With the increasing quantity of renewable energy being introduced to the grid the reliability of supply is effected due to intermittency. To increase security, as well as transmit power from generation plant located at large distances from load centres, High Voltage Direct Current (HVDC) transmission systems are being used to overcome the limitations of High Voltage Alternating Current (HVDC). Isolating faults within DC networks provides a greater challenge than within AC systems and as yet circuit breakers are limited in capability. This report covers an introduction to DC circuit breaker topologies and requirements.
1 Objective of Research

The introduction of a greater proportion of renewable energy sources within the UK and Europe potentially leads to intermittency of supply. To reduce the requirement for surplus spinning reserve and link diverse generation across large geographical distances High Voltage Direct Current (HVDC) links are being used. Currently only point to point HVDC systems are a reality, with a few exceptions. True multi-terminal HVDC grids are proposed to improve the reliability of grids with a higher proportion renewables.

A future multi-terminal HVDC grid would require circuit breakers in order to provide isolation from faulted parts of the system. Unlike Alternating Current (AC) Circuit Breakers (CB) Direct Current (DC) CBs are required to disconnect under full load/fault conditions and thus they have to absorb and dissipate the energy within the DC system. This makes the design of HVDC circuit breakers complex and as yet not a commercial reality.

The objective of this PhD is to improve on current HVDC circuit breaker designs, with the aim to make them more commercially viable. Initially by ascertaining the requirements of a DC CB during a DC side fault through simulations of a point to point Voltage Source Converter (VSC) based HVDC system.

2 Literature Review

Early electrical power generation and transmission was DC limiting the distance from power station to load. Higher voltage reduces the losses for transmission, however generally this is not appropriate for the end users requirements. This led to AC generation, distribution, and consumption becoming de facto. With an AC electrical system voltage levels could be boosted at power stations reducing the losses for transmission. These could be sited at large distances from load centres, allowing them to grow in size and become more efficient, whilst still delivering power economically. Closer to the end user the system voltage is reduced again using transformers to an appropriate level. Transformers are key to scaling from low to high voltage, and back again, and therefore not appropriate for DC transmission.

Long overhead lines and underground/subsea cables have a significant capacitance which limits their useful length for transmission purposes, as the capacitive current drawn encroaches on the current rating. DC transmission has no such restrictions for distance as there is no reactive power flowing within the system. High voltage Direct Current (HVDC) has been used to connect many large hydro plants that are located large distances from load centres as well as for grid strengthening, interconnection of grids at different frequencies, or non-synchronised grids.

DC transmission has a higher rated power than AC for a given land area (Figure 2.1) as it has a higher utilization of line capacity because peak and RMS are the same in DC. Cable saving is typically around 30% [1]. Cables have much higher capacitance than overhead wires and therefore the limiting distance of High Voltage AC (HVAC) in these systems is much shorter. However in order to transmit over DC local AC generation has to be converted to DC and then back again at the receiving end for the end user. This adds a large capital cost for the converter stations at each end of the system. The break even distance when HVDC becomes economical is generally in the region of 30km for cable and 500km for over-head line systems [2]. This is highly dependent on a project by project basis and HVDC systems are often implemented over much shorter distance for a variety of reasons.
One issue that is becoming more prevalent, particularly within the UK, is the difficulty of obtaining land rights-of-way. New overhead lines are met with strong objection and HVDC systems are meeting the requirement of grid strengthening whilst avoiding long legal battles as underground or subsea cables can be used. The western HVDC link is such a project that is increasing the north south transmission capacity between southern Scotland and north Wales/England and will increase the north south capacity by 50% through a, mainly subsea, cable based HVDC system.

The first HVDC system was developed in Germany in 1941. It was a ±200kv, 60MW, system with a cable distance of 115km however due to the end of the Second World War construction was not completed. The first working system came into operation in Sweden in 1954, with a capacity of 20MW over a 98km long submarine cable.

