HVDC Transmission Senior Capstone Project

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Introduction

High Voltage Direct Current (HVDC) transmission is the optimal choice for moving power over long distances due to lower transmission line costs, decreased right of way, and lower power losses than for equivalent AC lines. Since wind generation is often located far from load centers, HVDC is the ideal choice. Not only is direct current transmission chosen for economic reasons it is also advantageous when interconnecting asynchronous systems, bypassing network congestion, and increasing power flow through constricted transmission corridors without negative impacts on reliability. This paper offers a brief introduction to the various system components of an HVDC system and the inner workings of a wind power plant, as well as a case study of a proposed 3200MW, ±600KV intertie.

Most common HVDC systems utilize line-commutated converters (LCCs) as a means of rectification. While they are the most frequently used choice for large power systems they are not without their problems. This paper addresses both the advantages and disadvantages of this mature converter technology. In contrast, voltage source converters (VSCs) are a relatively new technology that is gaining popularity, especially in off-shore wind farms and other underground cable installations. AC and DC transmission differs due to fundamental differences in the signal being carried on the line. The relatively static electric field generated by a DC transmission line creates different local conditions than that of an AC line, requiring new considerations in regards to design operation, and the environment. These and other issues related to transmission are discussed. Due to the ever increasing demand for power and the growing concern surrounding carbon-based fuels, alternative means of generation are being pursued. One scheme that has seen large growth is wind power generation. This paper discusses collection system topologies, generator types and control interactions of wind generation. Finally, a case study which analyzes various interconnect scenarios is presented. Each model, created in PowerWorld, represents a potential solution.

By no means is this a comprehensive overview of HVDC topics. However, it offers the reader a basic understanding of the significant matters associated with direct current transmission.
Line Commutated Converters

Line Commutated Converters Introduction

Line Commutated Converters have been in use since the 1972, Canada-Eel River project; a 320 MW converter station which connects to the 230KV AC systems of Hydro-Quebec and NB Power [1]. They are the conversion technology of choice for over 100 HVDC projects and are utilized in the largest power transmission projects in the world such as the 2010, Xiangjiaba-Shanghai HVDC system; a 6400 MW, ±800KV system that stretches over 1200 miles [2].

These highly reliable converters use thyristors; which are bipolar, switching devices that are configured into elements named valves. They are most commonly constructed of two 3-phase Graetz bridge rectifiers connected in series to form a 12-pulse bridge. Each 12-pulse bridge contains 12 thyristors and a valve is built from as many elements as necessary to achieve the desired voltage. A 12 pulse bridge will result in 12 switching operations per cycle and generate harmonics of both 12n and 12n±1.

The term line-commutated refers to the line voltage of the AC system that the converter is connected to which creates the commutations from one valve pair to the next. LCCs cannot operate without a relatively strong, synchronous voltage source. They are considered to be current-source converters because they behave as such on the AC side, injecting both harmonics and grid frequencies. LCCs are constant current devices and as a result the current direction cannot be changed. The only way to change the power flow is to reverse the polarity of the voltage at the DC stations.

LCCs are incredibly reliable and their documented losses are now as low as .6 to .75% [3]. The individual failure rates within a converter station are only 1-2 thyristors per year [4]. However, they are not without their drawbacks. Areas of concern are reactive power consumption, sensitivity to connected AC networks, harmonics generation and susceptibility to commutation failures all of which are discussed in the following sections.
12 Pulse Configuration of Thyristor Valves

The basic building block for HVDC conversion is a thyristor, a bipolar switching device which functions similarly to a diode. Like a diode, it permits current flow in only one direction. However the thyristor has an additional input, called the “gate” which acts as a supplementary means of control. To turn on, the thyristor requires a positive forward voltage (positive potential at the anode with respect to cathode) as well as a pulse present at the gate terminal. It will continue to conduct as long as there is a positive forward voltage. The thyristor will turn off when the current goes to zero; which occurs each cycle in a line-commutated converter system.

When power flows from the AC side to DC side the valve is referred to as a rectifier. When it flows from DC to AC, it is called an inverter. The term valve itself is used to describe a series/parallel combination of thyristors. It is preserved from the days when mercury-arc valves were used in rectification.

Two valves are connected to the phase terminals; one is connected to the anode and the other to the cathode. As the AC sinusoidal wave oscillates, the anode of one valve pair becomes forward-
biased and begins to conduct. When the anode is no longer positive with respect to the cathode it will stop conducting. The proceeding phase voltage will then become positive and the following valve pair will be forward-biased and thus begin conducting current. The valves will continue to act as switches, each successive conducting pair operating throughout the oscillation of the associated AC network sine wave. Each valve will carry the full value of the current for one third of each cycle and two valves will always be conducting in series. The end result of this process is a “DC” output voltage with a ripple.

![Switching Pattern of a Six Pulse Current](image)

*Figure 1.2 Switching Pattern of a Six Pulse Current [5]*

If the two bridges have an applied voltage with a 30° phase difference between them it will decrease the variation between the applied AC voltage and the average DC voltage as well as reduce the harmonics produced by the converter. This phase difference is easily introduced by
connecting one bridge through a wye connected transformer and the second bridge through a delta connected transformer.

**DC Voltage Components**

The addition of the wye-delta connected converter transformer contributes a commutating reactance, called $X_c$. When current commutates from one valve to the next it cannot do so instantaneously. This is because some of the current from the previously conducting valve is flowing in the inductance of the transformer when the successive valve begins operation. As a result there is an overlap period.

The period of time between when the previously conducting valve turns off and the conducting valve turns on is called the overlap period, $\mu$ and it is expressed in units of degrees. There are four types of overlap modes: single, double, triple, and quadruple. If the overlap angle is less than 30° than it is considered in single overlap mode and commutation in the upper half of the bridge completes prior to commutation in the lower half. Double overlap mode describes a phenomenon in which commutations simultaneously occur and three or four valves may be conducting at a given time. The table below provides information on the triple and quadruple overlap modes.

<table>
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<tr>
<th>Mode</th>
<th>Overlap angle $(\mu)$</th>
<th>Maximum number of valves conducting at any instant</th>
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<tr>
<td>Low discontinuous current</td>
<td>$\leq 0^\circ$</td>
<td>1</td>
</tr>
<tr>
<td>Principal discontinuous current</td>
<td>$0^\circ$</td>
<td>4</td>
</tr>
<tr>
<td>Single overlap</td>
<td>$0^\circ \leq \mu &lt; 30^\circ$</td>
<td>5</td>
</tr>
<tr>
<td>Double overlap</td>
<td>$30^\circ \leq \mu &lt; 60^\circ$</td>
<td>6</td>
</tr>
<tr>
<td>Triple overlap</td>
<td>$60^\circ \leq \mu &lt; 90^\circ$</td>
<td>7</td>
</tr>
<tr>
<td>Quadruple overlap</td>
<td>$90^\circ \leq \mu &lt; 120^\circ$</td>
<td>8</td>
</tr>
<tr>
<td>Short-circuit</td>
<td>-</td>
<td>12</td>
</tr>
</tbody>
</table>

*Figure 1.3 Operating Modes of Thyristor Valves [5]*

The amplitude of the DC voltage can be controlled by adjusting the firing angle. The “firing” or “trigger” angle refers to the time delay from which the voltage across a valve becomes positive and the thyristors are turned on and begin conducting. The firing angle is commonly referred to as $\alpha$, and is expressed in units of degrees. As the firing angle increases the DC voltage decreases. An angle of $90^\circ$ will result in a DC voltage of zero amplitude and an angle of $0^\circ$ will result in the
maximum DC voltage. Firing angle control regulates the DC voltages of both ends of the HVDC system in order to obtain the desired power transfer.

All of the previously discussed components associated with the thyristor based valve contribute to the amplitude of the DC voltage. The output voltage can be mathematically described as a relationship between the commutating reactance, firing angle, direct current and line voltage by [5]:

\[
V_{DC_{p.u.}} = k \cdot V_{L-L_{p.u.}} \cdot \left( \cos \alpha - \frac{X_{C_{p.u.}}}{2} \cdot I_d \right)
\]

Where:

\[V_{L-L} = \text{the line to line input voltage of the AC system}\]

\[\alpha = \text{firing angle of the thyristor}\]

\[X_c = \text{the commutating reactance}\]

\[I_d = \text{the direct current}\]

\[k = \frac{V_{DC_{p.u.}}}{V_{L-L_{p.u.}}} \cdot \frac{1}{\cos \alpha - \frac{X_{C_{p.u.}}}{2}}\]

**Inverter Operation**

In inverter operation the firing angle exceeds 90° and is more commonly known as the extinction angle. The extinction angle, \(\gamma\), refers to the time after the overlap period when the recently extinguished valve becomes positive again. It is expressed mathematically as [4]:

\[\gamma = 180° - \mu - \alpha\]

During inverter operation the voltage at the terminals will be negative. This poses a problem since current cannot change direction in a thyristor. Consequently, inverter operation requires a separate current source for power flow to occur.

**Commutation Failure**

If two valves that are connected to identical phases conduct current at the same time a short occurs in the circuit. This happens when a valve in one half of the bridge fails to turn off completely. It will begin conducting again and current will cease to commutate to the successive valve. A commutation failure refers to the short circuit that ensues when the valve in the opposite
half of the bridge that is connected to the same phase begins conducting. Commutation failures require control action.

![Figure 1.4 Commutation Failure Circuit Diagram [5]](image)

**Harmonic Elimination**

Harmonics are of great concern in the HVDC converter stations and the converters are just one cause of harmonic distortion. Other contributors to harmonic distortion are rectifiers, drives, lighting, power equipment and large industrial loads. Effects of harmonic distortion are not limited to but can include the overloading of capacitor banks, overheating of electrical machines, and interference with both electronic and telecommunication systems. These effects are of grave concern primarily on the AC side due to its delivery to consumers. A filter's purpose is two-fold: to reduce the harmonic distortion as a result of the 12-pulse converters and to supply reactive power.

**AC Harmonics**

Harmonics present in the converter station are generally:

\[
12n \pm 1 \text{ where } n = 1, 2, 3, 4, \ldots k
\]

This is due to the 12-pulse bridge configuration of the thyristor valves and the 12 switching operations per cycle. Consequently, the harmonics of concern when designing filters for the AC side are the 11\text{th}, 13\text{th}, 23\text{rd}, 25\text{th}, 35\text{th}, 37\text{th}, 47\text{th}, and 49\text{th} [6].
There are four commonly used AC filter types: the single-tuned band-pass filter, high pass filter, double-tuned band-pass filter and the C-type filter. Most commonly the filters are passive but on rare occasion an active filter will be used.

A single-tuned filter, also referred to as a band pass filter is generally used for the $11^{th}$ and the $13^{th}$ order harmonics. It is referred to as “tuned” because it is designed to attenuate for a specific frequency rather than a range. Characteristics associated with this filter type are a high Q factor and as a result low damping. These filters consist of a series RLC circuit with a small resistance. Both the losses and maintenance associated with this circuit are low.

Figure 1.5 One possible variation of a Single-tuned Filter, designed with parallel capacitance [5]

The double-tuned filter is generally tuned to the $12^{th}$, $24^{th}$ and the $36^{th}$ harmonics. Double-tuned filters function like two single-tuned filters. They consist of a single tuned filter in series with the parallel combination of a RLC circuit. They have lower losses than single tuned filters, reduce the number of high voltage capacitors needed and help to decrease the number of filters necessary since they are tuned to attenuate multiple harmonics.

Figure 1.6 Double-tuned Filter [5]
A broadband filter (high pass filter) is used for all higher order harmonics from the 23rd on. These filters have a low Q factor and high damping. The circuit which characterizes this filter is a capacitor in series with a parallel combination of an inductor and resistor. This circuit can attenuate over a wide spectrum of harmonics and is low maintenance but has higher losses than tuned filters.

Finally, the C-type filter is used for all low order filtering, such as the 3rd, 5th, and the 7th harmonic. This filter consists of a capacitor in series with a parallel combination of a series capacitor / inductor and a resistor. The C-type filter achieves its dampening by forcing currents with higher than fundamental harmonics to travel through the resistor. As a result losses associated with the fundamental frequency remain low.

The requirements for filter design on the AC side are the reactive power needs and the calculated harmonic currents. The reactive power needs of the converter station also determine the size of the filter banks.
DC Harmonics

There is still concern of the effects of harmonics on the DC side, primarily interference with the telecommunication systems [5]. Harmonics on the DC side are generally described as:

\[ 12n, \text{where } n = 1,2,3,4 \]

Therefore the harmonics of concern are the 12\(^{th}\), 24\(^{th}\), 36\(^{th}\) and 48\(^{th}\). Filters commonly used are the double-tuned filter for the 12\(^{th}\) and 24\(^{th}\) harmonic and the triple-tuned filter, tuned to the 12\(^{th}\), 24\(^{th}\) and 36\(^{th}\) harmonic. The triple tuned filter is a parallel combination of a single-tuned filter and two doubly-tuned filters.

The information required to design filters on the DC side are the harmonic voltages which are injected into the line, the performance and the requirements for different operating conditions. The harmonic voltages can be found at each point on the line with the knowledge of the DC line impedance and the station equipment impedance. The performance requirements can be found with the sum of the harmonic currents and the telecommunications interference. The operating conditions include general bipolar operation but also must account for possible monopole operation with ground return.

Bipolar Configuration

Bipolar operation refers to two poles, independent of one another, each operating with its own converter. It utilizes two conductors of opposing polarity. The primary advantage of this configuration is its ability to operate as a monopolar scheme in the event of an outage. To prevent any substantial time using ground return a metallic return transfer breaker (MRTB) can be
installed. This breaker allows the system to switch from ground return to metallic return without interrupting power flow.

\[\text{Figure 1.10 Bipole HVDC Scheme with Metallic Return for Pole Outage [5]}\]

**Reactive Power Support**

Converters absorb reactive power at alarming rates, an estimated 50-60% of their active power [7]. When operating with a delayed firing angle they are considered a lagging load. In addition to the converter, transformer impedance creates a lag in the current and the combination of these two lagging loads results in an overlap angle. This power consumption creates a dire need for reactive power control that extends beyond the limits of the converters. Choosing an efficient means of support is absolutely necessary as up to 15% of station costs can result from reactive power needs.

The primary component of reactive power support within an HVDC station is an AC filter bank but switched shunt capacitors and mechanically switched capacitor damped networks (MSCDN) may be used when it is no longer economical to add more AC filters to the switchyard.
Unfortunately, these two means of reactive support can only supply capacitive power. Shunt capacitors are tuned to a specific frequency to avoid additional harmonics within the system.

**STATCOMs**

Static Synchronous Compensators (STATCOMs) are a fast-acting means of reactive power support. A STATCOM uses a power electronic converter to generate a sine wave that can lead or lag the AC system waveform. This allows reactive power to be generated or absorbed. STATCOMs use voltage source converter (VSC) technology and their voltage source is a DC capacitor. STATCOMs absorb reactive power when the voltage terminals of the VSC are lower than the AC system and generate reactive power when the voltage amplitude of the VSC is higher than the AC systems. STATCOMs have a quick response time due to the fast switching capabilities of the insulated gate bipolar transistors (IGBTs) of the VSC and they are less susceptible to a reduction of capacitive output during undervoltages [8]. They are considered part of the Flexible AC Transmission System, also known as FACTS. IEEE defines FACTS as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability" [9].

![STATCOM Circuit](image)

*Figure 1.11 STATCOM Circuit [10]*

**Static Var Compensators**

Static Var Compensators, referred to as SVCs are power electronic devices that provide reactive power. SVCs consist of a thyristor controlled reactor and a fixed capacitor. These two components combined provide the versatility of delivering reactive power that ranges from fully capacitive to fully inductive. The reactor controls the AC current flow and consequently the impedance as seen from the AC side. The fixed capacitor provides an optional leading source of
reactive power. SVCs are not a source of fast power control and their power output is greatly affected by undervoltages [11]. While they do not contribute to the common harmonics associated with converters they do produce their own harmonic currents and as a result may require additional filtering. SVCs are also part of the FACT family of devices.

Figure 1.12 Static Var Compensator Circuit [12]

**Synchronous Compensators**

Synchronous Compensators are machines that are connected to the AC system to provide energy losses but have no mechanical power input. The shaft of a synchronous compensator remains unconnected and it is allowed to spin freely. While their installation and operation are similar to synchronous motors their primary function is not the conversion of mechanical power to electrical power. Their purpose is to absorb or generate reactive power which can be continuously adjusted with ease. They are generally rated for between 20-200 Mvar [13]. They have the added advantage of being temporary energy storage and are not affected by the systems harmonics and can even absorb harmonics themselves.

