Examination of Power Systems Solutions Considering High Voltage Direct Current Transmission

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Abstract

Since the end of the Current Wars in the 19th Century, alternating current (AC) has dominated the production, transmission, and use of electrical energy. The chief reason for this dominance was (and continues to be) that AC offers a way minimize transmission losses yet transmit large power from generation to load. With the Digital Revolution and the entrance of most of the post-industrialized world into the Information Age, energy usage levels have increased due to the proliferation of electrical and electronic devices in nearly all sectors of life. A stable electrical grid has become synonymous with a stable nation-state and a healthy populace.

Large-scale blackouts around the world in the 20th and the early 21st Centuries highlighted the heavy reliance on power systems and because of that, governments and utilities have strived to improve reliability. Simultaneously occurring with the rise in energy usage is the mandate to cut the pollution by generation facilities and to mitigate the impact grid expansion has on environment as a whole. The traditional methods of transmission expansion are beginning to show their limits as utilities move generation facilities farther from load centers, which reduces geographic diversity, and the integration of nondispatchable, renewable energy sources upsets the current operating regime. A challenge faces engineers – how to expand generation, expand transmission capacity, and integrate renewable energy sources while maintaining maximum system efficiency and reliability.

A technology that may prove beneficial to the operation of power system is high voltage direct current transmission. The technology brings its own set of advantages and disadvantages, which are in many ways the complement of AC. It is important to update transmission planning processes to account for the new possibilities that HVDC offers. This thesis submits a discussion of high voltage direct current transmission technology itself and an examination of how HVDC can be considered in the planning process.

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Chapter 1: Introduction

At the beginning of electricity distribution in the late 19^{th} Century, direct current (DC) was the typical form of electrical power production. However, low operating voltages and high load currents from increasing demand caused high transmission losses and poor voltage profile. Voltage profile meaning the difference between the sending and receiving end voltages. Equipment for high voltage DC transmission is costly and therefore impractical. With the introduction of alternating current (AC), the development of a relatively efficient AC transformer, and the invention of efficient AC generators, AC power began to outstrip DC systems in use due to significant reduction in transmission losses and better voltage profiles.

Voltage transformation allows AC to maintain a stable voltage profile over the entire length of a line by reducing series conduction line losses. For this reason, AC's dominance in power systems, especially transmission systems, went practically unchallenged. However, as line lengths increase, the charging current required to charge the shunt capacitance of the line erodes a lines capacity to transmit real. AC also has skin effect, where the current density is non-uniform through the conductor, which raises its effective impedance; the frequency associated with alternating currents gives rise to this phenomenon. Finally the requirement for synchronism (phase, frequency, and voltage magnitude matching) when connecting lines makes AC more difficult to interconnect. Advancements in power electronics technologies have provided and will continue to provide the ability to operate efficient systems at high DC voltages and makes them a more convincing solution for transmission.

In the last few decades, several developments have begun to erode AC's dominance in power systems. By far, the leading development was power electronics by way of the invention of semiconductors. As the 20^{th} Century progressed, several advancements in semiconductor technology led to the development of power electronics that could operate at grid-level voltages and a return to DC looked more attractive.

The following chapters will provide a discussion of HVDC as it pertains to transmission systems. Emphasis will be given to how the capabilities of power electronics technology can be used in HVDC solutions to solve systemic issues in contemporary electric power grids rather than focusing on minutia pertaining to things like specific control schemes or governmental regulations. It will be organized in the following way. The remainder of Chapter 1 consists of an introduction to HVDC technology; the discussion focuses on the advantages and disadvantages of the technology. Chapter 2 provides a historical context for HVDC; by knowing about the beginnings of HVDC, perspective can be gained about how the technology has evolved. Chapter 3 focuses on the current trends of HVDC technology– the latest converter technologies and latest switching devices – and system configurations where HVDC can be beneficial (e.g. line congestion, connecting intermittent generation).

Chapter 4 is the methodology proposed by this thesis and is the contribution that this thesis strives to make. HVDC is different from previous grid technologies and a discussion of the advantages and disadvantages of using the technology and the impact that those have on the transmission planning process is necessary for HVDC to be considered a viable solution in power systems. Chapter 4 explains the transmission planning process methodically and the types of considerations that go into each step of the process. To demonstrate how the methodology works, it is applied to a system model where some of the system configurations discussed in Chapter 3 occur. Chapter 4 shows through simulations that in certain situations, HVDC can be leveraged in a power system to provide solutions to operational limitations where AC simply cannot. The final part of Chapter 4 discusses the development of the model and the modeling assumptions that were made in the simulations throughout the methodology discussion. Chapter 5 evaluates and concludes the discussion about the methodology, its applications, and future areas of research.

1.1 Advantages of HVDC Transmission [1]

As mentioned in the introduction to this chapter, HVDC has several advantages over HVAC. The bulleted list below shows of the distinct advantages of HVDC. Immediately following the list, the discussion expands on each bullet.

- Stability of long distance bulk power transmission
- Systems synchronization between terminals is not necessary
    - No frequency matching
    - No phase angle matching
    - No voltage magnitude matching
- Decoupled active power and reactive power (if voltage source converters are used)
- More predictable energization
- Minimal contribution to short circuit current during AC system faults
- Reduction in number of conductor and land needed.
- Quick response time to changes in transmission network

Stability of long distance bulk power transmission. The foremost advantage of HVDC is its stability over long distances. The impedance of a transmission line is dominated by the inductive reactance of the line. In the example in Table 21, the reactance of the line is nearly 21 times larger than the line's resistance. While the reactance itself does not contribute to the line's real power dissipation, long lines will have a larger share of the available complex power dedicated to the reactive needs of the line. In addition, long lines will have a higher accumulated capacitance, which causes the charging current of a line to increase. The effects of reactance on AC lines cause complications in operation, such as difficulty in adequately protecting the line in all of its reasonable operating configurations and maintaining a good voltage profile during light and heavy loading conditions. In many cases, the reactive compensation needed for proper operation of long AC lines is more costly and cumbersome than is typically wanted, which is especially true for underground or undersea lines that tend to be extremely capacitive even at relatively short line lengths. With HVDC, there is no inductive or capacitive reactance because reactive voltages and currents do not exist in DC therefore all the transferred complex power transfers as real power where the only losses occur due to the DC resistance of the line and losses through the converters. Since resistance of the conductors (which is usually small) is the only limiting factor, for practical purposes, HVDC lines can provide utility in many instances where AC lines cannot by allowing connections between very distant points.

Interconnection of separate AC systems. The second advantage and a well-known example is that by converting from AC to DC, frequency and phase are removed as requirements; this is helpful when interconnecting two or more asynchronous systems. Without needing to be in synchronism, this kind of connection, usually called an intertie, allows for power transfers between systems. For example, the Eastern, Western, and Texan Interconnections in the United States are tied together using back-to-back converters.

The separation that comes from using interties isolates oscillations occurring in one system from the other system. For example if two system were connected using HVDC links(s) yet isolated in terms of AC, a system event propagating through one system is not transmitted across the DC link; for extreme cases, such as brownouts or blackouts, the HVDC converters in a link or back-to-back arrangement would shut down.

Decoupling of active and reactive power controls. Older HVDC technology (line commutated, current source converters; discussed later) only gave the ability to control the active power link and the link was unidirectional. In addition, a strong AC system (i.e. one with significant generation capacity) is needed on either side of a link for it to work properly. However, in newer technologies (self-commutated, voltage source converters; also discussed later), the converter technology provides independent active and reactive power control and the converters can be connected to either a strong system, which also has large mechanical inertia, or to a weak system, meaning one without significant generation capacity and low mechanical inertia. This capability allows for more control over reactive power support; if more reactive power is needed at one end of the HVDC system, the converter can be commanded to provide more if it is within its capacity to do so.

More predictable energization. For transmission lines (both AC and DC), the inrush current is very high when the line is energized. During AC line energization, the traveling waves produced cause the voltage at the receiving end of the line to be extremely large (twice or more depending on the impedances prior to and after the line). AC equipment must be made to handle the temporary increase in voltage. DC does not have this problem because energization occurs as a smooth voltage ramp.

Predetermined contribution to AC fault currents. A DC link allows for power transmission within specified ranges, which is associated with the operating limits of the converter, though other limits could be imposed. During AC side fault, the output current of the converter will increase, but it will be limited to a maximum value by the converter (safe current levels for the switching devices) and also the series reactor. (The topic of HVDC station structure is discussed later.) The converter’s control scheme has the ability to detect abnormal conditions on the AC system (under or over voltages and frequency) and can manage the output appropriately. Voltage source converters (VSCs, discussed later) can be set to provide ride-through capacity, which helps maintain system stability. The ride-through capability is useful when the HVDC system is the source of significant generation; if large of HVDC connected generation drop out during system faults, it could further contribute to the degradation of the system.

Reduction in transmission infrastructure. Aside from the operational benefits, HVDC lines typically require smaller towers than AC lines of the same power level due to the reduction in the number and weight of the conductors. Replacing AC lines with DC lines allows more power to be wheeled through the same corridor.

Quick response times. The controller that operate the converters can react quickly and independently to changing system conditions – faster than any human operator can. This ability allows them to provide the best connection between the AC and DC sides. For example, a change in power demand at the terminals of an HVDC based generation facility will register immediately with the converter's controller, which can then respond appropriately to maintain AC system stability through real and reactive power injections.

1.2 Disadvantages of HVDC Transmission [1]

Though HVDC does offer distinct advantages, it also has its share of disadvantages. Below are some of the weaknesses of HVDC. After the bulleted list, the discussion continues with more explanation.

- Large, fixed, initial costs for converter stations
- Converter substations can be large when compared to AC substations
- Coordination between devices is extremely important
- Protection is difficult
- Needed knowledge base is often lacking

HVDC vs HVAC Costs. Transmission losses are directly related to losses in revenue. Therefore, balancing reduction in transmission losses and the cost of creating a more efficient system is paramount. Figure 1 shows the cost versus distance comparison between AC and DC transmission lines.

Points (1) and (2) in Figure 1 mark the cost of the terminals for AC and DC, respectively. It is clear that the initial costs for HVDC is much higher than HVAC; this is due to the large investment in the converter stations. Operating voltage and power level dictate much of the cost of the converters. The next cost is the construction of the transmission lines and structures. The costs for AC and DC are marked as (3) and (5), respectively, and it can be seen that AC is more costly than DC. As distance increases, shunt reactors must be added to the system every 100 km or 200 km intervals to correct undesired reactive flows from the large distributed capacitances that build up on long transmission lines; this is denoted as (4). Next, the transmission losses incurred by AC and DC are denoted as (6) and (7), respectively; this point is a breakeven point where the cost of HVAC is more than the cost of HVDC; as the lines get longer the ancillary equipment that must be added increases the cost of the project greatly. The final costs are denoted for AC as (8) and for DC as (9). The conclusion to draw is that for short distances, that is to say distances less than 450 km or 280 mi, AC is still the most cost effective solution compared to DC when considering cost as the only constraint. However, an important point to make is that while the costs are higher for short distances for DC transmission, other factors may change the cost comparison. Special cases like underwater and underground lines would shorten the length of line required for the link to be economical.

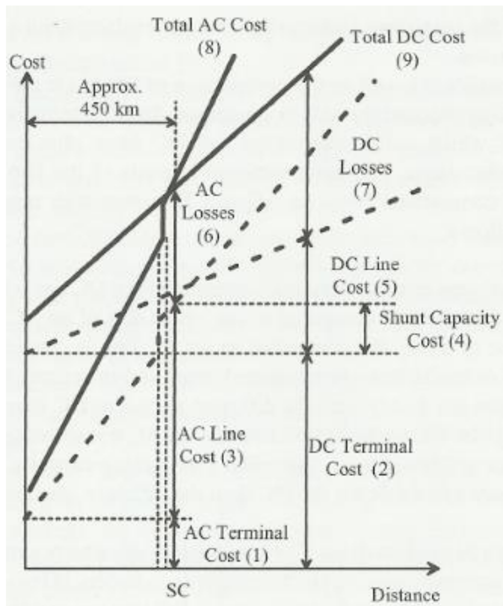

Figure 1: Transmission distance and investment costs for AC and DC power transmission lines [1] C.-K. Kim and e. al., HVDC Transmission: Power Converter Applications in Power System, Singapore: John Wiley & Sons (Asia) Pte Ltd, 2009. Used under fair use, 2015.

Size of HVDC stations. A difficult issue to overcome with HVDC projects is their size. Line commutated converters (LCCs, which are discussed later) have substations that are very large due to the need for more ancillary equipment, like cooling and filters, and their size increases as the operating voltage increases. For instance, the Talcher–Kolar HVDC system (East–South Interconnection II) in India, which operates at 500 kVdc in a bipolar topology (see 2.4 Veteran HVDC Topologies), has a substation in Talcher (Figure 2) that houses the converters, VAR support, and filters. The station is approximately 1600 ft by 1200 ft. The electrode station (used for asymmetrical monopole operation 2.4 Veteran HVDC Topologies), for the Talcher side of the link is located in Rohila (Figure 3) which is about 20 miles northeast of the converter substation and is approximately 1625 ft in diameter. Securing that much land means that the station will be located remotely and this will also make equipment difficult to move to the site.

Coordination. Achieving the coordination between the two ends of a long distance link is a challenge. Returning to the Talcher–Kolar system, the distance between the two stations is 901 mi (1450 km) [5]. Coordinating between the two converter stations is crucial for operation and achieved by means of a high-speed (fiber optic) communication channel that connects the two stations. Most companies that produce HVDC technology, like Siemens and ABB, have their own solutions for communication and coordination of devices; mixing technology from multiple manufacturers may not necessarily work. Without standards, utilities installing HVDC gravitate toward one manufacturer that leads to the manufacturer's monopolization of the market and a lack of competition as well as innovation. In addition, this subjects the utility to an increased risk of wide systemic errors should errors. The development of standards and regulations for HVDC transmission will ensure equitable competition, compatibility, and security. For a further discussion of HVDC standardization, the reader is directed to search HVDC literature for a more in depth discussion.

Figure 2: Talcher Converter Station (21°06'01"N 85°03'49"E) [6] Google Maps, 2015. Used under fair use, 2015.

Figure 3: Rohila Electrode Station (21°12'11"N 85°19'05"E) [6] Google Maps, 2015. Used under fair use, 2015.

Protection. The challenge with DC protection is that the voltage and current signals will never have convenient zero-crossings at which to open. The current method for protecting existing HVDC equipment is to have the converter shut down and to have a traditional AC breaker on the AC side open if there is a fault on the DC portion of the system [7]. This solution works for the moment as HVDC is more of an exception rather than the norm, but if HVDC is to become more mainstream, a better protection device is necessary. ABB has developed an HVDC breaker using a hybrid scheme using a combination of semiconductor technology (IGBTS, 3.1 Insulated Gate Bipolar Transistors) and traditional mechanical means [8]. The breaker is a significant development, but in its current state, it is not ready for commercial use until the breaker can operate at high DC current and voltage levels. The footprint must also experience a significant reduction for it to be practical; the addition of this hybrid breaker to a converter station would increase the needed ground footprint.

Shift in knowledge base. Traditional power systems operate according to readily understandable physics. Converter control schemes are developed or semiconductor devices are invented that achieve a specific operational benefit, but all the variants try to achieve efficient power conversion. Selection of the appropriate devices requires more understanding than most power engineers currently have.

Chapter 2: Historical HVDC Transmission

HVDC began almost immediately after the introduction of electricity to the public and the need to change voltage levels to mitigate transmission losses. René Thury, a Swiss electrical engineer, developed a system in 1889 that was able to attain “high voltage DC.” It employed a series combination of generators and motors to change voltages. While clever, it was very much a complicated electromechanical system and did not succeed due mechanical inefficiency.

2.1 Mercury Arc Valves

After its invention in 1902 by Peter Cooper Hewitt, the mercury arc valve (also called mercury arc rectifier) provided reasonably efficient rectification over other technologies of the era, like the rotary converter. There were many types of MAVs – a glass bulb like the one shown in Figure 4 or a steel or iron tank.

A MAV with a single anode pair is analogous to a modern single diode. Similar to the output voltage ripple in a half-wave rectifier, a MAV with a single anode-pair has the same problem with its output waveforms. To improve the output, more anode pairs were added. Usually, MAVs were connected to the AC system as three-phase rectifiers by a stepdown transformer. The AC system served as the commutation reference. Commutation is the process by which the conduction path between the AC and DC sides is changed. MAVs can be viewed as an early type of power converter that is called a line-commutated converter (LCC) [2]. 2.3 Line Commutated Converters gives more discussion on LCCs.

For what they were, MAVs were reasonably efficient. The Pacific Intertie and many other links thereafter used them in their operation of HVDC links, but as semiconductor technology developed throughout the 20th Century, they gradually fell out of use. Many lingered into the 1970s in subway and tram systems and there are likely a few still in use throughout the world, but now they are a very small minority.

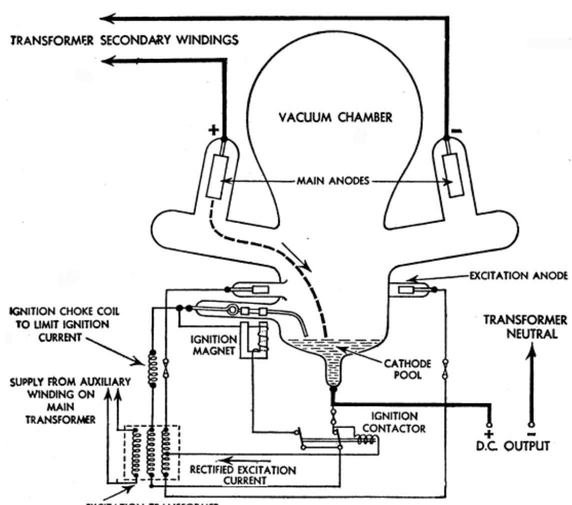

Figure 4: single mercury arc valve schematic [9] M. Harrison, "Mercury Arc Valves," 2014. [Online]. Available: http://www.electricstuff.co.uk/mercarc.html. [Accessed 14 January 2015]. Used under fair use, 2015.

2.2 Thyristors

Moving forward in time is the thyristor classification. All devices under this classification are constructed similarly to a bipolar junction transistor (BJT), but with an added layer of P or N material bringing the number of layers to at least four or more. Functionally, many thyristor devices can be simplified to a four layer device, but in actual construction it is more like two BJTs – one NPN and one PNP – that work together. This is reflected by the equivalent BJT circuit used to represent thyristor devices (see Figure 5). Normally, BJTs are not hysteretic devices but thyristors are because of positive feedback within the device [10]. Some examples of thyristors are shown in Figure 5. These devices formed the switching devices in bridge circuits inside HVDC converters. These semiconductor devices replaced the MAV as the switching device for the power rectifier. Many early HVDC links like the Pacific Intertie replaced the MAVs with thyristor in their converter stations. Different thyristor devices (there are many variants) remained dominant for most of the 20th Century. Only with the development of robust insulated gate bipolar transistors (see 3.1 Insulated Gate Bipolar Transistors) did the thyristor's dominance begin to wane.

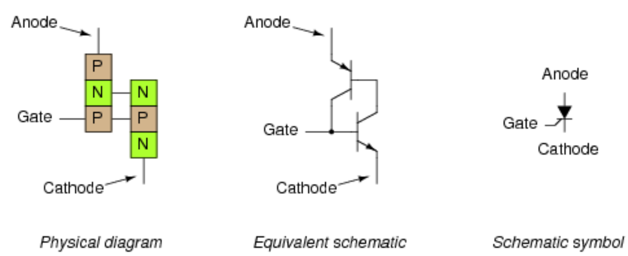

Figure 5: representations of a Silicon-Controlled Rectifier (SCR) – a member of the thyristor family [10] T. R. Kuphaldt, "Thyristors," All About Circuits, 2015. [Online]. Available: http://www.allaboutcircuits.com/vol_3/chpt_7/1.html. [Accessed 15 January 2015]. Used under fair use, 215.

2.3 Line Commutated Converters

In 2.1 Mercury Arc Valves, it was mentioned that that MAVs formed an early version of what is called a line commutated converter (LCC). MAV- and later, semiconductor-based systems rely on the AC system as their reference for the commutation process. LCC systems allow for active power conversion, but inductive reactive power is required for LCC to work. This is due to the firing delay and angular difference between the current and voltage where the current always lags voltage and causes the converter to consume reactive power [3]. The VAR support (i.e. capacitor banks) and the needed filtering to suppress the harmonics that are also generated require area in addition to the converter station, which is the biggest (and frequently fatal) issue with implementing LCC HVDC projects. Big cities, which would benefit the most from HVDC infeeds, generally do not have the available area to construct these kind of large substations. Therefore, the energy is brought close to major load centers where it is then transmitted by the AC system.