Transmitting power over HVDC link is a two part process. First the local AC generation has to be rectified into DC by a converter station, transmitting power over high voltage lines or cables, and then converted back into AC at the receiving terminal. In the first generation systems mercury arc valve rectifiers were used. In modern systems there are two main technologies used to perform the conversion; Line commutated converters (LCC) and newer Voltage Source Converters (VSC).

2.1 HVDC Converters

2.1.1 Line commutated converters (LCC)
The basic converter topology of an LCC is shown in Figure 2.2. LCC systems are constant current converters drawing blocks of DC current from each phase in turn. The valves shown are constructed from multiple Thyristor semiconductors in modern systems. These devices can be turned on when forward biased and continue to conduct until the system naturally brings the current to zero, or it is commutated into the next phase. The point at which the valve starts to conduct can be varied by delaying the firing pulse to turn it on. The point at which it is delayed beyond the natural point at which current commutates from one phase to the next is known as the firing angle (α). Increasing the firing angle varies the average voltage on the DC side of the converter, and thus the power being transmitted.

Current is commutated from one phase to the next at line frequency producing low frequency harmonics. Large filter banks are required at each converter station to absorb the harmonics. Generally in a system one converter controls the DC side current, whilst the other adjusts the DC voltage to control power flow. As the firing angle is increased the current drawn lags the voltage at the input. The power factor drawn by the converter is thus dependant on the power flow. Capacitor banks are switched in and out as the converter output changes so that the converter draws close to unity power factor from the local grid.

The commutation of current from one phase to the next is forced by the AC system requiring LCC systems to be located close to a strong local grid to operate correctly. Faults on the local AC system can result in commutation failure within the converter leading to disruption of operation, possible loss of power and damage to the converter.

### 2.1.2 Voltage source converter (VSC)

A VSC system is based on a stiff DC side voltage and the converter then switches the output between two or more voltage levels using fully controlled semiconductor devices. In a two level converter (Figure 2.3) there are three bridge legs, each consisting of an upper and lower IGBT valve which are switched in anti-phase. This allows voltage of the output to be pulled up to the positive, and down to the negative, voltage rails delivering an AC output.

Pulse Width Modulation (PWM) is used to vary the average output over one switching cycle allowing each leg to track a sinusoidal output voltage. This gives the VSC complete control over phase, magnitude, and frequency of the voltage output at each of its legs. The output in each leg is locked to the frequency of the local grid. Coupling reactors are connected between the converter output and the AC grid allowing two degrees of freedom, voltage phase and magnitude. This gives the converter independent control to source/sink the required real/reactive power to/from the AC side.
Modular Multi-level Converters (M2Cs) generate a stepped output voltage using number cells containing capacitors and IGBT switches. These cells can either impress the capacitor voltage positively (or negatively with H-bridge cells) or be short circuited. The number of cells will determine the number of different voltage levels the output can produce between $\pm V_{dc}$.

The required voltage output at any one point can be achieved by changing the number of cells which impose the capacitor voltage vs. the number that are short circuited. This is in contrast to two-level converters that are required to switch between two voltage levels rapidly. As the number of cells increases the converter can synthesis more voltage levels. PWM switching frequency can thus be reduced and becomes unnecessary when the number of cells is large enough. This can reduce reduces the switching losses in the converter and can bring the total losses to below that of a standard two level converter [3].

By increasing the number of voltage levels achievable the M2C can reduce, or even remove, the requirement for filtering on the AC side, normally occupying 50 % less space than “classic” LCC HVDC systems [4]. The size of the capacitor on the DC side can also be reduced as the DC voltage is now held by the internal cell capacitors, which will reduce the current injection during a DC side fault. During a DC fault two switch variants are able to block the internal cell capacitors from discharging into the fault. This has two benefits.

1. With a reduced DC side capacitor and cell capacitors blocked the peak current injection into the DC fault will be reduced. This relaxes the requirements of the DC circuit breaker.
2. After the fault has been cleared the capacitors remain charged. The time delay whilst the DC capacitors are re-charged is thus reduced.