**Converter Control**

HVDC systems are very complex and thus require a means of control at either operating terminal. The primary duties of an effective control system are to control the power flow between the terminals, stabilize the AC systems in the event of DC operational issues and to protect the equipment in the event of a fault. The typical hierarchy of a DC control system consists of a dispatch center which communicates power needs to the terminals. The terminal then acts as a
“master controller” coordinating the functions between the two terminals. Additionally, each terminal will also have local controllers [7].

![Block Diagram of DC Control System](image)

*Figure 1.13 Block Diagram of DC Control System [7]*

Extending beyond its primary functions a DC control system must also:

- Limit the maximum DC current to less than 1.2 p.u. for any substantial period of time. This is to prevent any permanent damage to the thyristor valves.
- Maintain a maximum DC voltage to prevent losses.
- Minimize reactive power consumption by coordinating the firing angle.

**Firing Angle and Tapchanger Control**

To limit the DC current, the converters have two primary means of control: the firing angle and the converter transformer on-load tapchanger. The firing angle is the time delay from when the voltage across a valve becomes positive and the point that it starts to conduct. As the firing angle increases the DC voltage decreases. Firing angle is used to control the DC voltage on both ends and to maintain a desired level of power. In practice, the firing angle never operates at 0° or above 180° [5]. Varying the firing angle is the only quick means of control and can occur within one-half cycle [7].
The converter transformers come with an on-load tapchanger. A tapchanger acts like a switch, stepping the transformer turns ratio up or down in small increments. Generally, there are 32 steps and each step adds or subtracts 1.25% of the converter turns ratio. This results in a maximum possible voltage change of 40% [5]. The tapchanger is a slow means of control. Each step change takes approximately 5 seconds [7].
Most converter stations utilize both the converter transformer tapchanger and the firing angle as a means of control. The tapchanger is used as a course means of control for steady state adjustments. The firing angle is used as a means of quickly responding to changing load demands.

**Reliability**

Overall reliability as categorized by CIGRE involves the annual data collection and reporting of a HVDC system’s “maximum continuous transmission capacity, energy availability, energy utilization and energy unavailability” [4]. Energy availability is the total possible energy available for transmission in the HVDC system and energy utilized is the total energy that was transmitted.

As reported in the 2009-2010 CIGRE Survey of Reliability: energy availability varies from 84.1% to 99.6% and the energy utilized can swing from 0 to 89%. Reported forced outages range from 0-8.44%, although 85% of the HVDC systems reported forced outages of less than 1% per year.

The cause of a forced outage can be related back to a specific type of converter station equipment such as the converter transformers. Many reported that none of the outages could be traced back to the valves with an average being 1.8 valve failures per year. Individual thyristor failure rates are below 0.5%. The most commonly occurring equipment failures were linked to “AC and auxiliary equipment”, most specifically the converter transformers. In fact eliminating the transformer failures decreased average system outages from 3.1% to 0.65%.

**Protection**

The general principles for establishing adequate protection for an HVDC system are no different than an AC system. It is customary to use overlapping zones and when applicable, redundancy to provide a reliable, selective and speedy protection scheme. In the event of a bipolar transmission system protection zones are doubled to ensure independence between the two poles. DC protection not only consists of digital protective relays but can also have incorporated converter regulation and control functions. Using the converters as a part of the protection scheme can help prevent full shut down and aid in restoring full operation more quickly.
To clear a short circuit in the rectifier bridge the converter group must be shut off as soon as possible to avoid excessive damage of the thyristor valves. Differential protection is used to detect any shorts that do not cause typical short circuit current values and to detect faults on the DC side that occur from the reactors or filter switchyard. A delay is used to avoid oversensitivity and allow for spikes of current when the DC voltage varies and on the AC side as well to protect the AC filter yard, capacitor banks and transformers.

Beyond the typical protection scheme HVDC systems require special protection functions for the cases of misfires and commutation failures. Misfires occur when the gate pulse of a thyristor valve ceases to fire. This can result in overvoltages of dangerously high values. The suggested action to prevent these misfires is to filter out the network associated frequency components of the DC voltage. Commutation failures occur when the current in one valve fails to transfer to the next. Bridge differential protection can be used to quickly detect commutation failures by detecting the difference between the transformer currents in the phases.

**Capacitor Commutated Converters**

LCCs are not without their concerns especially when dealing with a weak AC system. Among the primary concerns are the reactive power requirements and the expensive AC filter switchyard that is required to counter-effect the production of harmonics. A capacitor commutated converter (CCC) can be used to remedy these concerns. A CCC is built by inserting a series capacitor between the leakage impedance of the transformer and the main valve. The capacitor solves two primary issues associated with the LCC: the reactive power demand as a result of the leakage impedance and it “provides a forced commutation facility to the main valve” [14].

![Figure 1.16 Capacitor Commutated Converter Circuit Diagram](14)
Sizing the capacitor is of great concern because a capacitor that is too large will be not only be costly, but may result in overvoltages and also over-compensate for the reactive power resulting in the draw of a leading current from the AC side. A capacitor that is too small will not compensate for the leakage inductance and result in a lagging current.

Unlike an LCC, the voltage across the capacitor is proportional to the DC current and when both rise the DC voltage also rises. This results in a positive inverter impedance characteristic allowing it to function in a weak AC system. CCCs can also withstand drops in the AC voltage, up to 15-20% of the nominal voltage without suffering a commutation failure.

The CCCs capacitor impedance when compared to the leakage impedance of the commutating transformer reduces the short circuit currents to that 2-3 times less than a LCC. The overlap angle is also decreased and as a result “switching voltage stresses and losses are reduced” [14].

A CCC provides reactive compensation so the need for switchable shunt capacitor banks is eliminated. The AC filter requirements are also minimized. “Typically, the AC filters provide less than 15% of total converter reactive power demand as compared to about 55% for a LCC” [14]. Filters are only necessary to deal with harmonics of the system as opposed to LCCs where additional filters may be required for reactive power support. By reducing the number of filters necessary it also reduces the space required for an AC switchyard at the converter station.

The primary drawback of the CCC is the increased cost and maintenance. However, they may be the best solution when dealing with a weak AC system.

**Conclusion**

The primary concerns associated with LCCs are the reactive power support needed, harmonic generation from the converters, AC system sensitivity and a limited means of control. After 40 years of reliable use in the largest HVDC projects in the world all of these issues have been addressed and solutions for each have been implemented, tested and proven to be a reliable fix. AC filter switchyards are implemented as a means of dealing with the generated harmonics of the converter. They also provide much of the reactive support necessary for the converters. Additional reactive support can be provided by the means of a number of devices within the FACTS family such as the STACOM or a Static Var compensator.
Capacitor Compensated Converters can be used for weak AC systems. They reduce the reactive power needs and can withstand greater voltage variations without suffering commutation failures. Means of converter control may be limited but can be both fast and effective. The firing angle can be used to vary the DC current and operates in less than half a cycle.

LCCs have the lowest losses reported of the two converter technology options available. Converter stations report only 1 to 2 individual thyristor failures each year making LCCs the dependable, reliable choice in converter technology.

**Line Commutated Converters References**


http://en.wikipedia.org/wiki/Static_VAR_compensator


http://en.wikipedia.org/wiki/Synchronous_condenser

Voltage Source Converters

Voltage Source Converters Introduction
Voltage source converter (VSC) technology is relatively new to the power market. It debuted in 1997 and has come a long way over the past 16 years on the market. Since then it has evolved from 300 A to 1.8kA transmission. This advancement in power transmission is limited by current technology using insulated-gate bipolar transistor (IGBT). By using IGBTs the system’s response is incredibly faster and able to start from 0 volts or “Black Start” without the need of an alternative power source on startup. The other benefit of VSCs is the amount of real estate needed for the system. Size is reduced by 50-60% when compared to LCC’s. VSC also have the ability to provide great VAR support. This technology provides a great benefit for grids that are weak or passive, since it provides independent control of active and reactive. This section should provide you with basic information about voltage source converters.

VSCs
VSC technology is specifically designed for moving High Voltage Direct Current (HVDC) based on using voltage source converters with insulated-gate bipolar transistors (IGBT). IGBTs are large semiconductors that used as a switch to invert and rectify power. Previously, VSCs used to be based on two or three level switching technology for alternating the voltage levels to the AC terminal. Because the number of switching was so lo several hundred semiconductors were needed on each converter arm, they were connected in series and had to switch simultaneously in order to ensure uniform voltage. Below is a picture showing the differences of the three topologies including what is used today.
IGBTs

This is a three terminal semiconductor that is primarily used as an electronic switch for electric circuits. It switches electric power at a fast rate and is highly efficient, low power losses around 1% and no harmonics. It is design to synthesize complex waveforms with pulse width modulation (PWM).

Figure 2.1 VSC topologies. [1]

Figure 2.2 Introduction to HVDC VSC Alstom source.
(PWM is a technique for controlling analog circuits with a processor’s digital output. It is able to control the power supplied to form a sine like waveform. Though it is not a perfect wave, with combination of multi level converters, a more sine like wave pattern will emerge without the addition of noise to the line.)

It combines simple gate-drive characteristics of MOSFETs with a high-current and low-saturation-voltage capability of bipolar transistor by combing an isolated gate FET of the control input, and a bipolar power transistor as a switch, in a signal device. They consist of many devices in parallel and can have very high current handling capabilities up to 1.8kA; they are also capable of handling up to 6kV. The other plus is IGBTs produce a low frequency; this is ideal for power transmission because we do not have to add harmonic filters to the system.

![Three level converter principal circuit diagram](image)

*Figure 2.3 is a three level converter principal circuit diagram for one phase. Each diode symbol in reality represents over 150 IGBT modules. This is taken from the Murraylink layout for example. [4]*

Main advantages of the IGBT are:

- Very low on-state voltage drop due to conductivity modulation and a superior on-state current density.
- Low driving power and simple drive circuit due to the input MOS gate structure.
- It can be easily controlled as compared to current controlled devices in high voltage and high current applications. It also has superior current conduction capability compared with the bipolar transistor.
- Provides excellent forward and reverse blocking capabilities.

AC voltage contains harmonic components, caused by the switching of the IGBTs. The harmonics need to be limited in order to prevent them from interfering with system equipment or radio and
telecommunication signals. High-pass filters must be installed in order to prevent these occurrences. Phase reactors are used in controlling the active and reactive power and help reduce the harmonic noise caused by the IGBTs.

IGBTs can be connected in parallel [5]; this would be the same for VSC converter stations. It is possible to achieve a higher power rating to be somewhat comparable to LCCs. The difficult portion of this is the IGBTs must turn on and off every time simultaneously. This is critical to the current balancing in the parallel connection. To accomplish this you would need an external component that they would connect to.

In order to convert from AC to DC, the system uses multilevel switching so that it can take the DC waveform and convert it to a modulated sine wave. This is done by the same technology as used in telecommunications. By utilizing the IGBTs there is low switching frequencies, which illuminate the need for harmonic filters and help provide low system losses. [1] MMC technology is a multilevel converter that consists of six converter arms, within the arms; there are several power modules and one converter reactor connected in series. Power modules consist of two IGBTs and a capacitor. There are three separate states that enable power conversion. The first stage is having both IGBTs in the off state. If a power failure were to occur, all modules will have their IGBTs switches off. This is to allow current to flow from the positive DC pole in the direction of the AC terminal to charge the capacitor. When power flows in the opposite direction, D2 diode bypasses the capacitor. Normally during operation of the system this case does not occur, only in the event of something failing would you see this state.
Second state is the “Capacitor-On” state, IGBT1 will be energized which will charge the Capacitor, IGBT2 is switched off. The voltage stored in the capacitor is applied to the terminals of the power module. Current will either flow through D1 to charge the capacitor or through D2 to discharge it.

Third state is the “Capacitor-Off” state in which IGBT2 will be energized and ensures that zero voltage is applied to the terminals of the power module. The Capacitors provide an energy buffer to keep the power balance during transients and limit the voltage ripple.

**Control Systems**

Depending on the manufacturer there are a few different types of control systems readily available on the market today. Direct Power Control (DPC) is based on the instantaneous active and reactive power control loops. There are no internal current control loops and no pulse width modulator block; this is due to the converter switching states that are selected by a switching table based on the instantaneous errors between the commanded and estimated values of active and reactive power. This system is not common today due to the need for quick IGBT switching for frequency controlling.

Vector control method is another system that uses modeling of three phase systems by using axis transformations (d-q transformation). This system utilizes PWM converters for obtaining
independent control of the active and reactive powers. One of the most advantageous characteristics of vector control is that vectors of ac currents and voltages occur as constants in steady state. By using PI controllers, static errors in the control system can be eliminated.

D-Q transformation is transforming a three-phase system to a two-phase $\alpha$-$\beta$ coordinate system, and then transforming the $\alpha$-$\beta$ system to the d-q coordinate system.

![Figure 2.5 Axes for vector control.](image)

The d-q reference frame is rotating at synchronous speed $\omega$ with respect to $\alpha$-$\beta$.

![Figure 2.6 Voltage conversion process.](image)
The object is to regulate the dc voltage and maintaining the balance between the incoming ac voltage and the outgoing dc power. The voltage equations in d-q synchronous references are provided.

\[
L \frac{d\dot{d}}{dt} = -R\dot{d} + \omega L\dot{q} - Vd_{\text{conv}} + v_d
\]

\[
L \frac{d\dot{d}}{dt} = -R\dot{d} + \omega L\dot{q} - Vq_{\text{conv}} + v_q
\]

For the output side

\[
I_{dc} = C \frac{dV_{dc}}{dt} + I
\]

The power balance relationship between the ac and dc

\[
P = \frac{3}{2}(Vd \ast Id + Vq \ast Iq) = V_{dc} \ast I_{dc}
\]

The voltage vector is defined to the d-axis direction, and then virtual grid flux vector can be assumed to be acting along the q-axis. With this alignment the instantaneous real and reactive power injected into or absorbed from the ac system is:

\[
P = \frac{3}{2} Vd \ast Id
\]

\[
Q = -\frac{3}{2} Vq \ast Iq
\]

The transformation into rotating d-q coordinate system oriented with respect to the grid voltage vector. This leads to a split of the main current in two parts. One part determines the contribution which gives the required power flow into the DC bus; the other part defines the reactive power condition. The angle between the α-axis of the α-β frame and d-axis of the d-q frame is used for transformation between the α-β frame and d-q frame. The angular position of the voltage vector is given by,

\[
\theta = \tan^{-1} \frac{V_{\beta}}{V_{\alpha}}
\]
Where \( V_\beta \) and \( V_\alpha \) are components of voltage in stationary two axis reference frame, \( \alpha-\beta \). The instantaneous phase angle of the grid voltage is needed for independent control of active and reactive power.

**STATCOMs**

It is a static synchronous compensator that regulates the system voltage. For example; if the terminal voltage of the DC end is greater than the AC voltage, it will generate reactive current. When the DC voltage is lower than the AC voltage it will absorb reactive power. Unlike a thyristor based static VAR compensator, STATCOM has the ability to control the output current independently of the AC system voltage.

This system is used in voltage source converters to synthesize a voltage waveform of variable magnitude with respect to the system voltage. It offers both reactive power absorption and production capability. It allows for a faster response and improves overall power quality, which greatly improved when using PWM to control the system. It is very helpful in mitigating flicker from disturbances caused by customers that require a high power demand, such as steel mills and other large manufacturing plants. STATCOM has the ability to increase the power transfer capability where limited by post-contingency voltage criteria or under voltage loss of load probability. They are designed to keep the normal operating point within the middle of a dynamic range. After a disturbance the reactive power production will be decreased. This in turns limits the voltage output on the system.

**Protection**

DC protection can be achieved by using AC circuit breakers on the AC system. This strategy can be applied to VSC systems, using AC circuit breakers creates fast acting DC switches. The switches are only used to isolate lines and cannot break load or fault current. Each VSC will receive current measurements from their respective DC switches. When a fault occurs all of the AC circuit breakers associated with the system will trip. Each VSC must determine which one of its switches is open. This is done by measuring the magnitude and direction of the current through each switch. The switch that will be selected is the one with the largest positive fault current. A “hand
shaking” method defines positive as out of the node and negative into the node. When a fault occurs on a line, VSC receives current measurements on that line. The system can then route power to another portion of the grid until the fault is cleared, then switch back to the line that had the original fault.

DC protection utilizes IGBT-CB and fast acting DC switches. The IGBT-CBs can be placed at the terminals of each VSC or at the end of each line. The voltage of the capacitors will be monitored as well as the current through each line. When the current exceeds the maximum set point and the voltage begins to rapidly discharge the respective IGBT will begin to block and the fast acting DC switch will open once the fault is extinguished. This type of protection is advantageous because it isolates the individual lines without interrupting the entire network. This is true when each line has its own IGBT-CB. While this is a more effective method of protection, it is the most expensive option with further challenges. IGBT-CB cannot begin to block when a fault is detected on the positive line because two or more lines split from the positive or negative node. Since all lines that are connected to a particular node will feed fault on any other line connected to the same node, the faulted line must be detected. Three different methods to achieve this are large current change, rise time, and oscillation pattern.

