THE OPERATIONAL AND MARKET BENEFITS OF HVDC TO SYSTEM OPERATORS

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NOTICE

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Executive Summary

> Do you know that in the next 10 years, I hope the people of the United States realize it--we double the need for electric power every 10 years? …and when we do that this country will be richer, and our children will enjoy a higher standard of living….We must construct an efficient interconnection between electric systems, public and private, both within regions-as you have done so effectively here in the Northwest—and between regions, as has been proposed by means of a Pacific Northwest-Pacific Southwest inter-tie.

John F. Kennedy, September 26, 1963.

President Kennedy's words calling for the creation of the high-voltage direct-current (HVDC) Pacific Intertie were just as true then as they are today. The Pacific Intertie was completed in 1970 and has been upgraded several times since. Its utility has evolved from seasonal power exchanges of hydro and thermal resources to today's transfer of wind, thermal, hydro, and solar power, with power flows sometimes changing directions several times per day.

Since that early project, HVDC technology has evolved dramatically, and HVDC technology is playing a critical role in grid modernization efforts around the world. However, the U.S. is lagging behind in deploying HVDC lines, despite the need to dramatically expand the nation's transmission capacity to efficiently move low-cost power long distances to meet increased demand and ensure reliable power supply.

This report: (1) explains and summarizes the capabilities of modern HVDC transmission technologies; (2) reviews the operational experience that has already been gained with new HVDC technologies; and (3) summarizes the planning, operational, and market benefits that these technologies now offer to regional power system operators. The information provided is meant to facilitate the unbiased consideration of modern HVDC technology where it can address transmission needs more effectively, avoiding the often implicit preferences for more "traditional" but less effective transmission solutions.

The report first provides an introduction to the available modern HVDC technologies and their capabilities, with an overview of existing and planned HVDC projects worldwide and in North America (Section II). This includes a complete inventory of the system operations, market, resilience, and other capabilities that modern HVDC transmission technology can offer.

Sections III and IV discuss how these HVDC capabilities can be included in grid codes, analyzed with transmission planning models, and reflected in transmission benefit-cost analyses. Section V provides case studies from the already available and wide-spread commercial, operational, and planning experience from of existing HVDC transmission projects and planning efforts.

System operators new to HVDC transmission are able to take advantage of this substantial body of planning, project development, and operating experience that has been gained—particularly with modern HVDC technologies over the last 5–10 years. Yet, to facilitate the adoption and full utilization of modern HVDC transmission technology, a number of misconceptions and challenges must be addressed (which we discuss in Sections VI and VII).

BENEFITS AND CAPABILITIES OF MODERN HVDC TECHNOLOGY

HVDC transmission provides substantial benefits and unique grid management capabilities. As demonstrated through the quickly-growing body of commercial experience, HVDC transmission is a proven cost-effective solution for many bulk-power transmission needs that offers important advantages compared to the conventional high-voltage and extra-high-voltage alternating current (HV-AC and EHV-AC) technologies:

- High-capacity (2-5 GW) **long-distance** overhead, underground, and submarine transmission is capable of providing transmission capabilities both between and within synchronous grids and balancing areas;
- Lower environmental and community impacts through: (a) less right of way for overhead lines; (b) **more cost-effective undergrounding** options; and (c) the ability to **expand grid capacity** and double or triple the capacity of existing alternating current (AC) overhead rights of way by converting to HVDC;
- Power **flow control and AC grid congestion management**, including through mitigation of AC contingency and stability constraints (thereby increasing the transfer capability of the existing AC grid, particularly in system with high numbers of inverter-based generating resources);
- Ability to **support weak AC grids** (e.g., through grid forming operations) and high-density **load centers** (through attractive undergrounding options and fault current mitigation);
- A wide range of other **AC grid support** functions to improve reliability, resilience, and power quality—such as (1) dynamic voltage control; (2) fault recovery; (3) AC grid oscillation dampening, grid harmonics filtering, and phase balancing; as well as (4) frequency

regulation, black start, and system restoration in coordination with neighboring power systems or connected resources.

In summary, modern HVDC technology can enhance the AC grid by allowing it to run more efficiently, better control power flows, address grid stability and flexibility challenges, and increase grid resilience.

EXPERIENCE WITH MODERN HVDC TRANSMISSION

As the numerous individual case studies presented in Section V show, most of the unique capabilities of modern HVDC transmission technology are already utilized successfully by grid operators. This is particularly true for HVDC systems based on "voltage-source converters" (VSC), which is quickly replacing the line-commutated converter (LCC) technology that account for nearly all of the existing North American HVDC projects. These legacy LLC systems, while successful in their own ways, offer few of the VSC-based grid support capabilities.

European grid operators in particular have taken advantage of advanced VSC capabilities. Internationally, VSC-based HVDC technology has become the dominant HVDC choice over the last 5–10 years, with approximately **50 GW of VSC-based HVDC transmission projects in operation today and approximately 130 GW planned or under development through the end of the decade**. North America accounts for only 3% of all VSC-based HVDC systems in operation worldwide and—almost exclusively due to efforts by merchant transmission developers—for approximately 30% of planned and proposed VSC systems.

The already available operational and planning experience with modern HVDC systems is covered in over twenty case studies (presented in Section V) that include:

- *Experience with planning and procuring HVDC transmission overlays*: such as Germany's 10 GW of new HVDC backbone transmission projects, TenneT's "Target Grid" project for which procurement contracts for €23 billion HVDC equipment have recently been signed, Scottish & Southern Electricity Network's (SSEN's) five sets of 2 GW HVDC backbone equipment orders, and Terna's proposed €11 billion "Hyper Grid" HVDC transmission overlay project.
- *Experience with HVDC Transmission Planning in North America*: The California Independent System Operator's (CAISO's) planning process considers a wide range of HVDC-related benefits. CAISO recently evaluated a dozen HVDC projects, and approved two.
- *Operational experience with specific HVDC capabilities:* such as providing frequency support, system restoration, dynamic reactive power and voltage support, overhead line fault clearing, AC line emulation, mitigation of AC grid contingencies, and AC system stabilization.

- *Experience with regional and interregional HVDC line optimization:* such as market-to-market optimization of HVDC and AC interconnectors in Europe and the CAISO's market-based nodal co-optimization of HVDC transmission with generation commitment and dispatch.

The extensive planning and operational experience with modern HVDC transmission technology gained in recent years provides a substantial resource for North American grid operators who are seeking cost-effective solutions to address projected future transmission and grid operational needs.

CHALLENGES TO THE DEPLOYMENT OF HVDC SOLUTIONS

Despite the substantial and rapidly growing planning and operational experience, deploying modern HVDC transmission technology is still challenging for a number of important reasons:

- Some grid operators do not yet have the **experience, planning tools, and grid codes** necessary to evaluate and select HVDC transmission projects even when they offer a superior solution from a technology and economic perspective—though a substantial amount of experience and resources are available to address this challenge (as discussed in Section III).
- Grid operators can be hesitant to deploy VSC HVDC systems due to familiarity and comfort with conventional transmission technologies, outdated information, and a number of **misconceptions** about the capabilities and commercial readiness of modern HVDC technology (as addressed in Section VI.A).
- Incomplete **technology standardization** and vendor compatibility efforts still require extra care in the design and selection of technologies and vendors, although some regions in North America already take advantage of the substantial progress being made in Europe (Section VI.B).
- The success and attractiveness of HVDC systems has created **supply chain challenges** that will only be resolved as increasing commitments to HVDC solutions motivate HVDC vendors to increase their manufacturing capabilities and new HVDC vendors to enter the market (Section VI.C).
- And, finally, there are a number of **regulatory, operational, and market design** challenges that need to be addressed (as discussed in Section VI.D of the report)—such as: (a) implementing proactive, multi-value planning processes that are able to capture HVDC-related values, (b) updating grid codes so system operators are able to take advantage of

the technology’s grid-supporting capabilities, and (c) upgrading market-clearing software to be able to co-optimize generation and controllable transmission facilities.

RECOMMENDATIONS

To address these challenges, we recommend that grid planning authorities collaborate with transmission owners, HVDC equipment manufacturers, the North American Electric Reliability Corporation (NERC), industry groups, regulators, states, and the U.S. Department of Energy (DOE) and its National Labs to:

1. Develop and implement “grid codes” for interconnecting and embedding HVDC transmission (as ENTSO-E has already done) that can allow grid operators to take full advantage of modern HVDC capabilities;
2. Adapt grid planning tools and multi-value transmission planning frameworks to take full account of modern HVDC capabilities;
3. Provide training for planning, engineering, and grid operations staff so they are able to take advantage of modern HVDC capabilities (rather than being focused solely on preventing problems that might be encountered);
4. Address current supply chain challenges by building manufacturing capability through clear long-term commitments (as European grid operators have done in collaboration with their governments for both onshore and offshore HVDC systems);
5. Develop standardized HVDC functional and interface requirements, and vendor compatibility standards, taking advantage of experience gained in similar European efforts;
6. Develop new regulatory and cost-recovery paradigms that can take advantage of the controllable nature of HVDC technology (both regionally and interregionally), including merchant transmissions to permit greater competition and allow for more financial risk sharing with transmission owners;
7. Update grid operations to be able to take advantage of HVDC capability (learn from CAISO, NYISO, Canadian, and European grid operators);
8. Update market designs so system operators can co-optimize controllable embedded transmission with generation (as CAISO has implanted in 2013 and as NYISO is implementing now); and
9. Implement optimization of interregional transmission capabilities that can accommodate merchant HVDC transmission.

These recommendations are ordered roughly by priority and time sensitivity, recognizing that the first six recommendations significantly affect the planning and development of HVDC systems, while the last three recommendations are focused on their operations and market integration necessary once the HVDC facilities are placed in service. As permitting authorities and users of the transmission necessary to achieve public policy goals, states will have a critical role in facilitating HVDC investments and implementing some of these recommendations, including through multi-state collaborations.

*   *   *

In sum, while challenges to the deployment of HVDC technology exist, they can be addressed. Given its attractive capabilities and increasing value as the industry transitions to higher shares of inverter-based resources and a need for broader geographic diversification, modern HVDC transmission technology must serve as a key tool in the belt of every transmission grid operator. This will require changes to system planning processes and gaining familiarity with the characteristics, planning methods, and advantages of modern HVDC systems. Given recent technological advances and rapidly growing operational experience, remaining barriers to adoption of HVDC need to be addressed proactively to unlock the more cost effective, stable, and scalable solutions offered by HVDC transmission.

I. Background and Motivation

Transforming the power system to accommodate a dynamic and evolving energy mix is a defining challenge for many transmission system operators today. Traditional transmission solutions can suffice to meet emerging needs, but these are often suboptimal when considering the full scale of system evolution as a whole. Innovative and currently underutilized technologies are capable of enabling a more reliable and more cost-effective transmission grid and overall electric power system.

As the grid is modernized with diversified generation and interconnected regions, no task is more crucial than moving bulk power from low-cost, but often remote resources in weak areas of the grid to load centers. Currently, this task can still be achieved by traditional alternating current (AC) power lines, but these conventional solutions are challenged by the stability limitations of AC systems, which were not designed or built with the anticipation of transporting mainly inverter-based resources from often weak portions of the grid.

High-voltage direct current (HVDC) systems have long been recognized to be a **lower-cost option for long-distance bulk power transfers**. In fact, a number of long HVDC lines have been built in North American over the decades and several recent studies have identified significant amounts of HVDC transmission as cost effective in both status-quo and high-renewable-generation futures.[1] Yet, there is still limited recognition that—beyond addressing high-capacity, long-distance transmission needs cost effectively and at lower environmental impacts—**modern HVDC systems also offer substantial benefits to the existing AC grid from an operational, reliability, market efficiency, and resilience perspective**.

[1] See, for example:

A .Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, IEEE Transactions of Power Systems, May 2022, and NREL, *Interconnection Seams Study*, October 2020 at https://www.nrel.gov/analysis/seams.html.

NREL, The North American Renewable Integration Study, 2021 at https://www.nrel.gov/analysis/naris.html.

Energy Systems Integration Group, *Design Study Requirements for a U.S. Macrogrid: A Path to achieving the Nation's Energy System Transformation Goals*, February 2022 at https://www.esig.energy/technical-studies-to-design-transmission-expansion-for-a-clean-electricity-future/.

These additional benefits of modern HVDC technologies that facilitate a more affordable and reliable clean energy grid have not been adequately recognized in planning processes and many grid operators are still cautious about deploying the “new” technology. However, as substantial commercial operational experience confirms, modern HVDC systems can be safely and reliably operated and controlled to provide additional grid-support benefits that make modern HVDC technologies the more optimal solution for addressing transmission needs—even beyond high-capacity, long-distance applications.

For example, the Midcontinent Independent System Operator (MISO) has recognized in its Renewable Integration Impact Assessment (RIIA), the unique advantages that HVDC transmission solutions offer for addressing the integration and system stability challenges associated with the integration of high levels of grid following renewable generation in weak grid areas remote from the ultimate load served. While traditional transmission solutions, such as synchronous condensers and Flexible AC Transmission System (FACTS) devices can help stabilize the system, MISO’s RIIA study found that the for use of these solutions (to facilitate the interconnection of significant levels of grid following renewable generation in weak areas of the grid remote from load) would cause additional challenges—concluding that VSC-based HVDC transmission lines were the only solution capable of reliably and cost-effectively addressing the magnitude of future stability challenges driven by the siting of grid following renewable resources in weak grid areas remote from the ultimate load served.[2] Yet, capitalizing on these capabilities in transmission planning and operations remains a challenge due to a perceived lack of experience and a number of misconceptions about the technology and its commercial readiness.

While European grid operators and some in North America, like the California Independent System Operator (CAISO), already have substantial planning, development, operating, and market integration experience with modern HVDC transmission, the majority of North

2 MISO, *Renewable Integration Impact Assessment (RIIA) Summary Report*, February 2021, pp. 24–25, 118 at https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

MISO also noted in comments on a draft of this report that there may be other solutions, not studied in RIIA, that could represent cost-effective alternatives to VSC HVDC in some cases, such as the expanded use of grid forming inverters to facilitate interconnection of renewable resources in weak grid areas coupled with higher capacity EHV AC transmission such as 765 kV, or the use of high capacity EHV AC transmission such as 765 kV in stronger areas of the grid where reinforcement is still required to facilitate the integration of renewable generation. We agree that the full set of available solutions should be considered for addressing identified transmission needs—but stress that the selection of solutions should avoid an implicit preference for “traditional” options even when they are less effective (due to a lack of experience with or misconceptions about HVDC technology).

America's transmission operators still lack that experience and are still in the process of building the necessary expertise. For example, Southwest Power Pool (SPP) expects that HVDC transmission will play an increasingly important role in SPP's planning processes due to the system operator's expansion into the Western Interconnection—which is currently linked to the eastern SPP footprint only through a number of aging back-to-back direct current (DC) converters. To be able to address this need, SPP has engaged the Electric Power Research Institute (EPRI) to review the performance, study, and modelling criteria used by system operators worldwide and to make recommendations on HVDC grid codes and modelling criteria that SPP should adopt for HVDC systems.[3]

Fortunately, this also means that North American system operators who are only starting to consider HVDC solutions for their transmission needs can take advantage of the substantial HVDC-related planning and operational experience already gained by system operators in Europe and elsewhere to quickly address information gaps.

This report aims to support these efforts to gain HVDC knowledge and experience quickly, addressing existing information gaps by:

- providing a detailed technical primer of HVDC technology and documenting the capabilities that modern HVDC systems offer (Section II)
- providing guidance on transmission planning tools and benefit-cost analyses for HVDC transmission (Sections III and IV);
- documenting through case studies the planning, operational, and market experience that several grid operators have gained in recent years (Section V);
- discussing remaining misconceptions and current challenges associated with HVDC technologies (Section VI); and
- offering a number of recommendations on how to address the identified current challenges (Section VII).

[3] EPRI, *HVDC Recommendations for Southwest Power Pool: Review of performance standards, studies, and modelling of HVDC Grid Codes*, Interim Report, Technical Update, May 2023, posted with the SPP Transmission Working Group meeting materials for June 6, 2023 ("EPRI Report") at https://www.spp.org/spp-documents-filings/?id=18447.

II. HVDC Transmission Technology, Experience, Capabilities, and Use Cases

This section of the report offers a detailed technical primer that first describes the components of HVDC transmission technology and the capabilities that the different elements of an HVDC transmission system provides. These elements are the HVDC transmission lines themselves, the HVDC converters on either end, and their control modes that determine their interactions with the rest of the AC grid. As we show, each of these three elements contributes unique capabilities that combine to provide the substantial advantages that actively controllable HVDC systems can offer over passive AC transmission networks.

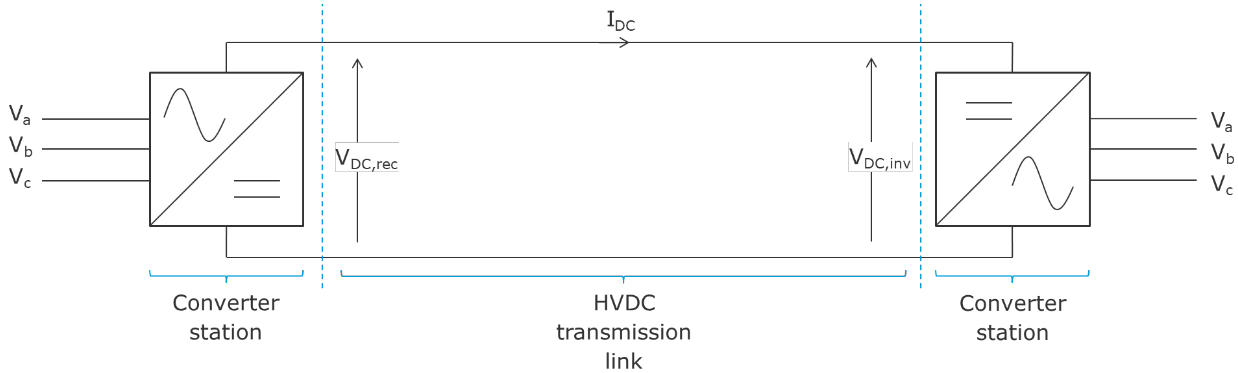
This description of HVDC technology is followed by a summary of HVDC projects and technology types that are operational today and additional HVDC projects currently planned and under development. The section concludes with a more detailed discussion of HVDC capabilities, attractive HVDC use cases, and AC grid services that are being or can be provided by HVDC systems.

A. HVDC Technology Description

Direct current (DC) is a transmission technology that has been used in some way or form since the 1880s. In contrast to alternating current (AC) technology, in which the polarity of the line voltage and resulting current changes continuously, the polarity of DC stays constant. This enables a high-voltage DC transmission system to efficiently and reliably transmit substantial amounts of electrical energy over long distances, including between different synchronous electricity grids, e.g., interconnectors.

As illustrated in Figure 1, such an HVDC system connects (two or more) different points on the AC grid with AC ↔ DC converter stations, which are then linked through HVDC transmission lines that can be a combination of overhead lines, underground cables, or submarine cables.

FIGURE 1. ILLUSTRATION OF A POINT-TO-POINT HVDC TRANSMISSION SYSTEM



HVDC transmission technology has several characteristics and capabilities that make it uniquely advantageous for long distance, high-capacity power transmission. These characteristics, capabilities, and associated advantages of HVDC come from three sources, each of which are discussed in more detail below:

1. The characteristics of HVDC transmission links;
2. The capabilities of the converter technologies; and
3. Different HVDC control modes that can connect different types of AC grids.

1. Characteristics of HVDC Transmission Link

The lack of alternating voltage and current offers several distinct advantages that increase the capability of physical transmission links compared to AC transmission technology. Compared to AC transmission links, HVDC transmission links can transmit more power over longer distances with less materials due to the following six characteristics (the first five, which are advantages and the last one, which is a disadvantage):

- **No "skin" or proximity effect**: In an AC system, a physical effect resulting from the changing magnetic fields induced by the changing line currents causes the current to be pushed to the outer layer (skin) of electrical conductors, effectively reducing the available conductor cross-section, and consequentially increasing the conductor's resistance and decreasing its capability to carry high currents. The skin effect does not exist in DC systems. Regardless of whether it is overhead line or submarine/underground cable based, DC systems thus <u>optimize the use of conductor material</u> and <u>increase the transfer capability of any given conductor design</u> or, alternatively, offer the same transfer capability as AC lines with smaller and lighter conductors.