The power flow is unidirectional meaning that power flows from one point where there is surplus power (typically large, remote generation) to another point some distance away. The converters use the same equipment for rectification and inversion, but a LCC system cannot instantly flip the direction of the power flow. To change direction of power flow, both converters must be shut down, polarity flipped, and restarted. The fact that LCC HVDC cannot have bidirectional power flow, the large land areas that LCC HVDC systems need, and the need for nontrivial reactive support and filtering have confined the use of LCC HVDC to a supporting role to AC transmission operations rather than the mainstream form of transmission. However, those limits do not apply to Voltage Source Converters (VSCs); that technology, discussed in Chapter 3, has bidirectional power flow and through better rectification and inversion processes, the need for extensive filtering and reactive support is eliminated.

2.3.1 Operation of Line Commutated Converters [3]

LCCs fall into a category called static power converters and most LCC systems currently in use also fall into a subclass called current source converters (CSCs). Conceptually, it may be helpful to think of converters as an AC-DC transformer; the AC power into the converter and the DC power out of the converter are the same minus the losses in the converter (mostly in the form of switching losses). Current source converters, as opposed to voltage source converters (3.2 Voltage Source Converters) are differentiated by the way they are connected to the external circuit. In CSCs, for stable power conversion to occur, there needs to be a series inductance on the DC side to smooth the current waveform and line-to-line capacitances on the AC side to offset the naturally inductive system at the terminals of the converter (Figure 6(c)).

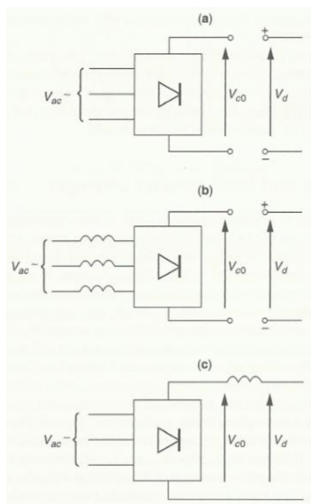

Figure 6: AC-DC voltage matching: (a) unmatched circuit; (b) circuit for voltage conversion; (c) circuit for current conversion [2] J. Arrillaga and e. al., Self-Commutating Converters for High Power Applications, West Sussex, United Kingdom: John Wiley & Sons Ltd, 2009. Used under fair use, 2015.

Prevalent in CSC is a three-phase bridge as shown in Figure 7 that forms the AC to DC circuit or vice versa. The figure shows LCC using thyristors, but those elements can be substituted for other switching devices. When two of the devices are conducting, the DC voltage is formed from the series combination of devices. As the AC system oscillates, the pair of devices (which are predefined) that is conducting transitions from one pair to the next in a specific order.

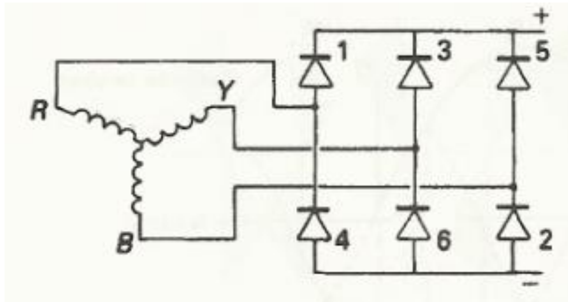

Figure 7: three-phase, 6-pulse bridge [12] J. Arrillaga and e. al., Flexible Power Transmission: the HVDC Options, West Sussex, England: John Wiley & Sons Ltd., 2007. Used under fair use, 2015.

Assuming the ideal case, there is instantaneous transition of the switching device from on to off, but these transitions take time to complete in reality. Due to this, there is a period where two valves are on simultaneously and is described by what is known as the overlap angle, u. Also, there is a period that is needed for a device that has been shut off to recover enough (meaning that sufficient charge has been removed from the semiconductor structure) to block reverse voltage; this is characterized as the extinction angle, γ. Small extinction angles represent better reverse voltage blocking characteristics of the switching device. These two allowances are necessary parameters in real converters. These concepts again have analogues in VSCs; a great deal of time in the development of three-phase converters has been spent creating semiconductor devices that are low loss during conduction and can operate reliably at high speed, but still retain the necessary voltage blocking capability.

Keeping those angles in mind, the equation that describe the instantaneous commutation current during operation under balanced AC condition is

$$I_d = \frac{V_c}{X_c\sqrt{2}}[\cos(\alpha) - \cos(\alpha + u)]$$

Where I_d is the DC side current, V_c is the phase-to-phase AC line voltage magnitude, X_c is the commutation reactance of the converter, α is the firing angle, and u is the overlap angle.

During rectification, the DC side voltage can be described as

$$V_d = V_{c,0}\cos(\alpha) - \frac{3X_c}{\pi}I_d$$

Where

$$V_{c,0} = \frac{3\sqrt{2}}{\pi}V_c$$

And the AC current flowing to the rectifier from the AC system can be described as below assuming the necessary harmonic filtering exists.

$$I = \left(\frac{\sqrt{6}}{\pi}\right)I_d$$

During inversion, the DC side current is described by

$$I_d = \frac{V_c}{X_c\sqrt{2}}[\cos(\gamma) - \cos(\beta)]$$

Where

$$\beta = \pi - \alpha$$

And the DC side voltage is described by

$$V_d = V_{c,0}\cos(\gamma) - \frac{3X_c}{\pi}I_d$$

Where γ is the extinction angle and β is angle of advance.

One of the benefits of using semiconductor is that they can be turned on and off by an outside controller. This leads to the ability to control the firing angle, α, of each valve (device pair). If the converter were perfect, the output DC voltage waveform would near constant after passing through a series DC reactor. Control over the firing angle is what allows the polarity to switch so the direction of power flow can be changed (after shutting down and re-energization) [12]. The concept of firing angle is key to the operation of three-phase converters and thus this concept will have an analogue in VSCs.

The power factor apparent at the terminals is not, as mentioned before, unity due to the delays from the commutation process. Assuming that there are no distortions from converter operation due to filtering, the power factor at the terminals of converter is defined as the phase difference between the fundamental frequency voltage and current.

The real power on the AC side is

$$P = \sqrt{3}V_C Icos(\phi)$$

The real power on the DC side is

$$P = V_d I_d$$

Ignoring the losses through the converter, the two real powers can be equated.

$$\sqrt{3}V_c Icos(\phi) = V_d I_d$$

And solving for ϕ

$$\phi = \arccos\left(\frac{V_d I_d}{V_c I\sqrt{3}}\right)$$

Or substituting the expressions for V_d and I_d, the power factor can be written in terms of the firing and overlap angles for rectification.

$$\phi = \arccos(0.5[\cos(\alpha) + \cos(\alpha + u)])$$

For inverter operation the power factor can be written as

$$\phi = \arccos(0.5[\cos\gamma + \cos\beta])$$

The reactive power can be defined in terms of P as

$$Q = (P)(\tan\phi)$$

In the vector diagram (Figure 8), converters during both rectification and inversion have negative reactive components of their complex power, which indicates that the converter, regardless of the operation mode, consumes reactive power. The constant consumption of reactive power during steady state operation shows the need for reactive compensation (i.e. capacitor banks) to compensate for this phenomenon. The amount of reactive power consumed varies with the amount of real power being transmitted through the converters by the cosine or sine of the operating angles. The less real power transmitted causes more reactive power to be consumed increasing the need for reactive support. This occurrence is usually combated with tap changers on the connecting transformers.

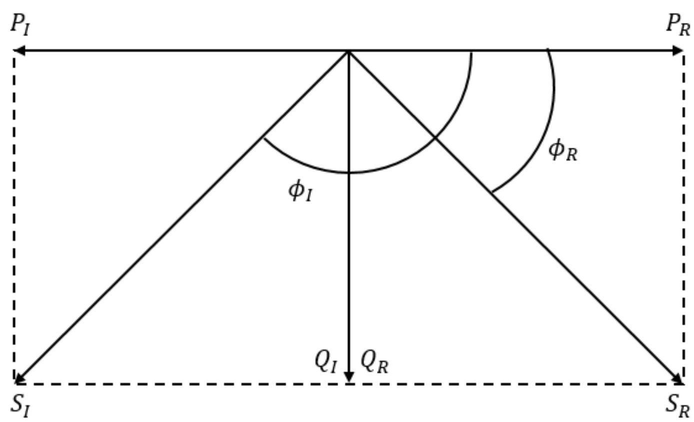

Figure 8: vector diagram for power; R indicates rectification; I indicates inversion

The 6-pulse configuration described here works, but this configuration causes significant harmonic injection on the AC side of the converter; this means that significant filtering is needed to block the harmonics from entering the AC network. However, a solution to this is to implement a 12-pulse converter as shown in Figure 9. By having an interface transformer with two sets of secondary windings – one wye connected and one delta connected – six phases are fed into the converter, which results in less harmonic content injected back into the AC network because the DC waveforms are much smoother than in a 6-pulse configuration. In his work in [3] and [12], Arrillaga et al. describe in detail the harmonic injection of LCCs. The reader is directed to those texts for a discussion on harmonic analysis of LCC converters.

In conclusion, LCCs were the first step in HVDC forming many of the foundational concepts for the operation of three-phase converters. As semiconductor technology progressed, the MAV based LCCs were replaced by more efficient and more controllable thyristor based LCCs. Also, improvements from the original 6-pulse to the current 12-pulse configuration improved the overall capability of HVDC converters. Many links that exist today are LCC converters of the 6- or 12-pulse variety. This technology set the stage for the next stage in HVDC transmission – the voltage source converter.

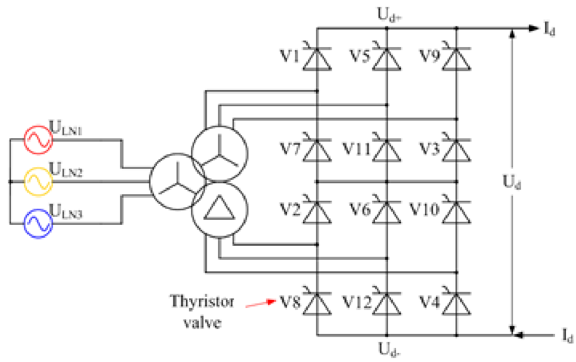

Figure 9: 12-pulse LCC [13] Clampower, "12 pulse bridge with thyristor valves," 29 November 2012. [Online]. Available: http://commons.wikimedia.org/wiki/File:12_pulse_bridge_with_thyristor_valves.png. [Accessed 21 January 2015]. Used under fair use, 2015.

2.4 Veteran HVDC Topologies [3] [4]

Contemporary HVDC links are point-to-point systems. One point in an AC transmission system is connected to another point in an AC transmission system; it can be connected to the same AC system as the first point or to a point in another AC system. There are a few exceptions that are three terminal systems, which connect more than two points – Italy–Corsica–Sardinia Link and Quebec – New England Transmission; these systems still have mono- or bipolar topologies and operate similarly to other HVDC systems. These systems are still the exception rather than the norm in HVDC; therefore, for more information, the reader is directed to the readily available literature.

HVDC links are composed of converters are connected by cables or lines; they take one of two forms – monopolar or bipolar. A monopolar system (see Figure 10) is one in which there is a single pair of converters. A symmetrical monopolar system (Figure 10(a)) is one in which the return path is a dedicated conductor; this type of link operates ungrounded. On the other hand, an asymmetrical monopolar system (Figure 10(b)) is one in which there is a single converter pair, but the return path is an electrode placed in either the earth or the sea. A bipolar system (see Figure 11) is one in which there are two pairs of converters each connected by a dedicated conductor; the neutral connection (if it exists; it is not necessary for operation) goes unused during normal operation, but if one pole is out of service, then the system can operate as an asymmetrical monopolar system. The maximum transferrable power in a bipolar system is twice that of a monopolar system if both systems were using poles with similar parameters [1].

Back-to-back ties are the other common configuration (Figure 12). They operate in the same way as links, but the difference is that no significant length of transmission line or cable is connected between the two converter units; this type of configuration could technically be either mono- or bipolar, but in practice, it is usually the bipolar topology. As stated in previous sections, this topology is typically used to interconnect adjacent AC systems or to connect generation without increasing short circuit current.

These topologies are still very much commonplace in the world of HVDC transmission. As discussed in later chapters, even with upgrades to the converter technology (i.e. voltage source converters), these topologies are more or less the same.

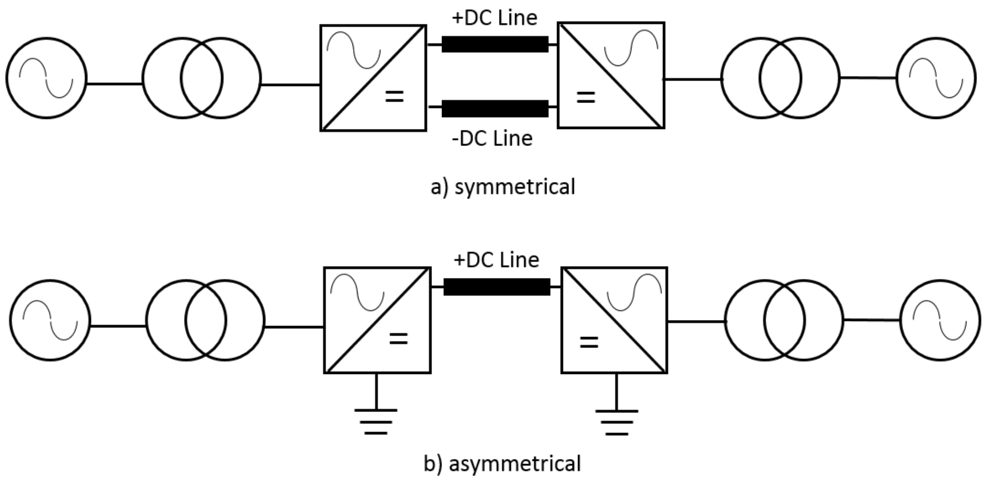

Figure 10: monopolar HVDC systems

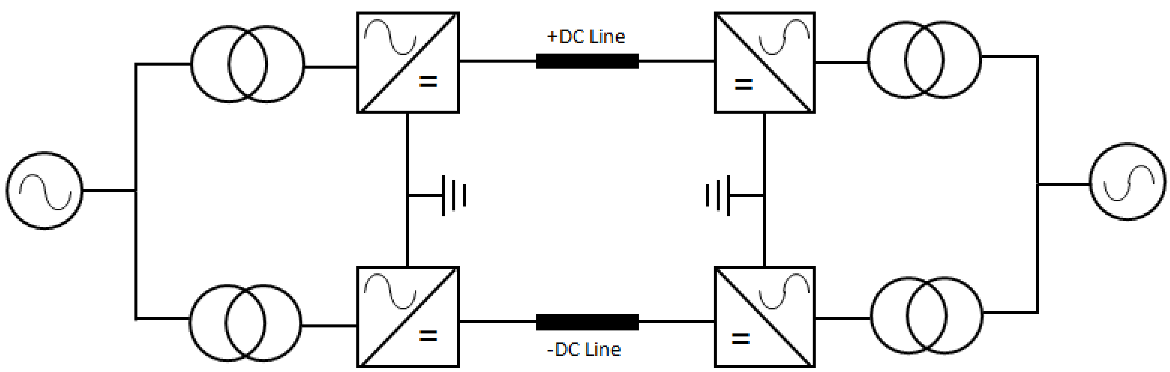

Figure 11: bipolar HVDC system

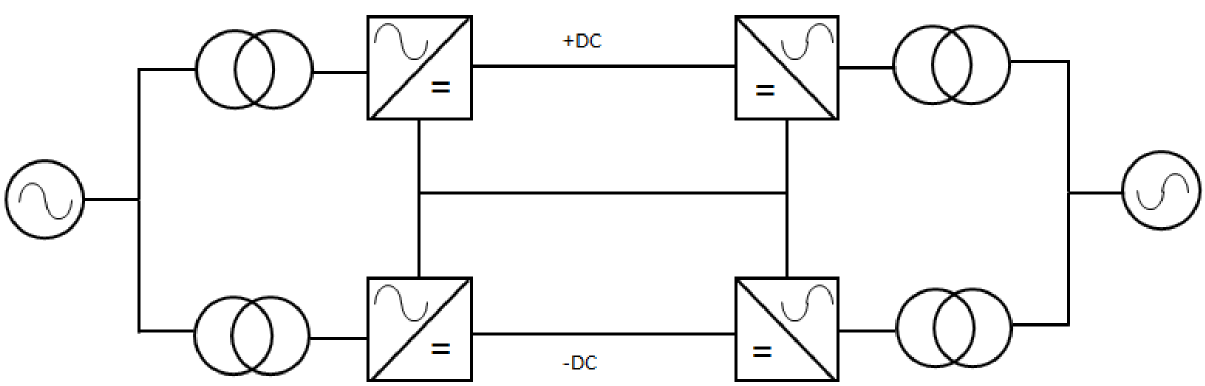

Figure 12: back-to-back HVDC system

Chapter 3: Modern and Future HVDC Transmission

Here in Chapter 3: Modern and Future HVDC Transmission, the discussion will address the latest advancements in HVDC technology and converter configurations as of the submission date of this thesis. In recent years, voltage source converters (VSCs), a type of self-commutating converter (SCC), have made many inroads into HVDC transmission because they can set their own power factor and produce fewer harmonics, which reduces the need for extensive filtering and consequently, the physical footprint for these facilities is smaller than that of CSCs. The use of IGBTs in these converters allows conduction and switching loss reduction that improves overall efficiency of the converter. It is the goal of this chapter to expand on the discussion of VSCs and IGBTs and how those technologies will be of use when considering the example system in Chapter 4: Examining Transmission Systems Considering HVDC.

3.1 Insulated Gate Bipolar Transistors [11]

In 2.2 Thyristors, several semiconductor devices were listed as precursors for the switching device inside HVDC converters. As is implied from its name, the IGBT combines MOSFET technology with that of BJTs. The MOSFET technology is useful because the gate driver circuitry used in driving the device is compact and inexpensive and can be integrated with the rest of the IGBT device; the MOSFET portion is used to provide the base current for the bipolar transistor. The BJT portion has high current carrying capacity along with low saturation voltage, which reduces the internal voltage drop when the device is conducting. While the devices can withstand high operating voltages (~2 kV) and currents (~5 kA), several are needed in parallel and series to provide adequate voltage and current division to form a converter where the devices are working within their operating ranges and controlling many devices simultaneously also makes their control complicated with fractions of a second making a difference during operation. Referring back to the discussion of firing, overlap, and extinguishing angles from 2.3 Line Commutated Converters, IGBTs turn on and off quickly and as a result they recover quickly in their off state allowing them to block reverse voltage more effectively. For a thorough discussion of IGBTs, the reader is directed to [11]. The best conceptualization for discussion here is that IGBTs are highly controllable and low loss switching devices.

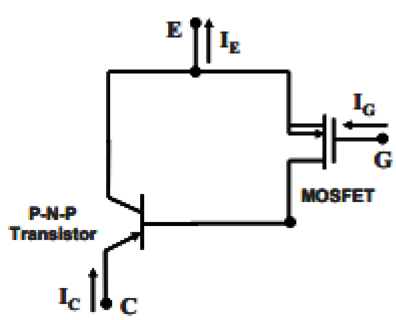

Figure 13: ideal equivalent IGBT circuit [11] B. J. Baliga, Fundamentals of Power Semiconductor Devices, New York: Springer, 2008. Used under fair use, 2015.

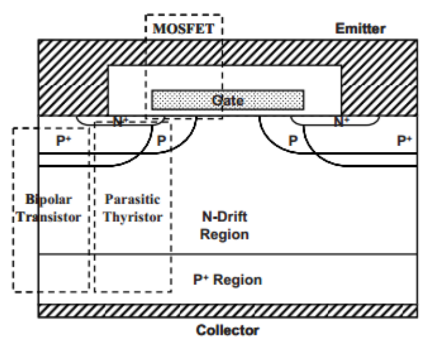

Figure 14: internal structure of IGBT [11] B. J. Baliga, Fundamentals of Power Semiconductor Devices, New York: Springer, 2008. Used under fair use, 2015.

3.2 Voltage Source Converters [2]

Self-commutating converter (SCC) voltage source converters (VSCs) do not require the AC system reference hence the "self-commutating" designation. Hereon, the term VSC will be used with the understanding that SCC VSC is what is meant.

A popular way to operate VSC is with pulse width modulation (PWM) [2]. PWM is well-suited technology for converter operation because it provides high controllability of the voltage signal used to trigger the switching devices to operate. The voltage signal pulses of varying widths turn switches, likely IGBTs, on and off. This action connects and disconnects the voltage source rapidly. This creates discontinuous voltage and current waveforms as well as discontinuous power transfer, but with inherently smoother rectification and inversion processes and filtering (series reactors on the AC side and shunt capacitors on the DC side), the non-idealities (harmonics) created by discontinuous operation can be suppressed to negligible levels. The switching frequency of a VSC (and converters in general) has a large impact on the quality of the output waveform. A higher switching frequency generally equates to a smoothing effect for the recovered analogue wave in the case of inversion. For power applications, the operating frequencies of a PWM device are on the order of kHz [12].