They are not however able to stop AC current in-feed due to the free-wheeling diodes. H-Bridge cell converters however are able to block capacitor discharge and AC current in-feed, as well as also providing a controlled method of post fault DC capacitor recharging. There is an economical trade-off between the additional functionality of the multi-level converter and its increased capital cost. The above benefits come at the cost of additional converter expense. H-bridge-cell M2Cs require four switches per cell, and thus the capital cost for gate drives and IGBTs goes up significantly.

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$^2$ [http://docs.exdat.com/docs/index-90006.html](http://docs.exdat.com/docs/index-90006.html)
2.2 Comparison of technologies

As VSCs have full control over phase, frequency, and magnitude of their output allows them to be connected to weak or isolated grids with no local generation and thus provide more control, and a wider variety of applications of HVDC, than their LCC counterparts. They can fully control their real and reactive power demand/supply independently and so do not require the large reactive power compensation as LCC systems do, making them more compact. The PWM switching frequency is generally in the kHz range and thus produces fewer harmonics than that of an LCC system, reducing the filter requirement.

The benefits described above have opened up the scope of applications of HVDC, such as offshore wind. The reduced converter size has allowed the first offshore converter terminals to be completed. Examples of this are TROLL A [5] which provides 88MW over a 75km cable to an offshore gas rig, and BorWin1, which can transmit up to 400MW from a wind farm 75km to shore [6], neither of which would be possible with LCC technology.

In order to change the direction of power flow within an LCC system the voltage polarity of the cables must be reversed which is a slow process and thus does not lend itself to a multi-terminal meshed grid structure where power flow will potentially change direction in a short period of time according to demand.

The system voltage is kept constant throughout VSC systems (other than voltage drop due to line impedance) and it is the DC current magnitude and direction that governs power flow. The ability to control the flow of real and reactive power independently at each terminal as well as the ability to change direction and magnitude of power flow quickly lends VSCs to multi-terminal systems more favourably.

LCC systems are a mature technology with decades of operating experience in many different environments. They have proved themselves as a reliable way of transmitting large amounts of power over extremely long distances.

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3 [18]

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Figure 2.4 - Modular Multi Level Converter (M2C)
distances, often from remote hydro-electric sources. Transmission power levels have now reached as high as 6400MW@ ±800kV \[7\] and are continuing to increase.

VSC technology is still relatively immature when compared to that of LCC. However as IGBT power ratings continue to increase, so will the power ratings of VSC systems allowing them to compete with in high power systems in which Thyristor based technology still dominates. VSC systems have now reached the gigawatt milestone with the INELFE 65km cable connection between France and Spain consisting of two 1000MW links at a voltage rating of ±320kV each \[4\].

2.3 Fault conditions
LCC systems are constant current based and so have large DC side inductors whereas VSC systems are constant voltage based and so have large DC side smoothing capacitors. During a fault on an LCC system the current di/dt is reduced by the large DC inductors. As LCCs are current controlled systems the converters are able to limit or completely block current feeding from the AC side to a DC fault.

Standard two-level, and diode clamped multi-level, VSCs are vulnerable to DC side voltage collapse as the anti-parallel diodes across each IGBT valve are held in reverse bias only whilst the DC side voltage is larger than that of the AC. During a DC fault the smoothing capacitors very rapidly discharge into the fault. The system voltage therefore drops, forward biasing the diodes and allowing current to flow from the AC to DC side, only constrained by the AC reactor impedance. Two terminal systems rely on AC side circuit breakers in order to stop the in-feed from the AC side, through the converters, to the fault.