- **Fewer conductors**: AC systems typically require one conductor for each of three phases. In DC systems, only two conductors are needed, one with positive polarity and one with negative polarity and, in some cases, a third return conductor. The return conductor does not require high voltage insulation. The reduced number of conductors, combined with the previously discussed more optimal use of conductor material, means that the cost per mile of DC transmission lines is lower than that of AC lines. For overhead lines, the use of fewer and lighter conductors is also associated with cost savings from narrower rights of way, smaller transmission towers, and fewer insulators that do not need to carry as much weight.
- **No reactance**: Transmission lines exhibit a physical property called reactance (a form of "magnetic resistance" to the transmission of electricity), which reduces the capacity of AC lines as transmission distances increase. Reactance is proportional to the power frequency (i.e., the number of times per second the grid voltage and current changes polarity, i.e., 'alternates' in HVAC systems, typically 60 Hz in the U.S.), so it is reduced to zero in DC transmission lines (in which the voltage and current do not periodically change polarity). The reactance-related limits to the capacity and distance of power transfer in AC systems (including through factors such as reactive power production, voltage- or phase-angle instability) are, thus, absent in DC systems. While AC transmission is associated with voltage drops due to both reactance and resistance, only the (much smaller) resistive voltage drop occurs in DC circuits. As a result, there is practically no technical limit to the distance over which DC systems can transmit power.[4] However, in AC transmission, the reactance slows down the system transient dynamics and reduces fault current levels as well. In contrast, the lack of reactance in DC systems can lead to faster dynamics and higher fault currents, which can create system control and protection challenges where two or more DC transmission links are interconnected into a networked DC grid.
- **No capacitive charging**: In AC transmission systems, the capacitances between lines and the ground produce reactive power, which reduces the effectiveness of the grid. This is particularly pronounced in insulated AC underground or submarine cables, in which the

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[4] For example, three 1,300 to 1,500 mile HVDC lines with a capacity of 2×4 GW and 7.1 GW are currently used to in Brazil transmit remote hydro generation to load centers. Power Technology, *The World's Longest Power Transmission Lines*, January 2020 at https://www.power-technology.com/features/featurethe-worlds-longest-power-transmission-lines-4167964.

A 2018 European Commission study showed that a 2,000 mile, 4 GW HVDC submarine cable between Europe and North America would be feasible—and cost effective due to the two regions' diversity in generation resources and loads. A.Purvins, L. Sereno, M. Ardelean, C.F. Covrig, T. Efthimiadis, and P. Minnebo, "Submarine power cable between Europe and North America: A techno-economic analysis," *Journal of Cleaner Production* 186, June 10, 2018, pp.131–145 at https://www.sciencedirect.com/science/article/pii/S0959652618307522.

cables' high reactive power production effectively limits the economically-feasible transmission distance to approximately 100 miles or less. In DC systems, the cable capacitance is not a concern during steady-state operations, which means the technically feasible transmission distance of DC cables is practically unlimited (unlike for AC cables).[5] However, an advantage of AC systems is that "capacitive field grading" can be used to control the strong electrical fields inside certain solid insulator-based components, such as cable terminations. In DC systems, more complex and temperature-sensitive resistive grading techniques must be used.

- **No induced currents**: Due to the constant nature of DC currents, there are no magnetically induced currents in neighboring metallic parts (however, depending on the converter technology used, some high-frequency "harmonics" may be present on the DC current). This means that no currents are induced in a cable's armoring or equipment tanks, and that any associated cable armoring or tank losses are avoided, which typically increases the components' power transfer limit. It also means that in case a DC link is installed next to railroads, or pipelines, fewer issues due to induced currents arise. However, these attributes also create challenges. In this regard, the main advantage of AC systems is that transformers, which rely on induced currents, can be used to easily change voltage levels and measure voltages and currents in a cost-effective way. Such voltage conversion in DC systems typically relies on back-to-back AC-to-DC converters with an AC transformer stage, which are often inefficient and costly. Moreover, measurement transformers, which are widely used in AC systems, cannot be used in DC systems, which means different technical solutions (such as fiber optical current measurements and resistive capacitive divider based voltage measurements) have to be applied.
- **No current zeros**: In AC systems, the presence of frequently occurring zero-current moments (i.e., each time the polarity alternates, twice every 50 or 60 times-per-second, a moment occurs with zero current) forms the basis for mechanical switches that can quickly interrupt (switch off) the transmission of power, including during short-circuit faults that draw very large currents which must be interrupted to maintain reliability. This is a distinct

[5] The longest HVDC cable in operations is the 450 mile 1.4 GW Northsea Link between Norway and the U.K. N. Skopljak, "North Sea Link begins regular operations," *Offshore Energy*, October 24, 2022 at https://www.offshore-energy.biz/north-sea-link-begins-regular-operations/.

A number of even longer HVDC cable projects are currently being planned. They include the twin 1.8 GW, 2,600 mile cable to deliver wind and solar power from Morocco to the U.K., for which manufacturing has already been arranged. M. Lewis, "The world's longest subsea cable will send clean energy from Morocco to the UK [update]," *Electrek*, April 21, 2022 at https://electrek.co/2022/04/21/the-worlds-longest-subsea-cable-will-send-clean-energy-from-morocco-to-the-uk/.

disadvantage of DC system because, to interrupt short-circuit currents in a DC system, separate equipment is required to create a local, artificial zero-current moment to enable mechanical switchgear to interrupt and isolate a faulty DC circuit. This "HVDC circuit-breaker" option to isolate network faults (discussed in section VI.A.11 is now also starting to become available for networked HVDC configurations but has not been implemented yet.[6]

These characteristics of HVDC transmission links lead to three distinct transmission planning advantages compared to AC transmission links, as summarized in the Table 1 below.

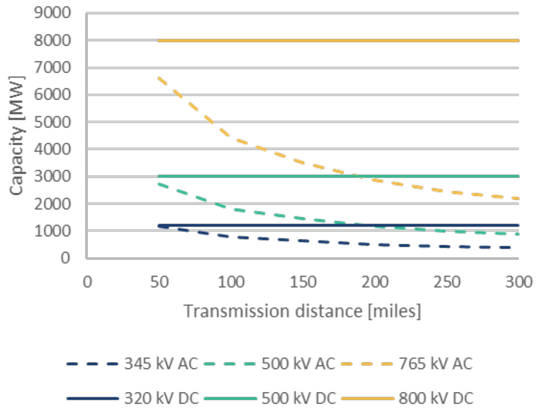
TABLE 1. ADVANTAGES OF HVDC TRANSMISSION LINKS COMPARED TO HVAC TRANSMISSION LINKS

Compared to AC, HVDC transmission links…	Optimize use of available right of way	Reduce total cost per mile of transmission distance	Increase technically feasible transmission distance
Reduce number of conductors	☑	☑	
Optimize use of conductors	☑	☑	
Minimize line/cable losses	☑	☑	☑
Have no voltage instability limit	☑	☑	☑
Have no angle instability limit	☑	☑	☑
Have no reactive losses	☑	☑	☑

The capability of HVAC and HVDC transmission links to transmit power over much longer distances is illustrated in Figure 2 (for overhead transmission lines) and in Figure 3 (for submarine transmission cables) below.

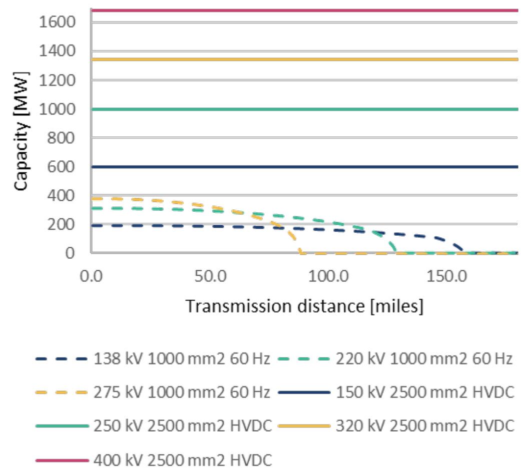
[6] Note that HVDC circuit breakers have been installed in several multi-terminal HVDC networks in China, but no information regarding their operational performance is publicly available. As an alternative to HVDC circuit breakers, HVDC short circuit currents can also be controlled by using full-bridge converter technology, as discussed in section V.16

FIGURE 2. HVDC (SOLID) AND HVAC (DASHED) TRANSMISSION CAPACITY AND DISTANCE OF OVERHEAD LINES



Source/note: DNV (adapted from discussion of AEP's Experience with 765 kV Technology, MISO PAC meeting, May 31, 2023).

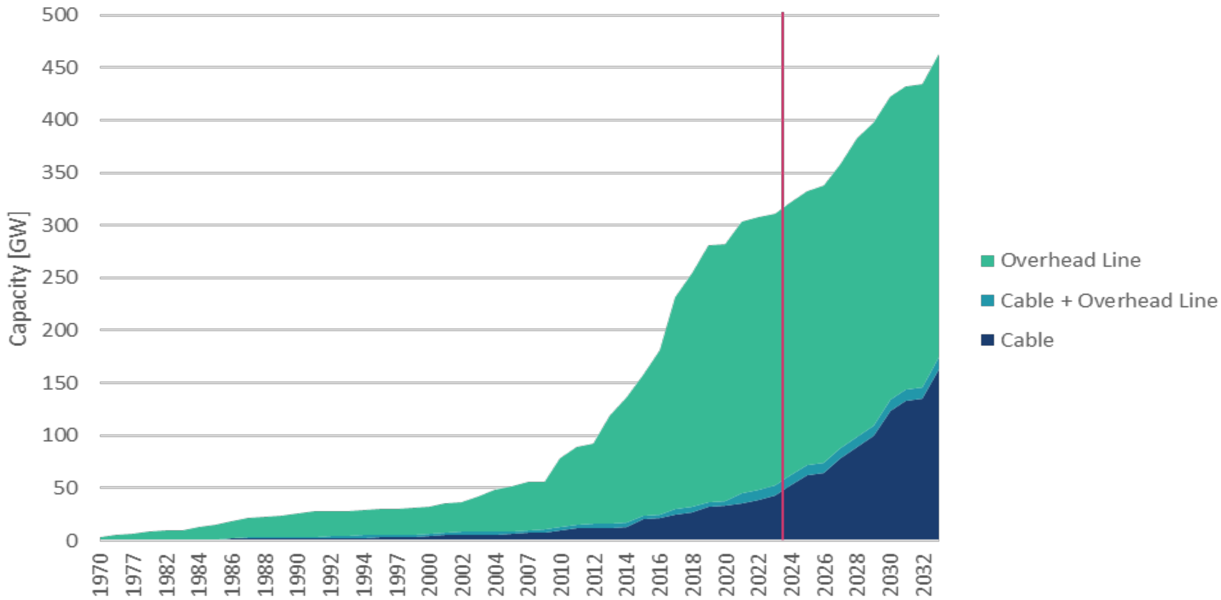
FIGURE 3. HVDC (SOLID) AND HVAC (DASHED) TRANSMISSION CAPACITY AND DISTANCE OF SUBMARINE CABLES



Source: DNV

Due to the HVDC transmission-related benefits mentioned above, substantial experience has already been gained with the technology over the years. As of today, over 300 GW of HVDC transmission capacity has been installed worldwide, as shown in Figure 4 below, with another 150 GW planned to be installed over the next decade. The majority of the HVDC systems in operation today are overhead line based, but the installed capacity of insulated cable-based systems is rapidly growing.

FIGURE 4. CUMULATIVE GLOBAL CAPACITY OF HVDC SYSTEMS BY LINK TYPE



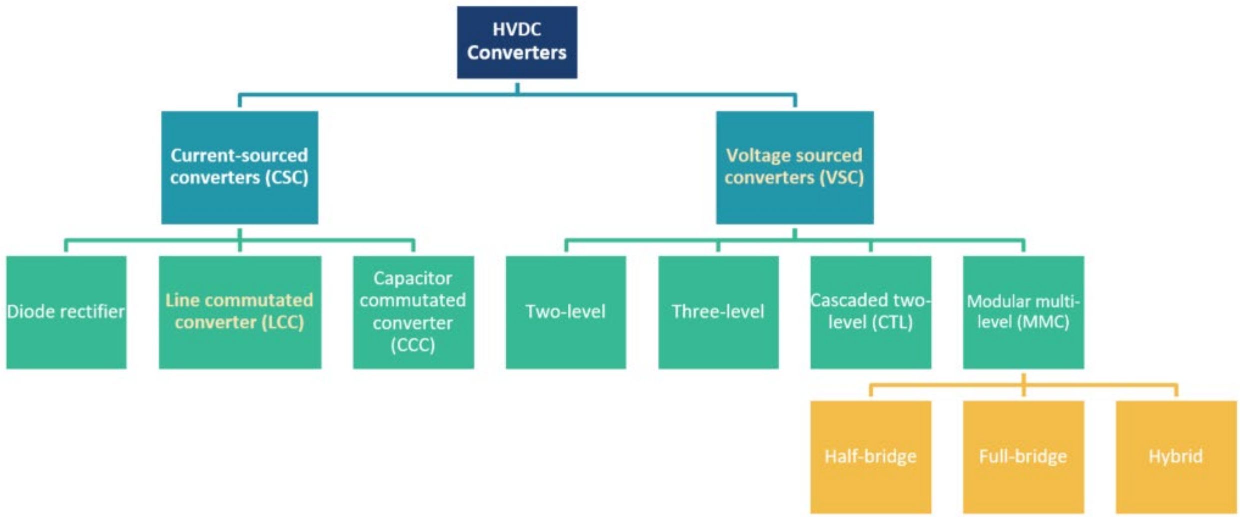
Source: DNV

2. Types and Capabilities of HVDC Converter Technologies

The transmission planning advantages of HVDC transmission links are further enhanced by the capabilities of HVDC converters. Connecting HVDC transmission links to the AC grid requires converter stations on each end that can convert the transmitted electricity from AC to DC and back again. Over the course of the last century, multiple different converter technologies have come and gone. Early technologies, such as “Thury machines” and “mercury arc rectifiers” have been replaced by power-electronics based technologies.[7] The different power electronics based converter technology types are summarized in Figure 5 below, and can largely be classified by the different types of semi-conductors which they use: current source converters using thyristors or diodes, and voltage sourced converters using transistors.

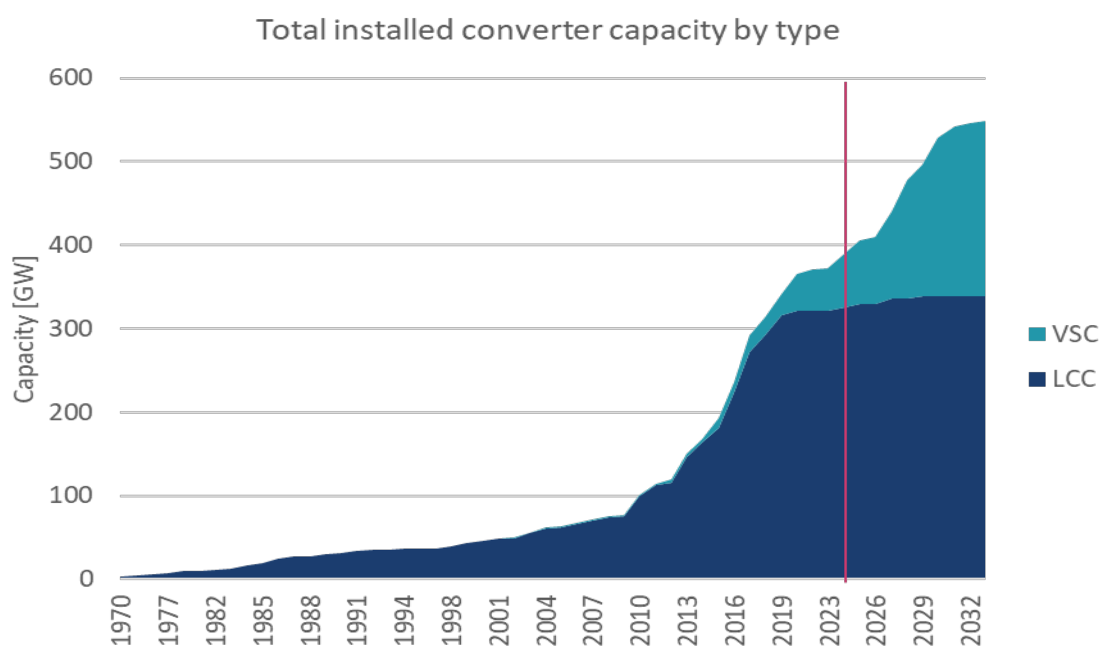
[7] Deepak Tiku, "dc Power Transmission: Mercury-Arc to Thyristor HVdc Valves [History]," *IEEE Power and Energy Magazine* Vol. 12, no. 2, March–April 2014, pp. 76–96, doi: 10.1109/MPE.2013.2293398 at https://ieeexplore.ieee.org/document/6742648.

FIGURE 5. CONVERTER TECHNOLOGY TYPES



Of these, two different types of converter technologies are used today: "Line Commutated Converters" (LCC) and "Voltage Sourced Converters" (VSC) as shown in Figure 6. For reasons that will be further discussed in later sections of this report, the use of LCC technology is being replaced by the more versatile and capable VSC technology.

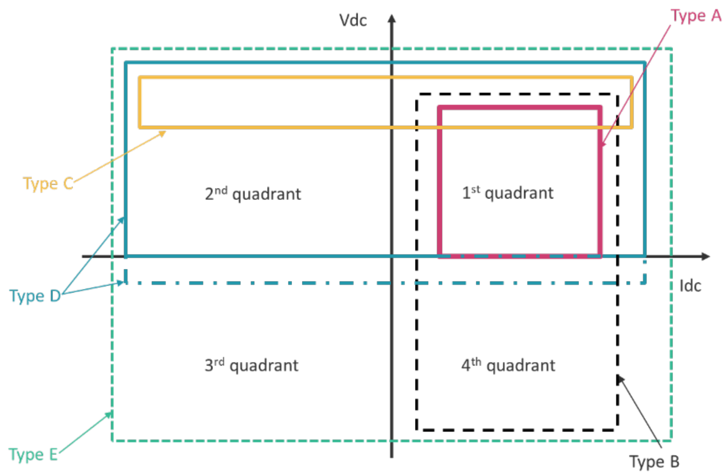
FIGURE 6. GLOBAL INSTALLED AND PLANNED HVDC TRANSMISSION CAPACITY BY CONVERTER TYPE



Source: DNV

Different converter technologies and designs are able to handle different magnitudes and polarities of DC voltage and current, as illustrated in Figure 7. As the chart shows, full-bridge modular multi-level converter types of VSCs (MMC-VSC) converters are significantly more flexible than any of the others.

FIGURE 7. COMPARISON OF DC VOLTAGE AND CURRENT CAPABILITIES OF CONVERTER TYPES[8]



- Type A: Diode rectifier
- Type B: Thyristor based LCC
- Type C: Half-bridge MMC-VSC
- Type D: Converter operating in Q1/Q2 and transiently in Q3/Q4, e.g., Hybrid HB-FB VSC
- Type E: Full-bridge MMC-VSC

Regardless of the converter technology used, all DC links allow for asynchronous transmission of power between different synchronous regions, or even linking 50 Hz and 60 Hz grids as seen in Japan—a significant transmission planning benefit. With back-to-back AC-to-DC-to-AC conversion, this can be accomplished without transmission lines. This application is available regardless of HVDC technology choices, such as VSC and LCC converters.

All converter technologies are characterized by the fact that they offer control over the power flow through the line. This enables grid planners to make very targeted grid reinforcements, as opposed to realizing the same power flows in AC grids which can take multiple paths, cause issues with loop flows and consequently require multiple system upgrades.

a. Line Commutated Converters

The largest installed base of converter capacity is based on the Line Commutated Converter (LCC) technology. LCC converters are a type of current source converters, which are designed around an electronic switch called a "thyristor." Thyristor-based LCC technology has been in operation since 1972[9] and is considered mature, robust, cost-effective, and has been installed

8 CENELEC—TS 50654-1—*HVDC Grid Systems and connected Converter Stations—Guideline and Parameter Lists for Functional Specifications*—Guidelines, March 1, 2018.