The important thing to note is that a VSC simply refers to the type of converter. When an active AC system is connected to an active DC system through a VSC, power flow is bidirectional. Here, an active AC system is an AC system that has mechanical inertia behind it; that is to say, that it has significant amounts of traditional generation connected to the AC network. An active DC system is a DC system that has another converter connected to it from which injection is possible. A VSC can achieve bidirectional power flow through the fixed voltage polarity of the DC system while the current is bidirectional. The real power exchanged between the AC and DC systems is:

$$P = \frac{V_1 V_2 \sin(\delta)}{X}$$

And the reactive power exchanged between the two is:

$$Q = \frac{V_2[V_1 \cos(\delta) - V_2]}{X}$$

Where V_1 is the system voltage source magnitude, V_2 is the converter voltage source magnitude, δ is the phase difference between $\boldsymbol{V_1}$ and $\boldsymbol{V_2}$, and X is system reactance.

Another distinguishing feature of VSC is the ability to provide different proportions of active and reactive power (usually called four-quadrant operation) and is created through angular difference provided by the angular difference between the system voltage and the converter voltage. This is possible because of the stiff system angle provided by the machines connected to the system. Figure 15(a) presents the operating range of an ideal converter in a strong AC system; the blue PQ points represent some of the possible operating points that the converter can take, but they must be within the red circle, which is the MVA rating of the converter. In real operation, the converter's operating range region is not bounded by a perfect circle; it will be an irregular shape that is dependent on the limitations of the switching devices and the limits imposed by the controller.

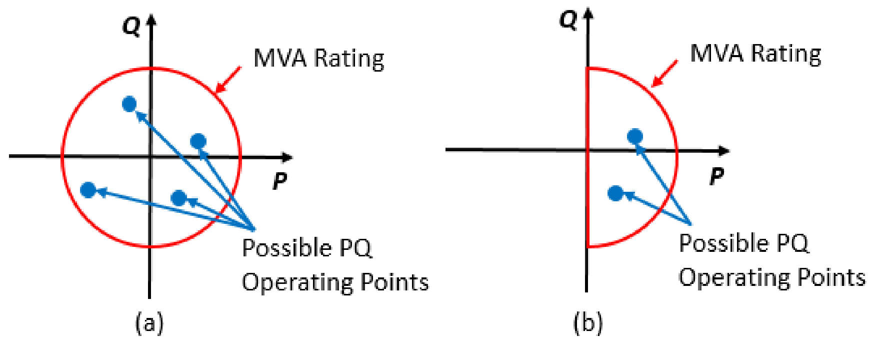

Figure 15: (a) ideal four-quadrant operation; operation in active AC system (b) ideal operation in weak or passive AC system

The ability to have a bidirectional (real) power flow is wholly dependent on having the stiff AC system on both sides of the DC system. If a passive AC system is connected, the VSC can only provide real power because there is no generation to provide power in the other direction nor is there a stiff AC system angle to reference. The ability to provide reactive power still exists because the firing angle is independent of the AC network. Figure 15(b) presents the operating range of an ideal converter in a weak AC system. This allows the converter to act as a generation source for the passive AC system in the sense of providing variable apparent power; the downside is that while the converter may act like regular generation under normal conditions, it has little inertia (there is no rotating machinery) and therefore the capacity for ride-through during system events is diminished.

The ability to control active and reactive power independently is a key advantage that VSCs have over LCC CSCs. Being able to control the both active and reactive power injection at the terminals has a two-fold benefit. The first is that a VSC can be made to consume little to no reactive power; this eliminates the need to have VAR support like with LCC CSCs. The second is that VSC technology has the ability to *provide* VAR support to the system at its terminals. An instance of this feature being utilized is in a static synchronous compensator (STATCOM), which can act like a source or sink of reactive power.

3.2.1 Voltage Source Converter Installation

In the previous section, the discussion was an overview of VSC operation and capabilities of VSCs. In this section, Figure 16 shows a basic VSC installation. Working from right to left, the next few paragraphs will discuss the components in the figure.

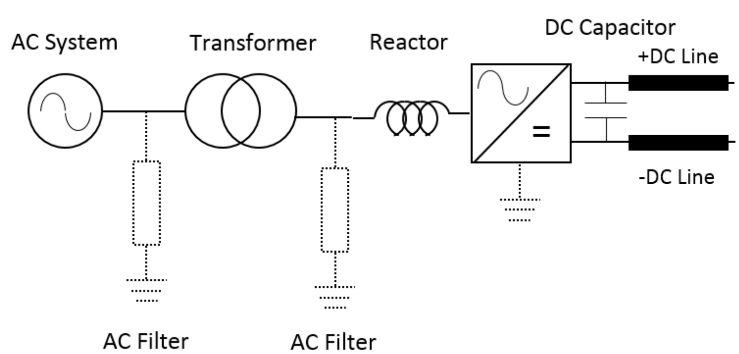

Figure 16: basic VSC installation; dotted equipment indicated that it is optional

DC Capacitor. The DC capacitor has the function of stabilizing the DC voltage and maintaining the proper DC system voltage regardless of the direction of power flow. Also, it aids in the suppression of current harmonics on the DC side caused by the switching of the converter. As mentioned before, the higher the switching frequency, the less harmonic content that is generated.

Converter Units. As described in prior chapters and sections, the actual switching of the converters is performed by semiconductor devices, in this case IGBTs. IGBTs are put in series and parallel, called modules, to handle the high voltages and high currents. More devices in series enhance the blocking capability and more devices in parallel are needed to support the high currents [2]. The challenge is enabling and disabling all the devices simultaneously because of all the variables that cannot be controlled fully by design engineers. Even slight differences between devices can cause the voltage to be unbalanced between the phases of the converter. Snubber circuits are typically added to the converter to help remedy the imbalances by aiding in the distribution of voltage across the numerous devices [2].

Phase Reactor. The inductance between the converter and the bus connecting the converter station to the AC network. This reactor serves to limit the short circuit current that can be drawn out of the converter; to suppress harmonic content coming out on the AC side of the converter to limit stresses on the interface transformer; and to smooth the output waveform to a sinusoid.

Interface Transformer. This transformer behaves as any other transformer typically used in an AC system. The output voltage on the AC side of a VSC is likely not the same as the AC transmission system voltage; this transformer matches the AC magnitude coming out of the converter to whatever the AC system requirements are.

3.2.2 Operation of Voltage Source Converters

VSCs converters originally came in two types– six-pulse and twelve-pulse. The twelve-pulse generally gives a better sinusoidal output, which reduces harmonics caused by sharp changes in the voltage and current waveforms; this performance improvement is similar to CSCs. This also has the added benefit of reducing the physical size of the harmonic filters needed. However, while this six- versus twelve-pulse distinction is generally true for VSCs as well, for a particular installation, especially one operating at lower power and lower voltage levels, the difference in performance is not always drastic enough to call for the extra equipment and extra complication that come with using a twelve-pulse configuration.

Taking Figure 17, a six-pulse configuration, as an example (the twelve-pulse would be essentially two six-pulsed converters in parallel), there are some important differences between the SCC VSCs from this chapter and LCC CSCs discussed in 2.3 Line Commutated Converters. The conduction angle for VSCs is 180° rather than the 120° to avoid a state where two of the bridge legs are off. There is no overlap between the conduction phases, which greatly simplifies the analysis and therefore many of the considerations of current source converters are not necessary. However, the resultant AC waveforms for each phase are still 120° apart. Through the controls for the switching devices in the bridge, the converter inverts the DC into a three-phase AC waveform.

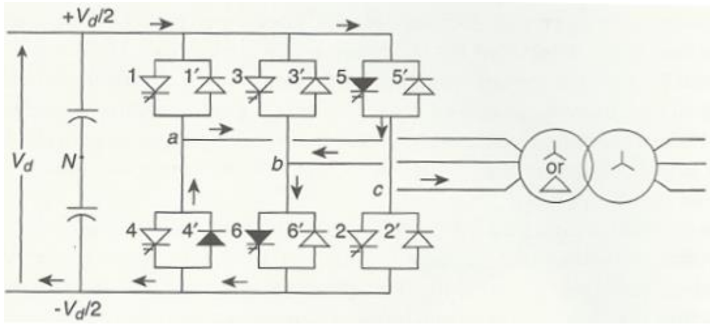

Figure 17: three-phase, two-level, six-pulse converter [2] J. Arrillaga and e. al., Self-Commutating Converters for High Power Applications, West Sussex, United Kingdom: John Wiley & Sons Ltd, 2009. Used under fair use, 2015.

The system voltages are shown in Figure 18 in which a perfectly balanced, sinusoidal AC system is assumed. The line voltages (v_{aN}, v_{bN}, v_{cN}) are not referenced to the AC system neutral (the neutral on the Wye of the transformer), but to the DC system neutral, the midpoint between the DC side capacitance, N. The voltage at the AC system (i.e. transformer) neutral, when referenced to N, is approximately a square wave and related to the DC neutral in that its frequency is three times the fundamental with one-sixth of the DC voltage magnitude. In the Fourier domain of the phase voltage, the fundamental component is positive sequence and so is the fifth harmonic, but the seventh harmonic is negative sequence and the triplen harmonics (i.e. odd multiples of the third harmonic) are all zero sequence.

By subtracting v_n from v_{aN} will yield v_{an}

$$v_{an} = \left(\frac{2V_d}{\pi}\right)\left[\cos(\omega t) + \left(\frac{1}{5}\right)\cos(5\omega t) - \left(\frac{1}{7}\right)\cos(7\omega t) - \left(\frac{1}{11}\right)\cos(11\omega t) \ldots\right]$$

The other phase-to-neutral voltages are similarly constructed, but ±120° out of phase. This voltage has three levels, $0, V_d/3$, and $2V_d/3$. Converting the phase-to-neutral voltages to phase-to-phase has three levels $\pm V_d$ and 0; the fundamental experiences a phase shift of 30° and the magnitude shift of $\sqrt{3}$ times the original amplitude of v_{an}. Shown as well are that the triplen harmonics have been removed.

$$v_{ab} = \left(\frac{2\sqrt{3}}{\pi}\right)\left[\cos(\omega t) - \left(\frac{1}{5}\right)\cos(5\omega t) + \left(\frac{1}{7}\right)\cos(7\omega t) \ldots\right]$$

The fundamental component, V_c, is related to the DC side voltage magnitude is:

$$V_c = \frac{\sqrt{6}}{\pi} V_d$$

The magnitude of the harmonics of the fundamental voltage is related by

$$V_n = V_c/n$$

Where n is the order of the harmonic. The relationship between the DC current and the AC current is given by

$$I_d = \frac{3\sqrt{2}}{\pi} Icos(\theta)$$

Where I_d is the DC current magnitude, I is the AC voltage magnitude, and θ is the firing angle and the power factor. The magnitude of current harmonics lie between the minimum at unity power factor and the maximum when the power factor is zero.

$$\frac{\sqrt{2}}{n^2 - 1} < |I_n| < \frac{\sqrt{2}n}{n^2 - 1}$$

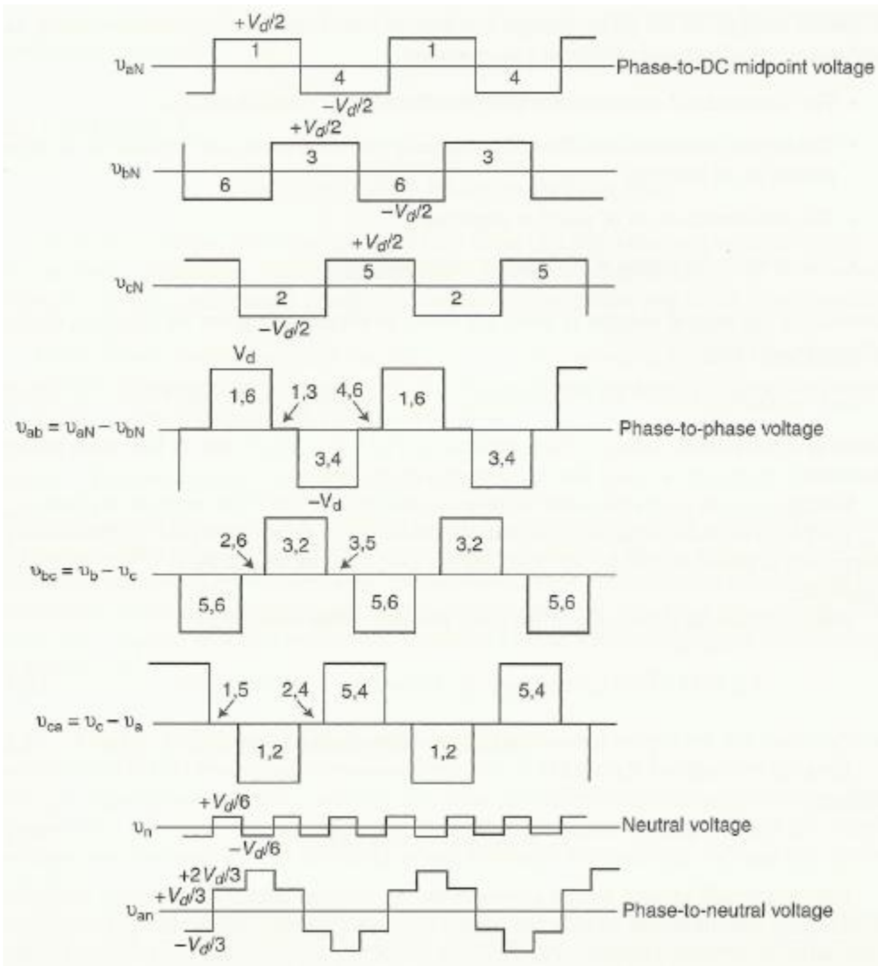

Figure 18: AC voltage waveforms of a 6-pulse VSC [2] J. Arrillaga and e. al., Self-Commutating Converters for High Power Applications, West Sussex, United Kingdom: John Wiley & Sons Ltd, 2009. Used under fair use, 2015.

Other pulsed VSC configurations, like twelve-pulse, operate similarly. An important result is the firing angle, θ, is controllable, which enables the switching pattern to be specified by the engineer. There are two types of patterns – symmetric and independent. Symmetric means that the control scheme approaches the problem considering the three phases as a unified characteristic and the output waveforms are symmetric, as the name implies. Independent refers to treating each phase individually allowing the three-output waves to be symmetric or asymmetric [2].

At first glance, the independent configuration does not seem more advantageous than the symmetric, but independent is useful when the desire is the purposeful injection of unbalanced, three-phase power into an already unbalanced AC system; if the injection is complementary to the existing unbalance, the converter could fix the unbalance. Also in independent operation, the switching pattern can be developed to selectively eliminate harmonics that the converter would otherwise generate. However, care must be taken when canceling out particular harmonics as the energy from that harmonic will be spread over the remaining unsuppressed harmonics, which may undesirably enhance other low-order harmonics. For a more detailed description of this technique, see Arrillaga et al. [2].

In their book [2], Arrillaga et al list two patterns and go into some discussion about each of them. In addition, research into switching pattern that yield an operational benefit like harmonic suppression or loss reduction is a popular research area. A deeper discussion of switching patterns is beyond the scope and relevance of this thesis. However, what can be said about them in general is that their goal is to mitigate the losses incurred by the switching devices and to reduce the total harmonic distortion that is output by the device; this is accomplished by changing the on-time of each switch along with when it occurs in the switching period.

3.2.2.1 Multilevel Converters [2]

Advances in converter technology (namely multilevel converters) are rendering the 6- versus 12-pulse distinction between the configurations mostly moot as they can produce better waveforms using "levels" rather than "pulses". The "levels" referred in "multilevel" are the converter's discrete output voltage levels. It is a logical conclusion that if the number of voltage levels is increased, the output will more closely approximate a sinusoid. To increase the number of levels a converter has, the number of switching devices must be increased, which also increases losses as current must flow through more devices. While the switching frequency remains at the fundamental frequency eliminating harmonics, the added complexity makes control more difficult as well as increasing the physical size of the converter. Another disadvantage is that the independent reactive capability at each terminal is removed, which existed with PWM based VSCs; adjustment of the DC voltage changes the AC output giving the stepped sinusoid that is characteristic of this configuration. Some varieties of multilevel are listed below. Modular but there is one exception that provides a multilevel approach without the restriction on four-quadrant operability is Modular Multilevel Converters (MMCs). For the sake of brevity and relevance, only MMCs will be discussed because that feature makes it the prevailing trend at the time this thesis was written.

Types of multilevel converters:

- PWM assisted multi-bridge
- Diode clamped
- Flying capacitor
- Cascaded H-bridge
- Modular multilevel

3.2.3 Modular Multilevel Converters [2]

The trend in recent years has been toward modular multilevel converters (MMCs). The modularity of switching devices, which form submodules, allows the devices to be optimized to minimize conduction losses and other stray losses. The number of submodules present in a converter roughly corresponds to the number of achievable levels for the converter; for example, a converter with 200 submodules can produce 201 different voltage levels [14]. The closer approximation of a sine wave greatly reduces the harmonic output of the converter thus lightening the burden for external filtering to the point of not needing it. In addition, the switching frequency for each submodules is reduced, which corresponds to a reduction in the switching losses and therefore cooling needs. However, the effective switching frequency is still high so that the overall harmonic reduction at the converter terminals is maintained. MMCs can also provide the independent control of active and reactive power at both line terminals while operating in a multilevel configuration.

The initial limitation with MMCs was that the submodules (made of IGBTs) struggled to handle high voltages, which limited them to lower voltage applications (<~200 kV). However, developments in MMC submodule technology have reduced the needed number of submodules because each individual submodule can operate at higher voltage and current levels. Since the submodules are approximately the same, converters can be customized for a particular installation by adding more or fewer submodules [15]; scalability simplifies design. Other HVDC variants allow for expansion in stages, but MMCs further increase this ability. For projects where there is not enough capital to install a bipolar system all at once, building monopolar systems in separate stages, and then uniting them to form a bipolar system is a way to show the project's merits and reduce initial costs. The same is true for the operating voltage – fewer submodules for lower power application and then as the link's usage increases, more submodules can be added.

3.2.3.1Operation of Modular Multilevel Converters

When MMC inverts the DC voltage to AC, it does by progressively turning on and off switching devices to build the sinusoid; each submodule can be conceptualized as a controllable voltage source. The more switching devices that are present, the smaller the change in the voltage step between the previous and next device. Figure 19 shows a conceptualized version of how the switching devices are connected inside the converter and the waveform shows a single phase of the output. The realized wave is sent though the series reactor before it goes out to the AC system. Like with other types of VSC, MMC have real and reactive control over the power at their output terminals.

Each of the submodules (Figure 20) that make up the converter are constructed with IGBTs (typically) as and are marked as $D_1$and D_2. The submodules have three states, on, off, and blocked. In the on state, D_1 is on and D_2 is off and the output of the submodule, V_x, is equal to V_c and the charging or discharging of the capacitor is dependent on the direction of current flow. In the off state, D_1 is off and D_2 is on and V_x is zero and voltage across the capacitor remains unchanged. During the blocked state, only current is conducted through the freewheeling antiparallel diodes; when power flows from the DC side to the AC side, the capacitor is charged during this state; in the other direction, the capacitor is bypassed.

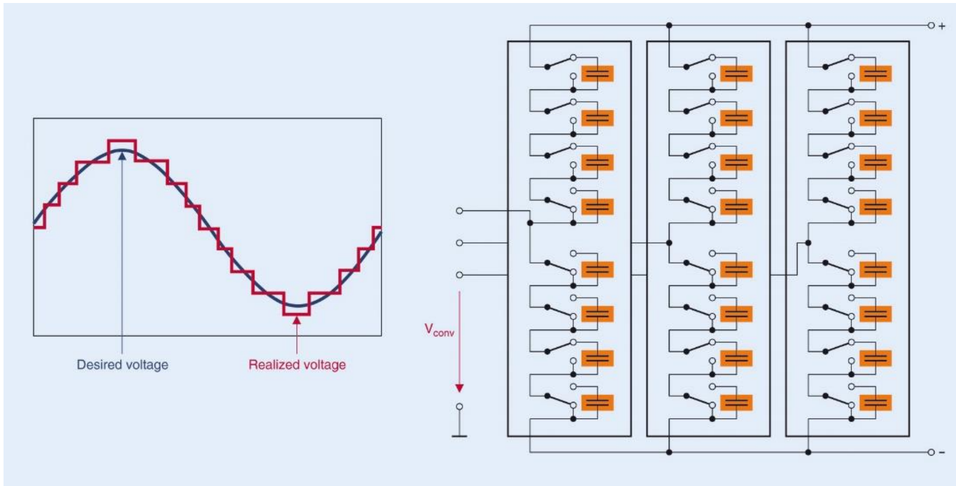

Figure 19: output waveform and conceptualized MMC [16] TDK, "Minimizing Energy Losses," April 2012. [Online]. Available: http://en.tdk.eu/tdk-en/373562/tech-library/articles/applications---cases/applications---cases/minimizing-energy-losses/171638. [Accessed August 2015]. Used under fair use, 2015.