The large current change method determines which lines are faulted by comparing the current magnitude of all lines feeding the fault. The line with the largest current change in a given time will be chosen as the faulted line. When a fault is detected, each VSC will measure the rise time of the current in their respective lines. The line with the fastest rise time will be identified as the faulted line. The oscillation pattern method looks for wide pulses without a change in polarity. This identifies the faulted line.

If a short circuit event were to occur between the DC terminals, the current will rise in excess of a predetermined threshold value in the converter arms. The IGBTs will switch off in a few microseconds in order to prevent current reaching a critical level. Since current flows from the three phase AC side, the only way this type of fault can be cleared properly is by opening the AC circuit breaker. This will cause a slight interruption in service; however the VSC can handle the removal of power in order to clear a fault since they do not need a backup system to operate.
IGBTs have a low surge current threshold capability. If a fault occurs and the diode receives a high amount of current, a press-pack thyristor is connected in parallel to the affected diode and is fired in the event of a DC line-to-line fault. This is installed to prevent the damage of the diodes which have been known to overheat and cause an explosion in their case. This can potentially damage other IGBTs or cause harm to others if in close contact.

**Black Start**

In the event of a fault, or the beginning of spring when wind turbines come back online, VSCs have the ability of going online without the need of an external power source. For example,
external power sources are usually diesel powered generators that provide power to start larger
generators in order to provide the system with enough megawatts to enable the substation to
come back online. VSCs however are not limited by this process of waiting for the generators to
kick on for the substation to be ready when the fault or event has been cleared. Instead a simply
battery is enabled in order to save the information of reference points for preparing the system to
come back online.

The great thing about VSCs is the fact that you do not need to have annual testing on equipment,
like you would for LCCs, because there are no mechanical components that could potentially fail.
VSCs have the ability to control the incoming voltage which can range from 0 to 1.1 p.u.[3] They
are able to control voltage dips when starting large motors and over voltage due to self-excitation
phenomenon associated with energizing high voltage AC lines, and the ability to provide on
demand frequency control. The sequence of switching certain loads and generation is no longer as
critical as in a traditional initialization process. To accomplish this VSC have the ability to provide
a soft start sequence for major power system equipment. This is to help limit the inrush current
and transient voltage and harmonics on the system. It will enable a faster process for bringing a
system online without putting further stress on the systems components, such as transformers,
breakers, etc.

During the system restore process, the AC voltage reference is established by a pre-determined
magnitude, phase angle and frequency. Since this information is saved in the event of a fault, the
system knows when to fire the system up at the correct phase angle as soon as the fault has been
cleared and power is restored. This is a significant factor when connecting two grids together. If it
was not synchronized correctly, it has the potential to damage other system generators and the
IGBTs themselves.

**Cooling**

In order to successfully transfer the rated power we need to keep our IGBTs at a cool constant
temperature. To accomplish this IGBTs are mounted on aluminum heat sinks that can hold up to
four devices. The IGBTs are cooled on one side by a large coolant system. The system is comprised
of two pumps, one to be running at all times and the other for a backup system if the first pump
fails. This is to ensure there is no interruption in service. It’s designed to deliver coolant at a
constant rate of $10 \frac{L}{min} \ (2.64 \frac{gal}{min})$ to the heat sinks. The coolant is comprised mostly of water and glycol and a few non-listed additives, to reduce the freezing point of coolant well below 0ºC. Electrical conductivity of the coolant is critical to the operation of the IGBT valves. Coolant is flowing constantly through a resin bed de-ionizer in order to maintain the conductivity of the coolant to be extremely low. This is to help prevent leakage currents in the coolant from effecting other equipment and maintaining a safe work area for substation personal. Bypass valves are in place to prevent very low temperature coolant from entering the IGBT valves at startup. This helps to prevent the risk of condensation on the valve surfaces.

**HVDC configurations**

There are several ways in which a converter station can be laid out in order to deliver the desired output. Some are intended on long distance delivery while others are intended for joining weak grids to stronger ones or different frequency grids together, such as a 50 Hz to a 60 Hz. Listed below are several methods for converter station layout.

**Monopole**

Two converters are connected by a single line and a positive or negative DC voltage is applied. There is only one insulated transmission conductor; ground is applied for a return instead of adding another line. This method can be used for a short amount of time; this is to prevent corrosion of underground equipment.

![Figure 2.9 Monopole configuration.](image)

**Bipole**

Two converters are connected by two lines, supplying both positive and negative DC voltage respectively. The two poles can be operated independently if both neutrals are grounded and in the event of a fault it can run on one line to provide power to the grid until the fault is cleared.
Figure 2.10 Bipole configuration.

**Homopole**

Two or more conductors have negative polarity and are operated with a ground or metallic return. This configuration is run in parallel to reduce insulation cost.

Figure 2.11 Homopole configuration.

**Back-to-back**

Designed for connecting two adjacent asynchronous AC systems. Two converter stations are located at the same site so there is no need for transmission lines. This is great when joining two AC networks that have conflicting frequencies or conflicting phase shifts from older networks to newer networks. Tres Amigas for example; located along the border of Texas and New Mexico, is a substation that features this topology. Its goal is combining the Eastern and Western interconnection to the Texas interconnection for a more stable system.
Multi-terminal

Three or more stations are separated and interconnected through transmission lines or cables. The system can run in either parallel or series.

For many HVDC systems the most common configuration and preferred choice is a bipolar configuration. This is simply because it can transmit in either direction on either line, including a return to ground in the event one side goes down due to a fault.

Advantages

VSC converters have many advantages for HVDC operation. It provides independent control of active and reactive power with less equipment. This is achieved by controlling the switching of the IGBTs. When power demand begins to spike, VSCs are able to control the system instantaneously based on demand needs. Such power disturbances are limited, such as flickering and harmonics.

Communications between the substations are not dependent on one another since both sides operate independently. They can also provide multi-terminal support for DC grids; this would be designed for city centers if power distribution would be changing from AC to DC. Transient over voltages can be counteracted by fast reactive power responses. Thus stability margins are enhanced because of reactive power support. VSC are not limited to the amount of power being
supplied to the converter station. Meaning as long as some power is being delivered, it is able to transfer it to the grid.

Full range of reactive power can be utilized. Active power transfer can be quickly changed in either direction without any filter switching or converter blocking. The amount of real estate required for the project is extremely less when compared to LCCs, which is why more projects are being started in heavily populated cities and off shore wind farms. It helps with the daily maintenance routine for the substation and the ability to swap out failed components relatively easier and in a timelier fashion. During initial construction is would be ideal, instead of building the entire project at once, you could split it up into three sections, each rated for 1000MW. Whereas LCCs would need to construct the entire converter station during the first phase.

Disadvantages
Currently VSCs are not able to supply the desired amount of power for the proposed project. They are rated for around 1.2kMW. It has a higher loss rate when compared to LCCs. Best case scenario in a controlled environment is about 1% loss, although on average it is around 1.7% loss per station. The reliability for a 30 year service life has not been proven, due to it being extremely new converter technology.

Past and Current VSC Projects
Table 2.1 lists some VSC projects in operation or under construction. From this table we see that VSC is an extremely new technology that has been in use for only 16 years. This is about half of the life span for normally rated power equipment. When compared to LCC, which has a 30+ year proven track record. Currently the only known project to be close to the specifications laid out for Trans West project is Inelfe. This is the largest VSC system in the world today; it will supply 2000 MW of power from France to Spain. The system is comprised of four VSC converters, two on either end that are capable of handling 1000MW of power. This is due to the fact that currently VSC technology is limited up to 1.2kMW. The pressing factor for VSC limitation is the present state of IGBT capabilities. However theoretically you could run VSCs in parallel on both sides in order to supply the amount of power required, if it is greater than 1.2k MW[6].
<table>
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<th>Transmission Station Location #1</th>
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<th>Cable length (km)</th>
<th>Overhead Line (km)</th>
<th>Voltage (kV)</th>
<th>Power (MW)</th>
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*Table 2.1 Existing and under construction VSC projects.*

**Operational Information**

This information is to give some insight into substations dilemmas and unforeseen challenges. It will also be for examining the first encountered problem at the Cross Sound Cable substation, located in Westborough, MA. It is an underground VSC system that is composed of two remotely controlled converter stations. From 2003 to 2009 they averaged around 1.16% for forced outages. In 2003 it was due to a failure in an overheated IGBT, 2006 there was issues with the software for converter protections this cause IGBTs to fail. In 2009 human error was to blame for forced outages when a maintenance worker crashed a lift into a 200kv bus bar. During the first three years of operation they lost 77 IGBTs. This is nearly three times the amount of the last four years of operation in which they only lost 28[2].

This site utilizes a total of 2,916 IGBTs at each station. They are laid out in stacks and are designed to be a fail-safe as a short circuit. This site was the first to use second generation technology of IGBTs, at the time the increase in DC operating voltage cause some unforeseen faults. Planning for these events is tough to consider when the technology is so relatively new.
**Conclusion**

If the project is to support an insufficient system or if the demand on the commercial side increases VSC will be the proper choice. They provide an excellent VAR support and are able to conform to demand. They operate independently and are on the verge of becoming more competitive when compared to LCC. The size of the layout being an estimated 60% smaller than LCC it makes VSC slightly more attractive. These are the main key points for choosing VSCs. While the only downside for this system is the upfront cost and their limited on power transfer and have higher losses than LCCs.

**Voltage Source Converter References**


HVDC with Voltage Source Converters – A Powerful Standby Black Start Facility, Ying Jiang-Hafner, Hugo Duchen, Michael Karlsson, Leif Ronstrom, Bernt Abrahamsson
**Transmission**

**Transmission Introduction**

Since its conception in the late nineteenth century, alternating current has been the primary form of transmitting high voltage electricity from one location to another. However, a gradual increase in the demand for reliable power has also necessitated an increase in supply. With this increase in electrical capacity within the grid, the fallacies of alternating current systems have come into consideration when designing new transmission lines.

With the creation of the mercury arc valve in the 1950’s, it became possible to convert alternating current to direct current for transportation purposes, and then back to alternating current for distribution and consumption. As mercury valve technology evolved, solid-state components made an entrance into the scene of high voltage transmission. The introduction of thyristor valves and insulated-gate bipolar transistors have allowed for the improvement in signal control, harmonic noise elimination, and reduction of converter station footprints. These changes, alongside continual technological advancements, have allowed HVDC to become a viable option in long-distance transmission schemes.

Due to the fundamental dynamics of an alternating current system, there will be both resistive and reactive losses under normal operation. While factors such as weather and ambient temperature may affect losses, it may be defined primarily as a function of the voltage, current, and the impedance of the line. As a result of the steady-state behavior of a direct current line, there will only be resistive losses during normal operation. However, it should be noted that reactive losses are still present within the converter stations. The benefits of lower losses can be seen in Figure 3.1 below. The principle of higher voltage, lower current to reduce losses holds true between both AC and DC lines. However, it can be observed that the losses within the DC lines will be considerably lower than that of the HVAC line.
The cost of materials in the form of conductors and tower steel also come into consideration when comparing the costs and benefits of a DC line. Since a DC line will typically have one or two poles instead of the three phases present on an AC line, the cost of aluminum conductor will be significantly lower in the case of the former. A lower minimum design strength of supporting towers is a direct result of this reduced conductor count, which brings down the cost of a DC line. Another resultant benefit of reduced poles (and smaller towers) is that the required right of way becomes narrower, further decreasing the cost of the transmission line.

One major factor that affects the viability of a DC line is the cost of the converter station on both ends of the line. The converter stations required to convert AC-DC-AC represent a significant portion of the cost of the system. In Figure 3.2, it is shown that the high principle cost of the converter station is offset by the reduced cost of materials and losses as the proposed line grows in length. It is expected that the minimum “break-even” distance will continue to fall as development in solid-state voltage sourced converters progresses.
Upon initial inspection, it would seem that DC transmission would be the solution for any long-range transmission project. However, as with all engineering solutions, there are undoubtedly fallacies that come with the benefits of such a system. One such issue is the difficulty in tapping into an HVDC line. Due to the radial nature of an AC line, tapping a line is as simple as running a line to a substation and having it stepped down for distribution. This is not the case with DC lines. The alternating waveform on an AC line allows traditional transformers to manipulate the current and voltage ratios using the magnetic fields generated by the waveform. The lack of oscillation within a DC waveform makes the application of this transformer technology a non-viable option.

In this section, the design considerations of a high voltage direct current transmission line will be inspected. Due to the continual growth of DC technology and a fluctuating market, exact prices are difficult to discuss. However, the underlying factors of design are static, and may be discussed such that a basic understanding of the design of a DC transmission line and the differences from an AC line may be obtained. Many of the concepts between DC and AC transmission line design, such as grounding, insulation, clearances, and corona, are shared. The main differences in these design considerations stem from the difference in the signals being transmitted. The lack of signal oscillation on a DC line creates a local environment that is very different from that of an AC line, which poses a new set of design criteria.
Line Design

Bipolar vs. Monopolar

In regards to physical line design, there are a few different configurations to be implemented. Bipolar and monopolar configurations are the most common, while homopolar and tripole configurations also exist. The basic HVDC scheme is the monopolar configuration, which involves a fixed polarity on each end of the line. This single potential across the line creates current flow from the positive terminal to the negative terminal, and requires a ground electrode or metallic return for the flow of neutral current. This configuration is simple, but lacks robustness in the sense that maintenance or a fault condition on the line would result in cessation of power transmission.

A line with bipolar configuration is essentially two monopolar systems tied back to back. One line will have a positive potential with respect to a common node, while the other will have a negative potential. This configuration increases the amount of power that may be transmitted between the two terminals with minimal impact on right of way and clearances. Furthermore, a bipolar configured line may operate under monopole mode while one line is experiencing an outage. The amount of power transmitted is then limited by regulations on ground current flow and physical line design. In Figure 3.3, two common monopolar and bipolar configurations may be viewed.

Figure 3.3 Monopolar and Bipolar HVDC Schemes in Ground and Metallic Return Configurations
Although bipolar configurations are the most prevalent, some projects are implemented in monopolar configuration. The similarities between monopolar and bipolar configurations allows bipolar projects to be constructed as a monopole as an intermediate step. Since most lines implemented are bipolar lines, this will be the main focus of this section.

**Clearances**

It is imperative that adequate line-to-line, line-to-tower, and line-to-ground distances are maintained to ensure public safety and reliable operation. The importance of these clearances is defined by the overvoltage conditions of a line, and is a function of gap spacing. The areas of interest include normal operation, switching-surges, contamination, variance of weather conditions (i.e. lightning and wind), and maintenance.

In AC lines, overvoltages result from switching operations: line energization, line reclosing, load rejection, fault application, fault clearing, and reactive load switching. The intrinsic nature of HVDC control schemes allows for smooth control of line voltage [2]. This allows for the issues of fault clearing, line reclosing, and reactive load switching to be dealt with on the terminal-ends of the system. The remaining issue of lightning strikes is remedied in part by overhead shield wires, while contamination is addressed by appropriately sizing insulator strings. Strategic placement of grounded shield wires on transmission structures create envelopes of protection for the live conductors underneath.

To maintain these mandatory clearances, the designer of a HVDC line must consider two criteria: line-to-structure for the positive pole and conductor swing due to an established contingency basis. Clearances, as per EPRI, range from 0.7m to 1.9m for ±300kV to ±800kV respectively.

On the subject of switching surges, the equation given for a fifty year contingency is dependent on gap distance and a static gap factor [2].

$$V_{50} = k * 500 * d^{0.6}$$

Where:

$V_{50}$ is the insulation critical flashover voltage (50% probability) in kV

d is the gap distance in meters

k is the gap factor;
k = 1.15 for conductor to plane
k = 1.3 for conductor-structure under
k = 1.35 for conductor – structure (lateral or above)
k = 1.4 for conductor – guy wires
k = 1.5 for conductor to cross-arms with insulator strings

With the distance from conductor to structure established, the spacing between poles must also be considered. Depending on the type of insulator used, the equation to determine the minimum spacing between poles may vary. For I-string conductors, we find that the minimum pole spacing is given by the following relationship between conductor bundling, insulator string length, insulator swing angle, and tower width [2].

\[ DP_{T0} = (R + d_{min} + (L + R) + \sin\theta) \]

Where:
\( d_{min} \) is the operating voltage or switching surge clearance

\[ R = \frac{a}{2 \sin\left(\frac{\pi}{N}\right)} \]

A is the sub conductor spacing.
N is the number of sub conductors in the bundle
L is the insulator string length
\( \theta \) is the swing angle for the wind speed
w is the tower width at conductor level and varies from 1.2 to 2.5 for voltages from ±300-±800KV

If V-strings are implemented instead, it would be found that there would no longer be a swing angle, as the insulator configuration would prevent lateral motion in the presence of wind. As such, the minimum pole spacing would become a function of only the V-string length and tower width [2].

\[ PS_{min} = 2 \times L \times \cos(45^\circ) + w \]
Where:

$L$ is the length of the V-string.