9 First project was Eel River project in Canada, made by GEC in the United States. Deepak Tiku, "History: DC Power Transmission Mercury-Arc to Thyristor HVDC Valves," *IEEE Power and Energy Magazine*, Vol. 12, no. 2, March–April 2014 at https://magazine.ieee-pes.org/marchapril-2014/history-12/.

in numerous applications across the globe. Thyristors are electronic power switches that can be switched on with an external control signal, but cannot be switched off the same way. Instead, they switch off (drop out of conduction) when the voltage polarity across its terminals reverses. This happens automatically 2×60 times per second if the converter is connected to a 60 Hz AC grid. For LCC technology to work, each converter terminal has to be connected to a strong AC grid. The lack of control over when each switch can turn-off also means that LCC converters produce a significant amount of harmonic distortion and reactive power.[10] To ensure grid code compliance, large numbers of harmonic filters and reactive power compensation devices are therefore required, which increases the footprint and cost of LCC converters.

Due to the characteristics of the thyristors and how they are controlled, LCC converters require a minimum operating power level of about 5–10% below which they cannot operate. Since thyristors are unidirectional devices and can only conduct current in one direction, power reversal in LCC systems is done by reversing the DC voltage polarity (e.g., from positive 500 kV to negative 500 kV). As the voltage polarity change is performed, power flow through the line is temporarily halted. The requirements for voltage polarity reversal makes the combination of LCC with modern extruded polymer insulated cables challenging due to space charge accumulation in the polymer insulation, limiting the application of LCC converters to overhead lines and cables with mass impregnated paper insulation. However, the polarity reversal is typically associated with electrical stress on the mass impregnated paper cable insulation, limiting the permitted number of polarity reversals over the HVDC systems lifetime. It also makes it a complex undertaking to connect multiple LCC-based HVDC transmission lines into a multi-terminal HVDC grid if bidirectional flow capability is required in multiple branches.

LCC converters are capable of blocking DC short-circuit currents caused by faults on DC lines, and minimizing the impact on the connected AC grids. This ability also enables LCC converters to quickly restore the power flow in case of temporary HVDC line faults. Depending on the pre- and post-fault power transfer, the inherent overload capability of thyristors also allows LCC bipoles to transfer all or a part of the power from the faulty to the healthy pole. Conversely, the need for an AC grid voltage to commutate the current between different valve arms means that LCC converters only have limited low AC voltage ride through capability. This issue can lead to

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10 M. P. Bahrman and B. K. Johnson, "The ABCs of HVDC transmission technologies," *IEEE Power and Energy Magazine*, vol. 5, no. 2, March–April 2007, pp. 32–44, doi: 10.1109/MPAE.2007.329194.

trips, and becomes increasingly pronounced as more LCC converters are connected in close vicinity, and lead to system instability.[11]

However, LCC converters have limited capability of reactive power control in terms of both control range and dynamic performance. LCC converters control reactive power through a combination of controlling the firing angle and switching in fixed compensation devices but the range of controllability for reactive power in LCC HVDC systems is limited by the inherent characteristics of the thyristor-based converter technology. As a result, LCC converters may not be able to quickly control reactive power within a large enough range in response to system operations, which may cause voltage stability concerns to the AC grid.

Today, LCC based HVDC systems with ratings up to 1,100 kV and 12 GW are in operation, as well as several multi-terminal systems.[12] Other types of current source converters have been considered for specific applications with limited success. For example, the Capacitor Commutated Converter was introduced in the 1990s and has found limited application in areas with low grid strength.[13] The use of Diode Rectifiers was proposed for the connection of offshore wind farms but never found application.[14]

b. Voltage Sourced Converters

Voltage sourced converters (VSC) are rapidly growing in popularity since their introduction in the 1990s.[15] VSC-based converters mostly use insulated-gate bipolar transistors (IGBTs), which are suitable for high-voltage, high-current applications. Unlike the thyristors of LCC-based converters, IGBTs can be both switched on and switched off with an external control signal,

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[11] H. Rao, Y. Zhou, S. Xu, Z. Zhu, *Research and development of Ultra-High-Voltage VSC for the multi-terminal hybrid ±800kV HVDC project in China Southern Power Grid*, DC Systems and Power Electronics 2018 Session Papers and Proceedings, B4-120_2018, 2018.

[12] "World's first 1100 kV DC line will be constructed in China," *Modern Power Systems*, August 29, 2016 at https://www.modernpowersystems.com/features/featureworlds-first-1100-kv-dc-line-will-be-constructed-in-china-4991040/.

[13] G. Persson, V. F. Lescale, and A. Persson (ABB AB, HVDC), "HVDC Capacitor Commutated Converters in Weak Networks," ABB AB, HVDC, n.d. at https://library.e.abb.com/public/ad88f26d817df269c12577f8006a6f72/GCC%20Cigre_CCC%20in%20weak%20networks_final.pdf.

[14] "Siemens Presents New DC Grid Connection for Offshore Wind Farms, "*T&D World*, October 23, 2015 at https://www.tdworld.com/overhead-transmission/article/20965834/siemens-presents-new-dc-grid-connection-for-offshore-wind-farms.

[15] G. Wolf, "A Short History: The Voltage Source Converter," *T&D World*, September 26, 2017 at https://www.tdworld.com/digital-innovations/hvdc/article/20970224/a-short-history-the-voltage-source-converter.

enabling VSC-type converters to offer superior performance and control capabilities. In reference to this capability, VSC converters are also sometimes referred to as Forced Commutated Converters (FCC). Other types of semi-conductors with turn-off capability such as Injection Enhanced Gate Transistors (IEGTs)[16] [17] and more recently the Bi-Mode Insulated Gate Transistor (BIGT)[18] [19] have since been introduced by different vendors to realize VSC-type converters with improved performance and higher ratings.

VSC converters can control the magnitude, phase angle, and frequency of their AC output voltage. The majority of VSC converters are grid-connected and are operated in 'grid-following' mode in which the control system synchronizes with the AC grid using a Phase Locked Loop (PLL) to independently and nearly instantaneously control the converters' real and reactive power output at any operating point within their physical limits. However, due to their forced commutation capability, VSC converters do not need to be connected to an AC grid and can also be operated in "islanded" or "grid forming" fashion. This ability enables black-start capability and voltage-frequency control. The independence of AC line voltage means that VSC converters have an excellent low AC voltage ride-through capability with controllable current injection during AC grid faults. Rapid full reversal of power flow can be achieved (in as little as 200 milliseconds for cable based systems) and ramp rates can be tailored to enable fast-acting grid support and smooth market operation, particularly with the growth of variable generation.[20] The excellent control capabilities of VSC converters also enables the creation of multi-terminal, interconnected HVDC transmission grids.

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[16] Toshiba, "PPI Switching Devices for HVDC Systems," *Technical Review*, Vol. 3, 2018 at https://toshiba.semicon-storage.com/content/dam/toshiba-ss-v3/master/en/company/technical-review/pdf/technical-review-3_e.pdf.

[17] Y.Sato, "Novel IEGT based Modular Multilevel Converter for New Hokkaido-Honshu HVDC Power Transmission", ISPSD, September 13 – 18, 2020, Vienna, Austria

[18] M. Callavik, et al., "Energy Transition: Evolution of HVDC Light," *ABB Review*, pp. 60–67, January 2018 at https://search.abb.com/library/Download.aspx?DocumentID=9AKK107046A1095&LanguageCode=en&DocumentPartId=&Action=Launch.

[19] Hitachi, "Dogger Bank A, B and C projects - Hitachi Energy accelerates green energy transition", 2023

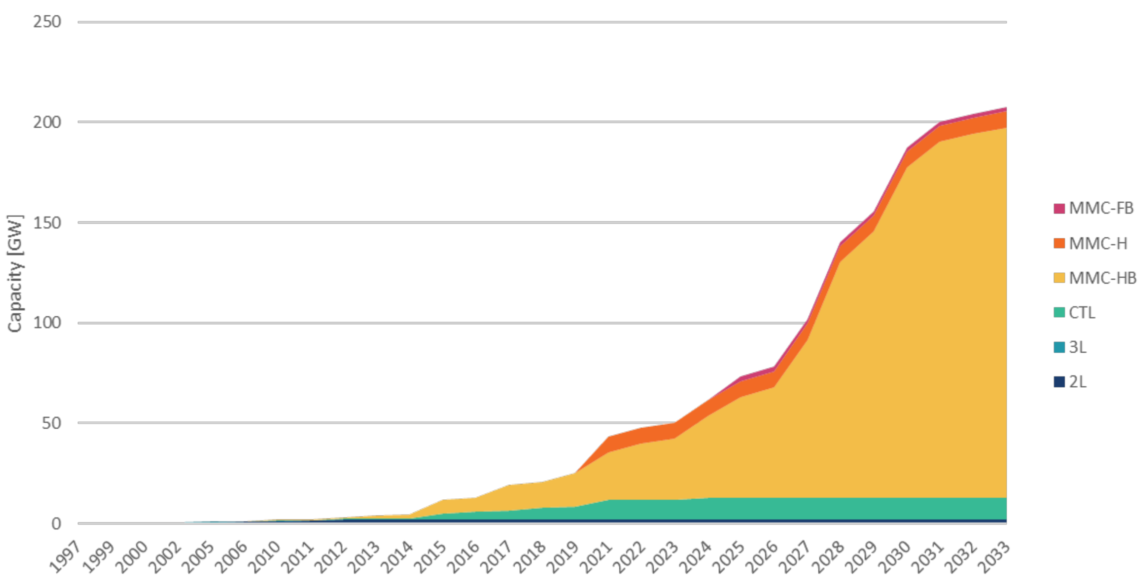
[20] Siemens Ingenuity for Life, *HVDC PLUS—the decisive step ahead: Stabilized power flows improve transmission grid performance*, Siemens AG, 2016 at https://assets.siemens-energy.com/siemens/assets/api/uuid:83dc80ed-cbd6-4027-9e48-83a87eab8e0b/263_160390_ws_hvdcplususlowres.pdf; and

ENTSO-e, *HVDC Links in System Operations*, Technical paper, December 2, 2019 at https://www.entsoe.eu/Documents/SOC%20documents/20191203_HVDC%20links%20in%20system%20operations.pdf.

Voltage sourced converters can be realized using different converter topologies, which have been used in HVDC transmission projects with varying degrees of success. Early VSC based systems used two-level (2L) or three-level (3L) converters borrowed from the medium voltage drives industry in which many series-connected transistors were switched using pulse width modulation (PWM) to achieve AC waveforms. These topologies initially suffered from high-losses and high harmonic distortion.

To achieve higher voltage and power ratings and improve performance, new topologies such as the cascaded two-level (CTL) and modular multi-level converters (MMC) were introduced by different vendors[21]. Today, as can be seen from Figure 8 below, the MMC topology is rapidly gaining in popularity, becoming the dominant VSC converter type due to its superior performance characteristics.

FIGURE 8. CUMULATIVE GLOBAL VSC-BASED HVDC TRANSMISSION CAPACITY BY CONVERTER TYPE



Source: DNV

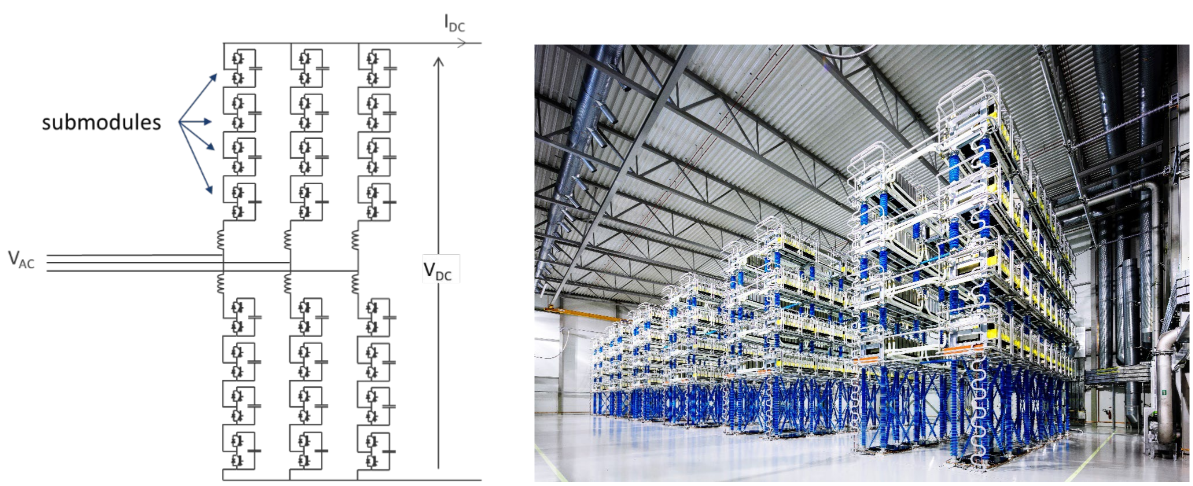
State-of-the-art MMC-based VSC converters are realized through connecting many submodules in series, as shown in Figure 9 below. They sequentially switch charged submodule capacitors in and out to create a smooth AC voltage waveforms with negligible harmonic distortion. As a result, VSC-MMC converters require no additional filtering and compensation equipment, which means they can be built on smaller footprints compared to non-MMC VSC topologies.

[21] K. Sharifabadi, L. Harnefors, H.-P. Nee, S. Norrga, and R. Teodorescu, *Design, Control, and Application of Modular Multilevel Converters for HVDC Transmission Systems,* Wiley-IEEE Press, 2016 at https://ieeexplore.ieee.org/servlet/opac?bknumber=7601527.

The VSC-MMC architecture also features low transistor switching frequency, which results in low conversion losses (~0.7% per converter).

The current and voltage ratings of each submodule are determined by the ratings of commercially available transistors. Today, the maximum available current ratings for a single IBGT (about the size of a book) are 3,000 Ampere at 5.2 kV, able to switch 15.6 MW. Other widely-used voltage ratings are 3.3 kV, 4.5 kV and 6.5 kV. Current ratings can be increased by paralleling IGBTs within the same submodule. To achieve the desired converter voltage rating, hundreds of submodules are connected in series. Due to the modular nature of VSC-MMC converters, the voltage rating of the converter equipment can be readily increased through the addition of more submodules, and is ultimately limited only by the maximum available insulation material strength. Today, VSC based HVDC systems with ratings up to 800 kV and 5 GW are in operation[22], as well as several multi-terminal systems.

FIGURE 9. TOPOLOGY OF (HALF-BRIDGE) MODULAR MULTI-LEVEL CONVERTER

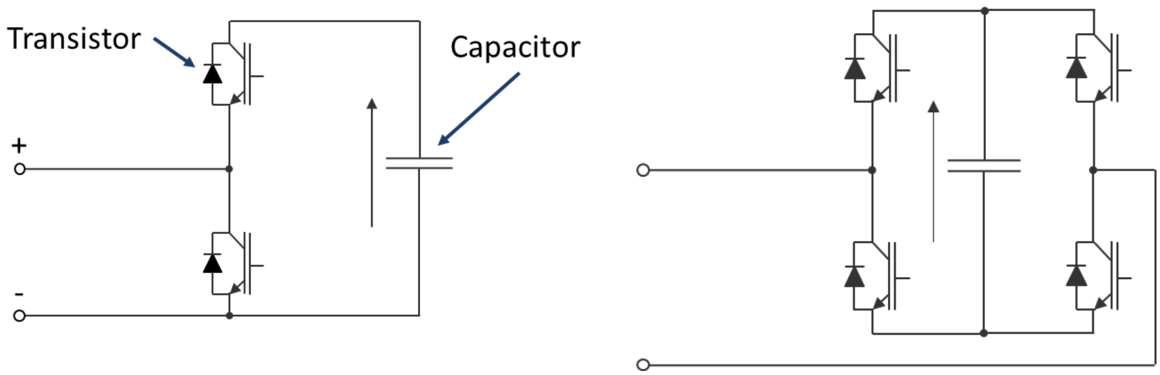


Courtesy of GE

Each module is equipped with a high-speed bypass switch that is closed if there is a malfunction. An additional < 5% of submodules are typically installed in series to enable redundancy. These take over operation from bypassed faulty submodules in real-time, ensuring high availability of the overall converter system. Faulty submodules are then replaced during regular (typically annually or bi-annually) planned maintenance intervals.

[22] Outside China, only systems with 525 kV are in operation (and 600 kV under planning) today.

FIGURE 10. DIFFERENT TYPES OF SUBMODULES



Half-bridge submodule Full-bridge submodule

VSC-MMC converters can be designed using "half-bridge" or "full-bridge" modules or a "hybrid" of them. The two types of submodule designs are shown in Figure 10 above and are mostly distinguished by the extra pair of transistors for the full-bridge design.

- A half-bridge submodule can connect the capacitors in series with the converter arm in one direction, or by-pass it. This means it can only produce a positive voltage at its submodule terminals. In addition, due to the intrinsically present anti-parallel body diode in IGBTs, a half-bridge submodule cannot stop current flow from its negative to its positive terminal. This means that a converter using only half-bridge modules cannot operate if the DC system voltage is lower than the AC system voltage, and thus also cannot block DC fault currents. Most MMC-HVDC converters in operation today are based on half-bridge submodules.
- A full-bridge submodule can use the additional pair of transistors to connect the capacitors in series with the converter arm in both directions, by-pass it, or block it. This means it can produce both positive and negative voltages at its submodule terminals and stop current flow from its negative to its positive terminal. This means that a converter using only full-bridge modules can operate at any DC voltage and is capable of controlling DC fault currents, and if necessary very rapidly suppressing them, without de-energizing the converters and without the need for DC circuit breakers.[23] This capability makes full-bridge converters suitable for connecting to overhead line-based systems in which temporary faults are more prevalent compared to underground or submarine cable-based transmission systems. This additional functionality comes at the cost of having double the amount of transistors which increases the converters' capital expense and conversion losses. Volume

[23] 'Siemens presents new technology for reliable power highways,' Press Release, Siemens AG, December 8, 2015 at https://assets.new.siemens.com/siemens/assets/api/uuid:9d1f5be1-c468-434c-b596-3bbebceeed62/pr20151208-reliable-power-highway.pdf

and weight increases are also required in case the full-bridge converter needs to operate at a high modulation index.

A middle ground can be found by realizing converters consisting of a mix of half-bridge and full-bridge converters. Different ratios of numbers of half-bridge to full-bridge modules result in different converter performances.[24] As the ratio of full-bridge submodules increases, the converter is capable of operating at ever lower DC voltages, and at ratios of 50% and above, it is capable of reversing DC voltage polarity and blocking DC fault currents.

Although the types of modules for the VSC-MMC converter may affect its capability of operating at various DC voltages and mitigating DC fault currents (see detailed comparison in Table 11), the benefits, control modes, capabilities, grid services, and use cases that we discuss in later sections apply to VSC-MMC converters with all types of modules, unless otherwise indicated.

c. VSC-HVDC Control Modes

As a result of the ability of VSC converters to synthesize AC voltage waveshapes, it offers full independent control of either the output voltage magnitude and frequency in grid forming mode, or the active and reactive output currents/power in grid-following mode. VSC control is achieved through multiple hierarchically nested control loops that independently control converter variables such as output voltage, current, and power at different time scales.[25] This enables VSC converters to operate at any PQ operating point within the safe operating area defined by the DC voltage, transistor current rating and output current ratings.

Several of the transmission planning benefits that HVDC transmission technology can deliver today are due to the superior control capabilities of VSC converters compared to LCC-based HVDC or HVAC transmission solutions. The extent to which these benefits can be realized depends on:

- the type of AC grid(s) to which the HVDC system is connected,
- how the HVDC system is connected to these grids,
- what operational “control modes” are selected for converter operation.

[24] H. Rao, Y. Zhou, S. Xu, Z. Zhu, *Research and development of Ultra-High-Voltage VSC for the multi-terminal hybrid ±800kV HVDC project in China Southern Power Grid*, DC Systems and Power Electronics 2018 Session Papers and Proceedings, B4-120_2018, 2018.

[25] J.Rocabert , A. Luna, F. Blaabjerg, and P. Rodríguez, “Control of power converters in AC microgrids,” *IEEE Transactions on Power Electronics*, vol. 27, no. 11, pp. 4734–4749, 2012.