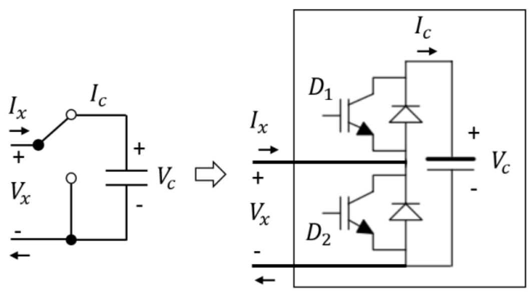

Figure 20: MMC submodule

For each phase leg of the device, the total number of submodules active in the upper arm (the devices connected between the positive DC voltage and the point connected to the AC network), n_1, and the total number of active submodules in the lower arm (the devices connected between the negative DC voltage and the point connected to the AC network), n_2, should equal a constant number, n, so that the converter can maintain a constant relationship between the DC side and the AC side voltages. For balanced conditions, $V_c = V_x$, therefore

$$V_{dc} = nV_x$$

Where

$$n = n_1 + n_2$$

Where

$$n_1 = 0, 1, 2, 3, \dots \; and \; n_2 = 0, 1, 2, 3, \dots$$

The maximum AC voltage magnitude is when referenced to $V_{dc}/2$:

$$V_{ac} = \frac{(n_2 - n_1)V_x}{2}$$

The adjustment of $n_1$and n_2, allows for the controllable creation of the waveform's frequency, magnitude, and phase. These are the parameters that provide the highly controllable output that is the hallmark of multilevel converters, but since changing the DC side voltage is no longer a requirement to providing the different voltage levels, each terminal of an MMC system can operate independently and provide four-quadrant operation.

An example of this technology in use is the Transbay Cable, which connects the Potrero Hill neighborhood of San Francisco to Pittsburg, California. The link provides much needed energy for peak demand – around 40% of peak demand [17]; functionally, the whole link can be thought of as a partial replacement for the peaking units lost with the closure of the adjacent Potrero Generating Station, which was a fossil fuel burning plant in San Francisco proper. The Transbay Cable was part of the solution the California Public Utilities Commission mandated to update the transmission system in the San Francisco area before the plant could close. Comparing the Transbay Cable to the Talcher-Kolar project highlights the improvements that have been made in the HVDC technology in the years between the two projects.

The Talcher Substation is approximately 1600 ft by 1200 ft for a total area of 192,000,000 ft^2 or 4,410 acres and with the addition of the electrode site, which is 8,200,000 ft^2 or 190 acres, the total area used is approximately 4,600 acres [6]. The maximum transferrable power of the link is 2,500 MW at ±500 kVdc. The Potrero Hill Substation is approximately 400 ft by 380 ft for a total area of 152,000 ft^2 or 3.49 acres. The maximum transferrable power of the link is 400 MW at ±200 kVdc [17] [18]. While this is not a completely fair comparison as the two systems run at different voltages and have different carrying capacities, the assessment can be made given transferrable megawatts per acre of land used. Potrero Hill station is about 110 MW per acre while Talcher is about 0.54 MW per acre. The use of MMC eliminated the need for filtering and VAR support at the Potrero Hill station. For that reason, it was able to fit on existing at the Potrero Hill Generation site.

3.3 Applications

Listed below are some of the attributes and abilities of MMC VSCs. These characteristics give VSCs, namely MMCs, an advantage over older LCC technology. The remainder of this section describes some situations where these advantages can be leveraged.

- Bidirectional power flow
- Separation of active and reactive power controls
- Ability to act as a voltage source for a passive AC system
- Reduction in cable and line size from AC and from older LCC technology
- Low harmonic output
- Ability to control each output phase voltage separately
- Modularity
- Scalability

3.3.1 Interconnection of Intermittent Generation to a Weak AC System

This subsection will consider the addition of large, but intermittent generation to an existing, but weak AC transmission system. What makes the AC system weak is that it is electrically distant from any significant generation due usually to geography. For example, large offshore wind farms or tidal stream generator farms (e.g. ~200 MW) is constructed offshore and the shortest point to mainland is where the existing AC infrastructure is minimal making the system weak. Due to the lack of infrastructure, significant power injection at this point will cause problems in maintaining a stable voltage and system frequency. Considering an AC cable from the offshore site to land, the cable would create a large reactive power source that would cause problems with the voltage profile and the intermittency of the generation would cause problem with maintaining a stable frequency.

To address the reactive source issue, the AC system would need help maintain stability through reactive support devices like STATCOMs or reactor banks. The voltage profile of the offshore turbines could be regulated by the turbines built-in controllers. For instance many European transmission system operators that have high penetration of wind generation have required intermittent generation, especially and specifically wind farms, to meet certain operational thresholds in terms of fault ride through, power reserves, frequency deviation, and voltage deviation. This keeps large segments of generation from tripping off during system faults and helps with system recovery because the turbine can use its reserves to help support the system. Only if the system voltage drops below that threshold can the unit disconnect. However, to do that, the system operator must have a way to command the individual units turning them from nondispatchable to quasi-dispatchable. This makes the wind generation profile complicated to manage.

If a DC setup were used instead, the necessary amount of cabling and associated repairs are reduced as well as removing the large reactive power source. The power from the individual turbines would be collected and brought to the converter for transmission to shore. Assuming VSCs are used, the AC system onshore does not have to be particularly strong and can even operate in black-start situations. This also provides a singular point to which transmission system operators can issues operational set points to maintain AC system stabilities. However, the converter stations in this configuration are now the biggest economic investment. In analyses presented in [19] and [20], distances from shore around 100 km or less or for power levels below 200 MW, the cost of installation, operation, and maintenance for HVDC systems is simply more expensive than an AC alternative; the performance improvements are not enough to offset the initial cost and yearly costs thereafter. However, the operational benefits gained by using VSCs combined with the improvements to IGBT technology make the cost difference between HVAC and HVDC connected wind generation smaller with each passing year.

3.3.2 Relieving Transmission System Congestion – Urban Infeeds

Earlier, an HVDC line was characterized as being able to wheel more power with less loss and requires fewer conductors to do so than an AC line with a comparable power rating. This benefit is somewhat negated by the increased area of the terminal substation. The auxiliary equipment (e.g. cooling equipment) and the space for the converter station currently make it impossible for an HVDC station to be smaller than an AC stations with the same power throughput. Although the size of an HVDC substation is one of the biggest concerns, there are many instances around the world of HVDC solutions being used to alleviate transmission system congestion by bring power directly where it is needed and bypassing the rest of the existing AC network.

An example of this use is the Transbay Cable. It helps serve peak demand in San Francisco without additional costly and (arguably) unsightly transmission expansion. This type of application (i.e. a station in a dense urban area) is recent in HVDC technology. When the constraints surrounding the Transbay Cable are listed, it is apparent that a transmission expansion of this magnitude would be difficult and expensive for a completely AC approach.

- Public demanded for removal of fossil fuel based generation in a population center
- Generation units had reached the end of their lifespans
- Environmental and health concerns caused by water and air pollution
- Prior to removal, transmission infrastructure must be upgraded to handle additional power flow from outside of load center

Without any type of generation at the Potrero site, the transmission system in San Francisco was inadequate to supply the energy demands of the city. Pacific Gas and Electric Co. developed a hybrid solution to build more AC transmission lines in the south to bring energy from elsewhere in California and the Transbay Cable was installed to help during peak hours [21].

Older style HVDC links, like Talcher-Kolar, could take energy from remote generation and bring it close to the load center where traditional AC systems must carry it the rest of the way into the urban area. This helps with insufficient local generation, but does nothing to remedy the loading on the existing AC system within the urban area. An MMC's ability to provide controllable power with a much smaller footprint can make an HVDC link an acceptable substitute for some generation needs in a dense urban area.

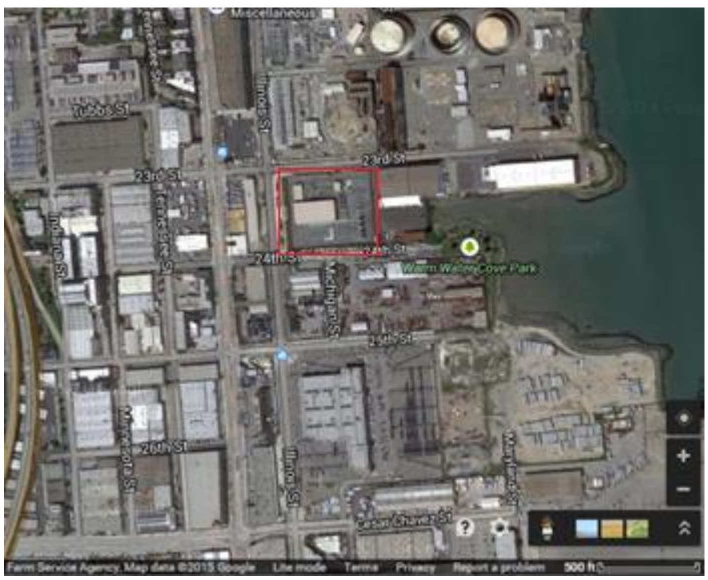

Figure 21: Potrero Hill HVDC Station (37.754804, -122.386112) marked in red [6] Google Maps, 2015. Used under fair use, 2015.

3.3.3 Multi-terminal HVDC Systems and HVDC Transmission Networks

The benefits of DC network are apparent in that it would remove much of the hassle that comes with having standing oscillatory voltages and currents - capacitive and inductive reactances, the need for synchronism of generation and systems, and a slew of other frequency-dependent phenomena that complicate power system planning. However, AC is fully entrenched in everyday life and most products that run on electricity expect AC sources. Leaving AC would mean leaving the many benefits that AC has like efficient generators, strong ride-through capability, and simple and efficient voltage transformation. Even if DC were used instead, the power flows in a network would still be dictated by classical circuit theory. In addition, the lack of a convenient zero crossing makes protection a challenge. A more likely scenario is a hybrid transmission system.

The most prominent scheme proposed in the literature is to make a DC backbone for existing AC transmission systems. This system would be akin to many transmission systems' highest transmission voltage (e.g. 500 kV, 765 kV, etc.) in that this portion of the transmission system only connects to generation or other segments of the transmission system, but never to the distribution system.

The benefit of this system is that it can be quickly used to move energy around a power system without having to flow through the AC system enabling a transmission operator to balance nondispatchable (renewable) generation in a system such as photovoltaics (PV). For example, if a PV plant dips out due to cloud coverage, the DC backbone could quickly move energy from another part of the system to the area normally supplied by the solar generation. Shown in Figure 22 are possible HVDC system topologies. However, the configurations in Figure 22 are not all equal. Figure 22(a) is a multi-terminal system, but there is no redundancy; a fault, which is an inevitable event, will bring down the whole system or if sectionalization is possible, remove nodes down line of the fault; the poor reliability of such a system would prevent it from becoming widespread. Figure 22(b) displays many point-to-point links, which is just simply unrealistic for a myriad of reasons, but chief among them being cost and space. Figure 22(c) and (d) look promising because they solve the redundancy problem.

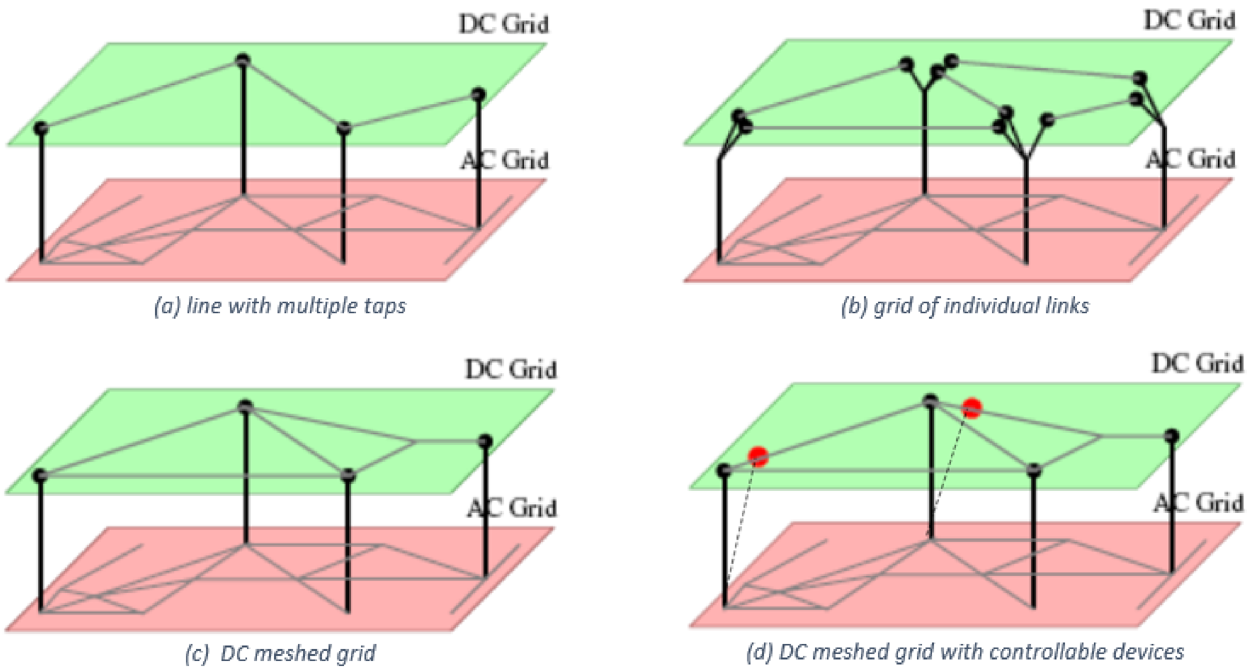

Figure 22: possible multi-terminal HVDC setups [22] N. Amed and e. al., "Prospects and Challenges of Future HVDC SuperGrids with Modular Multilevel Converters," in Power Electronics and Applications, Proceeding of the 2011- 14th European Conference on, 2011. Used under fair use, 2015.

The system in Figure 22(c) relies on methods for controlling the real power in the network like voltage droop, voltage margin, ratio control, or priority control (presented in [23]) and extensions of those presented in [24]. However, what all the methods have difficulty with is coordination of the converter stations. The authors of [23] opine that stability can be achieved with self-managing converters, but as the complexity of the DC system increases, it is not tenable. The authors of [24] incorporate coordination between the converter stations to manage which station or stations are performing slack node functions to balance the system, but again the hardware limitations of the converters is frequently a problem when the system handles large real power transfers; it is highly likely that the loss of power injecting converter(s) will cause an overload on the slack node converter. The grid topology in Figure

22(d) would provide the means to control the power flow by the node voltages instead of the impedance of the line (which is impossible anyway because the line is mostly resistive).

A node voltage control is shown in Figure 23 where the voltage across a capacitance is modified to change the power flow in meshed DC system. Looking at the figure, the DC node acts as the reference for the voltage gradient on the line; the second converter acts as the means to change the voltage gradient and thus change the current. The primary converter bares the burden of managing the large power conversions from AC to DC or vice versa. The second converter, which can be smaller, manages the existing DC rather than producing it itself [22]. However, this has the distinct disadvantage of increasing the number of converters needed at a given station; there would need to be additional converters for every line that control is desired.

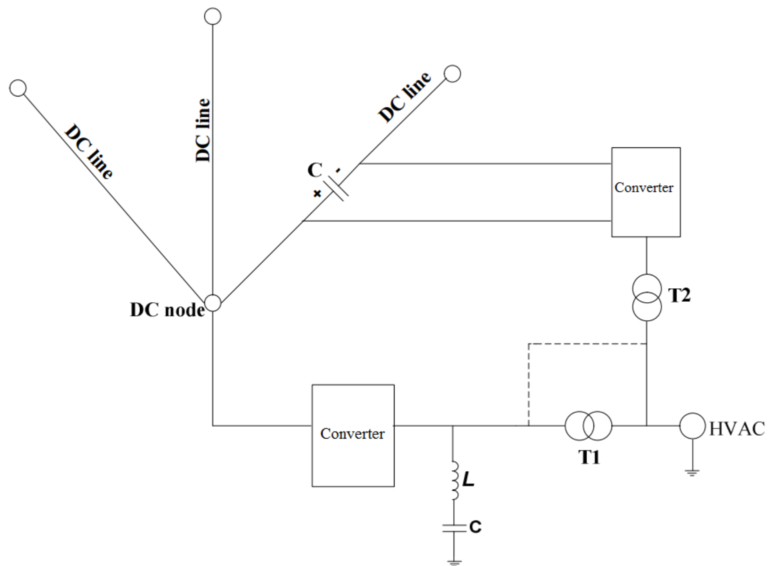

Figure 23: connection of converter with DC line [22] N. Amed and e. al., "Prospects and Challenges of Future HVDC SuperGrids with Modular Multilevel Converters," in Power Electronics and Applications, Proceeding of the 2011- 14th European Conference on, 2011. Used under fair use, 2015.

Companies and academia have put forth the idea of a “super grid” connecting European and North African systems with HVDC [22] [25] [26] [27]; ABB’s vision is shown in Figure 25. In Europe, there exist many point-to-point HVDC links already, especially, in Northern Europe where they connect Norway and Sweden with Denmark and Germany primarily (Figure 24). The aims of such a system would be to mitigate the effects of the nondispatchability through reinforcing the existing AC system by moving energy around quickly. This would compensate for generation deficiencies with the expectation that by pooling all of the renewable generation together there will always be enough to maintain stability.

However, an HVDC super grid requires much more technological development before it even remotely resembles the system shown in Figure 25. In [25], the authors, who are also authors in [22], acknowledge that a maintaining a stable system after experiencing a fault is foremost goal of an HVDC grid. At high DC voltages, the whole system would feel the effects of a fault within seconds and without much impedance or any mechanical inertia to steady the system, protection schemes and devices must respond very quickly to maintain system stability. HVDC breakers already exist, but they force a zero crossing in the DC signal where a mechanical breaker can be opened leading to significant lag time between detection of a fault and fault interruption. ABB has taken steps with its research into hybrid DC breakers [8], which operate much quicker, but in their current state, they are impractical for wide scale use due to their size and cost, which are similar to converter stations.

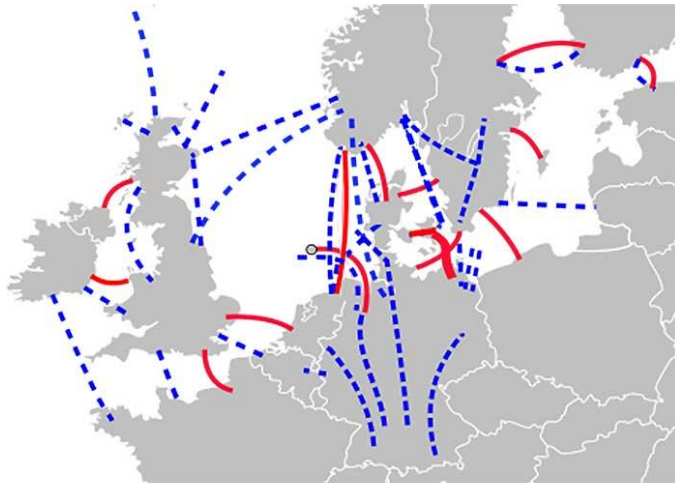

Figure 24: exiting HVDC links (red); proposed links (blue) [28] School of Electrical and Electronic Engineering, University of Manchester, "Voltage Source Converter," [Online]. Available: http://www.eee.manchester.ac.uk/our-research/research-groups/pc/researchareas/powerelectronics/vsc/. [Accessed 2015]. Used under fair use, 2015.

There currently exist no clear standards for HVDC transmission. Therefore, developing the standards for "super grid" technology would be an onerous process and it would take an unparalleled level of cooperation between private corporations, governments, and peoples for such a system to operate. There will inevitably be instances where the nation-state reaping the largest benefit is not the one that had to offer up the most land or money for construction or vice versa.

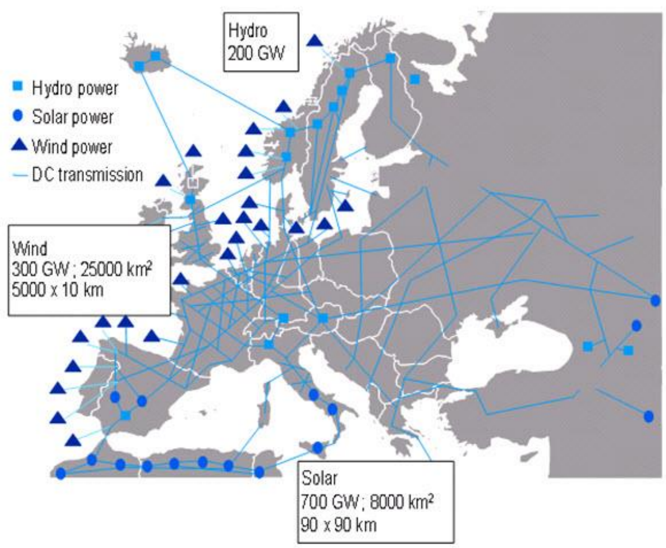

Figure 25: ABB's vision of an HVDC grid connecting a large portfolio of renewable generation [29] H. Bawa, "From 'joining the dots' to 'connecting the lines'," ABB, 7 November 2012. [Online]. Available: http://www.abb-conversations.com/2012/11/from-joining-the-dots-to-connecting-the-lines?_ga=1.7967026.1053514684.1392599070. [Accessed January 2015]. Used under fair use, 2015.