$w$ is the tower width at conductor level and varies from 1.2 to 2.5 for voltages from $\pm300-\pm800$KV.

In determining the tower height of a line, we find that it is a function of the conductor sag under operating conditions. Conductor sag is directly related to ambient temperature, line current and local weather conditions. The current flow within the line, along with the physical and electrical properties of the physical conductor, must be considered in the design process of the transmission line. This is to ensure that appropriate tower and conductor heights are chosen to prevent violation of regional transmission regulations.

**Right of Way**

Another area of interest for the design of transmission lines in general is right of way. Right of way is defined as the strip of land that a transmission line passes through. Right of way is dependent on the total tower width and insulator swing under high-wind conditions. In Figure 3.4, we can see that HVDC lines require a smaller right of way for equivalent amounts of power. This results from the presence of two poles, rather than three phases on the structure. With the total clearances of an HVDC line notably smaller than that of an AC line, the strip of land that must be cleared for installation of a DC transmission line is substantially reduced. A typical right of way for a $\pm600$kV line would range from 66m to 70m [2]. Other factors that may affect the right of way of a particular line are radio interference levels and audible noise levels.

![Typical Transmission Line Structures for Approximately 2000MW](image-url)

*Figure 3.4 Comparison of Typical Transmission Line Structures for Approximately 2000MW.*

[Siemens]
The two main configurations of HVDC transmission are monopolar and bipolar lines. Monopolar lines involve fixed polarities at each end and result in power flow in only one direction. While this implementation is less costly than a bipolar line, the trade-off is in reliability and operational flexibility. On the other hand, bipolar lines are more costly but offer superior operation in case of pole outages. Since reliability is of the utmost importance in electrical transmission, bipolar schemes are often favored over the simpler monopolar design.

When determining the physical configuration of a DC transmission line, it is mandatory to ensure that proper clearances (line-line, line-tower, and line-ground) are maintained. Factors such as local terrain and weather, regional regulations, nominal line voltage act as important constraints when establishing these clearances. These main ideas behind physical line design are interchangeable between AC and DC systems. The main discrepancy between the two modes of transmission lies in the fact that DC lines require only two poles, whereas AC lines require three phases. The benefit of running only two poles is that the supporting structure’s footprint may become much smaller, resulting in a smaller transmission corridor.

**Earth Electrodes**

**Introduction to Earth Electrodes**

A monopole configuration is the simplest HVDC transmission scheme to implement. This configuration may offer a low cost solution for some transmission projects. Since there is only a single pole raised to a high potential, current must flow in the opposite direction through some other medium. In the case of a monopole, it is necessary to have either a metallic return, in the form of a secondary conductor, or an “earth return”, where the neutral current of the system is injected into the low-resistance ground (or ocean) over a large area. This source of neutral current is then connected by a metallic conductor to the terminal substation. While there are examples of monopole systems with earth return operating around the world, environmental regulations and the impacts of current flow on buried metallic objects such as pipelines and foundations make this type of implementation less appealing. In an ideal bipolar system, current of equal magnitude but opposite polarity will travel in each respective pole. Although this is not the case in practice, the neutral current present within a bipolar system will undoubtedly be less than that of a monopolar system.
Design Considerations of Ground Electrodes

In this section, the design considerations of a ground electrode will be discussed. Topics will include physical design and arrangement, electrolytic corrosion, touch potential, and current flow within the earth due to the electrode. Within a two-terminal system, there is usually an electrode placed some distance from each respective terminal. For example, the Pacific DC Intertie between BPA’s Celilo Converter Station to LADWP’s Sylmar Converter Station uses a ground electrode and sea electrode, respectively.

The main factor that affects ground electrode design is soil resistivity. This in turn is dependent on moisture levels and soil composition. It is necessary to accurately estimate the amount of ground current that will be flowing within the electrode system in order to ensure that soil temperatures do not exceed the commonly accepted 75°C [3]. If the earth were composed of a uniform substance, the charge distribution would resemble a hemispherical Figure 3 centered on the electrode, and the temperature rise in this single-layer soil may be shown through the following relation of current, ground resistance, and the heat conductivity and resistivity of the soil [3].

\[
\delta = \frac{(IR)^2}{2\lambda \rho}
\]

Where:
- \( \delta \) is the soil temperature rise
- \( I \) is the electrode current in Amperes
- \( R \) is the ground resistance in Ohms
- \( \lambda \) is the heat conductivity of the soil in W/m-K
- \( \rho \) is the resistivity of the soil in Ohm-meters

We can see that a poor estimate of soil resistivity may result in unacceptable temperature rises. However, this formula is not directly applicable in practice; earth is usually multi-layered and has a large range of resistances, ranging from \( 10^3 \Omega \) to \( 10^8 \Omega \) for soil and rock, respectively.
It is also found that the resistivity of the earth is largely a function of the local moisture levels. This means that the temperature rise in an electrode site will vary on the present level of moisture within the soil and time since last rainfall. If the temperature of the soil rises too much during electrode operation, high power losses will result from excessive soil drying.

**Physical Configurations of Ground Electrodes**

Land-based electrodes are usually configured as rings, stars, horizontal linearly, or vertical linearly (deep hole). Simple version of ring and star configurations may be observed in Figure 3.5. Ring, star, and horizontally linear land-based electrodes have conductors buried within a few meters of the surface. Examples of ring electrodes would be Itaipu’s earth electrodes, with radii around 0.5km. Star electrodes have six rays that radiate out from the center of the electrode. This configuration uses more conductor than ring electrodes, but the inner and outer parts of the rays do not distribute current equally. The inner portion of the star distributes less current than the outer, and is an inefficient use of conductor. Due to their large size in nature, these horizontally configured electrodes must be placed some distance away from the terminal substation.

In contrast, deep-hole electrodes are less restricted by space. They are buried straight into the ground and can be placed within close proximity of the terminal substation. The Baltic Cable HVDC Link employs this configuration. Horizontal and vertically configured land-based electrodes must be designed for the mechanical stresses caused by high winds and pressure, respectively. As a result of being embedded within soil, land-based electrodes are all subject to soil dry-out.

Sea-based electrodes are preferable to land electrodes because the benefits of current dissipation may be achieved without as much concern of thermal factors such as soil drying. They may be
configured either horizontally or vertically. The design criteria for sea-based electrodes are sea bed currents and ice. Soil dry-out and other thermal stresses are not of significant concern. The Sylmar side of the Pacific DC intertie uses the Pacific Ocean its earth return.

Pond and shore electrodes are alternatives when the sea is unavailable for practical implementation. The design criteria for these electrodes are similar to that of sea electrodes; heavy waves and ice are of major concern. Due to the geographical restrictions of water-based electrodes, sea, pond, and shore-based electrodes are mostly used for submarine HVDC links.

Equations for the resistances of ring, vertical linear, and horizontal linear configurations are given below [4]. Due to the fairly large nature of these electrodes, we can see that the resistance is actually fairly small. The calculation of a star electrode is more in-depth, as it must consider electrical coupling between the arms.

Ring Electrode:

\[ R_e = \frac{\rho}{\pi^2 D} \ln\left(\frac{4D}{b}\right) \]

Horizontal Linear:

\[ R_e = \frac{\rho}{\pi l} \ln\left(\frac{2l}{b} - 1\right) \]

Vertical Linear:

\[ R_e = \frac{\rho}{2\pi l} \ln\left(\frac{4l}{b} - 1\right) \]

Where:

- \( R_e \) is the electrode ground resistance in Ohms
- \( \rho \) is the resistivity of the soil in Ohm-meters
- \( D \) is the diameter of the ring in meters
- \( I \) is the total length of the conductor in meters
- \( b \) is equal to \( \sqrt{d h} \), in meters
- \( d \) is the diameter of the conductor in meters
- \( h \) is the burial depth of the center conductor in meters
**Electrolytic Corrosion**

The design of an earth electrode must consider the direction of current flow during operation. A byproduct of this current flow is electrolytic corrosion. Electrolytic corrosion is the loss of ferrous matter from a buried structure due to the flow of current. Depending on the respective terminal end of each electrode, one will be considered a cathode and the other the anode. Since current enters the cathode, it is usually unaffected by corrosion. On the other hand, protection for the anode must be considered during the design of the electrode, especially if it is expected to function as an anode for a significant period of time. “Corrosion of alternating current cause about 1% as much corrosion as direct current of equal rms value [5].” Other affected structures range from underground power interconnections, communications lines, gas pipes, oil pipes, docks, structure foundations, and the electrode itself. The mass lost may be described as a function of time and current [2].

\[
m = \frac{M}{n \cdot F} \int_{t_1}^{t_2} i \, dt
\]

Where:
- \(m\) is the mass of the element removed in kg.
- \(n\) is the number of electrons transferred in half reaction.
- \(F\) is Faraday’s constant = 96,485 C mol\(^{-1}\).
- \(t_1\) and \(t_2\) being final and initial times in seconds.
- \(M\) is the average atomic mass of material.
- \(i\) is the current in Amperes.

To put this into perspective, subjecting an iron electrode to 1000 A dc for one year would result in a 9125 kg loss of material [2]. This side-effect of prolonged operation of a monopole system is clearly unacceptable. As a comparison point, a bipolar system with a 5 A dc unbalance will net a loss of 45,625 kg of iron. In both of these examples, the material losses are unacceptable.

This issue may be remedied through cathodic protection; the electrode may be backfilled with petroleum coke. Petroleum coke is a byproduct of the petroleum process and has an average resistivity of 0.3 \(\Omega\)-m. If good contact is made between the iron and coke, current will tend to flow
by electron flow from the iron to the coke. This results in loss of mass of the petroleum coke at a much lower quantity than unprotected iron, with the doubled benefit of coke being much cheaper per unit. Petroleum coke, graphite, magnetite, high-silicon iron alloys, and coated titanium alloys may be used the anode of an electrode. Petroleum coke, graphite, and copper may be used for the cathode. The use of these materials for the implementation of earth or sea electrodes allows for minimal material losses due to electrolytic corrosion.

**Touch/Step Potential**

In both land and sea-based electrodes, we will find that there will be an electric field gradient present within the physical site of the electrode. This gradient must be limited, as to reduce the negative impacts on humans and local wildlife. IEEE Standard 80 states that the maximum allowable step voltage for humans may be found as a linear function of maximum allowable current flow through the body and soil resistivity [4].

\[ E_{step} = I_b(1000 + 6\rho_s) \]

Where:

- \( I_b \) is the maximum permissible body current in Amperes
- \( \rho_s \) is surface soil resistivity in Ohm-meters

In practice, voltage gradient limit is determined by the area in question. On pasture land, 13 V/m to 16.6 V/m is acceptable. Areas where large fish can approach the electrode may have limits of 1.5 V/m to 2.5 V/m, and areas where only small fish may approach the electrode may have a limit of 6.7 V/m. For land applications, increasing the depth of the electrode may provide the benefit of reducing the voltage gradient at the cost of increased costs of excavation.

**Other Issues due to Earth Electrodes**

During an earth electrode’s operation, we find that there are other issues that may arise. Electrical current tends to flow in the path of least resistance. One caveat of using an earth electrode embedded within earth is that the local soil may not necessarily be the path of least resistance. Other grounding structures and the neutrals of electrical equipment may have a lower resistance than the earth. In the case of AC transformers, we find that the presence of a DC current within the neutral will cause the transformer neutral to become biased. The presence of this DC biasing creates the risk of transformer overheating, increased vibrations and noise, and most importantly, causes the AC transformer to become a source of harmonic signals during normal operation.
Harmonics are generated within the transformer due to the imbalances within the magnetizing forces caused by the DC bias. DC biases in transformer neutrals will also result in reactive power losses within the AC system. Solutions to this problem require modifications to the AC systems in question.

Three common solutions are to 1) use a series resistor in the neutral of the transformer, 2) add a series capacitor on the AC line, and 3) to add a series capacitor in the neutral of the transformer. Options 1 and 2 are non-optimal due to the cost of implementation. In Option 1, we find that the required resistor would be too large to be economical. It would also have effects on the pre-established protection equipment within the AC system, requiring even more modifications and cost. In the case of Option 2, we find that it may sufficiently reduce the amount of neutral current in the transformer. However, it is difficult and expensive to implement series capacitors on HVAC lines. Furthermore, the presence autotransformers on the line cause the implemented capacitor to be effective on only one tap.

Option 3 has been tested at Dayawan and Lingao nuclear power stations in China, and has been found to be the most effective and economical [6]. The scheme involves placing a low impedance capacitor in series with the neutral of the transformer, with a bypass in parallel with the capacitor. The reasoning behind the bypass is to reduce the cost and special presence of the larger capacitor required to handle larger transients in the event of a fault. Figure 3.6 shows a depiction of how this series capacitor and bypass would be implemented. In the event of a fault, the bypass switch would close, causing current to be shunted to ground through itself rather than potentially overloading the capacitor. Once the fault has been cleared, the initial position shown below will be re-established.

![Figure 3.6 Series Capacitor Implementation to Restrain Neutral Current in Transformer. [6]](image)
As a result of uneven current distribution between the live conductor and earth electrode are not equal, there will be uneven magnetic field distribution in the areas of the electrode and line. The result of this is that field, if strong enough, may cause compass deviations. This may be of problems in shallow sea-based electrodes, or within close proximity of the land-based electrode. Another issue that arises from earth electrode operation is the generation of chlorine gas and hydrogen. This is primarily an issue in seawater implementations, and when the electrode is operating as the anode of the system. The gas produced at the electrode is a function of the current and mass of the element. While the gas is poisonous to humans, it has been found that the presence of chlorine is a good deterrent for life around the electrode [2]. Furthermore, a majority of the gas is carried away by the seawater. The generation of gasses is not of major concern, but should not be neglected during the design of the electrode.

Earth electrodes are an important component for HVDC transmission schemes. While grounding schemes are implemented for protection purposes in AC systems, earth electrodes of HVDC systems are designed for both normal and emergency operation. However, the side-effects of continuous operation are less than desirable, and preventative measures must be implemented to mitigate the potential damage caused by current flow within the electrode area. These reasons are another advantage that bipolar schemes have over monopolar schemes- although more expensive, a bipolar scheme will be able to serve more power, more consistently simply because of the fact that it will have a very small amount of neutral current. The earth electrode in a bipolar system will only be used in during pole failure or maintenance. A monopole system’s electrode will constantly have the total magnitude of the line current flowing through the electrode, requiring extensive cathodic protection of the anode.

Other issues that arise from the implementation of an earth electrode are soil temperature rise, step potential, adverse effects in substation transformer neutrals, gas generation, and compass deviations. These effects make the implementation of earth electrodes more desirable in locations that are further from populated areas and important infrastructure.
Insulation

Typically, insulators may be classified as external or internal insulation. External insulation is exposed to weather conditions and contamination, whereas internal insulation is protected from these conditions. Examples of each type of insulation would be the air surrounding a suspension insulator and oil within a transformer, respectively. Insulation may also be classified as self-restoring and non-self-restoring. This is defined by the insulator's intrinsic ability to regain its dielectric capabilities after a disruptive discharge. Air would be classified as a self-restoring insulator, while paper insulation within a transformer would be non-self-restoring.

Suspension insulators are the connecting point between load bearing structures and the electrically charged lines. Under normal operations, these insulators bear physical load from the suspended conductors and also serve in establishing a self-restoring, external air insulator between the supporting structure and the line. As manufacturers take care of strength testing within their own design processes, electrical properties of insulating materials will be discussed in this section. Although HVAC and HVDC insulators both serve the same purpose of maintaining dielectric gaps from line-line, line-tower, and line-ground, the differences in their electrical operation cause some discrepancies in line insulator design. One major difference between the two modes of transmission is that HVAC line insulators are coordinated with switching overvoltage and lightning events as the main design criteria, whereas HVDC insulator coordination also must consider contamination buildup due to the unique aspects of HVDC fields.