Additional DC side inductance could be added to VSC systems to slow the current rise; however this would reduce the stability of the system as it no longer has a stiff DC voltage. These large inductors would also increase the losses of the system as they are series with the load current flow, which is undesirable.
Table 1 - Key differences between LCC and VSC based HVDC systems [8]

<table>
<thead>
<tr>
<th></th>
<th>LCC Based</th>
<th>VSC Based</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic element</td>
<td>Thyristor</td>
<td>IGBT</td>
</tr>
<tr>
<td>Harmonic related issues</td>
<td>Intense low-order harmonics</td>
<td>Weak high-frequency components</td>
</tr>
<tr>
<td>Reactive/active power</td>
<td>Consumes large amount of reactive power at each terminal</td>
<td>Reactive and active power can be fully controlled at each terminal</td>
</tr>
<tr>
<td>Losses</td>
<td>~0.7%</td>
<td>~1.6%</td>
</tr>
<tr>
<td>Maximum power rating (bipolar)</td>
<td>Up to 6400MW (±800kv, 4kA)</td>
<td>400-800MW (300kV)</td>
</tr>
<tr>
<td>Connection to AC grid</td>
<td>Converter transformer</td>
<td>Series reactor &amp; transformer</td>
</tr>
<tr>
<td>Reversal of power flow direction</td>
<td>Change of phase angle control</td>
<td>Control lose (due to diodes)</td>
</tr>
<tr>
<td>Control during DC fault</td>
<td>Adjust phase angle control</td>
<td>Control lost (due to diodes)</td>
</tr>
<tr>
<td>DC side inductors</td>
<td>Large</td>
<td>Small</td>
</tr>
<tr>
<td>Rate of rise of DC short-circuit current</td>
<td>Small and controllable</td>
<td>Large</td>
</tr>
</tbody>
</table>
3 Circuit Breakers

As LCC systems are current controlled it is possible to control the current during a fault using converters themselves, stopping the AC grid feeding into a DC side fault. However with a multi-terminal system this would require the entire DC grid to be de-energized, stopping any power flow between terminals which have healthy lines between them.

The desire for DC circuit breakers developed in the 1970s as presented in [9]. This would allow multi-terminal DC systems to operate much like their AC equivalents: When a fault is detected DC circuit breakers would trip, isolating the faulted section of line, allowing the other converter stations to continue to exchange power around the healthy parts of the network. However LCC circuit breakers were never realized as a commercial product.

With the advent of VSC technology meshed multi-terminal systems are now more deliverable. Circuit breakers for VSC systems have the same purpose as that of LCC systems: to isolate the faulted section so that converters can continue to exchange power over healthy lines. However the nature of VSCs causes the fault to impact the DC system with different characteristics than within an LCC system.

Free-wheeling diodes across each IGBT valve are kept reverse biased whilst the DC voltage is larger than that of the AC grid. When a DC pole-to-pole fault appears in a VSC system the voltage at the reservoir capacitors falls as current is sourced to the short circuit. Once the voltage falls below the peak of the AC the diodes will forward bias and conduct. At this point the converter acts as a six pulse diode rectifier and loses control of power flow with only the line and reactor impedances to limit the current.

A DC fault provides a low impedance path for current to conduct from the smoothing capacitors causing them to discharge extremely fast. The short time period over which this happens determines the speed at which any DC circuit breaker must operate in order to stop both the collapse of the DC voltage, and the in-feed of AC current to the fault.

AC systems have a current zero point twice per cycle which provides a natural place at which to break the current, as the stored energy in the line is minimal. AC CB will typically arc through high current periods making no attempt to clear until or about the current zero point, whereupon it will then isolate the circuit [10]. DC systems however do not benefit from this, by definition.

Mechanical DC CBs similar to those of AC CBs can be used to draw an arc greater than the system voltage, driving the current to zero in order to break. However the energy within the system is absorbed in the arc, and ultimately dissipated in the interrupter itself. For this reason their use is restricted to low power a systems. There is however scope for them to be used in applications where the load current is not interrupted, such as transferring it to a parallel line [11]. The DC circuit breaker must therefore initially force its own current zero within the breaker artificially to break current.