Depending on the application, different choices can be made by manufacturers, developers, and operators on which control mode(s) to include in the design and to activate during different system operations and conditions. The two major different control modes are "grid following" and "grid forming" as shown in Table 2 below, in which "grid forming" can be specified for either islanded or synchronous (grid-connected) operation.[26]

Where a VSC converter is connected to a strong AC grid, it can operate in grid-following mode. In this mode, the converter measures the AC grid voltage magnitude and phase angle and independently controls its real and reactive output currents to follow real and reactive power set points set by an operator or by an external control loop. As grid impedance causes an interaction between a converter's output current and output voltage, a grid-following converter requires an AC grid with a high short circuit strength compared to the converter capacity (i.e., a high short-circuit ratio or SCR). Most VSC-HVDC converters connected to the grid today operate in grid-following mode.

In case a VSC converter is connected to a grid that does not contain any generators or other devices that are capable of creating an AC voltage, then the VSC converter must have "islanded grid-forming" capability. In islanded grid-forming mode, the inverter controls the output voltage magnitude and frequency to set values, and supplies or absorbs as much real and reactive power as needed to do so. Typical examples of this are offshore converters that export offshore wind generation, or supply loads on oil & gas platforms or islands. In this control mode, the converter can typically adjust its output current very rapidly in case of AC grid disturbances.

In case a VSC converter is connected to an AC grid and is required to contribute to system strength, it can operate in "synchronous grid forming" mode. In this mode, the inverter acts as a voltage source behind an equivalent impedance, controlling its output currents to follow real and reactive power set-points. The rapid response characteristics of such grid-forming controllers are beneficial in improving grid stability and power quality in (weak) AC grids.[27] This control capability is becoming increasingly important in utility grids with declining system strength and inertia due to the retirement of large rotating thermal generators. Several system

[26] "TF-77 VSC HVDC Converters as Virtual Synchronous Machine," *Cigre*, September 30, 2019 at https://www.cigre.org/article/GB/news/the_latest_news/tf-77-vsc-hvdc-converters-as-virtual-synchronous-machine.

[27] "TF-77 VSC HVDC Converters as Virtual Synchronous Machine?," *Cigre*, September 30, 2019 at https://www.cigre.org/article/GB/news/the_latest_news/tf-77-vsc-hvdc-converters-as-virtual-synchronous-machine

operators in Europe are requiring future VSC-HVDC systems to have the option to operate in grid-forming mode for this reason.

TABLE 2. AC-GRID-FOLLOWING AND AC-GRID-FORMING FUNCTIONS OF VSC CONVERTERS

AC Control Mode	AC Grid Type	Controlled variables	Description/Features
Grid-Following[28]	**Strong AC grid**	Real power (P) Reactive power (Q)	Acting as a controlled current source that injects active and reactive power to the AC grid depending on the local AC grid voltage according to defined setpoints • Grid Feeding (Maximum Power Point Tracking, No/minimal Q support) • Grid Supporting (Active and reactive power adjustment to support the grid) The control system must first synchronize with the grid using a phase-locked loop (PLL) that measures the frequency and phase angle of the AC grid voltage
Grid-Forming[29]	**Islanded**	AC output voltage • Magnitude • Phase angle	Creating (forming) system voltage, often in stand-alone mode, e.g., offshore wind farms Absorbing or providing as much real and reactive power as needed to maintain the desired AC system voltage and phase angle / frequency within the physical limits Able to emulate droop characteristics and operate in parallel with other AC frequency regulating equipment and converters
	Synchronous	Real power (P) Reactive power (Q)	Acting as a controlled voltage source behind an impedance that adjusts its voltage to achieve an output current which depending on the local grid voltage results in the desired active and reactive power to the AC grid. Able to operate in parallel with other AC frequency regulating equipment and converters

Both "grid-following" and "synchronous grid-forming" converters can be equipped with additional control functions that are aimed at providing additional grid support functions to the

28 P. Roos, *A Comparison of Grid-Forming and Grid-Following Control of VSCs*, Uppsala Universitet, UPTEC ES 20020, June 2020 at https://www.diva-portal.org/smash/get/diva2:1444307/FULLTEXT01.pdf.

29 Entsoe, *Grid-Forming Capabilities: Towards System Level Integration*, March 31, 2021 at https://eepublicdownloads.entsoe.eu/clean-documents/RDC%20documents/210331_Grid%20Forming%20Capabilities.pdf.

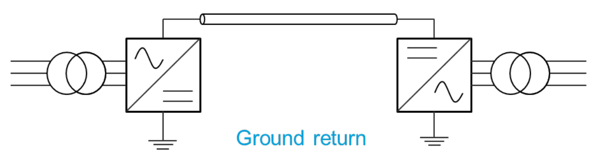
connected AC grid. An external grid supporting control loop can be added with, for example, emulation of line impedances or synchronous generator behavior such as droop characteristics for real power/frequency and reactive power/voltage. These enable a converter to work together with other grid-forming devices in the same grid or to automatically adjust its real and reactive power outputs based on local grid conditions. In choosing such external control layers, it is important to consider how the converter is connected to the AC grid and what type of AC grid it is.

3. HVDC Converter Configurations

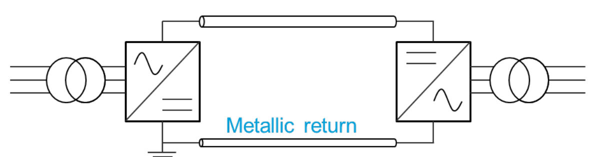
HVDC links (overhead lines and/or cables) and converters can be combined together to form an HVDC transmission system. Different configurations are possible that differ in:

- Number of converter poles per station
- Type of return connection
- Location of system grounding point

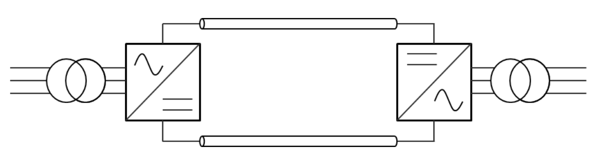
The choice of converter configuration predominantly determines operational performance of the link such as the presence of ground current during normal operation and the availability of the HVDC system during planned and forced outages of the converter and/or link.



Asymmetric monopole with ground return: The simplest of converter configurations, requiring only one high voltage conductor. It relies on electrodes to provide a return path for the current through the ground. In case of a line or converter fault, the full transmission capacity is lost. Requires transformers capable of withstanding DC voltage stress and high current electrodes.

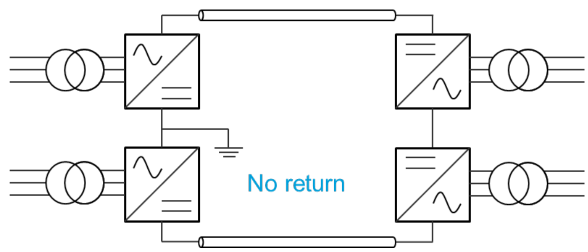


Asymmetric monopole with metallic return: Similar to the previous, but now with a dedicated conductor for the return current to avoid issues around ground currents. This configuration requires transformers capable of withstanding DC voltage stress.

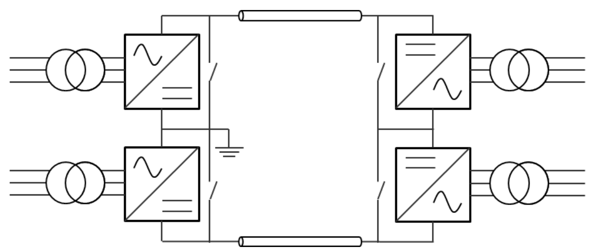


Symmetric monopole: The current loop is realized through two high voltage conductors, and the system grounding is realized in the midpoint through separate means. Normal power transformers can be used. In case of a DC short circuit, the full transmission capacity is lost, but due to its symmetrical grounding, the AC short circuit current drawn from the AC grid is limited. The drawback of this configuration is that in case of a DC line to ground fault, the healthy pole experiences an overvoltage, leading to higher (and more costly) insulation requirements compared to other converter configurations. This configuration is the most popular in offshore wind connections to date and small to medium capacity interconnectors that are typically smaller than the most severe single contingency level of the AC grids they connect to.

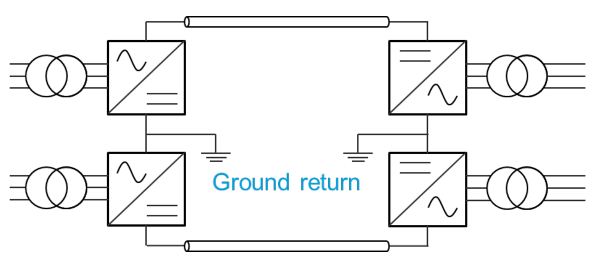
Rigid bipole: The most basic of bipole configurations which is essentially a combination of two asymmetric monopoles so that there are two converter poles per station at each end, and the return currents of each monopole are cancelled out against each other. This configuration is uncommon and offers no real operational advantages. Similar to the asymmetric monopole, bipole configurations require transformers capable of withstanding DC voltage stress.



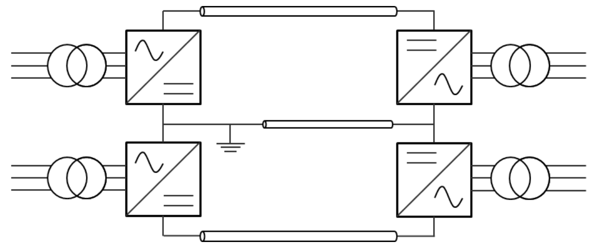
Rigid bipole with bypass switches: A more advanced version of the rigid bipole where in case of a converter outage (planned or forced), the converter can be by-passed with a DC switch and operation can seamlessly continue at 50% capacity using the high voltage cable as return. In case of a cable failure, the full transmission capacity is lost. This is a popular choice for long distance links where the cost of a third return conductor can be excessive, and where there is no benefit in unbalanced pole loading e.g. interconnectors



<u>**Bipole with ground/sea return**</u>: Adding a return path means that 50% capacity can be achieved for both line and converter outages. In this configuration, each pole can also be loaded differently, with the difference flowing through the return path. This has operational benefits when the bipole is used as a gen tie with different generation resources connected to each pole. This configuration can only be used if ground/sea current is permitted and requires high-current electrodes.



Bipole with dedicated metallic return: A dedicated metallic return can be added (typically a medium-voltage cable, but can be high-voltage for long links) to provide a return path. 50% redundant capacity can be realized for both line and converter outages. No currents flow through the ground during normal operation, and the poles can be loaded differently. This configuration is chosen for many of the new bipolar offshore wind HVDC export connections planned in Europe.



On the whole, for the same power and voltage rating, bipole configurations tend to be slightly more costly and have a slightly larger footprint for the converters. The slightly higher cost can, depending on the project, be outweighed by the increased transmission availability through the ability to operate the system with only one of the poles in operations. Moreover, in some regions, the bipole configuration is designed with higher ratings than the local maximum loss of infeed level (considering that an outage typically affects only one of the two poles), thereby allowing for a more cost-effective system design. Table 3 shows a comparison between the different converter configurations.

TABLE 3. COMPARISON OF DIFFERENT CONVERTER CONFIGURATIONS

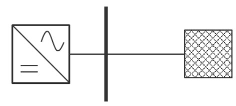
Configuration	Neutral implementation	Contingent capacity in case of outage in:		AC grid impact in case of DC fault (DC fault current)	Healthy pole overvoltage
		Converter	DC Link		
Asymmetric monopole	Ground return	0%	0%	High (low)	No
	Metallic return	0%	0%	High (low)	No
Symmetric monopole		0%	0%	Low (high)	Yes
Bipole	Rigid	0%	0%	High (low)	No
	Rigid with by-pass	50%	0%	High (low)	No
	Ground return	50%	50%	High (low)	No
	Metallic return	50%	50%	High (low)	No

4. Integrating VSC-HVDC Systems into AC grids

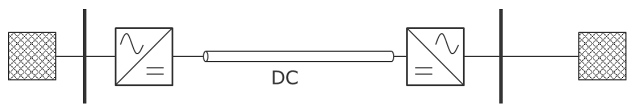
a. HVDC options for AC grid integration

The choice between operating a VSC converter in grid-following or grid-forming mode is determined by to what extent the converter is required to contribute to system strength, and how the HVDC system as a whole is connected to one or more AC grids. In general, there are five different ways for HVDC systems to be connected to or integrated into AC grids:

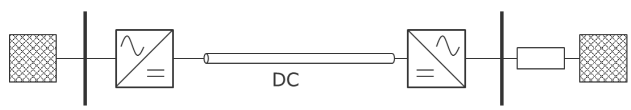
1. **STATCOM mode**—The converter is not connected to a DC line and only to an AC grid (e.g., HVDC links in which one converter or the cable/line has a planned or unplanned outage)



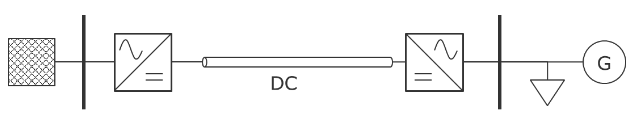
2. **Strong AC grid**—Each converter is connected to a strong asynchronous neighbouring AC grid (e.g., HVDC links which are used for long distance bulk transmission)



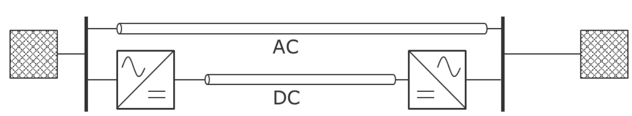
3. **Weak AC grid**—The converter is connected to a weak AC grid (low short-circuit strength) on one side (e.g., HVDC links which are used to supply remote geographies such as islands)



4. **Islanded AC grid**—The converter is connected to a grid with no voltage source and only loads and grid dependent power sources (e.g., offshore wind farm export links, or oil & gas platform power from shore supplies)



5. **Embedded**—The HVDC link is embedded within an AC grid and parallel AC transmission paths exist



(e.g., HVDC links which are used as grid reinforcement)

b. AC Grid Services provided by HVDC transmission

Depending on the type of AC grid connection and the type of converter technology used, HVDC lines can deliver a range of services to the surrounding AC grid. These HVDC-based grid services include various **reliability functions**, such as reactive power support, automatic sharing of frequency reserves, power oscillation damping, black-start, and precisely-controllable reliability functions that can be provided in conjunction with neighboring grids or HVDC-connected resources. HVDC transmission capabilities also provide a number of **market functions** and services, such as the ability to optimize power flows on the HVDC line to reduce congestion and losses on the surrounding AC grid, import frequency control and operating reserves, and fully optimize the energy and resource adequacy value of interregional transmission interties. The case studies in Section II of this report document how some system operators in Europe and North America have already started to rely on such HVDC-provided grid services, both in terms of reliability operations and market optimization.

We have grouped the wide range of HVDC-provided grid services into the following six categories, which are discussed in Table 4 through Table 9 below. How HVDC technology's ability to provide these grid services varies across specific applications or "use cases" is discussed further in Section II.C.

- Transmission-related functions (Table 4)
- Grid operation support services (Table 5)
- Autonomous line dispatch functions (Table 6)
- Power quality support services (Table 7)
- Emergency operation services (Table 8)
- Market optimization services (Table 9)

The speed with which VSC-based HVDC systems can adjust power flows offers unique value for the effective management of AC grid contingencies. However, in some cases the resources connected to the HVDC system cannot adjust their operation sufficiently quickly to adapt to contingencies, which means "dynamic breaking resistors" (DBRs) or "choppers" may be installed to handle the sudden power imbalances and help manage fault ride through. [30]

TABLE 4. TRANSMISSION-RELATED FUNCTIONS THAT CAN BE PROVIDED BY HVDC SYSTEMS

	Description/Features	AC grid connection	Converter type
Grid-forming AC voltage and frequency control	• VSC-HVDC converters can connect remote generators and loads by creating and regulating AC voltage waveforms. This enables the integration of remote or offshore wind or solar farms without a local grid connection	• Islanded AC grid	VSC
Reactive power control (static)	• Each VSC-HVDC converter can control their reactive power output (e.g., based on operator-instructed set points) • VSC-HVDC converters are able to do so (in STATCOM mode) even during an outage of the HVDC link or the other converter	• STATCOM mode • Strong AC grid • Weak AC grid • Islanded AC grid • Embedded	VSC
Real power flow control	• HVDC transmission systems can deliver exactly controlled amounts of real power at their converter locations, enabling market integration of energy resources, optimizing AC system operation, and avoiding loop flows	• Strong AC grid • Weak AC grid • Embedded	LCC & VSC

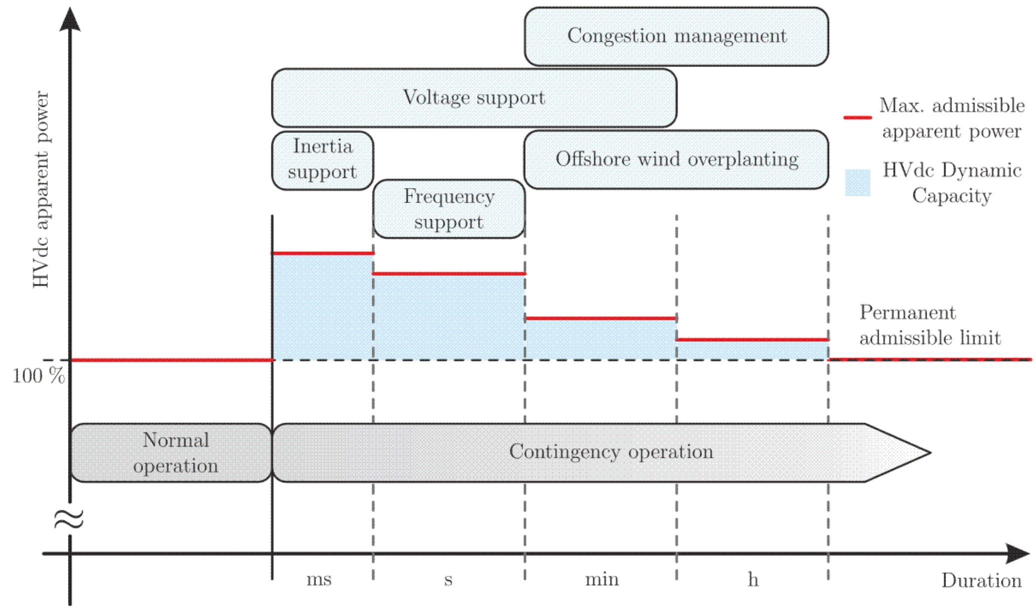
30 Depending on their purpose and application, DBRs can be placed on the AC side or the DC side of an HVDC system, on the receiving end, or on the sending end. Any HVDC gen tie (e.g., one end is connected to the AC grid, and the other end to a stand-alone generator like a solar or wind farm) is likely to have a dynamic breaking resistor to ensure AC grid fault and low voltage ride through. For example, for offshore wind farms with point-to-point HVDC connections, the DBR is placed on the DC side of the onshore converter station. Projects embedded in AC grids do not technically need a DBR, but may use one to address AC grid connection requirements, particularly to manage the impact of faults when connected to an AC grid in which sudden changes in power flow are not permitted (such as in the design of the Grain Belt Express project in the U.S.).

TABLE 5. GRID OPERATIONS-SUPPORT SERVICES THAT CAN BE PROVIDED BY HVDC SYSTEMS

	Description/Features	AC grid connection	Converter type
Reactive power control (dynamic)	VSC-HVDC converters can dynamically control their reactive power output: • to regulate voltage on the AC grid • to control the power factor on the AC grid • to provide dynamic voltage support In the event of a system disturbance • VSC-HVDC converters are able to do so (in STATCOM mode) even during an outage of the HVDC link or the other converter	• STATCOM mode • Strong AC grid • Weak AC grid • Islanded AC grid • Embedded	VSC
Synthetic inertia (from an asynchronous neighboring system or connected resources)	• VSC-HVDC converters can control the energy delivered from neighboring asynchronous systems, connected resources (including integrated capacitors or battery storage) fast enough to emulate an inertia-like response to a detected change in the frequency in the interconnected AC network frequency	• Strong AC grid	VSC
Frequency response sharing (from an asynchronous neighboring system or connected resources)	• HVDC converter controllers can detect AC grid frequency disturbances and adjust the active power flow (from neighboring systems or a connected resource) quickly enough to offer frequency response to the interconnected AC grid and assist in recovering the frequency back to nominal values	• Strong AC grid	LCC & VSC
Regulation, ramping, and spinning reserves sharing (from a neighboring system, or connected resources)	• VSC-HVDC transmission can provide precisely-controlled regulation, ramping, and operating reserves at the interconnection points by delivering the capability from connected generators and storage resources or through agreements with neighboring systems	• Strong AC grid • Embedded (between balancing areas) • Islanded AC grid • Weak AC grid	LCC & VSC

Note that, even though the maximum power rating of VSC HVDC stations has a hard limit, recent experience indicates that a significant amount of 'dynamic capacity' or 'temporary overloading' ability is present in converters depending on their operating conditions. Studies suggest that, depending on the project and operation specific characteristics, the power transfer through the converter can temporarily be increased to enable grid services, such as inertial and frequency support, as shown in Figure 11 below.[31] However, this capability has not yet been exploited in commercial projects and the economic impact and performance is not yet confirmed.