Chapter 4: Examining Transmission Systems Considering HVDC

Chapter 4: Examining Transmission Systems Considering HVDC comprises the contribution that this thesis by combining the research done in the first three chapters with the ideas and perspectives of the author into a methodology for evaluating HVDC as a solution in transmission expansion. The demonstration shows that the methodology can be applied to a system with varying topology (e.g. radial versus highly meshed portions) and demonstrate how HVDC could be beneficial in different cases. First, the methodology will be presented. Second, the evaluation criteria explained. The third will show those criteria applied to a valid example system. The results of PSS/E simulation will be shown where appropriate during the system evaluation. For an explanation of the simulation approach, see
4.5 PSS/E Simulations.

4.1 Statement of Criteria

Utilities – meaning electric utilities – are businesses like any other in that their ultimate goal is to make a profit. What drives change in power systems is a shifting – either growing or shrinking – industrial, commercial, and residential load; the desire to provide energy to customers on a continuous basis by assuring system reliability due to self-interested economics and regulatory mandates; and the desire to minimize the costs in providing the energy to customers. The question is how to devise power system infrastructure that balances all of those competing interests simultaneously. When looking at a power system, the steps listed below are a general guide to the planning process

1. Infringement of Operational Criteria - identify problem areas in a system due to congestion, thermal or voltage violations, or other system instabilities.
2. Scenario Development - determine a likely sequence of events for problem areas as time passes. Some possible factors to consider:
    a. Load growth/reduction
    b. Generation dispatch
    c. Generation growth/reduction – conventional and/or renewable
    d. System stress patterns
    e. Credible contingencies
3. Reliability Analysis – system state assessment of each case from Step 2
4. Benefit Analysis - following the sequence of events in Step 2, determine the locations that will have the greatest physical benefits to system stability, efficiency, and/or reliability
    a. Increase capacity with minimal increase to short circuit current
    b. Correct imbalance of transmission network
    c. Provide reactive power support
    d. Improve power quality – reduce/eliminate harmonics
    e. Evaluation of AC/DC system interactions
5. Engineering Goals - determine what voltage level, capacity, and technology would be needed to achieve Step 4
    a. Evaluate AC solutions versus DC solutions
6. Practical Constraints - For some stations, practical constraints or other pros and cons may render a particular solution stronger, weaker, or infeasible. Below are some typical characteristics that fall within this step.
    a. Land area available from existing ROWs or available through eminent domain or purchasing

   b. Proximity to population centers
   c. Accessibility of location
   d. Proximity to historical or cultural landmarks
   e. Geological stability and/or climatological factors
   f. Geography
   g. Restrictiveness of regulations – environmental and regulatory
   h. Suitableness for expansion or incorporation into larger network
7. Compare the evaluation of the practical constraints from Step 6 to the engineering goals of Step 5 and determine which locations meet both engineering and practical constraints
8. Estimate approximate cost of equipment, materials, labor, etc. that could be incurred during the installation process for each location that passes Step 7

4.2 Explanation of Criteria

Infringement of operational constraints. The principle reason that transmission must be upgraded is because as the loading on a power system shifts – increases or decreases – the current on the lines will shift as well, which in turn changes voltage and current profiles. Therefore, utilities must find ways to keep voltages within correct margins and currents below their thermal limits. Below are some typical strategies.

- Additional lines
- Reconductoring
- Increase operating voltage
- Construct new generation
- Upgrade transformer capacity
- Addition of fixed or variable capacitor/reactor banks

Scenario development. Looking at historical system patterns will be a helpful indicator in determining which parts of the system will likely have issues is important, but projections based on factors like public policy affecting generation or the sociopolitical reasons that are driving load growth or reduction and the characteristics of the load give more insight.

In addition, credible contingencies must be considered as well. If an N-1 contingency would cause a line or other equipment to violate its operational constraints, then that would indicate that the system is in an unacceptable state already.

Reliability Analysis. After identifying where system instabilities would likely occur, simulations evaluate which scenarios are more critical than others are; the results would likely show that all the scenarios are not equal in terms of severity.

Benefit Analysis. Benefit analysis seeks modification or improvements to the identified problem or problems that would yield the most benefit to the whole system. Solving particular ones may also mitigate or eliminate other problem that would otherwise exist.

Engineering Goals. When determining engineering goals, the consideration is to find the best solution given no other constraints aside from the ones related to system operation and reasonable costs. Included now are the possible solutions that HVDC offers.

Practical Constraints. As greater numbers of people live and work in a particular area, the consequence will inevitably be a greater electrical load and therefore, necessary infrastructure. This is further hampered by the desire of most people neither to live adjacent to the right-of-way (ROW) nor to have the ROW cut through or take up space on their property. Gathering information about proposed route gives an indication of how approval requests to regulators should be presented; failure to adequately plan for practical constraints will stall a project invariably.

When considering practical constraints, some locations that may need power are not always located in the most geologically stable or climatologically hospitable locations. The geology of the site also plays a role in general operation. For instance, early implementations of the Pacific Intertie in the United States relied on MAVs. In 1972, the Sylmar station was damaged by an earthquake rendering the Intertie inoperable until repairs were completed. A site in a location like this will require different construction techniques than at station located in less earthquake prone areas. Another geological consideration is the conductivity of the earth when installing a ground electrode; the best location on the surface may not correspond to the ground with the best geology for the return path; poor ground conductivity increases system losses, which may necessitate the electrode be placed far off to assure better conducting earth. In addition, the electrode cannot be placed close to the converter station so that the return current does not interfere with the converter operation [4]. Extreme weather also poses significant risk because it causes severe mechanical stresses on system components due to ice, strong winds, or water incursion. When equipment fails, it further stresses a power system.

Lastly, access to the site is important. Generally, this poses a problem moving large equipment. Even the best solution from an engineering and economic standpoint can be rendered impractical if millions of dollars must be spend to clear trees and/or build roads to get to the site.

Reconcile Engineering Goals with Practical Constraints. From an engineering standpoint, solutions must be evaluated in consideration of practical constraints. Here, these two aspects of a proposed solution must be reconciled by determining the degree of impact on the engineering goals caused by the practical constraints.

Large engineering projects are usually open to public debate and people understandably resist the construction of large, aerial lines or substations because they are viewed as unsightly and could cause depreciation of property values or spoil views; such is the case close to historic areas or landmarks. If the practical constraints cannot be reconciled with an engineered solution then that solution is, no matter how good, an invalid solution.

Cost. The final constraint on any project is its cost. In the previous steps, cost of the project was neglected except for barring nonsensical solutions. At this point in the methodology, the solutions that remain are the “best”. All the feasible projects are assigned approximate costs with a margin for unexpected expenses.

Final Decision. With all that information collected, the final decision can be made weighing economics, practical constraints, and operational improvements to find the solution appropriate for the situation.

4.3 Applying Methodology to a System

Now that the methodology has been established, it can be applied to a transmission system, such as the one shown in Appendix A – One-line Diagram of KTC's Transmission Network. It shows the one-line diagram of the transmission system belonging to the Kingdom Transmission Corporation (KTC) located in the Kingdom of Catan (Figure 26).

The system is located in a topographically and climatologically diverse area. To the south, there are high mountains that form the border between Catan and Athos. To the southeast, the mountain range continues forming the second border between Catan and Pentos. To the east, the mountain range continues from the southeast, which ends at a fjord forming the third border of Catan. To the north and west is the sea, which forms the fourth border. In the southeast, a pass through the mountains is where KTC connects to an adjacent system in Pentos.

Climatologically, Catan is classified as having a humid subtropical climate. There are four distinct seasons, which cause two transmission system peaks in the dead of winter and the dead of summer. Being a costal nation, Catan is subject to hurricanes, which can batter the western coast during the summer causing significant system stress and damage in the Peninsula and Southern Districts. In the Central district, tornados, though rare, do happen and cause damage to critical aerial lines that feed the capital. In the north, Catan Island has a dry-summer climate where summers are hot and dry while winters are cool and rainy. The mountains to the south and southeast are arid and windy. Therefore, communities primarily inhabit the foothills, which mostly share the humid subtropical climate.

The transmission system operates at three distinct levels – 500 kV, 230 kV, and 115 kV. The 500 kV system connects to large generation facilities, neighboring systems, or the 230 kV or 115 kV systems and forms the backbone of KTC's system. The 230 kV and 115 kV systems compose most of the transmission network infrastructure and both voltage levels are commonly stepped down to distribution voltages. KTC has historically been the sole generation and transmission operator in Catan, but gradual deregulation of the power market over the years has made room for competition though it is somewhat limited.

KTC has Catan's power demand has steadily increased due to a growing population, immigration, and emerging industry. To plan for this increase, KTC has employed the methodology from earlier in this chapter to its system in order to determine how, when, and where improvements should be made. Below is KTC's evaluation of the transmission system organized in a step-by-step order.

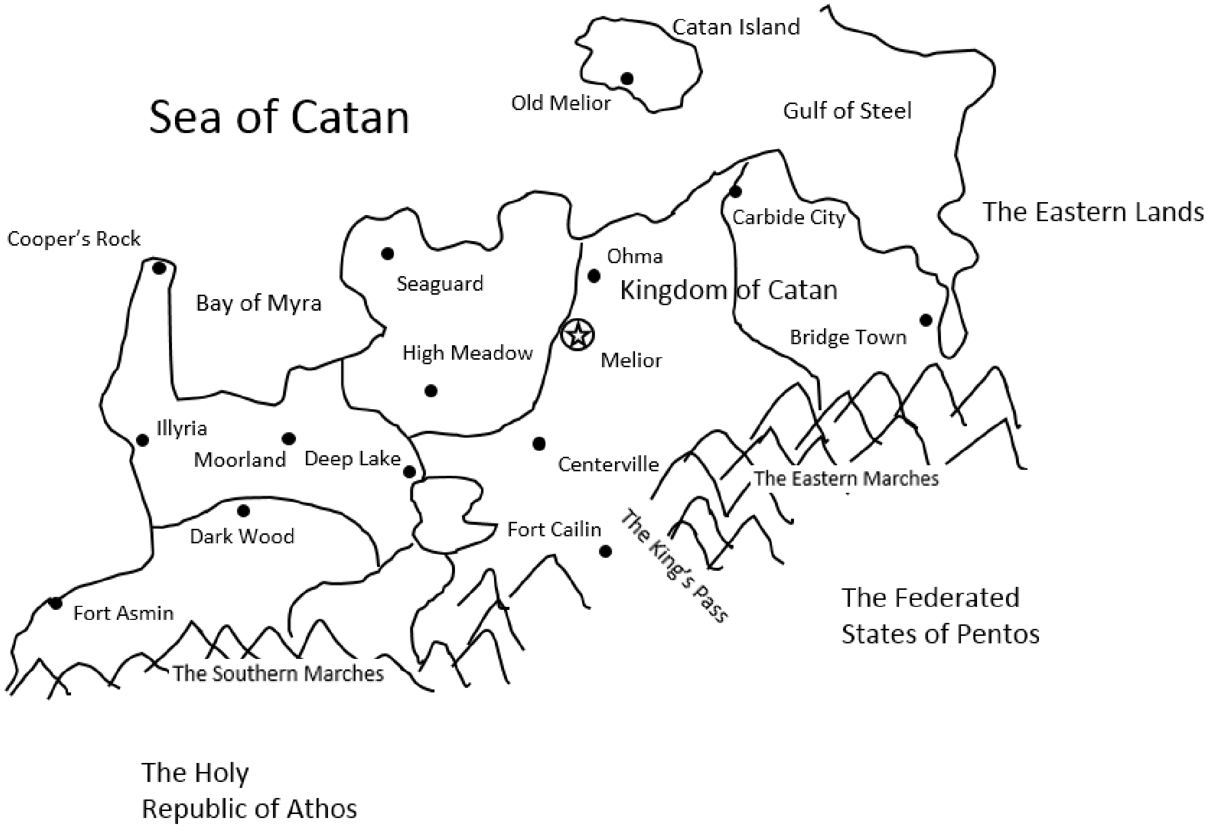

Figure 26: Map of the Kingdom of Catan

1. *Problem Identification*. The objective here is to identify an elements, parts, or equipment that may be reaching operational limits. Such limits may include voltage profile, thermal limits, stability criteria, or other parameters. The forecasted system load is shown in 10-year increments from 2015 to 2045 in Table 1, Table 2, and Table 3, which demonstrate how the major substations, lines, and transformers fare over a 30-year period. The assumption is that no other action is taken aside from increasing generation to match the increasing system load and providing the necessary reactive compensation to maintain stable voltage. In the tables below, buses or lines that are out of their voltage magnitude tolerance or are beyond their MVA rating are highlighted. The MVA ratings are maximum ratings of the line or transformer considering the aid of cooling equipment and natural heat dissipation for summer conditions.

   The stability criteria for the system are:
   - Transmission lines above 91% of their MVA capacity during normal operation and N-1 contingencies are overloaded
   - Transformers above 91% capacity during normal operation and N-1 contingencies are overloaded
   - Bus voltages outside ± 5% of nominal are in violation of voltage limits

   The conclusion from this step is that the system voltage is currently stable and will remain so for the future as long as the generation is sufficient to keep up with load demand. However, what can be seen is that many of the lines and transformers begin to reach their thermal limits and that loading is uneven across the system in the Capital and significant reactive support is needed throughout the system to keep it stable.

Table 1: Voltage magnitude during summer in pu

Substation		Voltage magnitude during summer (peak loading) in per unit			
Number	Name	2015	2025	2035	2045
101	Cooper's Rock	1.01415	0.99627	1.00693	1.00313
102	Illyria – 115	1.02860	1.02860	1.02860	1.02860
201	Illyria – 230	1.03128	1.02181	1.02891	1.02648
301	Fort Asmin	1.00287	0.98573	1.00428	0.99434
302	Dark Wood - 500	0.99693	1.01052	1.00822	1.00229
401	Dark Wood - 230	1.02223	1.03020	1.03121	1.02556
402	Mooreland - 500	1.00420	1.00141	1.00351	1.00263
501	Mooreland - 230	1.03399	1.00000	1.00000	1.00000
601	Deep Lake	1.00000	1.02968	1.03407	1.03225
701	High Meadow	1.00031	1.00000	1.00000	1.00000
801	Seaguard	1.00000	1.00000	1.00000	1.00000
901	Fort Cailin	1.00000	1.00195	1.00073	1.00000
1001	Melior	0.99839	0.99461	0.99114	0.99677
1101	Bridge Town	1.00966	1.02640	1.00468	1.00167
1201	Ohma	1.00441	1.00975	1.00236	1.00152
1301	Carbide City	1.00134	1.00562	1.00000	1.00000
1401	Centerville	0.99910	1.00117	1.00001	0.99917

Table 2: transformer loading during summer and percentage of used capacity

Zone	Transformer	Transformer loading during summer (peak loading) and percentage of used capacity							
		2015		2025		2035		2045	
		P	%	P	%	P	%	P	%
Capital	1	610.1	67.1	657	71	757.9	82	843.4	91
	2	610.2	67.1	652.6	72	752.9	83	873.9	93
	3	205.1	30	193.6	24	196.9	32	181.2	30
	4	315.9	41	366.9	27	438.1	67	511.9	78
	5	173.6	30	213.2	37	256.2	54	313.7	66
	6	289	37	325.8	42	375.7	58	429.3	66
Peninsula	1	52.1	30	65.2	35	80.3	43	99.2	53
	2	46.3	27	58.1	31	71.5	39	88.3	47
	3	54.9	30	68.7	35	84.7	44	104.5	54

Table 3: line loading during summer and percentage of used capacity

Line	Line loading during summer (peak loading) and percentage of used capacity							
	2015		2025		2035		2045	
	P	%	P	%	P	%	P	%
1	31.3	33	36.3	37	41.8	42	47.8	49
2	99.4	42	111.9	46	124.1	51	139.7	57
2-A	53.2	28	58.5	31	64.4	35	70.9	41
3	117.5	29	130.4	32	144.6	35	160.4	39
4	122.5	21	136.8	24	150.6	26	167.9	29
5	31.3	33	36.3	37	41.8	42	47.8	49
10	361.3	36.1	404.9	40.5	462.8	46.3	535.8	53.6
11	74	18.5	80.7	20.2	93	23.3	111	27.8
12	44.3	11	43.9	10.9	45.8	11.4	52.2	13
13	73.7	23	92.4	28.9	117.1	36.6	147.9	46.2
14	670.7	19.6	1028.8	30	1472.9	43	2019.2	59
15	670.7	19.6	1028.8	30	1472.9	43	2019.2	59
16	110.3	13.8	228.9	28.6	382.8	47.9	573.3	71.7
17	427.4	54.2	528.3	67	651.1	82.6	801.8	101.7
18	610.1	67.1	657	71	757.9	82	843.4	91
19	610.2	67.1	652.6	72	752.9	83	873.9	93
20	211.7	26.5	214.4	26.8	222.1	27.8	235.2	29.4
21	271.6	46.7	322.1	55.3	384.1	66	460.6	79.1
22	188.6	30	209	33.2	233.1	37.1	263.3	41.9
23	235.2	10.2	400.4	17.4	609.6	26.5	864.4	37.6
24	269.9	11.2	346.2	14.4	450.8	18.8	580.2	24.2
25	58.9	9.8	100.3	16.7	157.4	26.2	240.2	40
26	281.9	58.5	286.8	59.5	295.1	61.2	309.2	64.2
27	394.2	49	409.3	52	517	66	605.8	77
28	392.6	49	407.5	52	514.1	66	602	77
29	392.2	61	407.1	65	513.4	81	600.9	93
30	392	61	406.8	66	513	81	600.5	93
31	78.5	13	82.6	16	47.2	7	22.3	4
32	78.5	13	82.6	16	47.2	7	22.3	4
33	29.8	8	30.3	7	73.7	21	108.3	28
34	29	4	29.5	4	71.5	12	105.2	16
35	143.6	20	148.7	20	274.7	47	380.8	63
36	189.4	23.8	250.6	31.4	406.3	51	496.2	62.3
37	285.9	40	297.5	42	366.7	52	424.4	59
38	235.3	50	244.7	53	310	68	363	78
39	149.5	33	154.9	34	212.8	49	257.7	58
40	359.5	53	380.3	57	508.7	76	618.8	92
41	281.8	42	299.1	45	421.2	64	523.6	79
42	350.7	49	366	52	445.4	63	518.9	73
43	292.5	61	305.1	65	379.5	81	447	93
44	248	52	258.7	55	329.8	71	393.3	82
45	132	29	137.7	30	200.8	46	254.3	55
46	100.9	24	105.3	25	165.8	41	216.5	49
47	183.3	23	196.5	25	34.7	27	198.8	42
48	183.3	29	196.4	32	34.7	27	198.9	47
49	149.1	25	160.9	28	72.6	25	239.8	49
50	149.1	20	160.8	23	72.6	20	239.8	40
51	414.9	51	434.8	55	485.8	61	532.2	66
52	482.4	60	505.6	64	562	71	613.9	77

2. *Scenario Development*. The following are likely scenarios that the system would undergo.
    a. Around the capital, Melior, the load is forecasted to increase 2.54% (Table 4) in coming years due to industry and population increase putting stress on the system. In addition, there are several data storage facilities planned totaling 700 MW. Normally, the Deep Lake Generation Station produces a large segment of the power for Melior causing large power flows on Lines 14, 15, 18, and 19. In the past, the lines connecting Deep Lake to High Meadow (14 and 15) have suffered simultaneous outages due to severe weather conditions, namely tornadoes in the Central District, causing energy to flow through Moorland to High Meadow to Melior. The reliance on this corridor for energy needs poses a risk to the capital.

Table 4: system growth rates

District	Forecasted Growth Rate (%)
Capital	2.54
Central	1.57
Island	2.00
Peninsula	1.20
Southern	1.78
Western	1.58

    b. Catan Island's generation station (400 MW) supplies the energy needs. In recent years, there has been an uptick in travel to the island for vacationers. To accommodate the vacationers, many businesses are springing up to serve them causing a load growth of 2.00%. KTC is responsible for maintaining acceptable power quality even though it is 50 miles off the coast and isolated from the rest of the system.
    c. In the Peninsula District (a major and growing vacation destination), the Catanese government and KTC are planning a joint venture to install a 200 MW wind farm to harness the ample winds off the western coast of Illyria. The concern with the interconnection of the generation is that the system in this area already experiences significant stress during normal operation due to its radial construction and even more during weather-related contingencies. Occurring with some frequency, Line 3 or Line 4 is not in service due to tropical storms that batter the coast; sometimes both lines are out due to weather. When one is out, but the other is in service, the power will be shifted to the parallel path, but at 1.2% per year growth rate (Table 4), the individual lines become less able to handle the full load.
    d. Due to public policy, many of KTC's coal-fired plants are being decommissioned in the coming years (Table 5). This change in the generation base has forced KTC consider other options for generation – natural gas fired plants and renewable sources. KTC's share of the Pentos renewable energy project, 700 MW, will be brought in on Line 54 through the King's Pass. Currently, Line 54 operates at 500 kV and has a maximum rating of 2,500 MVA.