3.1 Resonant Circuit Breaker

The resonant circuit breaker (Figure 3.1) consists of a mechanical contactor in the main path and a resonant commutation path around it. The principle of operation is as follows;
The mechanical contactor conducts the full load current under normal operating conditions and provides a low impedance path, giving low losses. In parallel with this is a resonant LC circuit with a pre-charged capacitor whose polarity is such that it will inject current in the same direction as normal current flow. The parallel commutation circuit is isolated from the main CB for normal operation with a switch.

When the circuit breaker is tripped the mechanical contactor is opened and an arc is drawn between the contacts. The switch isolating the commutation path is then closed allowing the capacitor to inject current. This commutates the fault current from the main path into the resonant circuit leading to a current zero within the mechanical contactor. The arc will extinguish when the current in the mechanical contactor drops below the holding current of the device. Full current is then conducted via the commutation circuit. The voltage on the capacitor is then reversed as it charges it back up. The rate of rise of voltage impressed across the contactor must be controlled in order to maintain isolation and stop a secondary breakdown.

Energy from the total circuit current is then placed in the commutation capacitor as its voltage builds up. The large amount of energy associated with the DC circuit prior to the fault would lead to extremely large voltages across it if un-clamped, 7000kV in the analysis conducted in [11]. Therefore the function of commutation and energy absorption is separated, and a surge arrester is used to clamp the voltage of the capacitor and dissipate the system energy.

The following makes a comparison of the di/dt stress that a mechanical contactor is subjected to in a DC application vs an AC application. A 5000A HVDC system commutating current in 5µs exposes the AC CB to a di/dt of 1,000A/µs, whereas in an AC system running at 60Hz with a load of 40,000A would have a corresponding di/dt of 15A/µs. The demand on a circuit breaker within an HVDC system is far above what is expected of any AC equivalent. A method of profiling the di/dt prior to current zero is demonstrated in [11], allowing a practical AC circuit breakers to be used for this function.

The design pivots on the AC circuit breaker which is a mechanical switch and slow with opening times ranging 30ms [12]. Once the mechanical CB has been opened the current then needs to be commutated into the resonant path and finally the capacitor charged back up to absorb the system energy. LCC systems have large DC side inductances in order to smooth DC side current. This is naturally slows the di/dt when a fault is present on the DC side allowing the CB providing the circuit breaker a longer time to operate before damage is done to the converters or cables making resonant circuit breakers better suited to LCC systems than VSC ones. Prototypes have been demonstrated although they were never implemented on LCC multi-terminal systems.
3.2 Hybrid Circuit Breaker
The Hybrid CB topology (Figure 3.2) uses similar operating principles as the resonant breaker; a mechanical CB in the main path and a separate commutation path. The commutation path in this case consists of semiconductor devices. When the hybrid CB is tripped the mechanical CB will open, drawing an arc between its contacts and generating a counter voltage across the breaker, commutating current into the lower path. Once the current has been commutated into the lower path the arc will extinguish. The semiconductors must continue to conduct the full fault current until the plasma in the mechanical circuit breaker deionizes and withstand the externally applied voltage across it. When the circuit breaker opens whilst conducting current the maximum dv/dt recovery voltage is limited to 80 V/μs, delaying a 320kV system by 4 ms based on a single module being used [13]. This time could be shortened by splitting the circuit breaker into several modules with individual AC circuit breakers, which would only have to block a lower voltage, and thus have a shorter opening time.

During this period current will continue to rise, being limited by the size of the system inductance. This increases the maximum current the system must break, and that the semiconductors must handle. It is therefore desirable to minimise the time delay from opening the CB to switching off the semiconductors and thus de-energizing the line.

Forced commutation within the mechanical CB which reduces the current to zero, or close to, before it opens will lead to an increased maximum dv/dt that can be applied. A method is presented in [13] using a resonant circuit in the main path to force a current zero, with a reduction of maximum current of up to 30%. However this is a transient zero over a short space of time. The between the commutation circuit being initiated to the current zero is in the order of 45μs. This is orders of magnitude faster than opening time of a mechanical switch used within circuit breakers, and thus precise synchronisation would be critical.