While conventional AC lines have three phases that oscillate at a set frequency, DC lines are held at a set level during steady-state operation. The result of this is that the electric field around an AC line will also oscillate as a function of time, whereas the field around a DC line will be constant. Furthermore, the DC line has two poles that do not change in polarity, creating a constant, relatively static environment around each pole. The issue that this poses is one of uncertainty. As an example, the Itaipu ±600kV transmission system was only finished in the late 1980s. Although there is research done on the subject of insulator design, much information is also gathered through field implementations. These two combined sources of data allows for a much more comprehensive understanding of design. However, HVDC projects are relatively “new”, and as such, are lacking the extensive research that is available in their AC counterparts.
Insulator Materials

Over the past two decades, it has been found that it is necessary to incorporate specific features in DC insulator specifications to prevent premature degradations and ensure good performance over time [7]. Typical materials used in insulator design are glass, ceramic, and composite polymer. Although the IEC 61325 standard [8] has outlined design considerations for glass and ceramic insulators, there lacks an equivalent standard for composite polymer insulators under HVDC implementations. IEC 61325 discusses the resistivity of ceramic and glass through ionic migration and thermal runaway. These two properties may be described through the effect caused by the persistence of a unidirectional current flowing through the insulator bell. This current traveling through the dielectric can generate some depletion of the atomic structure of the material, reducing the material’s electrical and/or thermo mechanical and electromechanical properties [7]. The resultant effect of thermal runaway and ionic migration failure is insulator puncture or shattering. The main cause for these current are impurities within the structure of the insulator, such as sodium. In fact, thermal runaway studies have shown that the electrical resistances of glass insulators will decrease from hundreds of MΩ to tens of MΩ for temperatures of 90°C to 120°C, respectively [8]. As a result, it is important for the manufacturer of glass and ceramic insulator bells to maintain a high quality of materials and thus, dielectric resistivity. Dielectric purity is also the main limiting factor in ceramic and glass type insulator bells.

Although composite polymer insulators have not been in service as long as their ceramic and glass counterparts, there has been a fair amount of testing through application. A major benefit of utilizing composite polymer insulators on HVDC lines is that the composite may secrete hydrophobic oils that encapsulate contamination particles and repel water. The result of this passive flashover prevention makes composite polymer insulator strings increasingly attractive for HVDC applications.

Other factors that come into consideration are local contamination levels. Under the field of a DC line, it is found that airborne particles become attracted to the line and insulators. This continual buildup of contamination on insulators may result in severe structural and electrical degradation of the metal fittings of the insulators. In general, the positive pole of the line is considered for aging and degradation conditions. The resulting corrosion could potentially cause insulator failure, line drops, and adverse effects on leakage currents and flashover performance, particularly
on the positive pole of the line. In Figure 3.7 below, we can observe the comparison of insulator pins from Itaipu's ±600kV transmission system after 20 years of service. It is clear that corrosion is much more prevalent on the unprotected surface. The addition of a protective zinc sleeve on the pin has significantly reduced corrosion over the operational lifespan of the component.

*Figure 3.7 Pin Corrosion as a Result of Contamination from Itaipu ±600kV Bipole. Zinc Coating (bottom right) and No Coating (bottom center).* [7]

**Leakage distances**

Leakage distance may be defined as the shortest distance separating two conductors as measured along an insulating surface. In the application of suspension insulators, this distance is formed by the contour and sheds of the insulator. The unit for leakage distance is distance per kV, or mm/kV. As local pollutant levels (dirt, smog, salt) increase, this leakage distance will have to increase to reduce leakage currents and potential flashovers.

In AC insulators, the effective leakage distance may be calculated directly by the physical dimensions of the insulator. This is because flashover arcs tend to travel along the surface of the insulator string. However, in DC applications, flashovers tend to extend away from the insulator. This creates a condition in which the physical leakage distance of the insulator may not be fully utilized in the event of a flashover, requiring larger leakage distances and/or specialized shed design. Table 3.1 shows how the recommended leakage distances for ceramic and porcelain HVDC insulators increase significantly for varying levels of local contamination. It may also be noted that a much longer leakage distance must be used for HVDC lines in comparison to HVAC lines.
Table 3.1 Suggested Leakage Distances for AC and DC Insulators Under Contamination. [17]

<table>
<thead>
<tr>
<th>Contamination severity (\text{(mg/cm}^2)</th>
<th>Very Light (&lt; 0.005)</th>
<th>Light (0.005 - 0.02)</th>
<th>Moderate (0.02 - 0.05)</th>
<th>Heavy (&gt; 0.05)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDC Leakage Distance (\text{(cm/kV)})</td>
<td>2.0-2.5</td>
<td>2.5-3.2</td>
<td>3.2-4.0</td>
<td>4.0-7.0</td>
</tr>
<tr>
<td>HVAC Leakage Distance (\text{(cm/kV)})</td>
<td>1.6</td>
<td>2.0</td>
<td>2.5</td>
<td>3.1</td>
</tr>
</tbody>
</table>

Temporary Overvoltages and Lightning Performance

As per ANSI C92.1 and IEC Publication 72, the definition of an overvoltage is any transitory voltage between phase and ground or between phases with a crest value higher than the crest value of maximum system voltage [8]. An overvoltage may be characterized by insulator failure and/or disruptive electrical discharge. The magnitude of these overvoltages varies on the operating condition of the line and also the parameters of the initial event. Under operation, a line may experience overvoltages as temporary overvoltages, switching overvoltages, and lightning overvoltages. Events such as faults, changes in load, and open conductors may be classified as temporary overvoltages, and typically do not exceed much higher than 2.0 p.u. Line energization, line reclosing, fault occurrence, and changes in system reactance fall under the category of switching overvoltages. Finally, lightning overvoltages are caused by the contact of lightning strokes to the line. In the context of an HVDC system, it is found that the magnitudes of transient events such as switching are limited by controls on the terminal ends of the system. This leaves mostly lightning strikes and other weather events such as contamination as major concerns in insulator design.

Lightning strikes are extremely short duration, high voltage and current events caused by ionization of air. These events are of the highest concern when coordinating insulation for DC lines. In comparison, AC lines are primarily concerned with switching surges. In the Figure 3.8, we can see the increase of insulation requirements as altitude increases. It can be observed that insulation coordination for lightning strikes is more dependent than for switching surges and
contamination flashovers. Furthermore, the implementation of overhead shield wires act as an effective way of deflecting lightning strikes to live conductors.

![Flashover Performance and Contamination](image)

**Figure 3.8 Comparison of Insulator Requirements as a Function of Altitude. [1]**

**Flashover Performance and Contamination**

The voltage at which an insulator is able to sustain a dielectric gap across its length is called the withstand voltage, or $V_W$. The test process of establishing the withstand voltage is to apply a voltage across the insulator in question. Although the value of $V_W$ is a quantifiable value and the results of the test are binary, it has been found that the results of a repeated test may vary. For example, one may find that at an overvoltage event may occur at a voltage lower than one initial trial's established $V_W$. Furthermore, they might continue on to find that an overvoltage did not occur at a voltage higher than $V_W$. Due to this unreliability in results, overvoltage events must be defined in statistical terms.

Other important properties of an insulator are its critical flashover voltage, critical withstand voltage, and leakage distance. Critical flashover voltage (CFO) represents the voltage at which there is a 50 percent probability of a flashover occurring on a particular insulator. Critical withstand voltage (CWS) is defined as the value found when subtracting three standard deviations from the critical flashover value. As per BPA's experiments [10], this distribution assumes a normal or Gaussian distribution, and represents a 0.13 percent probability of flashover.

$$CWS = CFO - 3\sigma$$
Flashover occurs under conditions in which electrical stresses surpass the dielectric barrier formed by the insulator. DC systems are much more susceptible to flashover occurrences due to the lack of current zeros, and the line's persistent electrical field. Through experimental evidence, it is found that the addition of contamination – dirt, grime, dust, salt, etc., will tend to reduce the critical flashover voltage level for insulator strings. Contaminants are attracted to the insulator through three primary forces: gravity, weather, and electric field, with wind being the major factor in contamination deposition. With the exception of conductive contaminants such as metal oxide and petroleum coke, typical contaminants will not cause flashovers when dry. Typically, there are three conditions from which a flashover may occur [11]:

a) When an insulator is wetted after being energized at normal working voltage for a long time.
b) When a wet polluted insulator has just been energized at its normal working voltage.
c) When a wet polluted insulator is subjected to a transient voltage.

The common issue with these conditions is the presence of moisture. The presence of contamination will allow for moisture to adhere to the insulator's surface, creating areas of low resistance. This allows current flow, and thus, power dissipation in the form of heat, to occur on the normally non-conducting surface of the insulator. As the wetted areas begin to dry out and dry regions are formed along the surface, the local resistance in highly energized areas of the insulator will increase. Noting Ohm's Law and $P = I^2R$, we find that the power dissipation per unit area will increase with the resistance. The result of this drying action results in sparking across the dry insulating bands of the insulator, until the width of the dry bands becomes too large for the voltage potential to spark across. In the event that the electrical stress is sufficiently high to jump across the length of the entire insulator, a flashover will occur. This process will repeat until another flashover occurs, the insulator dries to a state where the voltage can no longer create a spark, or the contaminants are washed away and the activity driven by the uneven voltage gradient and leakage currents across the insulator fades away. Through empirical evidence, it has been found that the contamination distribution on an insulator string is typically uneven. The effects of rain washing, wind, and the presence of an electric field leave more contamination towards the line-end of the insulator string, and less towards the tower-end.
Due to the unpredictable nature of contamination distribution, researchers have developed Equivalent Salt Deposit Density, or ESDD, as the standard way of measuring and testing contamination on an insulator. However, it should be considered that live conditions may only be replicated to a certain extent. In practice, it has been found that the BPA’s standard testing for HVDC insulators include constant and variable voltage testing. Artificial contamination, such as kaolin, sodium chloride, Bentonite, and calcium chloride, may then be applied in four ways [10]:

- The specimen is dipped in a premixed slurry.
- The contaminant is flowed over the insulator specimen.
- The specimen is sprayed with either a wet or dry contaminant.
- The contamination is deposited through the medium of a fog.

Two other factors that affect the flashover performance of insulators are insulator profile and altitude. Insulator profile is an important aspect of insulator design because an effective profile may decrease the likelihood of a flashover occurrence. While an AC arc propagates from one underrib tip to another adjacent to the insulator surface, a DC arc is found to follow shorter paths through the air [12]. The result of this property of DC arcs is that effective creepage length of the insulator may be much shorter than the actual creepage length. The experimental results to a study on effective insulator creepage length will show that the effective creepage length of an HVDC insulator can be estimated in the formula shown below. It can be seen that the effective creepage length of an insulator under DC conditions shrinks in comparison to the physical creepage length as underrib complexity increases.

\[ S_{\text{eff}} = E(w/d)S = 1.0 - \exp[-\frac{k w}{d}] \]

Where:
- \( S_{\text{eff}} \) is the effective leakage length
- \( S \) is the arc formed by the underrib of the insulator in centimeters
- \( k \) is a constant dependent on the radius of the shed and contamination density
- \( w \) is the distance between the peaks of each underrib in centimeters
- \( d \) is the height of the underrib in centimeters
Figure 3.9 shows the results of a study done on the ±500kV Pacific DC Intertie [14]. The shaded region of the graphic represents the required insulator length of ceramic and glass insulator strings, while the red line represents a hydrophobic, high voltage composite insulator string. It is very apparent through this Figure 3.9 that composite insulators outperform their ceramic and glass counterparts by a large margin, particularly when contamination levels increase.

![Figure 3.9 Comparison between Composite and Ceramic/Glass Insulator Strings](image)

*Source: CIGRE [14]*

**Flashover Performance at High Altitudes**

In an experiment done on HVDC insulators and high altitude, it was found that composite insulators continued to have the best flashover performance in comparison to glass and ceramic insulators [13]. When comparing glass and ceramic insulator units, the bells with underribs performed better than those with multiple sheds. In Table 3.2, the experimental results showed that insulator types A and B had similar critical flashover voltage levels despite the physical difference in leakage distances. Also, insulator C showed a much lower critical flashover voltage than that of type B, despite identical leakage distance and physical parameters.
Furthermore, the experiment showed that an increase in altitude will cause the DC arcs to extend more easily from the insulator surface in comparison to sea level. The result of this change in arc behavior results in a lower critical flashover voltage. In Table 3.3, we can see the differences in critical flashover levels for ceramic bells operating at sea level and an altitude of 2000m for different contamination levels. Through this set of data, we can see that altitude has a definite effect of lowering the critical flashover levels of the ceramic bells in question.

<table>
<thead>
<tr>
<th>SDD mg/cm²</th>
<th>CFO (kV)</th>
<th>Percent Difference (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0 meter</td>
<td>2000 meter</td>
</tr>
<tr>
<td>0.03</td>
<td>15.89</td>
<td>13.99</td>
</tr>
<tr>
<td>0.05</td>
<td>11.25</td>
<td>9.94</td>
</tr>
<tr>
<td>0.10</td>
<td>8.52</td>
<td>8.05</td>
</tr>
<tr>
<td>0.15</td>
<td>7.17</td>
<td>6.53</td>
</tr>
</tbody>
</table>

*Table 3.3 Comparison of flashover voltage at sea level and 2000m at varying contamination levels. [13]*

To compare the performance of glass and ceramic insulators, the glass bells shown in Table 3.4 were used. Figure 3.10 shows the comparison of flashover performance for insulator types B, C, D, and E. It can be observed that the ceramic bell with underribs performed the best for the given test parameter, despite the fact that it did not have the largest leakage distance. The poorest performing insulator was specimen D, the smallest leakage distance and unit diameter. The results of this comparison show that flashover performance of DC insulators depends on shed
profile and shell diameter as well as physical leakage distance. The result of an increase in leakage distance may not result in a proportional, linear increase in flashover levels.

<table>
<thead>
<tr>
<th>Type</th>
<th>Insulator</th>
<th>Leakage Distance L. (mm)</th>
<th>Unit Spacing H. (mm)</th>
<th>Diameter of shell D. (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>D</td>
<td></td>
<td>620</td>
<td>240</td>
<td>360</td>
</tr>
<tr>
<td>E</td>
<td></td>
<td>710</td>
<td>195</td>
<td>380</td>
</tr>
</tbody>
</table>

*Table 3.4 Comparison of physical properties of insulator types D and E. [13]*

*Figure 3.10 Flashover Performance Comparison of Ceramic and Glass Insulator Types B, C, D & E. [13]*

When comparing composite polymer insulators, it was found that leakage distance had the same principle behavior as in ceramic and glass insulator units. An increase in the leakage distance resulted in improved, but non-linear flashover performance. The difference with composite and their ceramic/glass counterparts is that profiles may be shaped more freely. The shed diameter, shed spacing, and shed inclination angles of composite insulators may be altered to achieve optimal flashover performance. Due to this flexibility in design, and natural hydrophobicity of the composite material, these insulators continue to show superior flashover performance to their ceramic and glass counterparts in high-altitude environments.
In this section, a basis of insulator design considerations as well as lightning and flashover performance has been presented. However, it should be made clear that the flashover phenomenon is still not completely understood. While there is continual growth of empirical data and formulas in insulator design for various environments, there are too many variables to provide a straight-cut solution for every application. The research done in AC systems cannot be directly applied to DC systems, as the fundamental operation of each mode of transmission is different. The variance in testing procedures and lack of standards amongst researchers and utilities creates an inconsistent atmosphere to develop in. Contamination is unpredictable and varies from region to region, and may even show great variance within the span of the line. This further complicates the issue of insulator design, and means that special considerations must be taken into account for every line.

**Corona**

**Introduction to Corona Discharge**

By IEEE definition, corona is “a luminous discharge due to ionization of the air surrounding a conductor caused by a voltage gradient exceeding a certain critical value.” Although corona is an issue that must be dealt with in both AC and DC lines, the fundamental difference between the two lies in the presence and lack of oscillation of the signal, respectively. During a corona event on an AC line, we find that the ions are always attracted back towards the conductor, whereas ions with the same polarity as the conductor on a DC line will be able to continually repel away. The result of this is that AC corona is fairly local to the conductor, while the free charges may extend much farther on a DC line.

It is important to note that there are two zones around a conductor when considering corona. The ionization zone is found immediately around the conductor, about three orders of magnitude smaller than the conductor-to-ground zone. In the event of corona, the high electric field present on the line causes particles to collide with surrounding air molecules. If the particles are moving with sufficient force, we find that air molecules become stripped of electrons, which in turn become attracted to the positive pole or repelled from the negative pole of the line. Through this movement, a cascading effect occurs where more air molecules lose electrons, and the process continues. This results in ionization of the surrounding air, resulting in corona. The voltage on
the line resulting in corona is known as the maximum conductor surface gradient, with units kV/cm. Highest voltage gradients are found on sharp edges of surfaces, such as imperfections or damaged areas of conductors. Furthermore, it should be noted that “appreciable corona power losses do not begin at the critical onset voltage, but occurs only when the critical gradient for air breakdown extends outward an appreciable distance from the conductor surface” \[10\].