FIGURE 11. TEMPORARY OVER-CAPACITY USE CASES



Source: Cigre session 2022. Online Estimation of Dynamic Capacity of VSC-HVDC Systems – Proof of Concept in NordLink.

31 K. Schoenleber, "Online Estimation of Dynamic Capacity of VSC-HVDC Systems – Proof of Concept in NordLink", Paper 11089, presented at CIGRE Paris Session 2022, SESSION_2022_B4, also published as M. Langwasser, K. Schönleber, A. Wasserrab, M. Thiele and M. Liserre, "Online estimation of dynamic capacity of VSC-HVdc systems - power system use cases," ETG Congress 2021, 2021, pp. 704–709.

TABLE 6. AUTONOMOUS LINE DISPATCH FUNCTIONS THAT CAN BE PROVIDED BY HVDC SYSTEMS

	Description/Features	AC Grid Connection	Converter type
Tracking Control	• HVDC links can determine their power setpoints as a function of measured flows in the AC grid, e.g., as a percentage of power flow in a neighboring line, or control power flow in a connected AC line to zero, or track generation of renewable resources connected to the same grid	• Strong AC grid • Weak AC grid • Embedded	LCC & VSC
AC Line Emulation[32]	• HVDC interconnection behaves exactly like an AC transmission line characterized by a proper impedance • No direct operator active power set-point dispatch is needed • Control the ordered active power flow as a function of the phase angle over the parallel AC interconnections	• Strong AC grid • Weak AC grid • Embedded	LCC & VSC

TABLE 7. POWER-QUALITY SUPPORT SERVICES THAT CAN BE PROVIDED BY HVDC SYSTEMS

Grid Services	**Description/Features**	**AC Grid Connection**	**Converter Type**
Low-frequency AC grid oscillation damping and transient stability	• Fast and independent control of VSC-HVDC systems is highly effective in providing damping to low frequency oscillations in an AC network to increase system stability • VSC-HVDC controls can be either set up to damp a particular frequency of interest or be designed to track a targeted band of low frequencies that have the potential to cause or increase AC network instability	• Strong AC grid • Weak AC grid • Embedded • Potentially islanded AC grid	LCC & VSC
AC grid harmonics filtering	• MMC-VSC converters can be controlled to actively filter grid harmonics by damping resonances and/or providing a low impedance path for specific harmonics. The latter functionality may be limited by U.S. Total Harmonic Distortion limits on currents and adversely impact a converter's power rating, which may not be the most economic solution.	• Strong AC grid • Weak AC grid • Embedded • Islanded AC grid • STATCOM mode	MMC-VSC
AC phase balancing	• The precise and independent control of the AC infeed currents of VSC converters can be used to address phase imbalances on the AC grid	• Strong AC grid • Weak AC grid • Islanded AC grid • Embedded	VSC

[32] L. Michi et al., "AC Transmission Emulation Control Strategy in VSC-HVDC systems: general criteria for optimal tuning of control system," *2019 AEIT HVDC International Conference (AEIT HVDC)*, Florence, Italy, 2019, pp. 1–6, doi: 10.1109/AEIT-HVDC.2019.8740356 at https://ieeexplore.ieee.org/document/8740356.

TABLE 8. CONTINGENCY OPERATION SERVICES THAT CAN BE PROVIDED BY HVDC SYSTEMS

Description/Features		AC grid connection	Converter type
Run-back/run-up schemes	• HVDC transmission can automatically change its real power set points based on detection of events in connected AC grids, such as tripped transmission lines or exceeding measurement of local or remote parameters.	• Strong AC grid • Weak AC grid • Embedded	LCC & VSC
Emergency energy imports	• During emergency events, HVDC links can be used to import emergency energy from neighboring systems at high ramp rates and precisely-controlled flows (without loop flows on neighboring grids)	• Strong AC grid • Weak AC grid • Islanded AC grid • Embedded (between balancing areas)	LCC & VSC
Black start and system restoration support (from unaffected portions of the grid)	• In the event of a voltage collapse or blackout, a VSC-HVDC link connected to unaffected areas of the grid can provide synchronizing power to the blacked out system and allow the system to be restored • The VSC converter can also operate as an idling "static" generator, ready to be connected to a blacked-out network to provide the first electricity to critical loads	• Strong AC grid • Weak AC grid • Islanded AC grid • Embedded	VSC

TABLE 9. MARKET OPTIMIZATION SERVICES THAT CAN BE PROVIDED BY HVDC SYSTEMS

Description/Features		AC grid connection	Converter type
AC grid power flow optimization for congestion and loss reduction	• Through active and reactive power controls, an embedded HVDC link can be used to control flows to avoid overloads on constrained grid elements, manage congestion (including mitigation of AC grid stability constraints), optimize production costs, and reduce losses on the interconnected AC grid	• Embedded	LCC & VSC
Resource adequacy, capacity imports	• HVDC links to neighboring systems or remote areas provide diversity-based resource adequacy value, or can import capacity from dedicated resources	• Strong AC grid • Weak AC grid • Embedded	LCC & VSC
Intertie optimization	• Precise flow control allows for the optimization of interregional HVDC capability to maximize its value to the interconnected regions, including for trading and reliability	• Strong AC grid • Weak AC grid • Embedded	LCC & VSC

5. Comparisons of Technology Types

a. Comparing HVDC and AC transmission links

The main technology characteristics of AC and HVDC transmission lines are summarized in Table 10 below, not taking into account the characteristics of the converter technologies themselves, which are discussed in Section II.5.b.

From the above discussion and the table, it follows that the reality of a pre-existing AC system with the ability to use low-cost circuit breakers and transformers makes AC a more suitable technology to realize distribution of power from bulk supply points to end-users, and create network redundancy. However, the more efficient use of conductor material, reduced right-of-way, and the absence of reactive power and stability limits on transfer capacity and distance make HVDC a more suitable technology for long-distance bulk transmission, even if not considered with other HVDC technology benefits (as discussed further below). The transmission distance and capacity at which HVDC becomes more advantageous than AC is strongly situation dependent and should be determined by taking into account a full lifetime cost of ownership and system benefits comparison.

In some applications, such as transmission across asynchronous borders, or to connect remote offshore facilities, HVDC technology is the only option. In other situations, the ability of HVDC to realize long transmission links as underground cables can be the decisive factor to get projects permitted and consented.

With the development of modern MMC-VSC technology, additional transmission planning benefits are provided through its excellent controllability. This reduces the break-even capacity and distance of HVAC vs HVDC lines and results in an increase in applications where HVDC technology is more advantageous than conventional AC grid solutions.

TABLE 10. COMPARISON OF AC AND HVDC TRANSMISSION LINE CHARACTERISTICS

	HVAC Lines	HVDC Lines
Transport power across asynchronous borders	• Not possible	• Yes
Power flow controllability	• Limited in meshed networks; loop flows impact neighboring grids	• Yes; no loop flows; controllable for energy trading, grid congestion relief, system reliability/stability
Reactive power	• Limits capacity and feasible distance of lines and cables	• Not limiting (does not exist on DC side of link); VSC converters can provide reactive power dynamically
Impedance	• Surge impedance loading limits line length	• Only resistance, no stability limits
Number of conductors	• 3 high-voltage conductors	• 2 high-voltage insulated conductors • Sometimes 1 return conductor. This conductor is typically medium voltage but can be high voltage for long transmission distances
Conductor use	• Limited by skin and proximity effects, reducing thermal limit	• Full cross-section is used
Switchgear	• Both air and gas insulated switchgear are relatively low cost and mature	• Air insulated switchgear (except circuit breakers) is mature • DC Circuit breakers are high cost and under development[33] • Gas insulated switchgear is under development and not yet fully mature
Voltage conversion	• Low cost and mature transformers	• Need to use costly back-to-back HVDC converters
Availability	• High	• Lower than AC - Fewer HV conductors result in higher line availability, but converter stations require typically four (up to 14 days) 24 hour shift day planned annual maintenance outages
Short-circuit behavior	• AC lines increase short-circuit current	• Converters in DC lines block AC short-circuit currents; VSC converters can supply 1 pu AC fault current, full bridge converters can also block DC fault currents
Power quality	• AC lines propagate power quality issues: low voltage, harmonics, unbalance, resonances	• DC links block **AC power quality issues;** •
Electro-magnetic field[34],[35]	• Well-understood	• Potentially higher; environmental impact not well studied

[33] Full bridge converter technology can be used to control fault currents and avoid the need for DC circuit breakers in some cases.

[34] U.S. Department of the Interior, *Effects of EMFs From Undersea Power Cables On Elasmobranchs and Other Marine Species, Final Report*, OCS Study, BOEMRE 2011-09, May 2011 at https://espis.boem.gov/final%20reports/5115.pdf.

[35] Cigre Technical Brochure 473 - Electric Field and Ion Current Environment of HVDC Overhead Transmission Lines, 2011.

b. Comparison of LCC and VSC converter technology

Table 11 summarizes the characteristics of LCC compared to different designs of MMC-VSC converters. As shown, the main advantage of LCC converters is that they are available for higher-capacity and higher-voltage HVDC transmission solutions, such as in Chinese HVDC lines operating at 1,100 kV with a transmission capacity of 12 GW. The continuing technological progress in VSC-based HVDC converter technology, however, offers a number of increasingly significant advantages for transmission planners. The controllability, the resulting low grid impact, the reduced footprint, and the availability of sufficiently high power and voltage ratings means that MMC-VSC technology is the technology of choice for the majority of new HVDC transmission projects today, gradually replacing the use of LCC technology. MMC-VSC technology has become the state-of-the-art HVDC design, dominating 2-level, 3-level, and CTL topologies at higher power and voltage ratings due to its excellent harmonic performance, reliability and scalability.

MMC converters can be implemented with different types of submodules to realize different capabilities with respect to blocking DC fault currents and operating at reduced voltage or opposite polarities. For projects utilizing some ratio of full-bridge modules, the fault blocking, reduced voltage and opposite polarity operation must be weighed against the additional capital cost, losses, and unavailability.

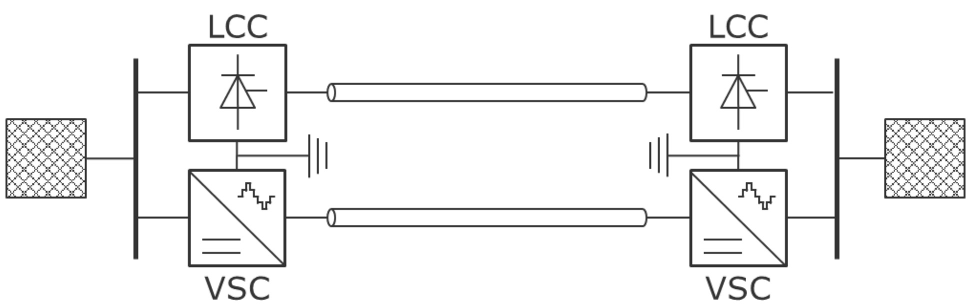
TABLE 11. CHARACTERISTICS OF LCC AND MMC-VSC CONVERTER DESIGNS

	LCC	MMC-VSC		
		Half-bridge	Full-bridge	Hybrid
Switching Device	Thyristor	IGBT, IEGT, BIGT		
Commutation	Line-Commutated	Self-Commutated		
Station Power Loss	0.6–0.8%	0.7–1%		0.6–0.8%
Availability	Higher	> 98%		Higher
Power Reversal	Voltage polarity reversal (requires interruption of power flow)	Current polarity reversal	Current and/or voltage polarity	Current polarity
Cable type compatibility	Only mass-impregnated paper insulated cables	Both mass-impregnated paper and extruded polymer insulated cables		
Minimum real power loading	5–10% (0% possible with special valve design)	0%		
Network Strength Dependency	Requires strong AC grid	Independent of AC grid strength		
Converter Station footprint	Larger	Smaller (40–50% less)		
Converter transformer	Special design	Regular AC power transformer for symmetrical monopoles, and special design for bipoles		
Overload capability	Some	Limited		
Harmonic distortion	Requires filters	No production of low-order harmonics, although amplification of existing harmonics can occur; damping and active filtering is possible		
Reactive power	No reactive output control capability, requires compensation	Full control over static and dynamic reactive power output		
Capable of blocking and recovering from DC fault	Yes	Not inherently capable, but possible with additional AC equipment	Yes	Yes
Capable of operating at reduced DC voltage	Yes	Not inherently capable, but possible down to 80% with additional provisions. Requires larger interface transformer tap changer range	Yes	Yes
Capable of operating at opposite DC voltage	Yes	No	Yes	No
Technology Maturity	High	High	Medium	Low
HVDC grid capability	Limited	Good	Excellent	Excellent
Highest ratings in construction/ operation[36]	12 GW / 1,100 kV (China only)	3 GW / 600 kV	1.8 GW / 380 kV	5 GW / 800 kV (China only)
Grid Support	Can deliver limited grid services	Can provide various grid services, as detailed in Table 4		

c. Hybrid VSC and LCC systems

Under some conditions the advantages of LCC and VSC technologies can be combined in hybrid VSC-LCC systems. One example of such a combined system is the 500 kV Skagerrak submarine cable bipole link between Denmark and Norway, shown in Figure 12, in which a second pole was added in 2015.[37] VSC converter technology was selected for the 700 MW expansion over LCC technology due to its ability to deliver reactive power support, black-start capability and have stable operation in the vicinity of other converters. The DC switchgear was designed to ensure that voltage polarity reversals can be achieved to change the direction of power flow whilst maintaining the VSC converters at the same operating polarity. Even though this type of configuration was realized as an upgrade of an existing project (and is highly unusual and unlikely to find widespread adoption), it illustrates the flexibility of voltage source converter technology.

FIGURE 12. EXAMPLE HYBRID LCC-VSC SYSTEM E.G. SKAGERAK 4 (DENMARK-NORWAY)

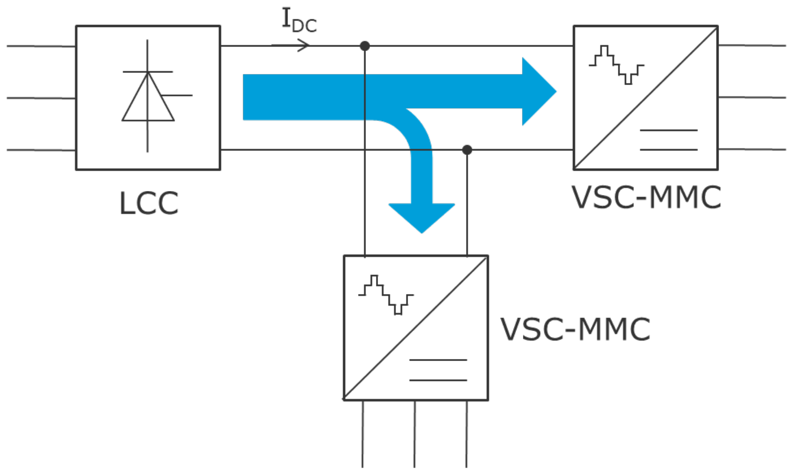


Another example of a hybrid HVDC transmission system in operation today is the Wu Dong De system in China,[24] shown in Figure 13. The project connects the world's seventh-largest hydropower plant, the 8 GW Wudongde Hydropower Station, to the load centers in Guangdong (5 GW) and Guangxi (3 GW) via overhead HVDC lines. This HVDC project is state-of-the-art in a number of ways.

36 The ratings given are for leading-edge technology with limited operational experience, not yet broadly available on the market (below TRL7, as detailed in Section B below).

37 Göran Andersson and Mats Hyttinen, "Skagerrak The Next Generation: HVDC and Power Electronic Technology System Development and Economics," LUND 2015, *Cigre*, 2015 at https://library.e.abb.com/public/59091e6efb69419dbe1ff4a6f9adac4e/Skagerrak%20The%20Next%20Generation.pdf.

FIGURE 13. EXAMPLE HYBRID LCC-VSC SYSTEM E.G. WU DONG DE (CHINA)



First, it uses a combination of LCC and VSC converters. The 8 GW converter at the Wudongde dam is of the LCC type, but the Guangdong and Guangxi stations were specified to be of VSC type to overcome grid stability issues due to the many large LCC stations in that part of China. Second, the 800 kV project uses the highest system voltage for VSC converters in operation today. Third, because it uses an overhead line, a hybrid full bridge-half bridge converter topology was chosen with enough full-bridge modules to be able to clear temporary line faults and operate at reduced voltage. Lastly, as is typical in many Chinese HVDC projects, the components and systems in the project were supplied by multiple (often state-owned) different vendors. It went into operation in late 2020, but no publicly-available information is available about its operational performance.

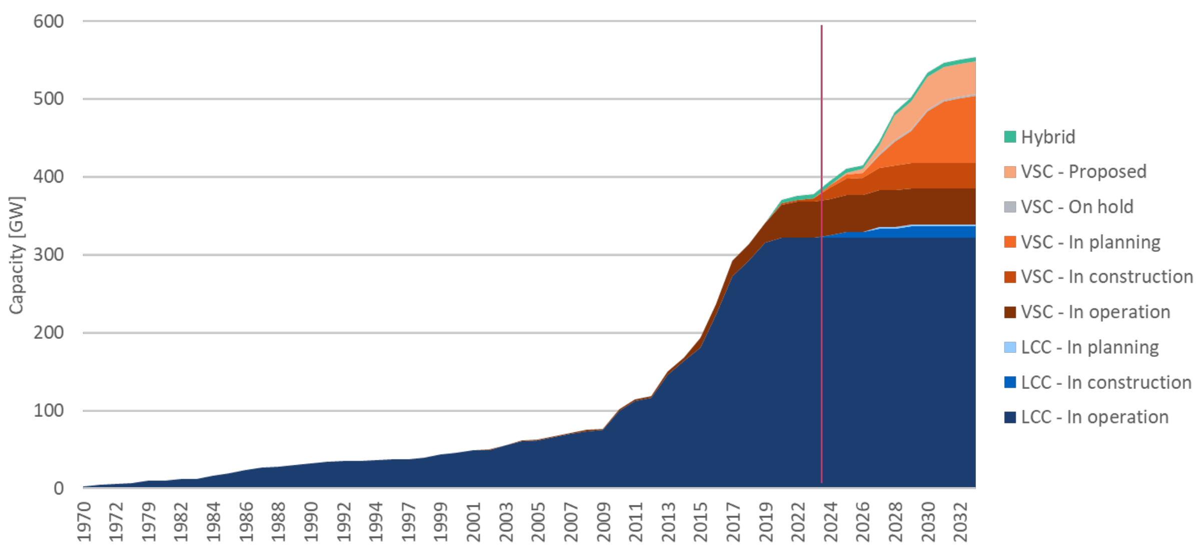
HVDC projects which combine VSC and LCC converters may be beneficial compared to a pure VSC or LCC project under very specific circumstances, such as:

- Unidirectional power flow from the LCC station towards the VSC station
- No need for polarity reversals
- AC grid characteristics: strong on the LCC side, 'weak' or otherwise constrained on the VSC side
- Sufficient
- space for converter stations

B. HVDC Experience by Technology Type

HVDC transmission systems have been in operation for over a century, and significant operational experience exists in the industry today, with over 300 GW in operation. Several different legacy converter technologies have been used and phased out as they became obsolete and replaced with more effective newer and more advanced technologies. A similar evolution is happening today, as the incumbent LCC technology is slowly being overtaken by the newer VSC technology. Nevertheless, as shown in Figure 14 below, with over 270 GW installed, LCC-based HVDC systems still make up the majority of HVDC transmission capacity—and will for the foreseeable future.