3.3 Solid State Circuit Breaker
Solid state CBs (Figure 3.3) offer much faster operation than the previous topologies described. In the other CB designs a mechanical CB is used in the main path. The opening time for this is around 30ms and generally a limiting factor in the speed of the CB. Increasing the speed of operation of the HVDC CB not only is necessary for it to protect the system. By reducing the time it takes to break the current, it also reduces the maximum current that it is required to break.

When the breaker is tripped the solid state devices in the main path are turned off, and a counter voltage will begin to rise across them. This will be clamped at a level set by the surge arrester placed in parallel. The overvoltage that this clamps at will determine the time it takes for the system to be de-energized.
Figure 3.3: Solid State Breaker Topology [13]

The solid state circuit breaker requires no mechanical contactor and therefore its main benefit is its speed, leading to a lower peak current experienced on the breaker components, as well as on the rest of the system. The CB is in series with the rest of the system and therefore carries full load current continually. This gives rise to the relatively high losses when compared to the other CB topologies, where a metallic contact is used in the main path in normal operation.

3.4 Proactive Hybrid Circuit Breaker

The proactive hybrid design (Figure 3.4) proposed by ABB is based around a regular hybrid design, but includes a method to induce a zero current in the mechanical circuit breaker before opening it.

Figure 3.4 - Proactive Hybrid Circuit Breaker Design (ABB) [14]

As previously discussed it is desirable to open the mechanical AC CB without current flowing, as this leads to a faster de-ionization and rate of rise of voltage blocking capability. Although the forced commutation hybrid topology provided this function the zero current imposed within the mechanical CB was a product of an LC resonant circuit, which generated only a transient current zero. The proactive design creates a fixed current zero at which point the mechanical can.

The operation of the proactive circuit breaker is as follows; when the CB is tripped the auxiliary DC breaker is switched off initially. Current is then commutated into the main DC breaker. The time this takes is governed by the stray inductance of the auxiliary and main DC breaker branches, and the voltage the auxiliary semiconductor is clamped to. Once the full current has been commutated the fast disconnector can then be opened with no current flowing. Once the fast disconnector is open the main DC breaker semiconductors can
then be switched off as there is no deionization delay. The counter voltage generated must be larger than the system voltage in order to demagnetize the line inductance. As voltage rises across the IGBTs current is transferred into surge arresters that are placed in parallel, clamping the voltage.

When an overcurrent is detected the proactive CB automatically commutates current into the main DC breaker path. This allows it to have the fastest reaction to then break current immediately after a signal to trip has been received, as the mechanical switch has already been opened. Once current is being carried in the main breaker path the CB can be operated in a current limiting mode by diverting current into the surge arresters periodically. The time period it can sustain this for will be determined by the energy absorption capability of the surge arresters and the fault current level.

The operation of the circuit breaker is in the time period of 2ms, however this is when the system includes an additional DC inductance of 100mH [14] in order to slow the di/dt during the fault. Such a large inductance reduces the stability of the system as the DC bus no longer stiff voltage source. Analysis would have to be conducted to see if such a large additional inductance was feasible within a real system, and the impact it would have on control particularly within multi-terminal systems.
4 DC Fault Characterisation

To assess the fault current profile a CB would be subjected in a meshed multi-terminal HVDC VSC system a Simulink model of a point to point VSC based HVSC system was created. This could then be extended to a multi-terminal system at a later date. The system was rated at 300kV and 1kA and uses two level converters with a three phase voltage source representing a strong AC grid at either end. The grid was directly coupled to the converter via reactors, using no transformers in order to simplify the model.

4.1 VSC Model

The point to point model is based on two identical, two level converter stations, reactors and AC grids. Each terminal switches between the positive and negative voltage rails using PWM switching based on a sinusoidal carrier. If the output of each of the phases is assumed be a sinusoidal voltage source then the power flow between the converter and the grid can be represented as in Figure 4.1. The output of the converter will contain harmonics from switching, however for the purpose of controlling power flow it is assumed ideal.