For a bundled conductor configuration, the average and maximum surface conductor gradients may be calculated by the Markt and Mengele method \[2\].

\[
E_a = \frac{V}{nr \cdot \ln \left( \frac{2H}{r_{eq} \sqrt{\left( \frac{2H}{S} \right)^2 + 1}} \right)}
\]

\[
E_m = E_a \left[ 1 + (n-1) \cdot \frac{r}{R} \right]
\]

Where:
V is the voltage applied to the conductors in kV
R is the bundle radius in centimeters (see Line Design)
r is the sub-conductor radius in centimeters
\[r_{eq} = R \cdot \left( \frac{n \cdot r}{R} \right)^{1/n}\]
H is the conductor height in centimeters
S is the pole spacing in centimeters

We can see that the average conductor surface gradient \(E_a\) is decreased with the number of conductors in the bundle. Similarly, the maximum conductor surface gradient is increased with additional conductors within the bundle. However, with economic costs in mind, more conductors than necessary are not desirable in practice.
Consequences of Corona

The major side effects of corona discharges are corona losses, radio interference, and audible noise. The factors that affect corona are weather - rain, wind, snow, etc, and line parameters such as conductor spacing. From BPA’s studies, we can see that losses for equivalent maximum conductor surface gradients increase drastically from fair-weather to rain-weather. “Mean rain-weather losses are 2 to 4 times the mean fair-weather losses, and short-term losses, such as during heavy rain, may be 10 times the mean fair-weather losses. In contrast, ac rain-weather losses may be as much as 50 times the fair-weather losses [10].” This trend continues for fog/snow and also with wind. To summarize BPA’s findings, maximum corona losses result from rain, with slightly lower losses in fog, and the twice the fair-weather losses in snowy conditions. In Figure 3.11, the relationship between weather and corona losses for AC and DC systems may be observed.

Figure 3.11 Comparison of EHVAC and HVDC Corona Losses as a Function of Altitude and Weather. [2]

Due to weather and other environmental factors such as contamination buildup being out of the designer’s control, it is difficult to calculate an absolute value of corona loss on the line in question. Instead, it is possible to estimate an approximate value of corona loss using the parameters that are known for the line using empirical relationships between line voltage, maximum voltage gradient, conductor height, pole separation, and conductor sizing [15].

\[ P_{\text{fair}} = P_0 \left( \frac{g}{g_0} \right)^5 \left( \frac{d}{d_0} \right)^3 \left( \frac{n}{n_0} \right)^2 \left( \frac{H}{H_0} \right)^{-1} \left( \frac{D}{D_0} \right)^{-1} \]

and
Where:
P are power losses by corona in dB above 1kW/km

\[ P_{\text{foul}} = P_0 \left( \frac{g}{g_0} \right)^4 \left( \frac{d}{d_0} \right)^2 \left( \frac{n}{n_0} \right)^{1.5} \left( \frac{H}{H_0} \right)^{-1} \left( \frac{D}{D_0} \right)^{-1} \]

\[ P_{0,\text{fair}} \text{ is } 2.9 \text{dB and } P_{0,\text{foul}} \text{ is } 11 \text{dB} \]

\[ V \text{ is the nominal line voltage in kV} \]

\[ g \text{ is the maximum gradient on the subconductor's surface in kV/cm} \]

\[ H \text{ is the average height of the conductor above the ground in m} \]

\[ D \text{ is the distance between the poles in m} \]

\[ d \text{ is the subconductor's diameter} \]

The constants for the formula are \( g_0 = 25 \text{kV/cm}, d_0 = 30.5 \text{mm}, n_0 = 3, D_0 = 15 \text{m}, H_0 = 15 \text{m} \)

**Corona and Audible Noise**

A portion of the energy lost during a corona discharge is acoustic energy in the form of crackling, sizzling, or hissing. Audible noise falls within the range of human hearing, with frequencies of 20 Hz to 10 kHz [16]. The major concern of audible noise is public annoyance. As with radio interference, audible noise is primarily generated from the positive pole of the line. In Table 3.5, the relationship between bundle sizing and the required right of way required by audible noise is shown. It can be observed that the implementation of more subconductors within each pole's bundle will tend to decrease the AN output, which in turn reduces the required right of way for the line. Consequently, smaller conductors will require that the right of way be wider than with larger conductors.
The main differences between audible noise generated on a DC line versus that of an AC line is that the former will tend to decrease during foul weather, while the latter will tend to increase. Through empirical and experimental data, CIGRE has found that AN may be calculated with the following formula for fair-weather conditions [17]. It can be observed that an increase in the number of subconductors will have a positive effect in reducing the total audible noise generated by the line. It is generally desired to have audible noise of 55dB or below at the edge of the transmission line’s right of way.

\[
AN = AN_0 + 86 \log(g) + k \log(n) + 40 \log(d) - 11.4 \log(D) + \frac{q}{300}
\]

Where:
- \(n\) is the number of subconductors
- \(g\) is the maximum bundle gradient in \(\text{kV/cm}\)
- \(d\) is the conductor diameter in centimeters
- \(D\) is the radial distance from the positive pole in meters
- \(k = 25.6\) for \(n > 0\) and \(k = 0\) for \(n = 1,2\)
- \(q\) is the altitude in meters

<table>
<thead>
<tr>
<th>kV</th>
<th>Conductor Bundle Size</th>
<th>MCM</th>
<th>Audible Noise Right of Way</th>
</tr>
</thead>
<tbody>
<tr>
<td>+600</td>
<td>3</td>
<td>2,515</td>
<td>52</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2,167</td>
<td>62</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,780</td>
<td>78</td>
</tr>
<tr>
<td>+600</td>
<td>4</td>
<td>2,515</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,780</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,113</td>
<td>60</td>
</tr>
<tr>
<td>+600</td>
<td>5</td>
<td>2,515</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,780</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td></td>
<td>798</td>
<td>44</td>
</tr>
</tbody>
</table>

*Table 3.5 Right of Way for Variable Conductor Sizes and Bundle Size.* [17]
AN₀ = -100.62 for n > 2 and AN₀ = -93.4 for n = 1, 2

In this section, DC corona events were briefly introduced. Corona discharges may generate radio interference, audible noise, and result in power losses within the system. Corona discharges may be reduced by the implementation of corona rings, which reduce the amount of sharp surfaces in the system. However, it is not possible to completely eliminate corona. While corona losses are certainly quantifiable, radio interference and audible noise during fair-weather conditions may be of higher concern during line design. This is due to corona losses being much lower on a DC line than that of an AC line.

In general, the basic mechanics of corona is understood. However, the interaction between the electric fields and ions generated by an energized line and their effects on corona is not. Although general rule-of-thumb statements have been presented in this section, there is much left to understand and study on the topic of corona phenomena.

**Field Effects of HVDC Transmission**

**Introduction to E&M Fields**

In the design of transmission lines, the presence of electric and magnetic fields generated by current flow through conductors must be considered. The major factors that affect field effects are corona events, voltage and current levels, weather conditions, and the geometric arrangement of the conductors and poles. The major difference between this section and the preceding sections is that field effects are primarily a function of line parameters, and not the main focus of line design criteria. It is important to establish dimensions of the line such that adverse effects do not arise. The main issues that arise from the presence of these fields are public perception, touch potentials, and interference.

**Introduction to Electric & Magnetic Fields**

The electric fields generated by a DC transmission line differ from that of an AC line because current lacks the capacitive component present in an AC line. The capacitive coupling that is produced by the AC line allows for currents to be induced in nearby objects. In contrast, the
electric coupling within a DC line is resistive. The absence of this capacitive component creates some difficulty in comparing DC and AC fields—measurements of magnitude a less-than-optimal since, they one parameter does not entirely describe the effects of the field.

In regards to magnetic fields, it is important to note that the Earth itself generates a magnetic field. Magnetic fields generated by the line may add to the Earth’s, and may potentially cause local interference with bird migration, compasses, and other navigation equipment. The magnetic field at the surface of the Earth is between 30–70μT. For a ±500kV DC line, it is found that the magnetic field generated is lower than 50μT. In general, HVDC lines generate magnetic fields with magnitudes of less than 70μT, and are not of major concern during the design process.

**The Effects of Electric Fields**

For a human of 1.73m in height, BPA found that 3μA was experienced while standing directly under a 4 x 30.5mm conductor line operating at ±600kV. In Table 3.6, a comparison of the interaction of current in humans between AC and DC lines is shown. It can be observed that even underneath a ±600kV DC line, no perception threshold was broken. Also, notice how there is a significantly higher threshold for direct current for each criterion.

<table>
<thead>
<tr>
<th>Current in Milliamperes</th>
<th>Direct Current</th>
<th>60 Hz rms</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Men</td>
<td>Women</td>
</tr>
<tr>
<td>No sensation on hand.</td>
<td>1.0</td>
<td>0.6</td>
</tr>
<tr>
<td>Slight tingling. “Threshold of Perception” level.</td>
<td>5.2</td>
<td>3.5</td>
</tr>
<tr>
<td>Shock; uncomfortable but not painful; muscular control not lost.</td>
<td>9.0</td>
<td>6.0</td>
</tr>
<tr>
<td>Painful shock; muscular control not lost. “Safe Let-Go” level for 99.5% of persons tested.</td>
<td>62</td>
<td>41</td>
</tr>
</tbody>
</table>

*Table 3.6 Physiological Effects and Thresholds for Body Currents and Shock Currents.* [9]
Although the field effects generated by HVDC lines have not been shown to have adverse effects on organic life, the negative perception of them still stands. The solution to this problem is to ensure that the right of way is wide enough to prevent the perception of strong physiological effects. Through BPA’s research, “enough data was acquired to show that annoyance shocks from objects adjacent to a dc line similar to the Test Line will rarely reach the “uncomfortable shock” level, and that under most conditions, “perception” energy levels will rarely be attained [10].”

Another physical concern of electric fields is the buildup of charge on objects such as fences, vehicles, and other metallic objects. Over a nine month study, BPA found that a barbed wire fence, 17m away from the projection of the conductor, needed to be 20km long to store a charge of 41mA, the “Safe Let-Go” level for women for direct current. For a metallic panel 30m from the line to reach the 5.2mA perception level, the panel would need to have an area of 23,600m², which is highly unlikely in such close proximity of a HVDC line [10].

Concerns in regard to vehicles are twofold. The first being risk of shock, and the second being potential fuel ignition. Vehicles with rubber tires may be simplified as a resistance with a capacitance. When placing a vehicle on a grounding pad with the tires still attached, a test vehicle was found to have 50MOhm of resistance to earth. Even so, the result was a mere “uncomfortable shock”. In practice, vehicles should be properly grounded when in proximity of a live line. Through experimentation, “the voltage attained by a person at ground level under or near a ±600kV line would seldom exceed 1.5kV, an energy level of 0.112 mJ or about 10% of the ignition level [10].” Also, it was found that voltage on a vehicle with direct contact with the earth never exceeded 1kV or a 1 mJ of stored energy. From these results, BPA deemed fuel ignition to be highly improbable under natural conditions.

Radio Interference Generated by Electric Fields

Radio interference (RI) is the major effect caused by the fields generated by an HVDC transmission line. Corona discharges are the main attributor to radio interference. Radio Interference is usually measured from the positive pole of the line, as the negative pole generates RI at about 6dB lower. The magnitude of RI may be characterized as inversely proportional to the square of the distance from the pole up to 50m, and then inversely proportional to the distance from the pole for distances greater than 50m. In Figure 3.12, this relationship between RI and distance on the positive pole of a ±750kV line may be observed. Average fair weather RI for
bipolar HVDC lines may be described by the equation below. We can see that the radio interference generated by an HVDC line is a function of maximum bundle gradient, conductor size, distance, altitude, and the frequency in question [17].

\[ \text{RI} = 51.7 + 86 \log \left( \frac{g}{g_0} \right) + 40 \log \left( \frac{d}{d_0} \right) + 10 \left( 1 - \left[ \log(10f) \right]^2 \right) + 40 \log \left( \frac{19.9}{D} \right) + \frac{q}{300} \]

Where:
RI is the radio interference level measured at a distance D from the positive pole in dB above 1uV/m
\( g \) is the maximum bundle gradient in kV/cm
\( d \) is the conductor diameter in centimeters
\( f \) is the frequency in Megahertz
\( D \) is the radial distance from positive pole in meters
\( q \) is the altitude in meters

\( g_0 = 25.6 \text{kV/cm} \) and \( d_0 = 4.62 \text{cm} \)

![Figure 3.12 Lateral Profile of Radio Interference vs. Distance. [18]](image)

An established method of measuring RI and whether it is within acceptable limits is through its Signal-to-Noise Ratio (SNR) [10].
The frequency band that is of interest for RI studies is 500 kHz through 1.7 MHz. These frequencies represent the radio band used in AM broadcasting. Noting that acceptable radio interference is purely subjective, BPA found that a tolerable SNR was about 10:1. This means that the signal must be 20dB above the radio interference generated by the line at the receiving antenna. In comparison to AC lines, it appears that DC systems have a lower threshold for acceptable interference—acceptable SNR for the former range from 15:1 to 25:1.

In general, DC radio interference is lower in humid weather than it is in clear weather. The opposite is true in AC systems—RI is typically enhanced during foul weather in comparison to fair weather. Radio noise is typically increased by wind, particularly when the direction is from the negative pole to the positive pole. DC RI also tends to increase with temperature, whereas there have been no trends observed between RI and variations of altitude.

Although it is important to consider every aspect of a project, we find that adverse effects from electric and magnetic fields are more of an annoyance than limiting design criteria. Physiological threats such as charge buildup require impractical or already un-safe conditions to be present in close proximity of the live line. Radio interference is more difficult to gauge, as it is judged on a subjective scale. However, established SNR levels point to this issue to not be of much concern; the noisy signal generated by a HVDC line will tend to degrade quickly from the conductor, but must retain a high magnitude with respect to the signal wave that it is interfering. The side effects of these fields, even in close proximity to a HVDC line, prove to be relatively safe, and can be dealt with by picking an adequately sized right of way.

**Transmission References**

[i] L. Weimers, “Bulk power transmission at extra high voltages, a comparison between transmission lines for HVDC at voltages about 600kV DC and 800 kV AC”, ABB Power Technologies, ABB.


Wind Power Plants

Wind Power Plants Introduction

Wind power generation is the most rapidly growing technology for renewable power generation [1]. However, wind power plants (WPPs) vary greatly from their traditional power generation counterparts like hydro, nuclear, and coal generation plants. Beyond the issues of social, economic, and environmental impacts, which will not be covered in this paper, there are certain technical challenges that present themselves.

First, the differences between traditional power generation versus wind power generation, and the associated technical difficulties, will be described. General wind turbine topics such as size and descriptions of the various generator types that are currently available, including the advantages and disadvantage of each, will follow. Design concerns of the collector system, including feeder topology and transformer topics, are described in the next section. Then, system stability and control interactions will round out the information presented regarding WPPs.

Traditional Power Generation vs. Wind Power Generation

Traditional power generation schemes are tried and true and leave room for very few surprises. In stark contrast, WPPs have many problems with low voltage ride-through, harmonic distortion, power system stability, and reactive power control, which require greater efforts on the part of planners and operators in the areas of technology and decision-making. Other fundamental differences in reliability, cost, and regulations further complicate WPP installation.

Hydro, nuclear, and coal plants are well-known for their reliability. They produce consistent, quality, base-load power. The reliability issues with wind generation include a non-constant prime mover (i.e. wind), wind turbine generators that are under constant development so they have not been tested over the long-term for wear and tear and reliability, and adverse effects on the local and larger grids created by WPP.

One of the topics of concern is the highly volatile costs associated with wind generation. This is due to factors such as [2]:

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• Shortages of turbines and components. This is a direct result of the dramatic recent growth of the wind industry in the United States and Europe. Supply chains are hard-pressed to keep up with the ever increasing demand.

• The weakening U.S. dollar relative to the euro. Since many major turbine components are imported from Europe and there are fewer component manufacturers in the U.S. the cost in U.S. dollars remains relatively high.

• A significant rise in material costs, such as steel and copper, over the last few years. Also, there has been a marked increase in the cost of transportation fuels over the last few years.

• Unpredictable government incentives. For example, the Production Tax Credit has been on-again, off-again. This causes uncertainty which hinders investment in new turbine production facilities and encourages hurried and expensive production, transportation, and installation of projects when the tax credit is available.

• Unpredictable demand for wind turbines. When tax credits are available there are surges in demand for wind generators. This prompts manufacturers to meet the demand by cutting corners when producing the machines, e.g. lower quality lamination techniques. This causes an increase in down time and repair costs to WPPs.

The connection agreements outlined for traditional generation plants, including rules governing planning, metering, communications, and protection & control, are well-defined. In contrast, the regulations defined for interconnections for wind energy have, historically, been somewhat of a moving target. Innovation in the wind generation sector has been driven by the need to keep up with complicated interconnection agreements and technical requirements for large wind plants such as low voltage ride-through capabilities, power factor design criteria, and control & data acquisition capability. These stipulations can prove to be onerous for the potential WPP owners and operators.
General Wind Turbine Topics

Wind Turbine Size

The question on many people’s minds regarding wind turbine size is, “How big will wind turbines be?” The 1MW threshold was passed in 1995. Currently, there are projects underway for offshore wind turbines that plan to top the 20MW rating. [3] Figure 4.1 below depicts the size evolution of wind turbines over time and compares the growing rotor diameters to the wingspan of an airbus A380, which has a wingspan of 80m. Also, it can be noted, that wind velocities increase at higher altitudes. This drives increases in wind turbine height.