FIGURE 14. INSTALLED AND PLANNED HVDC TRANSMISSION GLOBALLY BY LCC/VSC CONVERTER TYPE

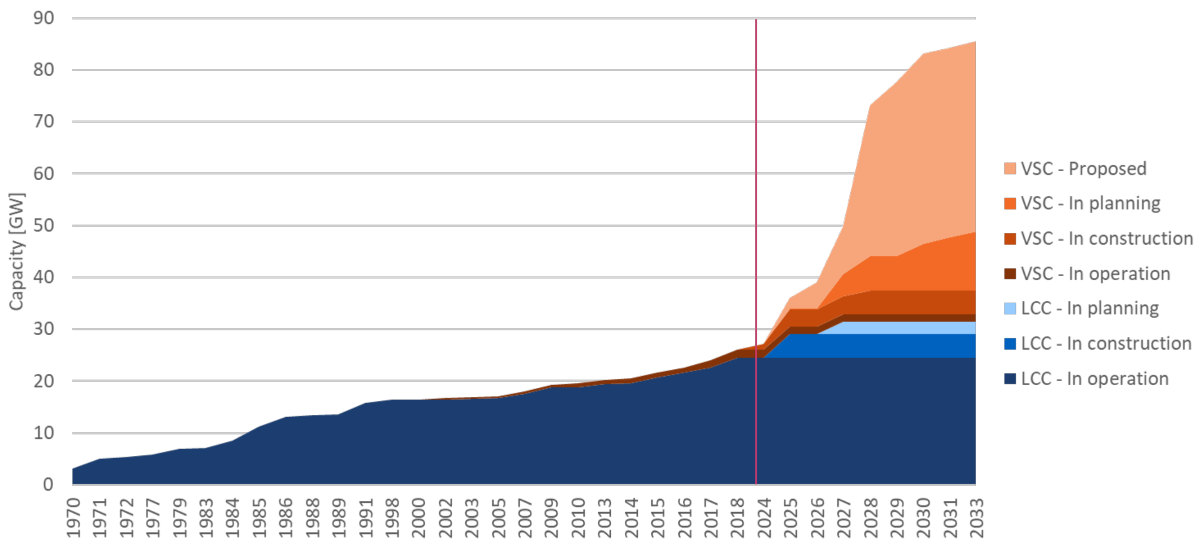


Source: DNV

However, as can also be seen in Figure 14, the amount of new LCC projects in construction (almost exclusively located in China, India and South America) is very small. In reality, the amount of LCC converter capacity in operation is expected to decline, as existing converter stations reach their end of life, which is not reflected in the graph. Instead, the vast majority of all future growth in HVDC transmission capacity will be VSC-based projects. As shown, the about 40–50 GW VSC capacity in operation today is expected to more than quadruple over the next decade. In some specific circumstances it also makes sense to combine VSC and LCC in hybrid projects (as shown in the top, green slice in Figure 14 above), but such VSC-LCC combinations are expected to remain a niche application.

In North America, as shown in Figure 15 below, currently only one new LCC converter-based transmission link is expected to be installed. Instead, a significant amount of VSC based projects have been announced, are being planned, or are in construction, that if/when realized, will bring the total installed HVDC capacity in North America to 70 GW within the next decade. Multiple renewable and merchant transmission developers have proposed HVDC projects to integrate renewables, relieve grid constraints, address interregional seams, and optimize markets. The uptake of HVDC is further encouraged by the inclusion of HVDC options within the planning frameworks of several ISOs. In addition, several eastern U.S. states now require offshore wind farms to connect to shore using HVDC links in order to reduce the number of cable corridors and associated community and environmental impacts.[38]

FIGURE 15. INSTALLED AND PLANNED HVDC TRANSMISSION IN NORTH AMERICA BY LCC/VSC CONVERTER TYPE



Source: DNV

Figure 16 shows that as VSC technology evolves and is being installed in North America, it enables projects to have higher transmission voltages and thus higher transmission capacities. The largest projects that are currently under development have nominal voltage ratings up to 600 kV and transmission capacities up to 5 GW. These projects are at the cutting edge of today's MMC-VSC technology capabilities, as illustrated in the Technology Readiness Level (TRL) chart shown in Figure 17 below.

[38] See J. P. Pfeifenberger et al., *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals*, January 24, 2023 at https://www.brattle.com/insights-events/publications/brattle-consultants-highlight-the-benefits-of-collaborative-planning-process-for-offshore-wind-transmission-in-new-report/.

FIGURE 16. VOLTAGES AND CAPACITIES OF NORTH AMERICAN VSC PROJECTS

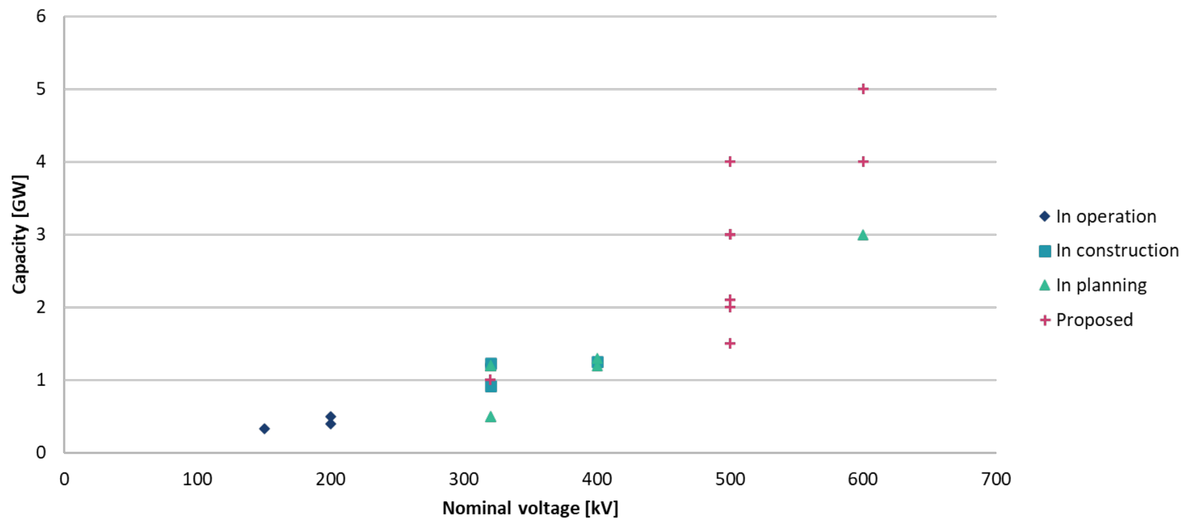
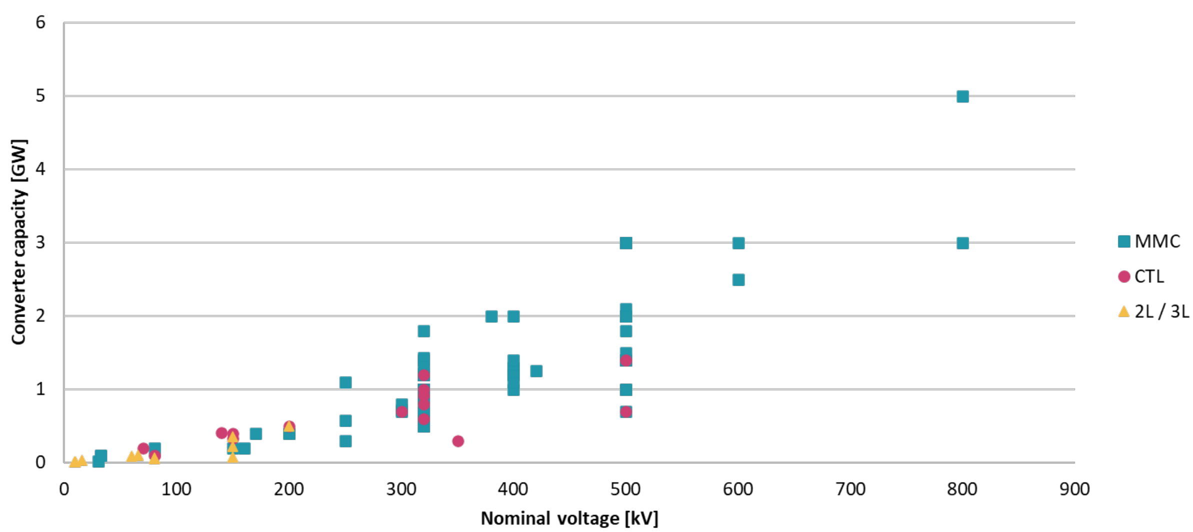


FIGURE 17. VOLTAGES AND CAPACITIES OF VSC PROJECTS GLOBALLY



The TRL is a measure of the maturity of a technology as it develops from analytical research at TRL 1, lab implementation, system integration, industrial manufacturing and finally into fully standardized and competitively manufactured product at TRL 7.[39] Generally, technologies can

[39] J.Wu et al, Technology Readiness Level Application in Power Transmission Systems, CIGRE Symposium Ljubljana 2021.

be considered sufficiently mature for a pilot or first-of-a-kind real world application at TRL 7. As shown in Figure 18 below:

- Overhead line technology for HVDC can be considered fully mature for voltage ratings up to 600 kV.
- In China, HVDC overhead lines with a voltage rating of 1,100 kV are in operation today. HVDC circuits with 800 kV rating are in operation in China, India, and Brazil.
- VSC converter technology can be considered:
  - Fully proven for 320 kV with ratings up to 1.2 GW. Systems with a rating up to 1.32 GW are in development and considered technically viable.
  - Complete and qualified for 400 kV with ratings up to 1 GW with one project in operation (NEMO Link). Systems with a rating up to 1.4 GW are in development and capacities up to around 1.8 GW are considered technically viable (Nautilus Link, Belgium to UK).
  - Demonstrated for 500 kV. Three CTL-VSC 500 kV projects are in operation today with capacities up to 1.4 GW (Skagerrak 4, NordLink, North Sea Link). No 500 kV MMC VSC projects are in operation today outside China[40], but the technology is fully qualified and many projects with ratings up to 3 GW are currently being developed and constructed. Capacities up to around 3 GW are considered technically viable.
  - Validated for 640 kV[41]. No 640 kV MMC VSC projects are in operation today outside China, but the technology is considered scalable and several 600 kV projects with ratings up to 3 GW are currently being developed and constructed in the U.S. Capacities up to around 3.6 GW are considered technically viable.
  - In China, one MMC-VSC and overhead line project with a voltage rating of 800 kV and a largest converter capacity of 5 GW is in operation today (Wudongde).
- Polymer insulated cable technology can be considered:
  - Fully proven for 320 kV with ratings up to 1.2 GW (Caithness Moray Link, Scotland). Systems with a rating up to 1.32 GW are in development and considered technically viable (Sofia, UK).

40 One of the 500 kV 3 GW converter stations in the Chinese Zhangbei grid is delivered by a European vendor (https://new.abb.com/news/detail/10464/abb-enables-worlds-first-hvdc-grid-in-china)

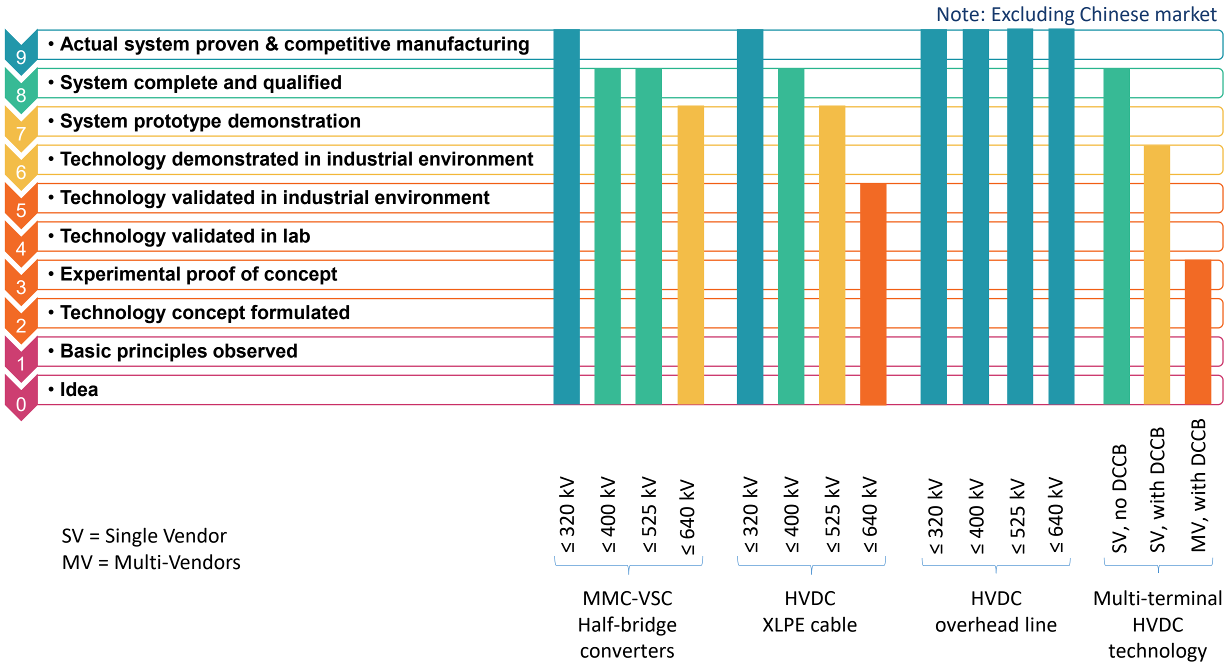
41 R. Rosenqvist, High Voltage Direct Current (HVDC): Technology Solutions for Integration of Renewable Resources, Hitachi Energy at https://www.ercot.com/files/docs/2023/06/26/4_HVDC-%20Solutions%20for%20Integration%20of%20Renewable%20Resources_HitachiEnergy_Rosenqvist_20230626.pdf.

- Complete and qualified for 400 kV with ratings up to 1 GW with one project (NEMO Link) in operation. Systems with a rating up to 1.4 GW (e.g., Nautilus Link) are in development and capacities up to around 1.6 GW are considered technically viable. 400 kV is the highest voltage for polymer insulated cable systems in operation today.
- Demonstrated for 500 kV. No 500 kV polymer insulated cable projects are in operation today, but the technology is fully pre-qualified by multiple vendors and many HVDC cable projects with ratings up to 2.1 GW (e.g., SOO Green) are currently being developed and constructed. Vendors claim that capacities up to 2.6 GW are possible, but this remains to be demonstrated.
- Validated for 640 kV. No 640 kV cable projects are in operation today. Cable vendors have developed and type tested prototypes up to 600 kV[42] and 640 kV[43] and claim transmission capacities up to 3 GW are technically feasible.
- The highest HVDC cable voltage in operation today is 600 kV (Western Link, U.K.) and uses mass-impregnated paper cable insulation.

[42] Prismian Group, *Extruded Cables for HVDC Power Transmission*, n.d. at https://www.prysmiangroup.com/sites/default/files/business_markets/markets/downloads/datasheets/BR_HVDC_2018_rev12__0.pdf

[43] NKT, World´s most powerful underground power transmission cable system: 640 kV extruded HVDC cable systems at https://www.nkt.com/products-solutions/high-voltage-cable-solutions/innovation/640-kv-extruded-hvdc-cable-systems

FIGURE 18. HVDC TECHNOLOGY READINESS LEVEL

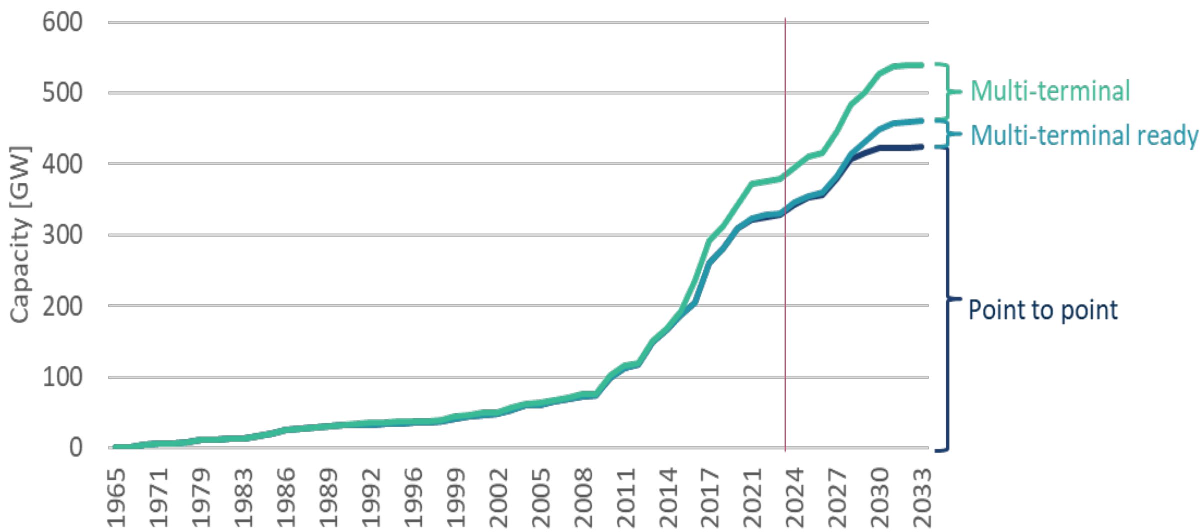


It should be noted that for techno-economic reasons, HVDC systems are predominantly implemented in the over 1 GW scale. At these ratings, the capacity of HVDC projects often exceeds the existing Most Severe Single Contingency (MSSC) in the connected AC grids. This triggers discussions about the impact of the project on the AC grid operation and may either lead to increased grid operation costs due to the need to procure more operating reserves, or to a restriction on the maximum HVDC circuit size. The typical range of the MSSC in different U.S. power markets is 1,200–1,800 MW. Some bipolar HVDC configurations are able to address MSSC concerns by being able to operate in monopolar mode at half the capacity, in case one of the poles has an outage. However, U.S. regions differ in how such systems are treated from a MSSC perspective and whether the entire bipole rating or only the monopole rating is used as the most serve single contingency.

The excellent controllability of VSC technology, however, makes it suitable for multi-terminal HVDC grids, although several technological challenges still need to be addressed before widespread implementation of multi-terminal HVDC grids is possible. Multi-vendor interoperability and the availability of a sufficient number of vendors to enable competitive tendering of HVDC circuit breakers are two of the major hurdles. However, in a single vendor setting, and if no HVDC circuit breakers are needed, VSC based multi-terminal HVDC grids can be built today. In fact, while point-to-point HVDC projects are still the predominant application as shown by the dark blue line in Figure 19 below, multi-terminal projects are beginning to be developed and some are already operational, as shown by the difference between the green and light blue lines in Figure 19 below.

Similarly, a number of HVDC projects under development have been designed as "multi-terminal ready" (as shown by the difference in light and dark blue lines in the chart below). This means that these projects are designed so they can be connected into a multi-terminal HVDC grid if needed and once (the mostly software-related) multi-vendor interoperability challenges have been resolved.

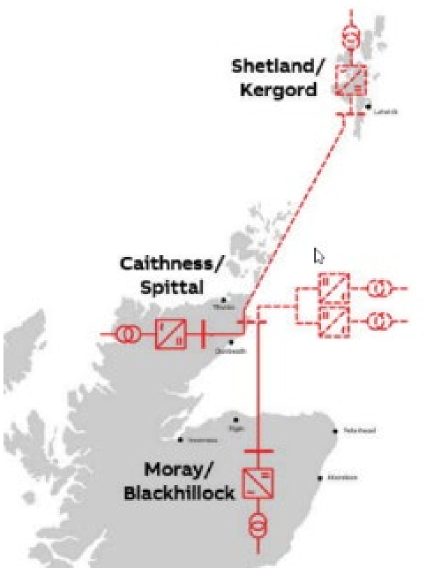
FIGURE 19. SHARE OF MULTI-TERMINAL (AND MULTI-TERMINAL-READY) HVDC SYSTEMS WORLDWIDE



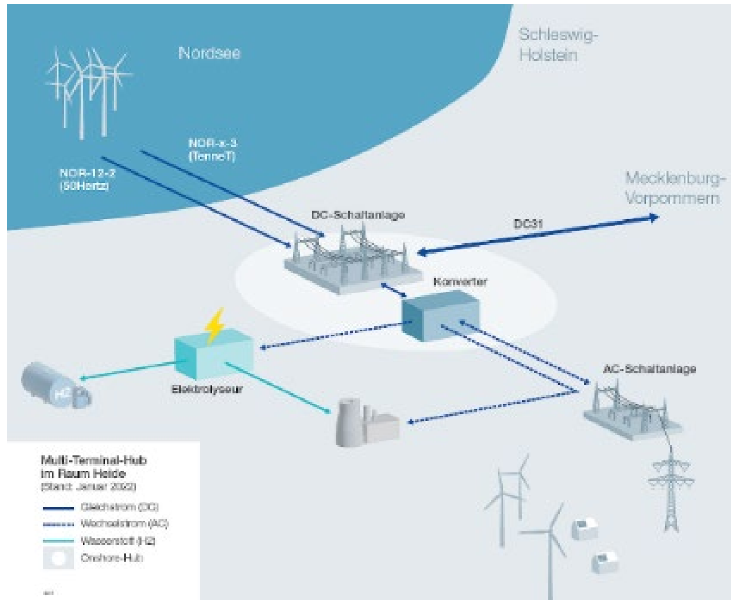
Source: DNV

Figure 20 (below) shows several of the European multi-terminal HVDC grid development efforts. The Caithness-Moray-Shetland system in Scotland, shown in Figure 20(a) is expected to be commissioned fully in 2024. It is a 3-terminal 320 kV symmetrical monopole system which connects the Shetland Island with mainland Scotland and reinforces the Scottish grid by means of a submarine link. The system is supplied by a single vendor, and since the largest circuit rating is 1.2 GW and less than the UK MSSC of 1.32 GW, no HVDC circuit breakers are needed.