Table 5: proposed generation facility decommissioning years

Decommissioned Facility Name	Year Decommissioned	Generation Loss (MW)
Centerville	2027	150
High Meadow	2035	400
Melior	2038	50
Carbide City	2045	450

3. *Reliability Analysis*. Performing the reliability analysis on the scenarios from Step 2, KTC reaches the following conclusions:
   e. While load growth in most of the Cantanese system is moderate, the load around Melior is forecasted to grow at a higher rate (2.54%) than the rest of the system. In addition, the 700 MW from the data facilities between 2025 and 2045. See Table 3 for simulation results that indicate which lines are overloaded. Line numbers correspond to those shown in the one-lines found in Appendices A, B, and C. Below in Table 6 is shown the average line loading in percent.

Table 6: average line loading in Capital

Average Line Loading Summer Peak in Capital District by Year (% of MVA capacity)			
2015	2025	2035	2045
35.2	37.9	47.9	58.4

Another contingency to consider are the critical transformers that connect the 500 kV system to Melior will get close capacity toward as 2045 approaches. Loss of a critical transformer (TX1 or TX2) causes the power to be shifted to alternate routes and ultimately causing system because the either transformer cannot support the load alone (Table 7).

Table 7: loss of Transformer 1 at Capital Heights

<table>
<tr><th rowspan="3">Transformer</th><th colspan="8">Transformer loading during summer (peak loading) and percentage of used capacity</th></tr>
<tr><th colspan="2">2015</th><th colspan="2">2025</th><th colspan="2">2035</th><th colspan="2">2045</th></tr>
<tr><th>P</th><th>%</th><th>P</th><th>%</th><th>P</th><th>%</th><th>P</th><th>%</th></tr>
<tr><td>1</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>2</td><td>807.6</td><td>88</td><td>828.3</td><td>93</td><td colspan="4" rowspan="5">System Failure</td></tr>
<tr><td>3</td><td>316.1</td><td>42</td><td>339.1</td><td>44</td></tr>
<tr><td>4</td><td>357.7</td><td>46</td><td>379.3</td><td>49</td></tr>
<tr><td>5</td><td>202.4</td><td>35</td><td>208.3</td><td>37</td></tr>
<tr><td>6</td><td>313.0</td><td>33</td><td>331.7</td><td>43</td></tr>
</table>

Another contingency to consider is if Lines 27, 37, 42, or 52 experiences an outage. The majority of the load in the Capital is served through these three lines and the loss of any one of the lines will cause significant system stress.

Table 8: equipment overload considering loss of a critical line

Equipment Overload Considering Loss of a Critical Line in 2045		
Line out	Number of lines overloaded	Equipment Overloaded
27	6	L35, L40, L41, L43, L44, L52
37	4	L29, L30, L43
42	5	L29, L30, L38, L40, L41
52	4	L29, L30, L40, L43

Should the 500 kV lines connecting Deep Lake to High Meadow be disconnected, which has happened due to tornadoes, the energy from Deep Lake will divert in an indirect path to get to the capital. While not shown in the one line diagram, voltages under 500 kV would also share in some of the transmission burden, but the 500 kV system tending to be the lowest impedance path, will still carry most of the power. Table 9 shows that during this contingency, the lines cannot handle the extra power flows.

Table 9: contingency if Lines 14 and 15 are out of service

Line/Equipment	Contingency – Line 14 and 15 out of service			
	MVA Rating	P	Q	%
10	1000	1034.4	1473	189
11	1100	685	846	104
12	402	523	502.7	196
13	909	694	602	101
TX4 – Moorland	914.4	141.5	276	37
TX5 – Moorland	914.4	141.5	276	37
TX1 – Dark Wood	914.4	313.4	120	48
TX2 – Dark Wood	914.4	313.4	120	48

b. KTC is responsible for Catan Island's power system under the same standards as the mainland system. Its assessment of the system over the growth in the next few decades is crucial in determining if there will be sufficient generation to meet the load Table 10 The island is also an island electrically as well. The current facility has a maximum output of 400 MW.

Table 10: forecasted real power usage and percentage of used generator MVA capacity

Substation		Real power during summer (peak loading) and percentage of used generator MVA capacity							
		2015		2025		2035		2045	
Number	Name	P (MW)	%	P (MW)	%	P (MW)	%	P (MW)	%
10	Old Melior	109.90	27.48	133.97	33.49	163.31	40.83	199.07	49.77

c. The Peninsula District, for most contingencies, remains generally stable despite loading projected for the future and being a radial system. Any instability is managed with the local STATCOM and capacitor banks. The only contingencies that are acute are the loss of Lines 1 or 2 because they will constitute an unwanted disconnection of load, but that is unlikely. If the success rate of a transmission line (i.e. the probably that the line will not suffer from a permanent outage) is assumed to be 0.99,

$$P(R) = P(L1)P(L2)$$
$$(0.99)(0.99) = 0.9801$$

Where R is the probability that the all the load connected Lines 1 and 2 is serviced and L1 and L2 are success rates of the their respective lines (i.e. that the line is operational). This shows that the loss of Lines 1 and 2 is unlikely.

The Peninsula District would experience no overloading in the next 30 years (see Table 11) without new generation, but adding it can eliminate indefinitely problems caused by Line 3 or Line 4 being out of service.

Table 11: real power during summer in pu and percentage of used capacity for Line 3 or 4 out

Line	Real power during summer (peak loading) in per unit and percentage of used MVA capacity for Line 3 or 4 out							
	2015		2025		2035		2045	
	P (MW)	%	P (MW)	%	P (MW)	%	P (MW)	%
3 (w/ 4 out)	241.8	60	268.6	66	298.5	74	331.7	83
4 (w/ 3 out)	242.3	59	269.1	65	299.5	73	332.2	81

The only break in the mountains is the King's Pass, which is narrow with the high mountains on either side. As a vital land route, most of the usable land is reserved for ground transportation with only a small corridor being available for transmission.

d. Table 12 shows the loading on Line 54. Even though load changes in Catan cause KTC to buy energy from Pentos, the loading on Line 54 is well within capacity.

Table 12: loading of Line 54

Line	Real power during summer (peak loading) and percentage of used MVA capacity of Line 54								
	MVA Rating	2015		2025		2035		2045	
		P (MW)	%	P (MW)	%	P (MW)	%	P (MW)	%
54	2500	127	5	190	7.5	250	10	326	15

Now that each scenarios has been explored for reliability, the diagnosis for the health of the system overall good, but there are pockets where attention is needed. Interconnection of renewable energy sources poses a challenge out west and in the capital, load growth coupled with likely decommissioning of nearby power plants could led to an unstable system around the Capital. Simulations show that the system on Catan Island will not have any issues in the future.

4. *Benefit Examination*. After examining the changes in reliability from the different scenarios. The methodology moves to explain how solving each of the scenarios would affect the system.
    f. An unusual growth pattern in addition to the normal load increase in the capital – the large data storage facilities – presents a unique problem because it acts like several

years of normal growth in a very compressed timeframe. As the load around the capital is justifiably important, improving the system around the Capital is important as well. Fixing the overloaded lines that are in Table 3 would improve the overall health of the system in the Capital District. Also the critical line outages demonstrated in Table 8 show that Lines 27, 37, 42, and 52 are vital for the system health in the Capital. Loss of any one of the lines, puts several of the lines outside of their thermal limits. A trend to notice is that the same lines are frequently the lines outside their thermal limits; this is due to the low capacity of the lines.

g. The Island of Catan has the resources to contend with load growth for the next 30 years. The current local generation will be sufficient to supply the load and provide for any reactive capacity. No heavy industry or installation of large load is planned for the island. The island system is not connected to the mainland and therefore has no effect on a majority of the system. Therefore, enacting changes on this portion of the system does not achieve much in the way of stability improvements.

h. Table 13 shows the 200 MW windfarm connected to the Illyria bus, which causes the power carried by Line 3 and 4 to be dramatically reduced. The new generation has the benefit of interconnecting a renewable energy source, providing local generation, and providing reactive support. Some of the power will always be used local load, since Lines 3 and 4's purpose is no longer to serve the load, they can be used to push energy into the rest of the transmission network when there is a surplus. From 3.3.1 Interconnection of Intermittent Generation to a Weak AC System, connecting the generation with VSC HVDC could provide the means to connect to the Peninsula system while maintaining desired power quality.

Table 13: real power during summer in pu and percentage used capacity for select N-1 contingencies after adding generation

Line	Real power during summer (peak loading) in per unit and percentage of used MVA capacity for selected N-1 Contingencies							
	2015		2025		2035		2045	
	P	%	P	%	P	%	P	%
3 (w/ 4 out)	38.6	10	64.6	16	93.4	23	125.3	31
4 (w/ 3 out)	38.6	8	64.6	14	93.4	21	125.3	29

i. The interconnection provided by Line 54 through the King's Pass is vital, but the currently installed line will not reach capacity within the next 30 years (Table 12). Even with 700 MW of renewable added the line would not become overloaded. Improving power transmission infrastructure through this corridor would not really achieve much since the line is lightly loaded now and will only moderately loaded in the future.

The conclusion that the benefit analysis shows are:

- Capital District needs improvements to handle large data centers and high load growth.
- Catan Island does not attention in the foreseeable future and no further consideration is required.
- Connecting the windfarm with VSCs provides a PQ injection that meets the system requirements and forgoes the reactive compensation that would have accompanied an AC connection

- Line 54 has sufficient capacity to handle the new renewable generation in Pentos and no further consideration is required

5. *Engineering Goals*.

Moving the focus to the capital, which proves to be a more difficult area, the text below discusses solutions to the problems experienced in Melior and elsewhere in the system due to its effect; note that unless otherwise specified, assume that in the system discussed is not the case where generation deficiency is described. The list below is by no means exhaustive, but puts forth many plausible solutions from an engineering standpoint.

1. The 500 kV line, Lines 18 and 19, both have sufficient capacity to handle power demands for a long time to come, but Transformers 1 and 2, which connect the 500 kV to 230 kV system, in Melior are the weak point for the connection between High Meadow and Melior and have a lower combined capacity than the two transmission lines possess. There are two options for improvement – add more transformers of either equal or greater capacity or replace the existing units with ones of higher capacity.

   For practical reasons, most utilities usually keep the selection of transformer types/ratings/voltage levels small because this allows spares to be used in multiple locations reducing the need for extensive and expensive storage to accommodate many different kinds of spares. For the sake of simplicity, it is assumed here that all the analysis for optimum transformer selection has been done correctly by KTC. In the table below is the pool of transformers that KTC has available for 500 to 230 kV. If ANSI/IEEE Standard C57.96-1989 is followed, the minimum useful lifespan of a transformer is approximately 20 years [30] though most serve long beyond 20 years.

Table 14: possible transformer selections for 500/230 kV

Option	Nominal MVA Rating	R (pu)	X (pu)	X/R Ratio	Lifespan (yrs)	Cost (US$)	Size
1 (current)	920	0.0001 - 0.00034	0.0149 - 0.0152	95 - 149	20	9.09M	65 ft W x 55 ft L x 50 ft H
2	1100	0.0001 – 0.00044	0.0112 – 0.01464	33 - 112	20	11M	80 ft W x 65 ft L x 60 ft H

   The list of options is short for preexisting unit types meeting the 500/230 kV voltage rating. In that voltage rating there are only two possible MVA ratings.

Table 15: possible transformer combinations

# 920 MVA units	#1100 MVA units	Gain over 2 – 920 MVA units	Total
2	0	0	1840
0	2	360	2200
3	0	920	2760
0	3	1460	3300

Looking at Table 13 can be misleading because the difference between the capacity of the units corresponds to a significant change in the per-unit impedance. For this reason, the mixed MVA options are generally a bad idea because the proportion of loading between the paralleled devices will be misaligned when compared to their MVA rating with the lower per-unit impedance transformer (typically the larger one) bearing a disproportionate amount of the load. Also, mismatched parallel transformers will also affect the voltage and current passing through them differently causing phasor mismatching on the secondary side of the transformer and possibly circulating currents between the parallel units.

If mixing different types units is not generally a good option, then adding another nearly identical unit is a logical decision. However, the lower effective impedance of the paralleled transformers causes issues. By putting a third unit in parallel, the effect is reducing the impedance of the path further. A reduction in the effective impedance will cause more power to select this path over other higher impedance paths. Many times this addition is not an issue if the transformers are not extremely loaded, but in the case of the capital, the addition of another transformer only unloads the rest of the system and does nothing to help with the transformer overloading.

Table 16: what-if scenario where 3rd transformer is added between High Meadow and Melior

Zone	Transformer	MVA Rating	R (pu)	X (pu)	Transformer loading and percentage of used MVA capacity	
					2045	
					P	%
Capital	1	909.3	0.00016	0.0152	773.8	101
	2	931.9	0.00016	0.0151	778.9	99
	3	909.3	0.00016	0.0152	792.4	106

It is clear from the discussions of the loading problem of Transformers 1 and 2 in Melior, simple replacement of transformers or adding units are inadequate solutions. Any change in the transformer configuration would need accompanying changes elsewhere in the system.

3. The next go-to solution for when a parallel line or parallel transformers does not solve the problem also is to increase the operating voltage of the system. Basic circuit theory says that this would be the easiest way to transfer more power using the same number of lines because it would lower the operating current thus lowering the I^2Z losses. It would seem that upgrading the 230 kV lines around the capital to 500 kV would be a solution. In Table 17, it is assumed that Line 52 is upgraded to 500 kV (neglecting the load that is connected at Fairfield) in the 230 kV system they are in currently.

Table 17: comparison of loading between 230 and 500 kV on Line 52

Voltage Level (kV)	Line R (pu)	Line X (pu)	Charging B (pu)	Active Power (MW)	MVA Rating	Percent Loading
230	0.001380	0.032400	0.04998	583.5	805	72
500	0.002700	0.017940	0.23540	976.7	2400	37

The operating voltage increase results in a reduced loading on the line. Assuming that a similar process were applied to the other lines in the system, the upgrades would provide much more capacity. However, this may be impossible or extremely difficult if the ROW is shared with other lines because to maintain the proper clearances, the ROW must be wider. In addition, upgrading the overloaded lines requires the updating of several things at once. For instance, if this were done with the lines leaving Capital Heights, Lines 27-30 and Lines 37-44 would all need upgrades to reach the overloaded lines. This would also mean that two new transformers would be needed at Progress Street and a new transformer at Davis Street in addition to the new distribution those transformers would be needed to service the load at each substation.

4. During contingencies, another possible solution would be to rebuild the lines identified in Table 8 so that they can handle the N-1 contingencies at the same operating voltage, 230 kV.

Table 18: line length for problematic lines

Line Lengths for Problematic Lines	
Line out	Line Length (miles)
29	3.1 (underground)
30	0.24
38	6.21
40	2.78
41	3.41
42	6.09
43	5.58
44	2.62
52	10.2
Total	37.13

The line lengths are approximately 10 miles or shorter making all, but Lines 29 and 30, replaceable. The frequency with which Lines 29 and 30 appear in Table 8 makes these lines problematic to replace because Line 30 is the above portion for Line 29 that is underground. In addition, the new conductors would weigh more necessitating that the entirety of the lines be demolished and rebuilt.

5. In addition to new transformer and lines, capacitor banks are also necessary to maintain acceptable system voltages in the Capital District. Table 19 shows that with the increased load over time, reactive support becomes increasingly necessary to maintain voltage if the line conductors are held constant. Expansion of the required reactive support becomes necessary after the addition of the block load from data centers between 2025 and 2035 which leads to dramatic increase in the level needed.

Table 19: capacitor bank values in the Capital District

Location and Maximum Values of Variable Capacitor Banks in MVAR				
Substation	2015	2025	2035	2045
Capital Heights	151	156	156	250
North Melior	54	54	54	54
Southgate Drive	151	156	156	172
Bridgeport	151	156	156	170
Progress Street	101	104	104	180
Armory	-	-	200	240
Carrytown	-	-	170	240
Diligence Drive	-	-	-	130
Davis Street	-	-	140	220
	608	626	1136	1656

6. So far, many of the discussions about the system in and around Melior have concerned themselves with overloading issues. The previous options solutions have contended with the growth in expected ways. Many of these solutions were shown to be ultimately ineffective. One option that has not been discussed is the addition of a high capacity line or lines that connects directly from Fort Cailin, where the energy from the renewable energy from Pentos enters KTC's system, to a new point in the Melior system to alleviate some of the congestion that exists on the current system – an urban infeed.

   The main reason why this solution has not been brought forward is that the geographical distance between Fort Cailin and the Capital is too great. As explained numerous times before, long-distance AC lines are difficult because a waystation would be needed to provide the necessary reactive compensation to make the line(s) operable. For the sake of discussion, if a direct corridor were to be made, the AC line parameters would be as in Table 20.

Table 20: parameters for theoretical 266.4 mi HVAC line

Parameter	Per unit (if applicable)	Value
Line length	-	266.4 mi
Operating voltage	1.00	500 kV
Operating frequency	-	60 Hz
MVA base	-	100
Resistance at 25C	0.0023976	5.994 Ω
Inductance	0.0556776	139.194 Ω
Charging susceptance	4.9284	0.00197136 S
Line charging	-	492.84 MVAR
Charging current	-	569.08 A

   For contrast, compare the charging current of the 266.4 mi line to that of a 64.38 line that is already in use (Table 21).

Table 21: parameters for 64.38 mi 500 kV line that is in use

Parameter	Per unit (if applicable)	Value
Line length	-	64.38 mi
Operating voltage	1.00	500 kV
Operating frequency	-	60 Hz
Wire type	-	3-1351 ACSR
MVA base	-	100
Resistance at 25C	0.00073	1.825 Ω
Inductance	0.01531	38.275 Ω
Charging susceptance	1.1607	0.00046429 S
Line charging	-	116.01 MVAR
Charging current	-	134.026 A

In comparison to the example line that is in use, the steady state charging current of the 266.4 mi lines is more than four times as large for the 64.38 mi line. A line such as this would need waystations to provide the shunt reactors to correct the line capacitance and would require a facility to be installed in a remote area to do so.

If an HVDC solution were used instead, a long distance connection is now feasible because there would be no need for a waystation to provide reactive support. With distance out of the way as a functional constraint, a link can provide a corridor that funnels energy directly from the Deep Lake generation facility or Fort Cailin directly to the Capital. The ABB Corporation offers a VSC solution, which it calls HVDC Light that can be up to 1800 MW at 500 kVdc. The product's website states that the technology is good for "city center infeed" [31]. If something like this were deployed at Fort Cailin, an infeed directly to the heart of the capital would circumvent the otherwise necessary "traditional" route of upgrading and adding lines and equipment.

The question that needs answering is where, if anywhere, the other side of the link should be constructed. The list below shows the Melior substations that are likely candidates due to most of the lines around them having significant capacity remaining; the substations are listed in no particular order.

- Armory
- Davis Street
- Carrytown

Table 22 shows the effect of adding a 600 MW link connected to each of the three buses as compared to the original case. Also shown in Table 23 is that if placement of the station is made near the where large data centers will be installed, the number of lines that are overloaded for the contingencies listed in Table 8 is eliminated. Previously, the AC lines must support the heavy load, but the new injection moves the load from the AC lines to the DC line.

To conclude this step, evaluating the other plausible options shows that the only way to use AC techniques to support the load is to perform extensive upgrades to the lines to increase their capacity and add capacitor banks to help support the voltage in the Capital District. However, the methodology also shows that the addition of an HVDC link from Fort Cailin to the Carrytown substation is also possible offering the benefit of new injection to a taxed system; the same station can be used as reactive support during normal or abnormal conditions with the effect of reducing the number and size of capacitor bank units. This addition simultaneously unloads lines and transformers in the Capital. In addition to benefits to steady state operation, another consequence of having the system unloaded is that during system contingencies discussed in Table 8, there is now enough extra capacity available on the existing lines to contend with the new transmission topology because the load from data centers is being supported by the DC link.

With respect to the offshore wind, the methodology determines that the injection of the wind generation at Illyria helps the system out in the area if the power can be injected stably. The wind generation unloads the lines into the Peninsula district making the current infrastructure serve beyond where it would otherwise.