![Size evolution of wind turbines over time](image)

*Figure 4.1 Size evolutions of wind turbines over time. [4]*

There are a few main drivers of continued wind turbine scaling. One of the reasons is because cost is directly associated to the number of towers that have to be erected. While larger capacity units are more expensive, a reduction in the amount of towers relative to MWs of installed capacity equates to a cost savings. Larger turbines can also use land and wind more effectively than their smaller counterparts. In the public funding of wind energy, size tends to be regarded as a metric of technological progress.
**Square-Cubed Law**

The energy produced by a wind turbine system is proportional to the swept area of the rotor and therefore the square root of the rotor diameter. Costs for the materials for the system are proportional to the volume of the mass of the material in the system, and therefore the diameter cubed. This relationship is known as the square-cube law. It implies that for the wind turbine alone, excluding capital and infrastructure costs associated with the wind farm, the cost per unit capacity increases linearly with wind turbine scale. There are variations to this rule when considering actual manufacturing processes and detailed modeling of systems, but it generally holds true.

**Betz’s Limit**

In 1919 physicist Albert Betz showed that the hypothetical limit of wind energy extraction by a machine is limited to $16/27$ (59.3%) of the kinetic energy of the wind to be captured due to the fundamental laws of conservation of energy and mass. Known as Betz’s limit, modern wind turbines may reach 70-80% of this theoretical limit allowing over 40% of the total kinetic wind energy to be captured. [5]

**Cut-In, Rated Output and Cut-Out Speeds**

The power output from a wind turbine varies with steady wind speed. At very low speeds there is insufficient torque exerted on the blades to make them rotate. The speed at which the wind must blow in order to cause the blades to first rotate is referred to as the cut-in speed. This is commonly between 3 and 4 meters per second. [6] As the wind speed rises above the cut-in speed the power output from the machine rises. However, there is a limit to this increase. At between 12 and 17 m/s the output reaches the electrical limit that the generator is capable of. This is the rated power output of the machine. As the speed of the wind increases above the rated power output of the machine, at some point, there is risk of damage to the rotor. As a result, power control regulations, as described below, are employed. This state of operation is known as the cut-out speed. Figure 4.2 below illustrates these wind speeds versus power output.
As mentioned previously, there are various wind speeds at which the turbine produces power and at which it ceases to operate in order to not become damaged. In order to control wind speed/power interactions two main methods are employed.

Stalling is a power regulation method designed to protect both the generator and the mechanical structures of the turbine during high wind speeds. Power production decreases with wind speed above a certain value. This is a passive power regulation scheme where the blades are designed to perform worse, in terms of energy extraction, in high wind speeds to protect the turbine. [7]

Pitch regulation works by increasing or decreasing the angle of attack formed by the angle of the blade to the wind. This is an active control type where the rotor blades are turned about their vertical axis. When the wind speed is not higher than that for rated power output the blade incidence stays near the angle of 0°. This captures the maximum amount of energy from the wind. However, when the wind is above rated speed the pitch control mechanism changes the blade incidence so that the output power of the generator is within the allowed range. Figure 4.3 below illustrates the power output versus wind speed difference between pitch-regulated and stall-regulated systems.
Figure 4.3 Power output difference between pitch-regulated and stall-regulated turbines. [7]

Besides one being active and one passive, the main difference between these control methods is the fact that pitch regulated turbines have the capability to capture maximum power from the wind all the way up to cut-out speed while stall controlled systems taper off in power output before full cut out. Pitch control systems have the ability to capture more power at very high wind speeds.

Materials

Of greatest concern in turbine material selection is the issue of fatigue. Materials can withstand great loads when applied once, but when a load is applied, removed, and applied again this can cause fatigue damage. Since the force of the wind is applied and reapplied over and over this topic must be taken into consideration. The loads that contribute to wind fatigue, including wind shear, yaw error, yaw motion, gravity, stochastic loads from turbulence, and wind gusts all contribute to component fatigue. These can vary widely depending on the location and the environment in which the turbine is installed. However, this value can be quantified and utilized in the selection of materials for a particular installation.

Two of the most important materials used in wind turbines are steel and composites, the primary material used in blade construction. The composites typically comprise fiberglass, carbon fibers,
or wood mixed together with a matrix of polyester or epoxy. Other common materials include copper (electrical components) and concrete for the base of the turbine structure.

**Wind Turbine Generator Types**

**Squirrel Cage Induction Generator (Type 1)**

The internal construction of squirrel cage induction generators (SCIGs) consists of a cylinder mounted on a shaft with conductive bars set into grooves and connected at both ends by rings, forming a cage-like shape; hence their name. The field windings in the stator of an induction motor set up a rotating magnetic field. The relative motion between this field and the rotor induces electric current in the conductive bars. In turn, these currents lengthwise in the conductors react with the magnetic field of the motor to produce force acting at a tangential to the rotor, resulting in torque to turn the shaft. In effect the rotor is carried around with the magnetic field, but at a slightly slower rate of rotation. The difference in speed is called slip and increases with load. [8] SCIGs are connected directly to the step up transformer. The turbine speed is (nearly) fixed to the electrical grid’s frequency. Real power is generated when the turbine shaft rotates faster that the electrical grid frequency, creating negative slip. While there is a bit of slip that causes variability in the generator’s output, SCIGs generally operate at or very close to rated speed. These turbines consume reactive power for their excitation field. Because of this there are compensating capacitors between the generator and the grid to control the power factor.

The reactive power consumed by these machines for its excitation field is a major drawback. Also, these machines can draw extremely large currents when starting. To mitigate this effect a soft-starter scheme, which effectively limits inrush current, is employed. These generators are not commonly used anymore except in small generation applications.
Wound Rotor Induction Generator (Type 2)

The wound-rotor induction generator (WRIG) or asynchronous generator operates similarly to the SCIGs described above as they mechanically turn their rotor faster than the synchronous speed, creating negative slip. The stator flux rotation is faster than the rotor rotation. This causes the stator flux to induce rotor currents, which create a rotor flux with magnetic polarity opposite the stator. In this way, the rotor is dragged along behind the stator flux. The stator flux induces currents in the rotor, but since the opposing rotor flux is now cutting the stator coils, an active current is produced in stator coils, sending power to the electrical grid. [10] Full rated power of the generator is reached at very small slip values, typically 3%. Meaning, with a synchronous speed of 1800 rpm, full output power is produced at 1860 rpm.

Like SCIGs, WRIGs are connected directly to the wind turbine generator (WTG) step-up transformer. However, they also include a variable resistor in the rotor circuit. These are either mounted externally or on the rotor directly. The latter eliminates the need for slip rings. The variable resistors can control the rotor currents so as to keep constant power even during rapidly changing wind conditions. The resistors allow some ability to control the speed in order to accomplish the best energy capture.
By adding resistance to the rotor circuit higher slip can be achieved and higher speed ranges. This allows some ability to control the speed by wind variations of up to 10% and achieve the best energy capture. Also, this offers some self-protective torque control that decreases the mechanical stresses on the machine.

Because these generators must be excited by a leading voltage they are not capable of black-starting should the whole plant be shut down for any reason. In order to restore generation of power they must rely on the external electric power transmission network. Like SCIGs, they are normally not used in large power generation situations anymore.

**Doubly-Fed Induction Generator (Type 3)**

Due to their low cost and versatility, doubly-fed induction generators (DFIGs) dominate the wind power market today. DFIGs are three-phase wound-rotor induction machines that feed AC currents into both the stator and rotor windings. The machine operates like a synchronous generator whose speed (i.e. the speed at which the shaft must rotate to generate power at the AC power network frequency) can be varied by adjusting the frequency of the AC currents fed into the rotor windings. This is to say that the magnetic field passing through the generator windings not only turns due to the generator rotation, but also due to the AC currents fed into the rotor windings. Thus, the frequency of the alternating voltage produced by the stator windings is determined by both the speed of the rotor as well as the frequency of the AC currents being fed into the rotor windings. When the magnetic fields of the rotor’s windings turn in the same direction as the generator rotor, the rotational speed of the rotor and speed of the magnetic field add up. Conversely, when the magnetic field of the rotor windings turns in the opposite direction
as the generator rotor the speed of the rotor and speed of the magnetic field subtract from each other. It is in this way that the frequency of the voltages induced across the stator windings of the generator can be controlled. The operation of DFIGs allows them to be directly connected to the AC power network as the frequency produced by the stator is in synch with the network.

![Figure 4.6 Double-fed induction generator. [11]](image)

The primary advantage of DFIGs is the ability to allow the amplitude and frequency of their output voltages to be maintained at a constant value, no matter the speed of the wind blowing. This is why they can be directly connected to the AC power network. DFIGs also have the ability to control power factor by adjusting the amount of reactive power exchanged between the generator and the AC power grid while still keeping the power electronics in the wind turbine at a moderate size. Also, in these variable-speed wind turbines, the speed of the rotor is allowed to vary as the wind speed varies. This means wind gusts won’t cause as great of stresses on the mechanical components such as the gear box and the rotor as their fixed-speed counterparts.

One disadvantage of the DFIG configuration is the complex power conversion circuitry required. Also, the slip-rings on the wound-rotor induction machine require periodic maintenance. While the DFIG requires two AC-DC converters, like the full-converter scheme (see below), these
converters are significantly smaller than the synchronous converters. DFIGs only convert approximately 30% (as opposed to 100% in the full-converter scheme) of the nominal generator output power to be exchanged between the rotor and stator and the AC network, so the power electronics are considerably smaller.

**Full Conversion (Type 4)**

Type four generators are direct drive generators that achieve variable speed operation by connecting the generator to the grid through an AC-DC-AC converter. The generator type can be synchronous, permanent magnet, or induction; the permanent magnet version being somewhat cost-prohibitive due to the current high demand for rare-earth metals. Also, it has been discovered that the permanent magnets tend to become demagnetized by the powerful magnetic fields inside of a generator.

![Figure 4.7 Full-conversion wind turbine generator. [11]](image)

Since wind as a prime mover is a variable speed source an indirect grid connection, or full converter scheme, is used to connect the generator to the AC grid. In this way it is possible to run the turbine at varying rotational speed, generating variable frequencies from the stator. Since AC current with a variable frequency is not suitable for the grid an AC-DC-AC conversion scheme is used. First, the variable frequency AC power is rectified to DC with the use of thyristors or large power transistors. Then, the fluctuating direct current is converted to alternating current of the same frequency as the grid using a pulse-width modulated (PWM) or thyristor inverter. Initially, the current that comes out of an inverter looks very little like the smooth current of the grid. However, these rectangular-shapes waves can be, mostly, smoothed out by using capacitors in an AC filter mechanism.
One advantage of this type of grid connection is that gusts of wind can be allowed to turn the rotor faster. This excess rotational energy can be stored in the rotor. This requires an intelligent control strategy in order to reduce peak torque (causing wear on the gearbox and generator) and reduction of fatigue loads on the tower and rotor blades. Another advantage of the full converter scheme is that, with the use of power electronics, the reactive power to the grid can be controlled. This can greatly improve the power quality to the grid, especially weak ones. This is also why this is often the generator type of choice for areas with strict grid regulations. There has been research regarding the production advantages connected to the ability to run the machines at optimal rotational speed, however, the economic advantage seems to be so small that it can hardly be taken into account when making decisions regarding generator types.

The main disadvantage of indirect grid connection is cost. The need of a rectifier and two inverters, one to control the stator current and one to generate the output current, can be costly. However, the price for solid-state power electronics continues to decline. The other disadvantage is the energy lost in the AC-DC-AC conversion process of the full rated power of the machine and the fact that, even with the use of power electronics, harmonic distortions may still be introduced into the grid.

**Synchronous Generator (Type 5)**

Synchronous WTGs consist of a variable-speed drive train connected to a torque/speed converter coupled with a synchronous generator. The torque/speed converter changes the variable speed of the rotor shaft to a constant output speed. The closely coupled synchronous generator, operating at a fixed speed (corresponding to grid frequency), can then be connected directly to the grid through a synchronizing circuit breaker. The synchronous generator can be designed for any desired speed (typically 4 or 6 pole) and voltage.
Since a synchronous generator is employed in these Type 5 machines an automatic voltage regulator is typically needed. These devices can be programmed to control reactive power, power factor, and voltage. Again, this can be very advantageous when connected to a weak local grid or a grid with extremely tight regulations.

**Collection System**

Wind WPP collector systems have many things in common with traditional utility electric systems. However, there are also characteristics unique to these systems that require special attention. Many of the considerations are driven by cost and reliability.

**Feeder Topology**

Feeder topology, or collection system layout, is unique to each WPP installation and can vary widely based on factors such as turbine placement, terrain, reliability, landowner requirements, economics, and expected climactic conditions for the location. [12] Turbine locations and the point of interconnection (POI), where the WPP feeds into the electrical grid, are the primary factors in determining the feeder layout. The collector substation can be directly connected to the POI unless the POI is located far from the WPP, in which case a transmission line may be required.

Most WPPs built in North America have radial feeder configurations with a system voltage of 34.5kV because distribution transformers of this rating are readily available for purchase. Turbines
are connected in a “daisy-chain” fashion outward from the substation to the furthest turbine.

Figure 4.9 below illustrates a typical collector circuit. The feeders are commonly underground, but overhead lines may also be built. Each feeder string may also have branch strings connected by sectionalizing cabinets or junction boxes. These have separable connectors which allow a feeder string to be isolated for maintenance or repair while allowing the remaining wind turbines to stay in operation. One alternative to sectionalizing cabinets are pad-mounted switches that can more easily isolate a feeder for maintenance or troubleshooting. However, the increased cost needs to be weighed against the expected frequency of operation.

![Figure 4.9 A Typical collector circuit. [12]](image)

The number of WTGs connected to an individual feeder string is limited by conductor ampacity. In addition, the total number of collector circuits is limited by the size of the substation transformer at the collector substation. Underground feeders are generally limited to 25-30MW per string due to soil thermal conditions and practical cable sizes. Parallel conductors may be combined at the collector substation circuit breaker in order the increase the number of WTGs on a feeder.
Overhead conductors can carry more power than comparable underground conductors, typically up to 40-50MW per sting, but will have higher losses associated with them. Overhead conductors typically have more outages than underground circuits but the outages will usually be shorter in duration. If a feeder sting experiences a failure, the entire generating capacity of that string is lost until it can be repaired. The aforementioned sectionalizing cabinets can help to isolate the damage and allow some portion of the WTGs to be returned to service more quickly.

**Turbine Step-Up Transformer**

For wind turbines of the MW size a step-up transformer is needed for each WTG. Pad-mounted three-phase distribution transformers are commonly used for WTG step-up transformers. While transformers are sometimes located in the nacelle or on platforms in the tower these will be of varying proprietary design since they are provided by the manufacturer. Many WTG manufacturers specify delta (MV)-grounded-wye (LV) connections for wind turbine step-up transformers. This is intended to provide isolation of the WTG from the zero-sequence behavior of the collector feeder; e.g. a phase voltage rise during ground faults. Grounded wye-wye transformers are more commonly used for utility load-serving applications, and are thus more widely available. These transformers are a commodity and meet the required function at minimum cost.

Pad mounted transformers are usually protected by internal fuses. Due to the short-circuit current available in most wind applications, current-limiting fuses are usually needed. These fuses are either coordinated with expulsion fuses, or full-range current-limiting fuses are applied. LV molded-case circuit breakers are sometimes installed inside the transformer secondary compartment to provide coordinated protection through to the end of the secondary cables and may help in reducing arc-flash levels. Attention should be given to the ambient temperature for the mounting location, based on the molded case circuit breaker specifications. An internal MV oil switch, typically referred to as a load break oil rotary switch, is commonly specified to allow isolation of the transformer and permit continued operation of other WTGs further down the line.

Transformer primary terminals can either be live-front bushings, or separable connector (“elbow”) bushings. There are two types of elbows: load-break elbows, which are rated up to 200A load current, and dead-break elbows rated up to 600A. Load-break elbows allow the transformer connections to be opened “live” under load current conditions, using a hot-stick. To operate the
600A elbow connections the circuit must be de-energized. When elbow bushings are applied, it is common to specify a feed-through configuration, which provides two bushings for each phase, and an internal connection between each pair of bushings. This allows both the substation-side and remote-end side cables in a daisy-chain radial configuration to connect directly to the transformer without junction boxes. Where there is a number of wind turbines connected in a radial string, the 200A capability of load-break elbows is a significant restriction. Also, many wind plant operators do not have hot-stick-trained technicians on their permanent maintenance crews.