FIGURE 20. EUROPEAN DEVELOPMENTS TOWARDS MULTI-TERMINAL HVDC GRIDS

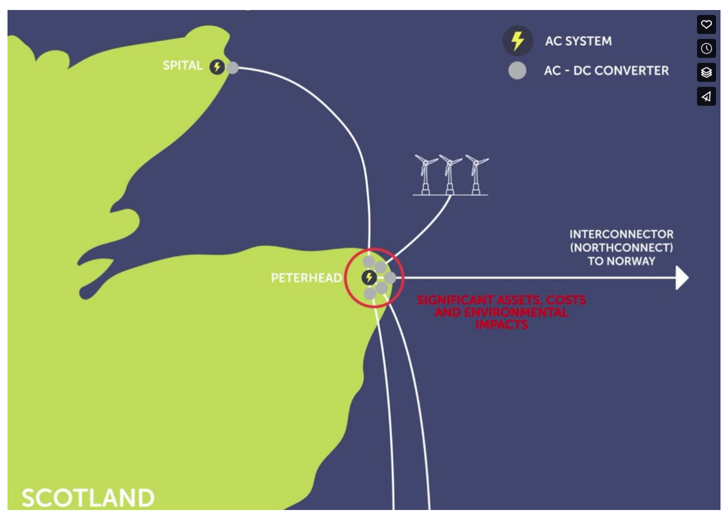


a) Caithness-Moray-Shetland (Scotland)[44]



b) Heide hub (Germany)[45]

c) Hypergrid (Italy)[46]



d) Project Aquila (Scotland)[47]

44 R. Hanson, C. McHardy, and K. Linden, 'Planning and implementation of an HVDC link embedded in a low fault level AC system with high penetration of wind generation,' Cigre 2020 Paris Session 48, at https://search.abb.com/library/Download.aspx?DocumentID=9AKK107991A7086&LanguageCode=en&DocumentPartId=&Action=Launch.

45 Elia Group, 50Hertz and TenneT to jointly bring wind power from the North Sea into the extra-high voltage grid for the first time, Press release, January 17, 2022 at https://www.50hertz.com/en/News/FullarticleNewsof50Hertz/12105/50hertz-and-tennet-to-jointly-bring-wind-power-from-the-north-sea-into-the-extra-high-voltage-grid-for-the-first-time.

The Heide hub in Germany, shown in Figure 20(b), will be a 4-terminal 500 kV bipole system which connects a 2 GW offshore wind farm to the mainland Germany and to a terrestrial 2 GW HVDC link which transports the wind power south towards the load centres. The connection is realized through collaboration between two different German system operators. It will pilot the use of a HVDC circuit breaker which can split the two separate links in case of a contingency. A back-up by-pass is included in case the HVDC circuit breaker is not operational. The project has been given the green light by the German government but is still in early phase development.

The Italian Hypergrid, shown in Figure 20(c), is a long-term vision presented by the Italian transmission grid operator Terna as discussed further in Section V.4. It encompasses multiple HVDC links to connect Italy's islands as well as reinforce the onshore transmission grid. The vision includes multi-terminal HVDC grid overlays using HVDC circuit breakers to achieve the desired reliability. The vision is currently in its conceptual phase and more detailed design phases still need to be started.

Project Aquila in Scotland, shown in Figure 20(d) is being taken forward by SSEN-Transmission, who own operate and develop the transmission network in the north of Scotland, and the National HVDC Centre, which is a center offering grid simulations, training, and insights in the de-risking of integrating large-scale HVDC converters into existing networks. Project Aquila aims to deliver:

- A DC Switching Station (DCSS) at Peterhead, located in the North East of Scotland allowing a multi-terminal arrangement to be established, limiting the number of required converters at Peterhead, and providing environmental and cost saving benefit
- A design which permits multi-vendor delivery of the multi-terminal arrangement and a variability in the terminals allocated to each arrangement via a DCSS design enabling "safe to fail" through staged demonstration.
- The de-risking and specification and delivery of multi-vendor at the National HVDC centre via a process building on insights developed by the center as part of its support of the first Multi-terminal VSC-HVDC project in Europe (Caithness-Moray-Shetland) and its work to support implementation of DC networks under the EU-funded PROMOTioN project.

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[46] Terna Driving Energy, TERNA: 2023 Development plan for the national electricity grid presented, Press release, March 15, 2023 at https://www.terna.it/en/media/press-releases/detail/2023-development-plan.

[47] https://www.ssen-transmission.co.uk/news/news--views/2022/7/pathway-to-2030-underpins-7bn-investment-in-north-of-scotland-transmission-network/

While the number of multi-terminal projects is still small, several other developments are testament to the controllable, long distance and high capacity power transfer capabilities of HVDC. They include (1) multi-terminal-ready designs, such as TenneT's 2 GW program; the Eurasia Interconnector between Israel, Cyprus, and Greece; and the Danish and Belgian Energy Islands;[48] (2) multi-purpose interconnectors, such as the Nautilus and Lion Link;[49] and (3) long term HVDC grid strategies such as EUROBAR and Target Grid.[50]

North America has historically been at the forefront of HVDC technology developments and has seen multiple notable first-of-a-kind applications of HVDC technologies:

- **Eel River** (New Brunswick, Canada)[51]—The world's first commercial solid state (thyristor) switch based LCC converter, 320 MW, built in 1972. The original valves were built in Canada, and have been replaced with modern valves in 2014.
- **Québec-New England Phase II HVDC Project**[52]—The world's first large-scale multi-terminal HVDC system. It is a bipolar system based on LCC converters with a total rating of 2,000 MW, built in 1986-1992 and is still in operation today.
- **Eagle Pass BTB** (Texas, USA)[53]—The world's first commercial application of 3-level VSC converter technology. It is a 36 MVA back-to-back system installed in 2000 and is still in operation today.

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48 See TenneT, The 2GW Program, at https://www.tennet.eu/about-tennet/innovations/2gw-program; EuroAsia Interconnector, EuroAsia at a Glance at https://euroasia-interconnector.com/at-glance/; Danish Energy Agency, Denmark's Energy Islands at https://ens.dk/en/our-responsibilities/energy-islands/denmarks-energy-islands; Elia Group, Princess Elisabeth Island at https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/princess-elisabeth-island; and North Sea Wind Power Hub Programme, Beyond the Waves at https://northseawindpowerhub.eu/beyond-the-waves.

49 National Grid, Nautilus Interconnector at https://www.nationalgrid.com/national-grid-ventures/interconnectors-connecting-cleaner-future/nautilus-interconnector and TenneT, LionLink at https://www.tennet.eu/lionlink.

50 Eurobar at https://eurobar.org/ and TenneT, Target Grid at https://www.tennet.eu/target-grid.

51 W. A. Patterson, "The Eel River HVDC scheme—A 320 MW asynchronous interconnection between the New Brunswick Electric Power Commission and Hydro-Québec employing thyristor valves," *Canadian Electrical Engineering Journal*, vol. 2, no. 1, January 1977, pp. 9–16, doi: 10.1109/CEEJ.1977.6592831 at https://ieeexplore.ieee.org/document/6592831.

52 Hitachi Energy, Québec-New England, The first large-scale multi-terminal HVDC transmission in the world at https://www.hitachienergy.com/ca/en/about-us/customer-success-stories/quebec-new-england.

53 T. Larsson, A. Eris, D. Kidd, F. Aboytes, Å. Petersson, and R. Haley, "Eagle Pass Back-to-Back Tie: a Dual Purpose Application of Voltage Source Converter technology" at https://library.e.abb.com/public/4f9e1da87ec65947c1256fda003b4cf0/IEEE SM 01 Paper1.pdf

- **Cross-sound Cable** (Connecticut-Long Island, USA)[54]—The world's first commercial application of CTL based VSC HVDC converter technology, built in 2002, the 150 kV, 330 MW link is still in operation today.
- **Transbay Cable** (California)[55]—The world's first commercial application of MMC-based VSC HVDC converter technology, built in 2010, the 200 kV, 400 MW link is still in operation today.
- **Maritime Link** (Canada)[56]—The world's first VSC-based HVDC link with bipolar converter configuration: 200 kV, 500 MW, built in 2017.

C. HVDC Transmission Experience by Use Case

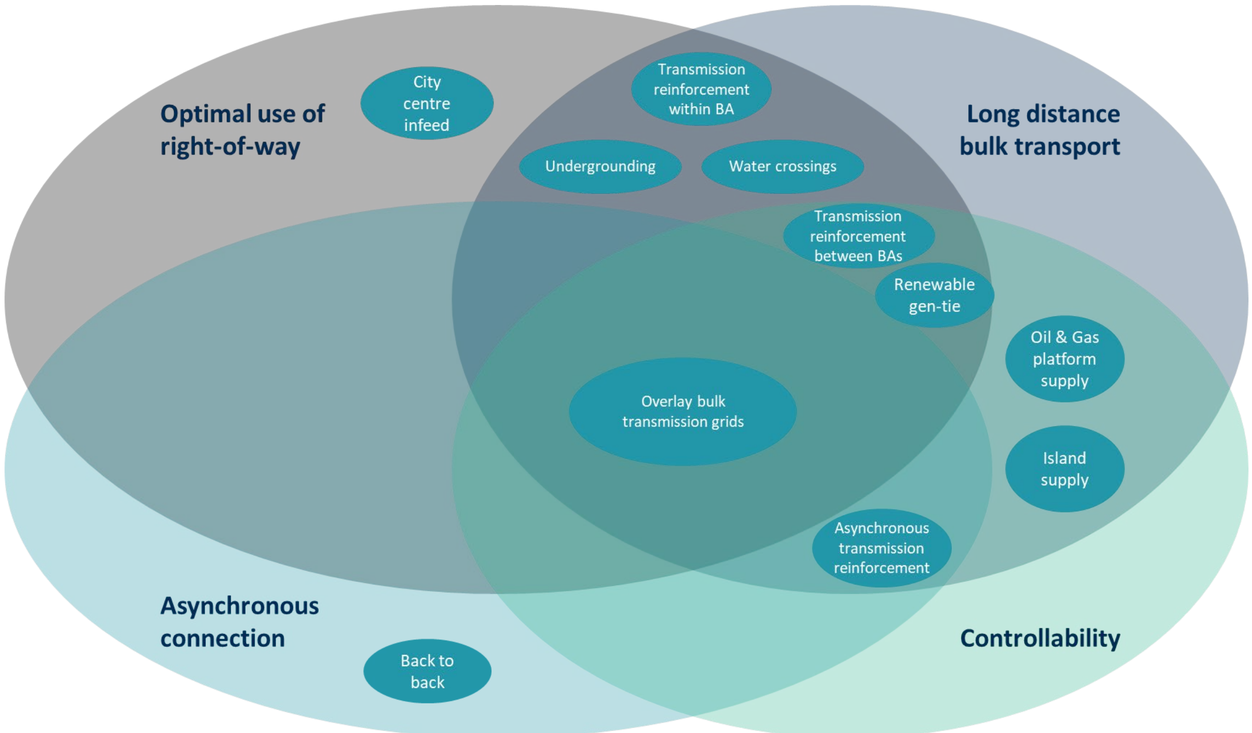
HVDC transmission technology has capabilities that make it uniquely beneficial for a number of different use cases, of which long-distance transmission and the interconnection of asynchronous AC grids are only the two most recognized HVDC applications. How HVDC capabilities are utilized for different use cases is illustrated in Figure 21 below. As shown, HVDC use cases can broadly be classed into: (1) suitability for transmission across synchronous borders, (2) long distance bulk transport, (3) more optimal use of right-of-way, and (4) controllability. More specific applications rely on combinations of these elements, as illustrated by the smaller circles in Figure 21.

[54] Cross Sound Cable Company, LLC at https://www.crosssoundcable.com/.

[55] Trans Bay Cable at https://www.transbaycable.com/.

[56] Emera, Maritime Link Infrastructure at https://www.emeranl.com/maritime-link/maritime-link-infrastructure.

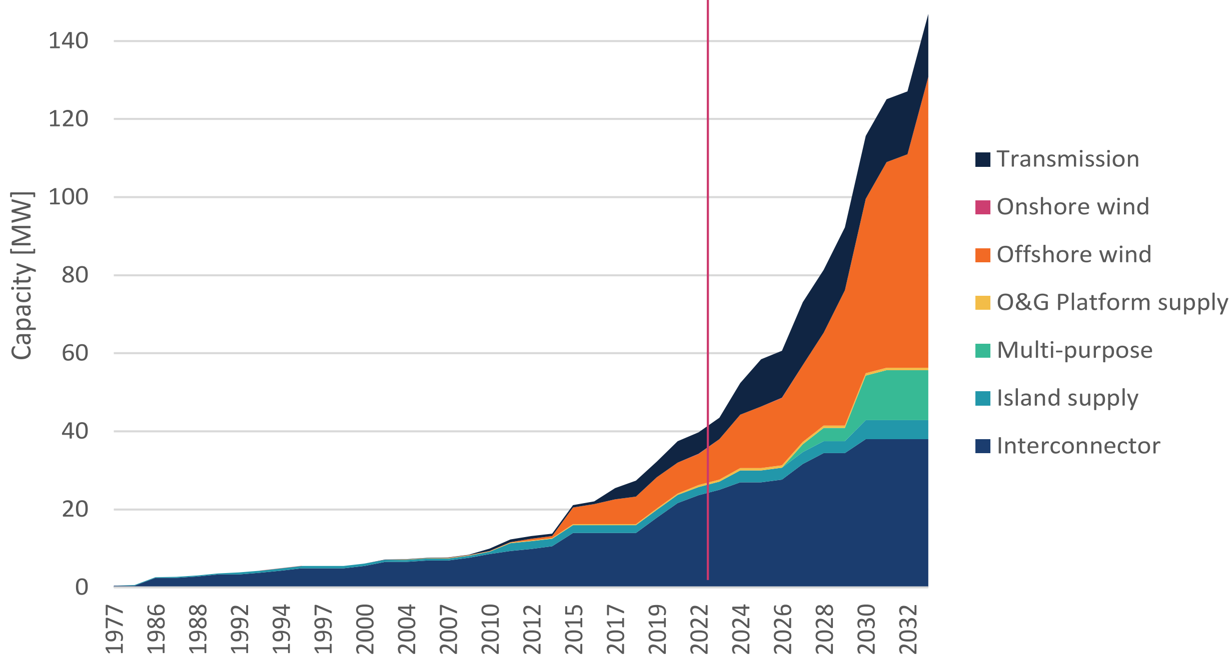
FIGURE 21: OVERVIEW OF HVDC TRANSMISSION USE CASES



BA = Balancing Area

Figure 22 below summarizes the existing global experience of VSC-HVDC technology for several specific transmission use case. The dark blue slice at the bottom of the chart shows that more than half of the approximately 50 GW total European HVDC capability is associated with "interconnectors" between countries, mostly relying on long-distance submarine HVDC cables, such as the interconnectors between Britain and France, Britain and Norway, Netherlands and Norway, and Germany and Norway. The second most frequent HVDC use (shown in light green) is for connecting large offshore wind plants to often distant points on the onshore grid. HVDC transmission lines that are integrated with the onshore grid (shown as the black slice at the top of the figure) represent the third-most-frequent use case. Looking forward, we also see planned multi-purpose uses of HVDC transmission for offshore networks that combine the integration of offshore wind generation with increased interconnection capacity between countries.

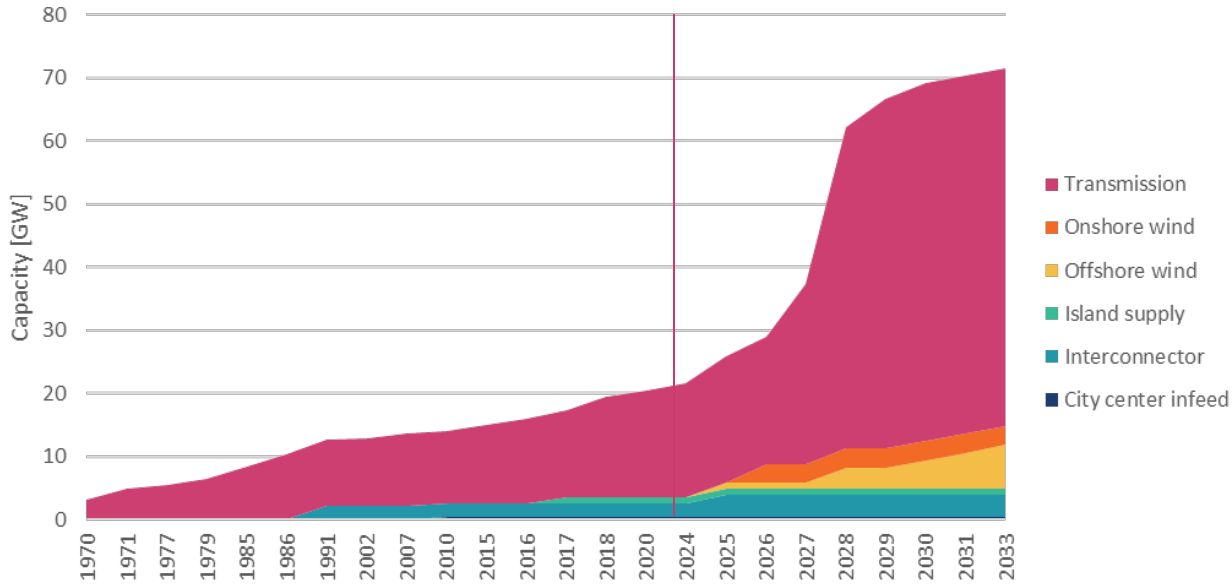
FIGURE 22. USE CASES FOR INSTALLED AND PLANNED VSC-HVDC TRANSMISSION (GLOBAL)



Source: DNV

Figure 23 summarizes HVDC use cases in North America for both LCC and VSC technologies. As shown in the chart, embedded onshore HVDC transmission built to supplement the AC grid is the dominant use case. HVDC lines to support the integration of onshore renewables and offshore wind is a growing use case as well, with the remainder being accounted for by interconnectors between asynchronous grids, such as connectors involving ERCOT, Hydro Quebec, or between the larger Eastern and Western Interconnections. This chart does not include the capacity of the already existing back-back converters in the U.S. that also use HVDC technology.

FIGURE 23. USE CASES FOR INSTALLED AND PLANNED HVDC TRANSMISSION IN NORTH AMERICA



Source: DNV

Table 12 summarizes in more detail the specific HVDC-related benefits that drive the choice of HVDC technology for seven major use cases. As shown in the table, and consistent with the discussions above, HVDC technology offers unique advantages over AC transmission for these use cases based on capabilities that are applicable for some but not all of these use cases.