Table 22: effect of adding 600 MW injection at a given capital bus in 2045

Line	MVA Rating	Original		Davis Street		Armory		Carrytown	
		P	%	P	%	P	%	P	%
27	788	605.8	77	483.7	62.0	492.9	63.0	502.4	64.0
28	788	602	77	481.2	62.0	490.3	63.0	499.7	64.0
29	637	600.9	93	480.5	73.0	489.6	74.0	499.0	76.0
30	637	600.5	93	480.2	72.0	489.4	74.0	498.7	75.0
31	637	22.3	4	94.3	14.0	126.1	19.0	44.2	7.0
32	637	22.3	4	94.3	14.0	126.1	19.0	44.2	7.0
33	478	108.3	28	35.7	20.0	44.8	22.0	175.5	38.0
34	797	105.2	16	34.0	12.0	44.8	13.0	171.0	22.0
35	797	380.8	63	167.0	51.0	149.9	50.0	132.5	49.0
36	797	496.2	62.3	398.8	54.0	403.3	53.0	407.9	54.0
37	713	424.4	59	368.8	51.0	373.3	52.0	377.9	52.0
38	470	363	78	307.9	66.0	312.3	66.0	316.9	67.0
39	478	257.7	58	203.0	48.0	207.4	48.0	211.9	49.0
40	674	618.8	92	489.3	73.0	498.0	75.0	507.1	76.0
41	674	523.6	79	395.4	62.0	404.0	63.0	413.0	64.0
42	713	518.9	73	453.4	64.0	458.4	65.0	463.5	66.0
43	478	447	93	382.7	78.0	387.6	79.0	392.6	80.0
44	478	393.3	82	329.3	68.0	334.2	69.0	339.2	70.0
45	478	254.3	55	190.4	42.0	195.2	43.0	200.2	44.0
46	470	216.5	49	152.9	37.0	157.7	38.0	162.7	39.0
47	788	198.8	42	390.7	62.0	377.2	61.0	363.3	59.0
48	637	198.9	47	390.8	73.0	377.3	71.0	363.4	69.0
49	637	239.8	49	431.8	76.0	418.3	74.0	404.4	72.0
50	788	239.8	40	431.9	61.0	418.4	60.0	404.4	58.0
51	813	532.2	66	495.8	61.0	487.9	60.0	479.8	59.0
52	797	613.9	77	576.4	71.0	568.4	70.0	560.1	69.0

Table 23: reduction in line loading during contingencies

Equipment Overload Considering Loss of a Critical Line in 2045		
Line out	Number of lines overloaded	Equipment Overloaded
27	0	N/A
37	0	N/A
42	0	N/A
52	0	N/A

6. *Practical Constraints*. Many times natural impediments, like geography, or political impediments, like the refusal of local governments to issue permits, make a power system project onerous or just simply impossible. In efforts to compromise with the public and regulators, lines are frequently rerouted, substations relocated, or any number of changes to find a solution that satisfies all parties.

The previous step showed that without line length as a restriction, the best option to improve the system in the Capital was the addition of an HVDC link from Fort Cailin to Carrytown to bring the energy from down south into the capital. The land that this line would traverse is mostly plains used for farming and cattle grazing and thus easements or rights-of-way should pose little trouble if the landowners are amply paid for their land or the use of their land. Also, the new structures needed for the DC lines would be narrower thus limiting the needed space or if wider corridor is obtained, it could be useful later should another line be installed.

The goal is to reach one of the substations located deeper in the Capital, but around the Capital in all directions are very dense suburbs and a sprawling metropolitan area that have fully surrounded KTC's existing corridors making it difficult to obtain any new ROWs. Gaining ROWs could be prohibitively costly due to the value of the real property that must be paid to the landowners, the funds spent in possible protracted legal battles with landowners and the government, the length of time it would delay the project, and/or the uncertainty it introduces into the planning process. Therefore, it is reasonable to consider that the existing corridors will not be expanded nor will the creation of new corridors be possible in the timeframe needed.

The existing AC corridors into the city have their aerial capabilities fully used and replacement of the lines with the DC is not an option due to taps on the line, but the underground portion of the ROW is still unused. As the lines near the capital, they can be buried in parallel with existing overhead lines. The goal will be to keep the lines aerial for as long as possible. Therefore, merging the HVDC line with Line 20's ROW is the best solution; the line could be buried and run to the Carrytown substation following Line 20, then Line 36, then Line 35.

At first inspection, there is no room to build the converter station. The Carrytown station is fully boxed in on all sides by residential developments. Looking at the rest of the substations, Armory also is boxed in but by urban development (this station already has buried AC lines under a roadway), and Davis Street is partially boxed in as well but one of the sides is a park rather than residences. Since outright building is not possible, the following are options:

- Obtain adjacent land from residents at Carrytown or Davis Street
- Obtain land from the park adjacent to Davis Street

- Rebuild the Armory substation to accommodate new equipment by building vertically with all or part of the substation possibly being below ground
- Rebuild Carrytown or Davis Street to have the converter station below ground

By burying the line in the ground in the existing ROW, the need for obtaining large swaths of land is avoided making the acquisition of a few parcels of land more workable. In residential areas, even VSC technology will still make for a big and unsightly addition to the area. Burying it is not an option either as the significant cooling equipment would still be visible in addition to the awkward empty space that it would create. One solution here would be to turn the land into park, but this again might be an unwanted change for the surrounding property owners. These complications make the Carrytown solution unattractive. In addition, the prospects of rebuilding the Armory substation are not good either because the station is tightly surrounded by development, which would necessitate a complete rebuild of the station, which would remove a critical substation and pose a logistical nightmare due to disruption of the area during construction.

The land taken from the park in the Davis Street solution does not have this problem though. If the hall and even the transformers are buried, the land can be reused as open space once construction is complete; the cooling units for the transformer and converters would be located close to the existing station to minimize impact. Many athletic fields are larger than an acre (a typical baseball field is larger than an acre). By creating a sports complex (not meaning large, heavy structures like a stadium; the intention would be mostly open area like can be found in many communities for recreational leagues) on top would provide a dual service of providing power and open space for recreation and sports. An example of an underground station can be seen in Figure 27 and Figure 28.

Figure 27: satellite view of substation [6] Google Maps, 2015. Used under fair use, 2015.

Figure 28: drawing of space below park occupied by substation [32] B. Strassburger and P. Glaubitz, "Modern Subterranean Substations in GIS Technology - Challenges and Opportunities in Managing Demographic Change and Infrastructure Requirements," Siemens, 2009. Used under fair use, 2015.

A final consideration is for the return path. If a bipolar or symmetrical monopolar converter topology is chosen, which is preferential it reduces the losses through the return path. If the system is to be operated exclusively as an asymmetrical monopole or the installation wants the ability to operate a bipolar system as a monopole, the connection to an electrode site, which cannot be the ground mat of the station, is also needed. A location several miles away (e.g. 10 to 30 miles) from the site is preferred because it prevents unwanted current flows between the system neutral and the ground even with the current balancing from the devices.

7. *Reconcile engineering goals and practical constraints*. When viewing the three options concerning which substation should be used, all three are nearly identical in their performance characteristics on the system. The decision is selecting which option provides the best solution from the point of the practical constraints.

Considering all the practical constraints, the preferred solution is the Davis Street substation. The land used from the park is much better than the other options because it is not privately occupied and after construction is complete, the land will be mostly reclaimed for park space. Using any residential land would require it to be occupied by the power station in perpetuity. Selecting the Armory station is the least attractive option because there is no land that can be acquired. This would necessitate rebuilding the station in its entirety; this would remove an important node in the system. To even consider it would require going back and performing analysis to check the system's reliability during the construction phase when the station would be taken out of service. The prospect of performing extensive studies is not something that is desirable when there are other near equal alternatives available. Carrytown is not selected either due to the complications that the ROW acquisition would bring.

8. *Cost*. While it is arguable that cost should be considered in the engineering goals or in the practical constraints, it is more beneficial to consider it separately due to its weight in the process. After the seven previous steps, the myriad of possible options has been whittled down to a select few. In this case, there are a few favorable stations and of those, the Davis Street substation is selected.

Aside from the cost of the actual technology, the construction costs tend to be as large, if not larger, than the cost of the technology itself. Implied in the practical constraints, the site chosen greatly influences the construction costs. Factors like the type of soil require careful thought if lines are to be buried. Any existing underground systems, which can be considerable like in Melior, must be because the lines would have to avoid exiting pipes, subway tunnels, or distribution circuits. It is therefore difficult to give an estimated cost for what project connecting Davis Street to Pentos would be. However, based on the data given in Table 24, the cost would likely be somewhere around $1 billion.

*Table 24: rough cost breakdown of an HVDC project**

Rough Cost Breakdown of an HVDC Project			
	Per Unit Cost (MUSD)	Number/Length	Total Cost (MUSD)
Substation/Converter	200/each	2	400
Lines – Overhead	1.0/mi	240	288
Lines – Underground	12/mi	26	312
Approximate Grand Total			1,000

* Values are based on Potomac-Appalachian Transmission Highline Project data [33]

9. *Final Decision*. Of the options available, an HVDC connection between Fort Cailin and Davis Street weighs appropriately the operational constraints against the practical constraint yielding the best solution possible. For example, in Table 25, which assumes the link would go into operation between 2035 and 2045, the new injection in the system reduces the used capacity on many of the lines bringing them back to levels they were at years prior; if the lines still have years left in their lifespans, the effect is that it increases the years the line can serve. With adequate energy being provided by the renewable project in neighboring Pentos along with existing generation and available land make it possible to build the HVDC infrastructure at Fort Cailin. For the end of the line in the Capital, Davis Street was chosen

due to the availability of land adjacent to the substation. Burial of the converter hall and step up transformers allows the land to be used for the needs of the power system then returned to the surrounding community as recreational space.

Table 25: effect of adding 700 MW of injection in the capital on selected line loadings

Examination of 2045 Capital Loading for Candidates Based on % of MVA Capacity				
	Original	Davis Street	Armory	Carrytown
Average (%)	59. 9	54.9	55.5	55.7
Standard Deviation	25.5	19.7	18.8	19.4
Loaded above 90%	4	0	0	0
Loaded above 80%	5	0	0	1
Loaded above 70%	11	7	7	6
Loaded above 60%	14	16	16	13

4.4 Summary of Methodology

The methodology seeks to augment existing transmission planning procedures by considering HVDC as a possible solution. The first step of the methodology, infringement of operational criteria, looks at current state of the system and then considers future loading conditions without system modifications (e.g. new lines). As load is forecasted, it becomes apparent where steady state operability in the system does not meet operational thresholds in either voltage profiles or line loading. Identifying these points in the system gives an indication where the planner should focus their investigations because they have a finite amount of time to develop solutions; therefore, appropriate allocation of time is paramount. The example system given in Chapter 4: Examining Transmission Systems Considering HVDC searches for areas in the example system that are outside their operational constraints.

The next step in the methodology, scenario development, is related intimately to the last step. This step identifies what real world changes are propelling the change described in the last step and quantifies that change. Knowledge of external factors directly influences how the load changes in the system. In the case of the example, knowledge, like the addition of large block load in the form of data centers, is critical in the planning process in Catan. This tells the planner that what areas of the transmission system will likely need attention. Other identified changes, like the load growth on Catan Island compared with the island's generation.

Further focusing the decision making process, the reliability analysis takes the areas identified in the previous two steps and seeks to group the reliability issues by finding the commonalities between the reliability issues; the investigation will likely show that many of the issues are related to one another. After grouping, this step of the methodology seeks to determine the reliability of each stressed area identified in previous steps. From the example, some of the cases this step considered was the loss of Transformer 1 in the Capital District and the loss of the Lines 14 or 15. The methodology shows what system components are closely related and what the effects of the loss of system equipment are.

Now, continuing the focusing of the methodology, the greater the number of related system issues grouped together by the reliability analysis indicates to the planner that a benefit analysis in the identified areas would show which groupings, if rectified, would provide the greatest benefit to the system as a whole by removing adverse system conditions. The benefit analysis deems some of the reliability concerns identified in the scenario development to be nonissues, like loading on Catan Island, because any adverse system conditions will occur far into the future and therefore do not require resources at the moment; this eliminates these areas from future consideration cutting out wasted effort on further investigations into areas that will have little return on time and capital investment.

The methodology designates any of the areas making it passed the benefit analysis as "needing attention" and some sort of solution must be implemented to eliminate the adverse system conditions. The engineering goals seeks to do this through the use of any of the methods at the utility's disposal to develop feasible solutions. Any plausible solutions to the problem are considered because this will help free the planner from gravitating to old solutions that may not provide the best results. Running through a variety of solutions to the problem will highlight the relationships between system components and the effect on the system by changing them. For example, replacing Transformers 1 and 2 in the Capital District will lower the effective impedance of that corridor, which increases the MVA loading on through it. The example considers several AC solutions and shows to achieve a feasible solution using AC that several smaller projects (e.g. line and transformer upgrades or rebuilds or the addition of capacitor banks) are needed to address the system's problems. However, included in the utility's repertoire now is HVDC, which the methodology proposes in the example to transmit renewable energy from the south to the Capital District. The HVDC solution gives the ability to provide power within dense urban area of the Capital along with reactive support. The methodology arrives at the conclusion that the operational benefits that are provided by the HVDC system make it the preferred technical solution from the engineering goals step; it also identifies three buses within the Capital that provide the best operational benefits to the system.

With the preferred solution determined, the practical constraints surround each variant of the solution are a necessary discussion. Around dense urban areas like in the Capital, land is at a premium making the acquisition of new ROWs or expansion to existing ROWs extremely difficult if not impossible. This permitting is often an arduous process and can add significant lead-time due to public opposition and government bureaucracy. Practical constraints are a vital part of the methodology; if a project cannot be completed by the time system conditions demand it be done, the solution is poor no matter how good it is from a technical standpoint. In the example, some practical constraints were that the ROWs were surrounded by development and major roadways.

Next reconciling the engineering goals with the operational constraints will test the variants of the HVDC solution to see if the engineering goals can be achieved when placed under the practical constraints in Capital. For the example problem, some of the substation locations were dismissed from the methodology because the practical constraints surround the sites, namely the development and roadways, would prevent the expansion of the existing substation to accommodate the new HVDC infrastructure. In efforts to achieve reconciliation, one of the solutions, Davis Street, proposes that a portion of the substation be located below ground. This solution allows for the operational benefits that the engineering goals sought within the confines of the practical constraints.

After narrowing the possibilities, the cost of the project is estimated. Cost heavily factors into the viability of a project; see the discussions in the cost section (Part 9 of 4.3Applying Methodology to a System). The project's overall cost plus some extra margin for unforeseen occurrences must be weighed against the operation benefits of the project. Costs of a project include the actual cost of the materials, labor, construction, permitting, and other unforeseen expense. Most expenses can be estimated, but unforeseen problems obviously cannot and usually occur during the construction phase of a project when they are most expensive because the project is already underway and capital has already been expended. A concealed cost in the permitting process are legal costs that may be incurred in court cases surrounding the construction of a project. Legal proceeding introduce uncertainty into the material purchasing process because a utility does not want to buy millions of dollars of equipment only to have court proceeding forbid a project; for this reason, planner should endeavor to develop solutions that are as uncontroversial as possible.

With all pertinent information gathered and analyzed, the final decision can be made. The goal of the entire methodology is to narrow the field of possible solutions to a single or at least a select few choices. This is the only way that a planner can find the best solution for the given circumstances. The final solution should achieve maximum operational benefits within operational and practical constraints for the lowest cost possible. In the case of the example, the solution that fits these characteristics is an MMC HVDC line spanning the 260 miles from the Fort Cailin substation to the Davis Street substation.

4.5 PSS/E Simulations

PSS/E is, according to the Siemens website, "high-performance transmission planning software" and "the probabilistic analyses and advanced dynamics modeling capabilities included in PSS ®E provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks." PSS/E was chosen over other simulation software like PSCAD primarily due to KTC's system model already being in PSS/E. Incorporating HVDC technology into power system requires that the technology be evaluated in a real system. To get realistic simulation results using a system created especially for this thesis would have been a challenge and any results from the model would be dubious since the model could be constructed to highlight the benefits touted in earlier chapters. Therefore, to have meaningful results, the thesis uses a preexisting model, which is known to converge using any variant of the Newton-Raphson Method, as its base model and did not try to convert or create a model in another simulation software.

4.5.1 Description of PSS/E Model

The base model referred to in the introduction of Section 4.5 began as KTC's interconnection mode that also included the system in Pentos and Athos. The original size of this model was approximately 32,000 buses and hundreds of thousands of lines, transformers, capacitor banks, generators, SVCs, and STATCOMs. Using this model for 2015 was fine to simulate contingencies and system events, but any modification to the system model made maintaining convergence near impossible to manage and truly beyond the scope of the author to manage. Using other variants of the Newton-Raphson model provided in PSS/E made little difference in achieving convergence. The dynamic model that accompanied the steady state model had convergence issues, which were not solvable in a timeframe consistent with the completion of this document.

To make the system model more manageable, properties of the steady state model were used to drastically reduce the model, namely it only shows one operating point – the peak summer load and that operating point at steady state (i.e. no dynamics) at 60 Hz. This constraint greatly lower the required capabilities of the model and allow the definition of a smaller model. Another technique to reduce the full model is to hold the inter-utility transfers constant at the "boundaries" between systems. Identifying the interconnection points is readily discernable from the system map provided by KTC. All of the interconnection points were simulated as power transfers as either constant positive power loads if the power is leaving into KTC's system or constant negative power loads if the power is entering KTC's system and any modeling outside KTC's system is eliminated. This greatly reduces the size of the model from tens of thousands of buses to just over a thousand. Before this action was taken, the voltage and angle at the boundaries were noted as well as the power flows by creating a duplicate of the model for comparison. After the removal of the modeling exterior to KTC's system and replacement with the loads, the models were compared to see the difference; the change was not drastic.

Even with the reduction of the model from tens of thousands of buses to just over a thousand, maintaining convergence was still difficult with all the equipment on the system. Therefore, the Equivalence Networks function of PSS/E to further simplify the model.

The Equivalence Networks function uses the Ward Method, which comes in two types – injection and admittance – and seeks the equivalent by removing lines, changing line impedances, repositioning injections, and changing loads to give similar results; this shortens computation time for large networks. In short, the methods seek to take a highly non-linear system and linearize it to the point where an equivalent can be taken with respect to specified bus(es). Each method's goal is to have a response at the bus or buses of interest resemble the same response to perturbation whether the full system model is used or the equivalent model is used.

According to the PSS/E documentation [35], the method that the program uses to produce the equivalent is the so-called admittance bus (or Y-bus) reduction. The method defines a boundary around the area of the model, which the user chooses, and the program makes an equivalent either in or outside the area chosen depending on the user's intent for the model. For an in-depth discussion of this method, the reader should read Chapter 8 of the PSS/E 32 documentation [35].

The results when compared to the original model resulted in very slight changes from the original model, which signaled that the equivalent was reasonable for continued use.

4.5.2 Method for Simulating Converter Operation

As of the date of submission of this thesis, there are a limited number HVDC models available from academia and industry and these models were developed by the companies, such as ABB who manufacturer the technology. Transmission planners are reliant on the companies' models to determine how the technology will interact with the existing system for fault calculations and sequencing. However, the validity of these models is also verified by the companies when they compare the model's response to that of the actual device.

Here in this thesis, it was initially considered to include the ABB's HVDC Light model, which is a PWM VSC model, for the HVDC link from Fort Cailin to Melior and for the connection of the wind generation at Illyria, but the model was ultimately not included because of difficulties acquiring the model, the analysis that this thesis was trying to achieve made its inclusion an unnecessary complication, and the dynamic system model was inoperable. The aim of this thesis is to show how, through an evaluation of a system described in Chapter 4: Examining Transmission Systems Considering HVDC, the steady state operability of the system is improved through the addition of MMC VSC HVDC. For that reason, the VSC model was abandoned.

To simulate the wind generation, the power injection was simulated in a similar way to the reduction method used to eliminate the system outside KTC's system. At the point of interconnection in Illyria, the injection is simulated using the PSS/E load model but negative values were used signifying that power was flowing out of the load rather than into it. This functionality of the model, while likely not its intended application, is allowable in the model's coding as can be seen from how reactive power is treated by the model; some of the load modeling in the system is capacitive and therefore showed as negative reactive power consumption or conversely put, showed reactive power injection.

This method was also used for the HVDC link. The terminal that ends in Melior at Davis Street is simulated as constant PQ injection and the terminal that begins at Fort Cailin is simulated as a constant PQ load. The results of the simulations are provided in the earlier parts of this chapter where appropriate.

Chapter 5: Conclusion

In the last few decades, the reemergence of DC as a major contender for electric power transmission has proven that it can be an advantage for power systems as a whole. The public demand for cleaner sources of energy and scientific evidence relating to global climate change and to the negative health effects of air, water, and ground pollution have led to decommissioning of many base load generation stations and the relocation of them far from load centers. The remoteness of many generation stations has proven to be a serious challenge for traditional transmission technology because the optimal location of a plant, whether it is a solar, hydro, wind, or fossil fuel, is often at odds with the operational constraints of the system. If 400 miles separates where the energy is and where the energy is wanted, the question of how to efficiently transmit it using HVDC links.