It is common practice to select transformers with a standard kVA rating, as listed in IEEE’s C57.12.24 standard, which is at least as large as the kVA rating of the WTG. This is extremely conservative in applications due to the cyclical loading of the WTG step-up transformers. It is common practice in utility load-serving transformer applications to intentionally select a transformer rating less than the minimum load, thus subjecting the transformer to limited-duration overloads. The loss-of-life of a transformer due to loading is a cumulative function of the temperatures to which the windings are exposed, and the winding temperature. IEEE C57.91 specifies transformer thermal modeling and aging functions that can be used to determine a transformer kVA rating that provides adequate service life for the particular WPP application; both loading cycles, and the contemporaneous ambient temperature conditions.

**System Stability**

**Flicker**

Flicker is a voltage control issue that directly relates to wind turbines because wind is a constantly fluctuating prime mover. In constant-speed turbines (Types 1 and 2) prime mover fluctuations are directly translated into output power fluctuations because there is no buffer between mechanical output and electrical output. [1] This can cause fluctuations that cause unwanted grid voltage fluctuations. These can be especially troublesome to weak grids. However, in variable-speed wind turbines (Types 3 and 4) wind speed fluctuations are not directly translated to output power fluctuations. The rotor inertia and power converter schemes act as energy buffers.
Low Voltage Ride-Through

Low voltage ride-through (LVRT), or fault ride-through, capabilities during periods of low grid voltage are an important factor in the selection of WTGs for a WPP project. In systems where there are many distributed generators subject to low-voltage disconnect, like WPPs, there is the possibility to create a chain reaction which will take the entire set of generators down. This can occur when there is a voltage dip that causes one of the generators to disconnect from the grid. This disconnection causes further voltage drop which then causes another generator to trip creating a cascading failure. A full-cascading failure could cause unreasonable stress on a weak AC grid. FERC order 661-A calls for WPP to ride-through a three-phase fault on the high side of the substation transformer for up to 9 cycles [13]. Type 1 WTGs may require a central reactive power compensation system in order to meet the FERC standard. Most Type 2, 3, and 4 WTGs manufactured today meet the requirements of the order. Since Type 5 synchronous generators are so similar to standard grid-connected generators their LVTR capabilities are well-known. In order to meet FERC requirements the turbine control system, excitation system, and protection systems are coordinated for each specific site.

Short Circuit Behavior

The short circuit behavior of WTG generators depends on the type. The short circuit current behavior of the induction-type WTGs is the same as for induction motors. The initial current contribution to a three-phase fault can be modeled as the sum of the generator’s subtransient reactance and the system impedance from the machine terminals to the fault [14]. Generally, the current that is added to the fault by the generator extinguishes as the rotor flux collapses. This is unless there is some sort of reactance maintaining the generator excitation. For unbalanced faults both the positive and negative reactances are considered to be equal. WTGs are normally ungrounded so they do not usually feed fault current from the ground. Generally, studies of WPPs model many WTGs as one equivalent generator. This is also the case for short circuit modeling. The rating is equal to the sum of the WTGs in the plant in series with an equivalent impedance representing the plant generator transformers, collector cables, and substation transformers. For DFIGs, if during the fault, the rotor power controller remains active, the stator current is limited to 1.1 to 2.5 p.u. of the machine rated current. However, if the rotor circuit fails the DFIG contributes currents as high as 5 to 6 p.u.
For full-conversion generators the fault currents will be limited to just slightly above rated current. Due to the sensitive power electronics in the power converter controls it is necessary to protect the power semiconductor switches. This is done through the highly controllable pulse-width modulation at the heart of the full-converters. Type 4 WTGs short-circuit currents can vary greatly because of differences between manufacturers proprietary control designs.

Type 5 generators exhibit typical synchronous generator behavior during grid short circuits. Current contributions can be calculated based on machine constants available from the manufacturer. Typically, generator fault current contribution can range from 4 to more times rated current for close-in bolted three-phase faults. For single-line to ground faults it can range from nearly zero amps, when the generator neutral is ungrounded, to more than the three-phase bolted level.

**Control Interactions**

To build up the electromagnetic fields needed for power generation reactive power is drawn from the grid. In wind power this poses a particular challenge; because of changing wind speeds wind turbines cannot generate electrical power at a constant rate. If a substantial amount of reactive power has to be drawn, as in the case of a black start-up of the WPP, it can have adverse effects on the AC system or even cause an outage. Reactive power capabilities in WTGs are especially important since most grid codes require reactive power capability at the POI to be between ±5%. [5] Also, without reactive power compensation, the integration of wind power in a network may cause voltage collapse in the system and under-voltage tripping of wind power generators.

**Reactive Power and Power Factor**

Type 1 and 2 generators typically use power factor correction capacitors (PFCCs) to maintain reactive power at a specified amount. [9] When a full-load compensation scheme is used the PFCCs are sized for unity to slightly lagging power factor. The PFCCs are typically multiple stages of capacitors that are switched by a low-voltage contactor. Type 3 WTGs have reactive power capabilities of 0.95 lagging to 0.90 leading at the terminals of the machines. Some of these machines can deliver reactive power even when and no real power in being generated. Type 4 WTGs offer full control of the effective power factor over a wide range of voltages. These machines can also deliver reactive power when the machine is not operating mechanically. Type 5
WTGs typically offer a range of 0.9 leading to 0.9 lagging power factor. At outputs below rated power, the reactive power output is only limited by rotor and stator heating, stability concerns, and local voltage conditions. Like some Type 3 and 4 WTGs the machine may be operated as a synchronous condenser, with adjustable reactive power output. This could prove to be especially useful where the WPP is connected to weak grids.

**Static VAR Compensators**

Static compensation like PFCCs, may be unable to prevent voltage collapse at the POI, however, dynamic reactive power compensation using static VAR compensators (SVC) is successful in maintaining acceptable voltage levels where the WPP is connected to the AC power transmission network. [15] SVCs have the ability to provide voltage support at the POI either by supplying or absorbing reactive power. They are a part of the flexible AC transmission system (FACTS) family, known for regulating voltage and stabilizing systems. SVCs are automated impedance matching devices that bring the transmission system closer to unity power factor. When the WPP is consuming reactive power the SVC's capacitor banks are automatically switched in, thus providing a higher system voltage. The main advantage of SVCs over simple mechanically-switched compensation schemes is their near-instantaneous response to changes in the system voltage.

**STATCOMs**

A static synchronous compensator, or STATCOM, is a regulating device based on a power electronics voltage-source converter. It can also be implemented to maintain appropriate voltage regulation at the POI to the AC system. It acts as either a source or sink of reactive power to the AC network. It is also a part of the FACTS family of devices. The STATCOM is a voltage source with variable amplitude. If the amplitude is set to a higher value than the grid voltage the STATCOM injects reactive power into the grid. Inversely, if its amplitude is lower than the grid voltage it absorbs reactive power. One of the main advantages of STATCOMS is their continuous and dynamic voltage control, which allows them to continuously control reactive power levels. Because of their design, they also have very fast response time. The maximum available reactive power from a STATCOM is proportional to the voltage so, consequently, the available reactive power decreases more slowly for STATCOMs than for SVCs when the system voltage decreases.
Conclusion

It can be seen that many parameters affecting cost, efficiency, and reliability of a WPP must be taken into consideration when the system is designed. Through careful analysis of each proposed wind turbine project the optimal cost per megawatt can be obtained. As more of these installations age we will be able to better analyze the long-term effects that a stochastic resource such as wind has on the various system components. Until that time we will continue to modify our design processes as new information and innovations become available.

DFIGs would be the optimal choice for the installation that is being considered. They offer flexibility in reactive power support so they do not need to use the existing AC system for reactive compensation. Since we are tied to a relatively “weak” AC system, in this case, this is of special importance in our WTG selection. DFIGs are tied directly to the existing AC system and only convert approximately 30% of their full power for the VSC on the rotor. This means that the power electronics are small and less expensive than their full-conversion counterparts. This also means that there will be less power losses than when compared to a full-conversion generator scheme. DFIGs are the best compromise between technical specifications and cost.

Wind Power Plants References


System Modeling

System Modeling Introduction
The purpose of this modeling section is to investigate the impact of a DC connection between the south-central Wyoming region and load centers in Southern California and Las Vegas. This interconnection is being researched because of a proposal for the construction of wind generation in Wyoming and the need to send that power to load centers in Nevada and Southern California. This section will explore the effects of building an HVDC link between the existing systems in Wyoming and California using freely available power flow analysis software. For this purpose, the PowerWorld simulator software will be used. The required system data and control system data required to run a transient simulation is not freely available, and in many cases proprietary, which makes a transient study outside the scope of this paper. Studies of many specific contingencies become useless without access to a full-topology Western Electricity Coordinating Council (WECC) base case. Therefore, the objective of this model will be to study the impact on existing systems in providing reactive support to the DC transmission line.

Wind Turbine Modeling
As mentioned in the preceding Wind Generation section, a wind power plant is a collection of many wind turbines, and that they are each feeding onto a collector system through step up transformers at the base of each turbine. When high level modeling is considered, the modeling of each individual generator and transformer provides no great advantage over an aggregate model, and could potentially complicate any troubleshooting effort should an issue arise with the model. For this reason a consolidated model is used where all the generators in the generation site are modeled as a single generator, and all of the collection transformers at the base of the turbines are modeled as a single transformer. Within the bounds of using freely available power flow software, the free version of PowerWorld simulator limits the user to 40 busses. The aggregate model of a wind plant requires 4 busses, one for the generator, another for the step up transformer, a third for the collector cable, and a fourth for the transmission to the point of interconnection (POI). Because the typical size of a single site is 50-200MW, and we are looking to model the addition of 3100MW of wind generation into the
Wyoming region the maximum allotted busses of the software would be exceeded by the wind generation alone. It is for this reason that we will not model the entire collection system. The wind generation will need to be modeled as several wind plants with their respective collection transformers, but without the collection line or transmission line to the POI. An example of this configuration can be seen in Figure 1. The model data for the wind generation and collector transformers is from the Dodge Junction wind site outside of Walla Walla Washington. These generator/transformer wind plant models will be connected directly to the converter station because the proposed wind capacity would overload the lines of the existing system which defeats a major design criterion to minimize effects on existing systems.

![Diagram of wind generation systems](Figure 5.1 3100 MW of Wind Generation)

**Modeling Requirements**

In modeling the DC interconnection between south-central Wyoming, on the northern end and the Southern California/Las Vegas region, on the southern end, the two systems are characteristically very different. The southern region is what is called a “stiff” grid, this region has many 500kV lines which are heavily looped and many voltage control devices such as shunt
capacitors/reactors and SVC’s. This means that the bus voltages in the region do not vary widely due to power flow, generation profile, or small to medium changes in system topology.

The northern region operates in a very different manner than the southern region. This region has no 500kV lines, and relatively few voltage control devices. This is why the northern region can be termed a “weak” grid, because the bus voltages are prone to swings as a result to changes in power flow or system topology. These swings are undesirable because they can result in voltages which are outside of specifications, and can shift the system along the power voltage (PV) curve towards a voltage stability limit. Additionally, there is a large baseline generation facility, Jim Bridger, adjacent to our modeling region which acts as the source for the existing power flow through our model. Jim Bridger and this existing flow are important to model in order to study what effect additional flows will have on the northern system.

**Modeling Methodology**

Modeling the “stiffness” of the southern region is accomplished by utilizing the generator model with a negative generation. This will act as a load and will be used to maintain bus voltage by allowing the negative generators to have an almost unlimited reactive capability. To further construct the behavior of the region, the 500kV and 230kV loops between the busses that immediately connect to the southern HVDC converter system are modeled. The looped nature of the southern system provides a “stiff” voltage characteristic by allowing multiple paths for power flow. This will result in lower equivalent impedance and subsequently less voltage drop for a given transmission of power. In maintaining a realistic voltage profile, the 1.0pu regulated busses with the negative generators will be the 230kV busses in the model because in the load center region, lower voltages denote proximity to actual load. For modeling purposes this can be dangerous. The power flow analysis requires each region to behave as independent islands, both with their own slack busses. If our only modeled generators are at the 230kV busses, then when the island slack picked up any load that was not transferred through the HVDC connection its power would flow through the lowest impedance paths (500kV lines). This would cause the 500kV busses to have a lower per unit voltage than the 230kV busses, which is not the physical case (think of voltage drop across a line from source to load). For this reason a single negative generator will regulate one 500kV at 1.1pu in order to maintain an appropriate voltage schedules.
at both the 500kV and 230kV levels. This will not be required for the VSC based system, as the converter station will be able to regulate the 500kV system as seen below in Figure 2.

![The VSC based model of the Southern region](image)

*Figure 5.2 The VSC based model of the Southern region*

The northern terminal of the HVDC link connects to a string of 230kV busses extending from Jim Bridger to Miners substation in Wyoming as shown modeled below in Figure 3. This section of the grid strings out eastward with only a few, mostly radial, lines branching off of it. The lines that branch off of it will be replaced with loads equal to the power flows from the 2015 WECC heavy summer planning case. This will establish a baseline flow across the existing 230kV system and an excellent representation of the system for us to connect our HVDC line and wind generation.
HVDC Modeling

Two models will be built for both the LCC and VSC based converter technologies. We will use the included PowerWorld LCC model to implement the LCC based line. The standard way to implement a VSC connection in a steady state power flow simulation is to create a negative generator on the sending terminal, and a positive generator on the receiving end. This will allow the generated power in the northern region to be consumed by the negative generator at the converter station and the corresponding power to be “generated” at the generator on the southern terminal. The two generators will be given a large reactive capability in order to model the VSC’s ability to regulate AC bus voltage.

Interaction Studies

The goal of studying these models is to quantify the way in which the HVDC link between the northern and southern regions affects the existing system in the northern region. The effect on the southern region is not studied because of the “stiff” characteristics of the region, and it has been modeled in such a way to stay relatively consistent through the entire range of desired HVDC power flows.

For the study of the LCC a near infinite reactive source modeled as a generator with zero power capability and a large reactive capability is added to the northern converter bus to represent one of the several compensation devices being considered (SVC, Statcom, or Synchronous Condenser). Allowing this unit an infinite capacity to source and sink VARs will give us an “ideal” value of local (to the converter station) VAR support which minimizes impact on the existing system. From that value we can limit the compensation device until we reach the bounds of allowable voltage on the converter bus; in this situation .92pu to 1.1pu was selected as the bounds being outside the standard ±5% with the goal of approaching a voltage stability limit. This will
give us an absolute minimum value for reactive compensation. The study was performed at DC flows ranging from 100MW to 3100MW. Ideal and minimum reactive compensation was found and is summarized in figure 4 which plots the ideal and minimum values against the range of studied HVDC flows.

![Figure 5.4 Minimum and ideal reactive compensation](image)

The interaction study for the VSC-based system operates in much the same way, except that since the VSC can source and sink VARs into the system, a compensation device will not be required on the northern terminus. Flows will be simulated as a negative generation on the northern end, and a positive generation of 94% of the sending power on the southern end to simulate a conservative 6% loss. Both generators will be given free range to provide or consume VARs. The VARs provided or consumed will be recorded to be used toward specifying the VAR injection capability for the VSC system being considered. This study was performed through a range of DC flow levels from 100MW to 3100MW. The resulting VAR support on both the northern and southern terminals is displayed below in figures 5 and 6. These plots show the reactive support provided by the VSC converter at each DC flow level studied for each converter terminal.
Fault Analysis

A final test is to check the fault characteristic of the model. Typically a DC system's ability to “ride through” a fault is tested through a transient analysis. Because the required dynamic data for the transient behavior of an HVDC system is not freely available, we will conduct a steady state fault analysis on a line in the northern region. The selected line to fault was the Latham-
Converter 230kV line as requested during a meeting with POWER Engineers. This test was performed with 1400MW flowing across the LCC DC line, with the converter compensation device limited to 200MVAR. It was found that a balanced 3 phase fault at 50% of the Latham-Converter line drew a fault current of 3544.21A or 14.119pu. This is relative to a pre fault flow of 127.42A at the Latham end of the line. While one end of the fault was fed by the existing AC system, the other end was fed by wind generation, and any effects on the DC line are not reported the PowerWorld fault analysis tool. For this reason, it is unfortunate that with the tools available, a more comprehensive fault analysis of the DC system is not possible.

**Conclusion**

The modeling of this proposed HVDC link served two purposes: to demonstrate the difference between LCC and VSC systems in regards to reactive compensation and to establish preliminary specification values for reactive compensation in both the LCC and the VSC cases. For the LCC the minimum and ideal compensation required was 626MVAR to 1612MVAR, and in the VSC study, the northern terminal required up to 125MVAR while the southern terminal required up to 265MVAR. At this point it should be noted that because the southern system was modeled only for stiffness in voltage characteristic, that any reactive support values for this region do not reflect the existence of other local voltage support schemes. In summary, the LCC system requires more reactive support, but is a more established technology available at lower cost while the VSC system actually acts to support the local AC system, but is a newer technology with a premium price to prove it.