It can been seen how control over the phase and magnitude of the converter output (Vi) will determine the current magnitude and phase angle flowing between the converter and the grid. A phase-lock-loop (PLL) is used to track the local grid voltage and provide a frequency and phase reference. The converter voltage magnitude and phase angle are then augmented relative to this to achieve the desired current.

![Figure 4.1 - VSC & Grid Phasors](image)

The output of the converter is controlled via a current loop controller operating in the rotating DQ reference frame. This allows the control to take place at DC whilst the system is in steady state. The current loop controller uses a PI controller to augment the PWM DQ voltage of the converter and thus control real and reactive current that flows.

The reference for the inner current loop controller is set by an outer loop controller, which can take many forms. In the point to point model the sending end controls power from the local grid to the DC side. Given that the magnitude of the voltage on the local grid is fixed, a fixed DQ current reference effectively sets the power for the sending terminal.

The receiving terminal includes an outer loop DC voltage controller. This modulates the current demand reference using a PI controller to hold the voltage at the smoothing capacitors at the receiving terminal at the desired level.

If the sending terminal (T1) increases its power onto the DC side, the DC voltage will begin to rise. The DC voltage controller on the receiving side (T2) will correspondingly adjust (in this case increase) the D current demand on its inner loop controller until equilibrium is reached.
4.2 DC fault simulation results
To evaluate the impact of the fault, based on its location, the point to point model was used. The fault was placed between the two PI sections of each pole that represented the line impedance between the converter stations. To move the fault from one station to the other the number of PI segments on one side was increased, whilst the others were consequently reduced, keeping the number of PI segments per km the same for each test.

The DC fault current was measured on the DC side entering the transmission line. This point in the system experiences the most severe maximum fault current as it subjected to the smoothing capacitors discharging into the fault. The time for the smoothing capacitors to discharge is also measured for each terminal, shown in Figure 4.2.

![Figure 4.2 - Capacitor DC fault characteristics](image)

In this simulation T1 is the sending end and T2 is the receiving end. The peak current next to the capacitors is larger for the sending terminal, 16.5kA in T1 vs 15.5kA in T2, when the fault is placed 10% of the line distance from the respective converters. This can be attributed to the higher voltage at the sending end because of ohmic voltage drop across the line. The simulation clearly shows the large time difference between how long the fault takes to penetrate depending on which converter station it is closest to. When the fault is 10% of the line distance from T1, it takes close to 20ms for the capacitors at T2 to discharge, whereas T1's discharge in closer to 5ms.
4.3 Impact of DC fault on converter

A fault was applied to the system running at full capacity (300MW) at 0.8s, after the system had stabilised into steady state operation. Figure 4.3 shows the current on the DC side flowing out of the upper capacitor, into the upper transmission line, and out of the upper converter devices. It can be seen in the shorter time scale in Figure 4.4 that once the fault is applied current into the transmission line is rapidly increased, feeding the fault. This is sources primarily from the reservoir capacitor, causing the DC voltage to fall. The current in-feed from the AC side is much slower to respond due to the AC reactors and grid impedance.

When the capacitor voltage falls just below zero they can no longer supply current as their voltage becomes clamped by the free-wheeling diodes within the converter, preventing them from reversing polarity more than the on-state voltage of the diodes. Because the transmission line has an associated inductance the current flowing is then immediately commutated into the free-wheeling diodes of the converter, as can be seen at 0.8045s. This dramatically increases the current that is drawn through the free-wheeling diodes, leading to damage to the converter valves if unprotected.
Simulations carried out with additional DC inductance at the converter terminals show that the initial DC current can be decreased Figure 4.5. The current is reduced and the rise time is delayed, assisting any DC circuit breaker. However the benefits are only seen if the circuit breaker operates within a short period of time as the steady state current remains the same.
Figure 4.5: Variable DC inductance
Figure 4.6 - VSC HVSC Simulink Model
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