quadrants is possible. This means that the converter can be operated in the middle of its reactive power range near unity power factor to maintain dynamic reactive power reserve for contingency voltage support similar to a static var compensator. It also means that the real power transfer can be changed rapidly without altering the reactive power exchange with the ac network or waiting for switching of shunt compensation.

Being able to independently control ac voltage magnitude and phase relative to the system voltage allows use of separate active and reactive power control loops for HVDC system regulation. The active power control loop can be set to control either the active power or the dc-side voltage. In a dc link, one station will then be selected to control the active power while the other must be set to control the dc-side voltage. The reactive power control loop can be set to control either the reactive power or the ac-side voltage. Either of these two modes can be selected independently at either end of the dc link. Figure 17 shows the characteristic ac voltage waveforms before and after the ac filters along with the controlled items Ud, Id, Q, and Uac.

Conclusions

The favorable economics of long-distance bulk-power transmission with HVDC together with its controllability make it an interesting alternative or complement to ac transmission. The higher voltage levels, mature technology, and new converter designs have significantly increased the interest in HVDC transmission and expanded the range of applications.

For Further Reading

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Biographies

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