Without the restrictions that the reactive impedance places on transmission lines, distant points in the system appear electrically closer much in the same way that high AC transmission voltages make geographically distant points appear electrically closer. This electrical closeness can be achieved at lower voltages. It also requires fewer conductors and smaller towers to support those conductors. In addition, subterranean or submarine applications are also more attractive than their AC counterparts due to fewer conductors and the avoidance of effectively large capacitances that require correction. The ability to operate independently of the surrounding system allows the VSC HVDC to act as an infeeder to dense urban or suburban areas without the same environmental impacts that traditional generation units have and limits the increase in short circuit current (e.g. Transbay Cable).

Despite all their advantages, the disadvantages are also very real. To be able to transmit power via DC, large converter stations must be constructed to house the devices that rectify and invert the power. As was discussed in Chapter 4, these stations are not inexpensive nor are they small. Even with the improvements that MMC technology has made, the inability to find suitable locations for the converter stations competes with the cost for the greatest limiting agent. As converter technology continues to improve, namely the switching devices, the utility of HVDC solutions will continue to grow and refinement of manufacturing process will lower costs.

5.1 Future Work

Even in the brevity of this thesis, the struggle was how to limit the scope of the document. The body of information to consider is immense and for an HVDC project to be viable from an engineering standpoint, more investigation than what is given here is needed. Below are some (though certainly not all) of the problems remaining.

5.1.1 Protection

Faults on DC systems are felt quickly due to the lack of impedance between the source (i.e. the converters) and the location of the fault. Like classical AC faults, the desire is for the faulting piece of equipment to be sectionalized as quickly as possible to prevent the fault from causing a system collapse and damage to components. In addition to line faults, the converters can experience faults of their own when the switching devices fail or misoperate.

HVDC has to operate at high voltage and current for it to be efficient, but without zero-crossings to open at during faults, a DC breaker would have to be mechanically robust to open at operating voltages and currents and contemporary devices, like ABB's hybrid breaker, while significant breakthroughs, operate too slowly to clear faults in extremely short periods and these breakers require extensive areas for their construction. For that reason, the current technique is to use protection devices on the AC side of HVDC systems. The AC breakers are operated with microprocessor relays that are ubiquitous in protection schemes today, the relays can monitor both the AC and DC line quantities in addition to monitoring internal quantities of the converters; if abnormal conditions are detected, the AC breakers open on both sides of the faulting HVDC pole. In this sense, protection is similar to traditional techniques.

However, the interaction of faults on a hybrid system is different enough that the many popular traditional protection schemes for transmission are not technically feasible. Overcurrents, over- and undervoltage, and over- and underfrequency schemes are readily applicable, but protection schemes that rely on the impedance of the lines and the sequencing of the AC system are no longer applicable in the sense that an AC scheme cannot reach through the converter to detect faults within the converter nor on the DC line and there is no sequencing with converter based technologies. If the HVDC system is bidirectional, this makes the logical determination of the fault location ambiguous because current directionality is not sufficient to determine whether the fault location is on the DC system or the relays have detected an AC system fault. One method is to wrap the HVDC system in differential schemes to protect various devices; this would enable the detection of faults within converters or on the lines, but this requires high-speed communications (i.e. fiber optics) and for HVDC systems that span great distances, the investment in the communication channels is a nontrivial capital investment. Furthermore, a differential around the converters themselves may prove useful in bipolar schemes to sectionalize a faulted converter, disconnect its mated converter, and transfer the lines from the faulted pole to the other and create a symmetrical monopole; this requires extra effort to perform because the appropriate DC switchgear must exist in the substation.

It is useful for the HVDC system to have some ride-through capacity because most faults will likely be temporary for overhead systems. The structure of VSC installations allows for some fault protection on the AC side through the series reactors and converter controls, which will limit the contribution to AC and DC faults. However, there must be limits for ride-through capacity to prevent damage to the very expensive IGBT converters and/or lines. If the fault is permanent (which is often the case for underground lines), the AC breakers on both sides of the HVDC link are opened. Having automatic reclosing with HVDC is not a good idea as subjecting the converters to multiple high transient conditions shortens the lifespan the technology. If internal converter faults are detected, which can be permanent depending on the failure mode of the switching device, the converter should be shut down to prevent further damage. In many converters, energy storage components aid in the conversion process and during a shutdown, the stored energy must be safely removed.

Further investigation about which protection schemes are appropriate for given converter topologies or interconnection conditions should be part of the methodology in the reliability analysis step as well as in engineering goals because they affect cost, size, and complexity of the project. Reliability analysis should include the behavior HVDC system during contingencies; their special protection needs may affect overall system reliability after system events.

5.1.2 Mutual Coupling between DC Lines and AC Lines

In AC systems, lines that are in close proximity couple with each other due to Faraday's Law. The induction between the lines changes their effective impedance enough to be non-negligible. Even with mutual coupling, operation and protection are manageable, but if the use of HVDC becomes more prevalent, HVDC lines will likely encounter existing AC infrastructure. Close proximity of AC lines to DC lines will cause mutual coupling between the lines. The static magnetic field of the DC system in steady state will not influence the AC lines appreciably. However, the AC coupling to the DC line will superimpose AC currents onto the DC system necessitating filtration of DC or contend with the harmonic content passing through the converters and interface transformers. The complementary situation is when transients occur on the DC system that give rise to signals with non-zero frequency; these signals would couple with the AC lines, which if not adequately accounted for can cause misoperation of existing AC protection schemes and cause unaccounted for stresses on transformers and other equipment. Part of the methodology should be evaluating the steady state influence of the AC lines on the DC system and the influence of transients from the DC system on the AC system. Investigations may show that even though the converters themselves might not cause appreciable harmonics during steady state operations, transient conditions may and this would necessitate the installation of detection and suppression equipment. Any extra equipment needed adds cost and area to an HVDC station's footprint, which means that these considerations should be included in the methodology.

5.1.3 Economic Dispatch

Given that storage of electrical energy efficiently is currently impractical, power systems operate on the principle that generation must match the load plus system losses as closely as possible; this prevents wasting fuels and maintains a power system within its operating constraints. An assumption made in this thesis is that the system is operating at peak summer loading and that the converter is operating at its maximum capacity to help offset load. However, when loading is not at its peak, such as in the fall or spring, maximum injection by the converter will likely not be the best condition for operation. Reducing the link's throughput is within the system operator's control, but a further operating constraint is that an HVDC link has a minimum power transfer needed to keep it alive and less energy flowing through the link means that it is not providing maximum return on the initial economic investment. For this reason when determining the feasibility of an HVDC project, the economics of the HVDC system during the off-peak season must be considered. Underutilization of the link could mean not earning enough return during this period of the year making the system an uneconomical investment overall. Additions to the methodology considering the engineering economics of the link will be essential in evaluating the efficacy of an HVDC system.

5.1.4 Dynamics of Multi-terminal and Hybrid Systems and Standardization

There are no good real-world examples of a grid like HVDC networks or of HVDC systems beyond three terminals. The three terminal systems are protected as discussed before where the AC side is used in conjunction with converter shutdown for fault clearing. Some of the difficulties of a multi-terminal DC system are mentioned in the 3.3.3 Multi-terminal HVDC Systems and HVDC Transmission Networks, the foremost of the difficulties is the development of adequate quickly operating HVDC sectionalizing devices and protection schemes. In addition, the management of the system during dynamic conditions poses an issue because injection into the system must quickly adapt to situations to when the system topology changes or the loss of the converter, which is injecting a significant portion of the DC system's energy.

Aside from needed to operate very quickly, the converter's control schemes operate on devices with nonlinear physics and predicting their response to faults on the AC and DC sides of the circuit is difficult because the behavior of the converters is not readily predictable with classical power system analysis tools. Determination of any interactions require extensive modeling and field testing of devices, which requires additional capital and time investment. In addition, the control schemes are patented and obtaining models that are of sufficient quality to use in planning procedures will be hard due to the heavy redaction that companies would want to place on the models. This detracts from the attractiveness of HVDC projects in an industry where the system reliability is heavy regulated by the government.

Compounding the difficulty in predicting the behavior of HVDC systems, there are very loose standard from IEEE and IEC that govern the operation of HVDC systems, which allows companies developing the technology to set the converter's control scheme and other system attributes as they see fit. This makes the interaction between converters from different manufactures difficult to determine; it is not unreasonable to expect that converters from different manufacturers would be incompatible presently due to the lack of standardization in HVDC. Finally, individual utilities can cause non-uniformity across the industry because due to a utility's lack of expertise and novelty of the technology. Certain functionality of the converter may or may not be enabled at the request of the utility. If the task is to use HVDC for long distance transmission and the beginning and ending points are not in the same system, non-uniformity in approaches will lead to disagreements between individual utilities about the proper operation of the HVDC system posing a significant barrier to implementation of cross-utility projects.

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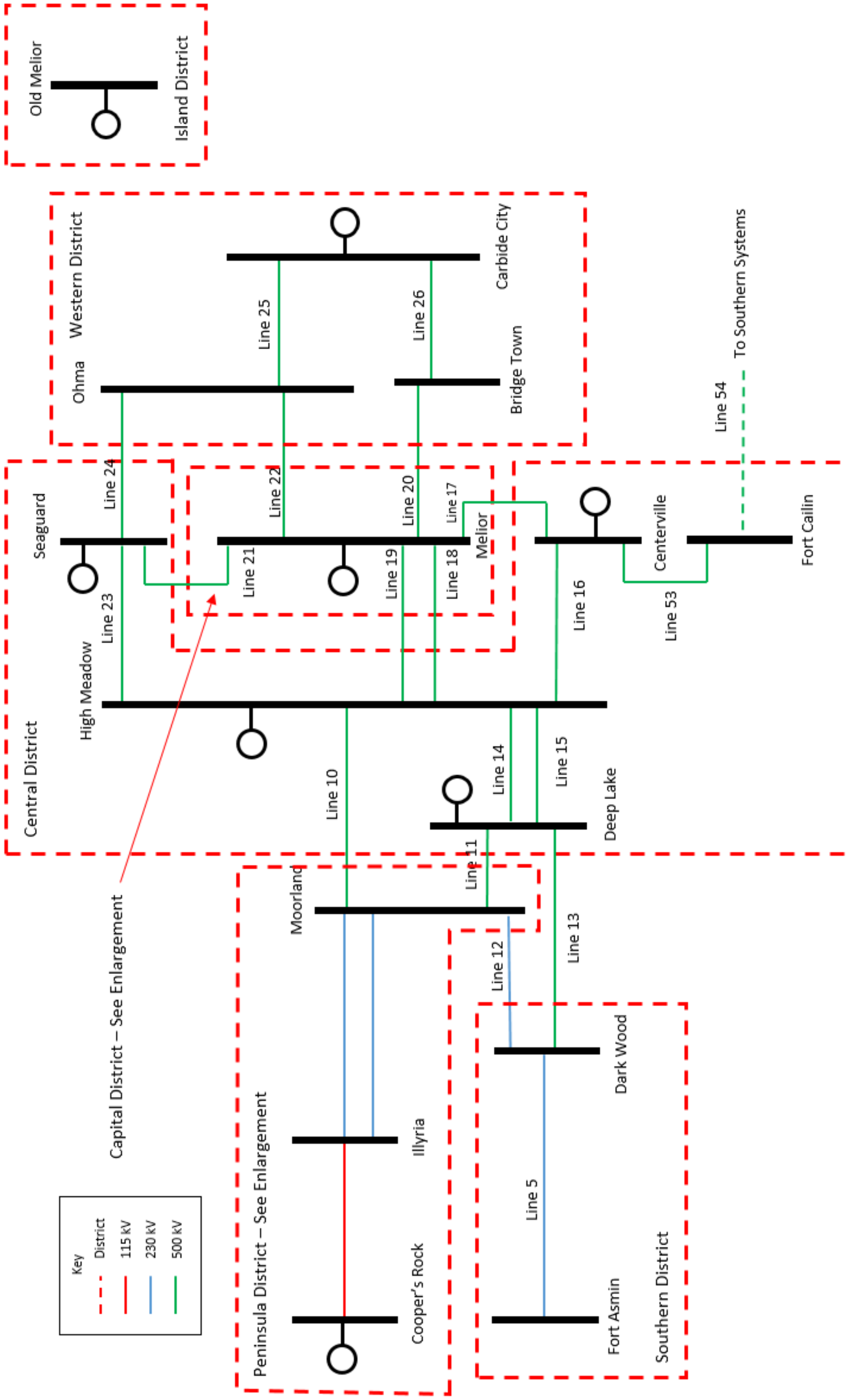
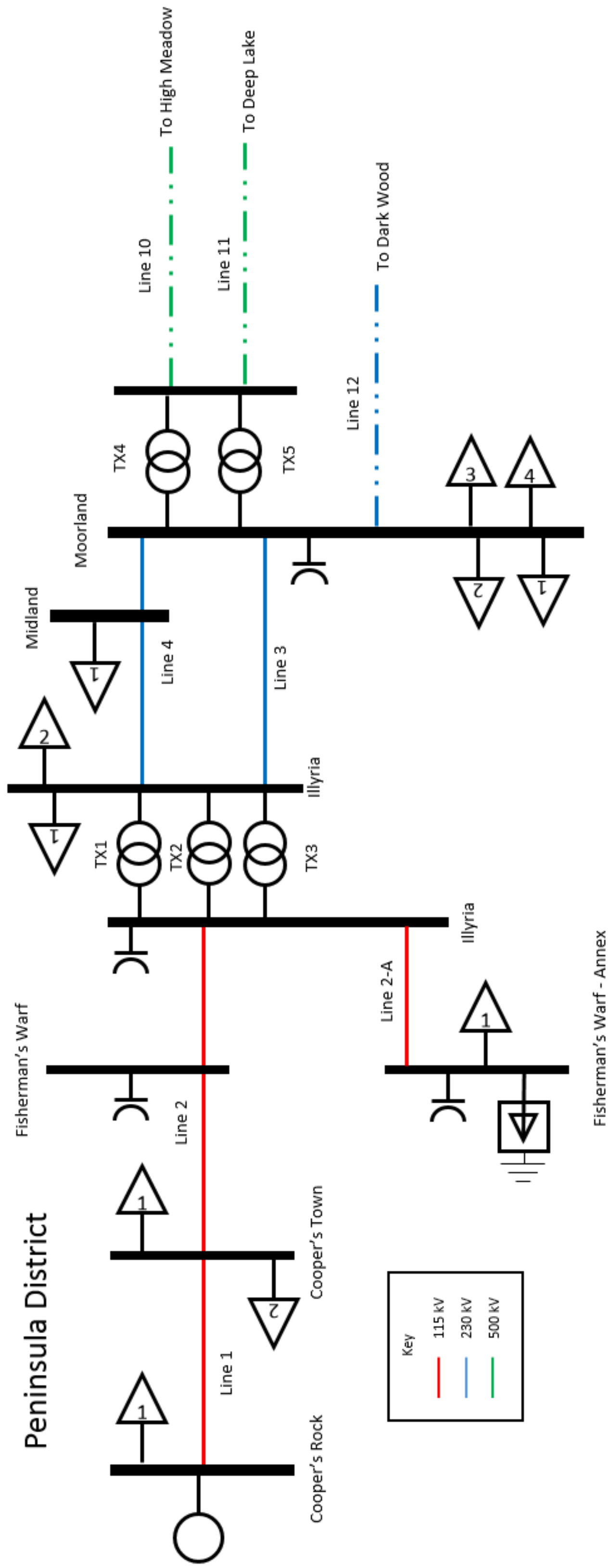
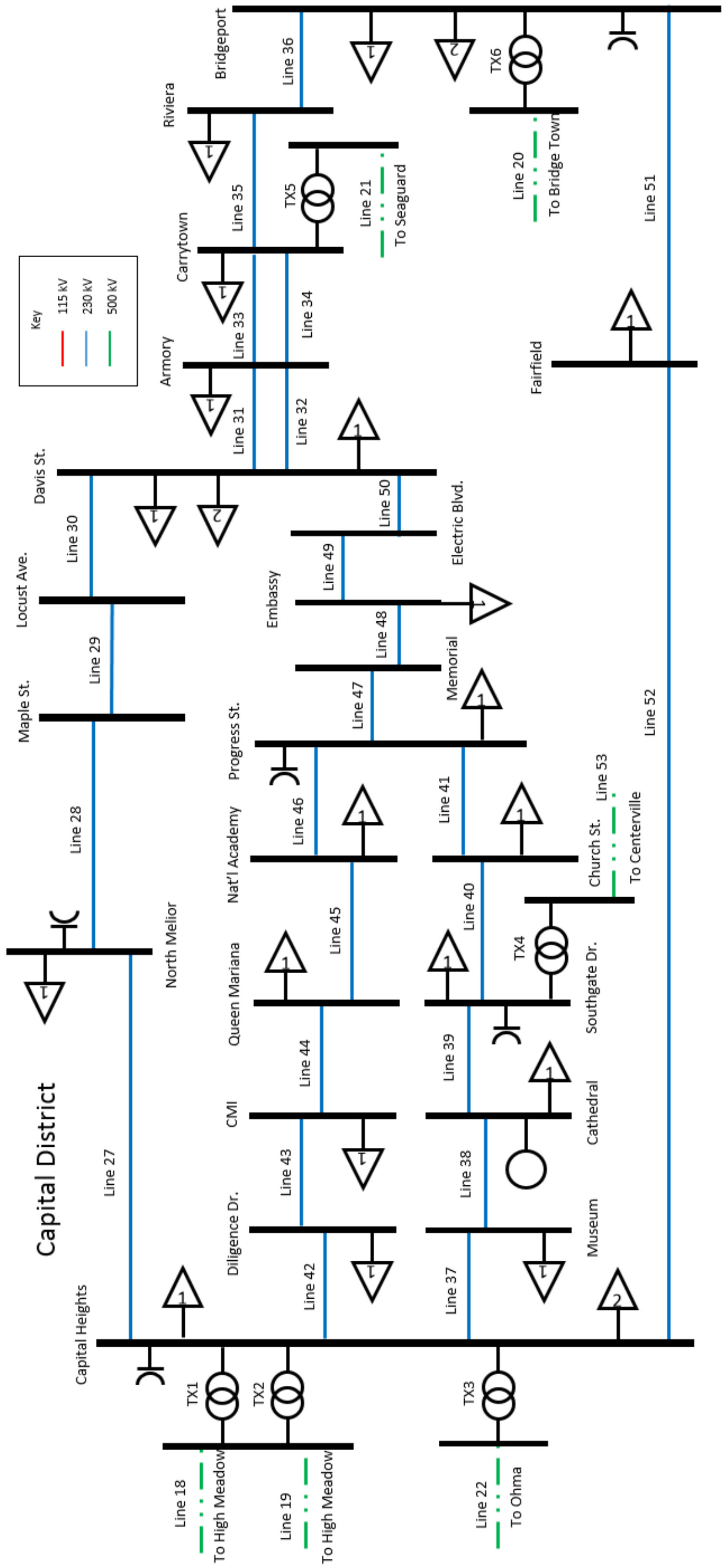
Appendix A – One-line Diagram of KTC's Transmission Network



Appendix B – One-line Diagram of Peninsula District



Appendix C – One-line Diagram of the Capital District



Appendix D – Existing and Future HVDC Project

Table 26: various VSC line projects with power and area figures[5]

Name of Site	Operating Voltage (± kVdc)	Power (MW)	Installation Year	Manufacturer	Area of Valve Hall (feet)[1]	Total Site Area (feet)[2]	Cable length (mi)[3]	Cost (MUSD)[4]
Caprivi Link	350	300	2010	ABB	280x180	1500x1500	590	180
DolWin2	320	900	2015	ABB	*	*	170	1000
East West Interconnector	200	500	2013	ABB	*	700x300	310	550
Aland	80	100	2015	ABB	*	*	100	130
BorWin1	150	400	2015	ABB	200x240	1700x1000	250	400
Skagerrak4	500	700	2014	ABB	160x110	*	244	180
NordBalt	300	700	2015	ABB	170x350	1000x900	151	580
NordLink	525	1400	2020	ABB	*	*	390	900
Eagle Pass-Pierdas Negras	15.9	36	2000	ABB	100x100	400x300	0	*
Transbay Cable	200	400	2010	Siemens	200x100	430x380	105	529
Mackinac	71	200	2014	ABB	320x140	500x520	0	90
Cross Sound Cable	150	330	2002	ABB	110x300	330x500	205	120

* indicates that information could not be obtained or deduced by the author

[1] all values are approximated from satellite imagery [6]

[2] Many of the total site figures include switchyards that may have previously existed as solely AC stations, but were expanded to include the HVDC station; all values are approximated from satellite imagery [6]

[3] Total cable length aerial, underground, underwater; includes all poles if they exist [31]

[4] Costs are as manufacturer reports the contracts' worth [31]

[5] For a more complete list of HVDC projects see [34]