TABLE 12. USE CASES FOR HVDC TRANSMISSION

Use Case	Description/Features
1. Integration of remote renewables and offshore wind	More cost effective and stable for long-distance access to remote renewables Offers relatively high availability and capacity, low maintenance, and low losses for long distance transmission of renewables Superior controllability for integrating volatile renewable generation and stabilizing AC networks Allows for large export capacity from weak (but renewable rich) portions of the AC grid
2. Long-distance bulk-transmission	Overhead HVDC lines: Offers lower-cost, high-capacity transmission over longer distances, with lower losses, and less right of way than AC transmission lines Underground and submarine HVDC cables: offers lower-cost, high-capacity transmission over long distances; using underground HVDC minimizes environmental impact and reduces outage risks
3. Corridor transfer capability increase	Conversions of AC transmission to HVDC (and upgrades of aging HVDC lines) allow for substantial increases in the transfer capacity of existing transmission lines and corridors without the need for additional right of way and new greenfield transmission lines
4. Interconnections between asynchronous grids	Allows power transmission between AC grids that are not synchronized Asynchronous HVDC interconnection also allows for precise control of power transfer (for both reliability and trading) and the blocking of cascading failures without an increase of the grids' short-circuit current Two asynchronous systems can use HVDC to provide each other frequency support, balancing power, and operating reserve when needed
5a. Interconnections between BAs within a synchronous region	An HVDC link connecting neighboring balancing areas within a single synchronous AC network allows the BAs to exchange energy (for reliability and trading), provide balancing power, and share operating reserves (similar to HVAC transmission links) HVDC can additionally provide AC grid support services, such as power flow control (avoiding the need for phase shifters), dynamic voltage control (avoiding the need for STATCOMs), and system stability and dynamic support
5b. Transmission Embedded within a single BA[57]	HVDC transmission connected to different points of the AC grid within a single balancing area provides large transfer capability without imposing stability issues or loop flows on the AC grid It also provides power flow control functions within the AC network (such as for congestion management and loss reduction), dynamic voltage control (at each interconnection point), system stability improvement (including mitigation of stability-based AC transmission constraints), and the mitigation of AC-grid contingency impacts and system cascading failure risks
6. Infeed to load centers/urban areas	Allows for more cost-effective, high-capacity transmission feeds into urban areas and other large load centers where overhead lines are not an option or rights-of-way are very limited VSC-based underground DC transmission can be added to existing transmission rights-of-way to reliably deliver more power to load centers without increasing short-circuit levels Provides additional reliability services, such as dynamic voltage support within the load center
7. Providing power to remote locations (including small islanded grids and offshore platforms)	VSC HVDC transmission can support weak or even passive islanded or remote grids, stabilize the islanded AC networks, and improve grid performance in the event of power disturbances

57 See also CTC Global, Technical Brochure: Influence of Embedded HVDC Transmission on System Security and AC Network Performance, Ref 536, at https://e-cigre.org/publication/536-influence-of-embedded-hvdc-transmission-on-system-security-and-ac-network-performance.

Table 13 below summarizes the extent to which different HVDC use cases avail themselves to provide the AC grid services discussed in Table 4 through Table 9 in Section II.4.b above.[58]

TABLE 13. HVDC GRID SERVICES BY USE CASE

	Type of AC grid connection →	Islanded AC grids		Strong / weak AC grids			
					Embedded		
	Type of use case → Grid Service ↓	Integration of remote renewables	Providing power to remote locations	Connections between asynchronous regions	Embedded within a synchronous region	Embedded within a single BA	Infeed to load centers/urban areas
Transmission functions	AC voltage and frequency control	VSC	VSC				
	Reactive power control (static)	VSC	VSC	VSC	VSC	VSC	VSC
	Real power control	**HVDC**	**HVDC**	**HVDC**	**HVDC**	**HVDC**	**HVDC**
Grid operations support	Voltage support/reactive power control (dynamic)	VSC	VSC	VSC	VSC	VSC	VSC
	Synthetic inertia*	*		VSC	*	*	*
	Frequency response*	VSC		**HVDC**	*	*	*
	Regulation, ramping, spinning reserves*	VSC		**HVDC**	**HVDC**	*	*
Autonomous line dispatch	External Power (Tracking) Control			**HVDC**	**HVDC**	**HVDC**	**HVDC**
	AC Line Emulation			**HVDC**	**HVDC**	**HVDC**	**HVDC**
Power quality support	AC grid oscillation damping			**HVDC**	**HVDC**	**HVDC**	**HVDC**
	AC phase balancing			VSC	VSC	VSC	VSC
Contingency operations	Run-back / run-up schemes			**HVDC**	**HVDC**	**HVDC**	**HVDC**
	Emergency energy imports			**HVDC**	**HVDC**	**HVDC**	**HVDC**
	Black-start and system restoration	VSC	VSC	VSC	VSC	VSC	VSC
Reliability & Market Optimization	AC grid power flow optimization			**HVDC**	**HVDC**	**HVDC**	**HVDC**
	Resource adequacy, capacity imports*			**HVDC**	**HVDC**		
	Intertie optimization*			**HVDC**	**HVDC**		

HVDC = both LCC & VSC can provide the service
VSC = only VSC converters can provide the service
* requires coordination with neighboring system or connected resource (e.g. storage)

The table also indicates whether the specific grid services can be provided by both LCC and VSC based HVDC systems ("HVDC") or only by VSC-based HVDC systems ("VSC"). As shown, not all HVDC grid services can be provided from all use cases. For example, an HVDC line embedded within a synchronous AC grid will not be able to provide frequency response services, unless generation or storage resources are directly connected to the HVDC system. Similarly, HVDC

[58] "Long distant transmission" and "corridor transfer capability increase" are not listed in Table 13 because the grid services that HVDC technologies can provide under these circumstances depend on the subset of listed use cases shown in the table.

lines based on LCC technology will not be able to deliver black-start services, unless a suitably-sized generator is included to provide startup commutating voltage.

III. HVDC Planning Studies and Grid Codes

The modeling tools that grid planners use for their planning studies need to be adapted to be able to capture HVDC characteristics. Only then can planners evaluate the extent to which HVDC solutions can be used to address identified transmission needs. Similarly, grid codes need to evolve to define the standards and requirements for the performance of HVDC systems and their impact on the AC networks. While not all system operators have developed grid codes for HVDC systems or adapted their planning tools to be able to evaluate HVDC transmission solutions, substantial experience already exists as shown in our earlier discussion of the SPP-EPRI HVDC effort.

A. Planning Studies for HVDC

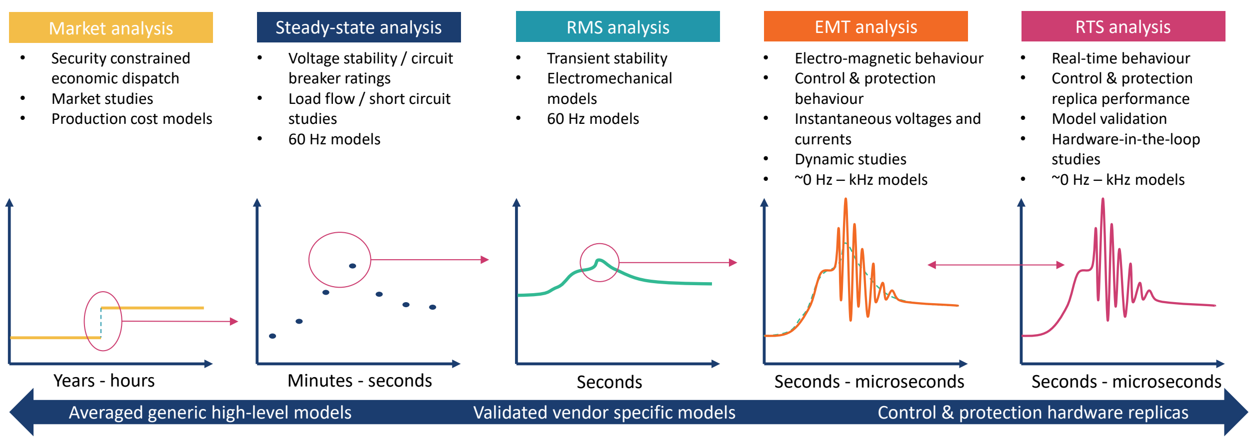
Similar to AC transmission expansion planning projects, HVDC systems need to be analyzed through a number of often sequential studies which gradually add more detail in terms of scope, system performance, model fidelity and temporal granularity, as illustrated in Figure 24. The first studies to be performed are often market studies, focusing on the HVDC system impact on the power system economics as whole, often looking at the hourly performance over a horizon of years to decades under varying energy mix scenarios. Depending on the application, these studies are used for the economic justification of an HVDC project, or to provide insight into the revenue streams and risks to the business case.

In subsequent steps, the technical impact on the grid is analyzed. This starts with steady-state analysis such as power flow analysis to assess the impact on thermal ratings of the AC grid, as well as short-circuit analysis to assess the impact on short-circuit ratings and breaker ratings of the existing AC grid. Next, a dynamic/transient stability assessment is typically performed using root mean squared (RMS) models which are an averaged representation of the electromechanical behavior of the AC grid at 60 Hz. Finally, the majority of the system integration studies are performed using electromagnetic transient analysis, studying the HVDC systems behavior and performance at sub-cycle timescales.

Each subsequent analysis step requires representations or models of the HVDC system that become increasingly more representative of the actual system which will finally be installed. The first analyses can be achieved with generic averaged or approximate representations, but as more detail is required, the models used in the study need to incorporate increasingly more aspects of the converter technology used. Since the behavior of HVDC systems is to a large extent determined by the non-standardized vendor specific technology implementations and control & protection systems, it is imperative to start using vendor specific models in the more detailed technical studies.

The ultimate step in power system analysis are the control & protection hardware-in-the-loop real-time simulation studies, in which the dynamic performance of the actual HVDC control and protection systems is studied and verified in real-time. In this case, a hardware replica of the real control & protection system of the HVDC link is used instead of a model to ensure all possible effects are captured.

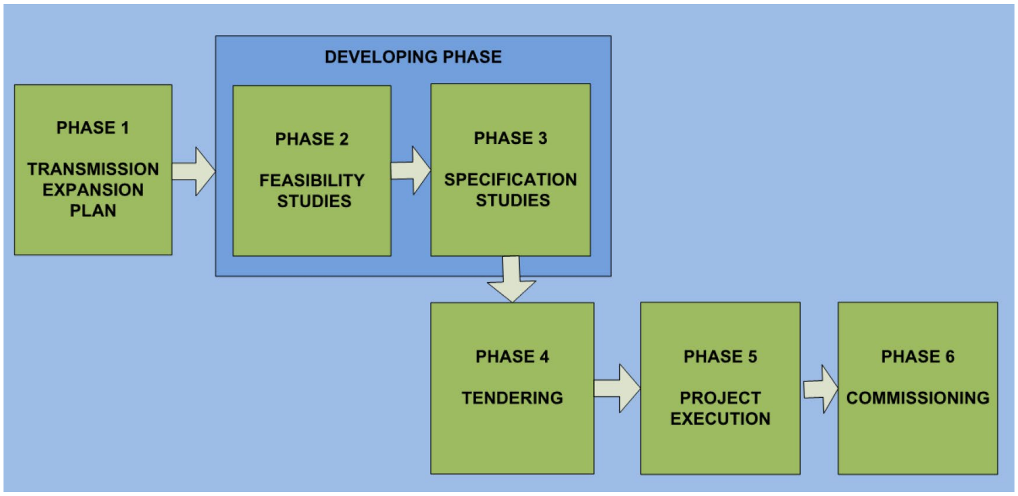
FIGURE 24. TYPES OF POWER SYSTEM ANALYSIS USED IN THE INTEGRATION OF HVDC SYSTEMS



To assist system operators in their effort to analyze HVDC options in planning studies, IEEE's HVDC & FACTS Subcommittee established a Working Group on "Studies for Planning of HVDC," which published a technical report (PES-TR86) summarizing how the relevant studies in each planning phase should model and evaluate HVDC projects, including in each of six planning and project development phases ranging from Transmission Expansion Plan, Feasibility Studies, Specification Studies, Tendering, Projects Execution, to Commissioning, as summarized in

Figure 25 below.[59] System operators and owners will need to be involved in all phases shown in the figure.

FIGURE 25. PLANNING, DEVELOPMENT, AND GRID INTERCONNECTION PHASES FOR HVDC PROJECTS



Source: IEEE PES-TR86 Technical Report "Studies for Planning HVDC," February 2021, (Figure 1).

During the transmission **expansion planning** phase, system operators first identify the "needs" for new transmission based on long-term load and resource forecasts and planning criteria. They then assess candidate solutions through technical reliability assessments—and sometimes economic/market and social/environmental evaluations—to select the most cost-effective, most valuable, or otherwise most attractive solution for addressing the identified transmission needs. The evaluation and procurement of HVDC solutions requires the following studies, analyses, and efforts.

Feasibility Studies for HVDC solutions to address the identified need will have to evaluate the impact of a new HVDC project to the existing AC system. The first step in that evaluation gathers and verifies AC and preliminary DC system data, transmission routes, and technologies, based on which the second step performs modeling and simulation studies to examine all credible options for transmission expansion and identifies several alternatives for further consideration in more detailed studies.

The analyses for feasibility studies of HVDC systems and their performance in the interconnected power grid include:

[59] IEEE PES-TR86 Technical Report "Studies for Planning HVDC," February 2021 at https://resourcecenter.ieee-pes.org/publications/technical-reports/PES_TP_TR86_TD_022521.html. See also Table 1 for the roles of different stakeholders in these study phases.

- Steady-state power flow analysis to determine desired interconnection points, operating range of the HVDC links, and the need for additional equipment such as SVCs and STATCOMs;
- Short circuit analysis to evaluate system strength (short circuit level), protection issues, ratings, and operating range;
- Transient and dynamic stability analysis to address dynamic performance of HVDC and its impact on AC networks in terms of voltage, frequency, angle stabilities for transmission line trips and potential HVDC failure;
- Electromagnetic transient (EMT) analysis to examine harmonics and resonances, commutation failure, etc.; and
- Preliminary cost and benefit evaluation, potentially also considering environmental concerns and policies.

The **Specification Studies** then provide more details and additional information for which additional simulations are performed to identify required HVDC system behavior and formal requirements. All specification studies are performed by the system operators. The technical specifications require an update of the preliminary DC data for each HVDC system in addition to updated existing and foreseen AC system data. The technical specifications:

- Define the expected Short Circuit Capacity (SCC) range, dynamic performance requirements of HVDC, and the expected reactive power response and temporary overvoltage limit;
- Perform EMT simulations with detailed HVDC models including the converter valves, filters, transformers, communication delays, and detailed controllers;
- Determine harmonic impedance of the existing AC grid;
- Study coupling effects if HVDC is routed parallel to AC lines; and
- Perform multi-infeed and interaction studies.

This phase also includes the specification of grid code requirements for AC and DC systems, integration requirements, communication and control interfaces, control system performance requirements, protection system performance requirements, and protection of AC systems close to an HVDC System.

During the **Procurement Phase**, manufacturers and vendors of the HVDC systems perform AC system integration and interaction studies, a main circuit parameter study, digital transient model simulation, losses calculation, external isolation and air clearance analysis, and an impact study of HVDC converters on sub-synchronous torsional damping, the output of which informs converter station design.

The **Project Execution** phase involves detailed system engineering, converter station design, converter station construction for the HVDC station, and the assessment of network interaction. The associated studies include AC equivalent, transient stability analysis incorporating frequency control, power modulation control, and EPC, black start studies, multi-infeed and interaction studies, and factory acceptance tests.

B. HVDC Models for Planning Studies

Generic and detailed HVDC models, in the relevant industrial software packages, are needed to conduct the simulations used in different phases of the planning studies summarized above. Accurately modeling HVDC links and their interactions with the AC networks for credible operating scenarios are essential to evaluate the technical performance and economic effects, to determine the most suitable options, and to prepare the necessary detailed technical specification.

Detailed models of HVDC systems are vendor specific and are typically delivered as a "black-box" to protect the vendors' intellectual property (i.e. the user cannot see what is inside or change parameters). Due to this lack of visibility, it is important to contractually specify the provision of the models, the depth and detail of modelling, and the (independent or independently witnessed) validation of the model using control & protection hardware in the loop real-time simulation. Similarly, throughout the lifetime of the HVDC link, the models should get updated any time a material modification is made to the control & protection software that affects the behaviour and performance of the converters.

Even in North America, which lags Europe and other parts of the world in the deployment of HVDC technology, the industry has made significant progress in developing HVDC models suitable for planning studies. For example:

- CAISO has already started efforts in finding and promoting standard models and approaches for assessing VSC-HVDC and is in the process of assessing applicable models for dynamic stability analysis.[60]

[60] California ISO, 2022-2023 Transmission Plan, May 18, 2023. Available at: http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf

- The steady-state and dynamic stability software analysis package PSSE which is used in the majority of the US includes standard library models for HVDC converters. The WECC region, however, uses a package called PSLF™ which did not include HVDC models in its standard library. Cal Western has been working with industry experts to develop dynamic stability models for VSC-HVDC lines and to find modeling solutions that work in a PSLF™ environment; they are now able to do dynamic analysis of VSC-HVDC lines using PSLF™.[61]
- ISO-NE has used phase measurement unit (PMU) data to validate their HVDC model for transient stability analysis.[62]
- EPRI is currently working with SPP to help them develop the required planning and grid codes for HVDC, in addition to EPRI's previous R&D efforts for HVDC model development and validation for planning studies.[63,64] EPRI reviewed existing performance, study, and modeling criteria used in United States and other countries and then provided recommendations on planning criteria and performance requirements of HVDC systems including reactive power and voltage control, active power control, frequency ride-through and control, stability and other oscillations, under voltage fault ride through, temporary over-voltage, emergency power controls, power quality, system restoration, and grid forming controls. EPRI also recommended the studies and associated software and models to be performed by HVDC system owners in different stages of an HVDC project including feasibility, planning, and design studies, and the network models to be provided by system operators that represent their AC transmission systems including detailed network models, short-circuit model, and frequency dependent impedance loci for power quality studies. Moreover, recommendations are provided on the model requirements and simulation tools including preliminary RMS model (feasibility studies), preliminary EMT model (planning studies), as built EMT and RMS models (design studies).WECC's HVDC Task Force has been working on developing simple planning models for both powerflow and dynamic time-

61 https://stakeholdercenter.caiso.com/Comments/AllComments/6cdb6ed2-f22c-4064-96e1-739c8db239ef

62 NASPI Technical Report, Model Validation Using Phasor Measurement Unit Data, March 20, 2015. Available at: https://www.naspi.org/sites/default/files/reference_documents/19.pdf?fileID=1416

63 EPRI, Technical Update: FACTS and HVDC Modeling for Power System Stability Studies, 2013; and EPRI, Models and Model Validation for Planning Studies: Technical Update, 2011.

64 EPRI, HVDC Recommendations for Southwest Power Pool, Recommendations for planning criteria, grid code performance, models and simulations tools, June 2023.

domain simulations for HVDC point-to-point transmission including both LCC and VSC HVDC technologies.[65]

- NERC's ongoing project SAR 2022-04 aims to update the NERC Standards by including EMT models and studies to ensure reliable operation of the bulk power grid.[66]
- U.S. DOE has recently supported a multi-lab effort (NREL, ORNL, and PNNL) on developing EMT models for HVDC including (1) advanced simulation algorithms for fast simulation of high-fidelity models of scalable DC architectures; and (2) a library of DC network components' EMT models (vendor agnostic HVDC converter substations, breakers, DC line/cable, scalable radial multi-terminal DC (MTDC), meshed MTDC, and MTDC grid architectures).[67]

We are concerned, however, that some of the current efforts are overly "defensive" in nature—developing grid codes and interconnection criteria that are focused only on possible HVDC-related problems that might occur, without making sure to implement planning and operational processes that take full advantage of modern VSC-based HVDC capabilities. HVDC technology should not be held to a "higher" standard than other technologies without understanding how its capabilities can best be utilized.

C. Grid Codes for HVDC

Grid codes define the general requirements and characteristics for new equipment that is planned for interconnection with the existing power grid. They are developed by system operators to ensure stable and reliable system operation.

In North America, a significant part of the grid code is defined based on NERC standards. The existing transmission planning (TPL) and balancing (BAL) standards do have provisions for HVDC systems, but these appear to be based on the characteristics of terrestrial overhead line and

[65] Pouyan Pourbeik, Power and Energy, Analysis, Consulting And Education, PLLC, Memorandum to WECC HVDC TF & EPRI P40.016 re Proposed Model Specification for Simple VSC-HVDC, March 7, 2018 (Revised 5/1/18; 11/12/18) at https://www.wecc.org/Reliability/Propose%20Generic%20VSC-HVDC%20Model.pdf.

[66] NERC, Program Areas & Departments, Standards, Project 2022-04 EMT Modeling at https://www.nerc.com/pa/Stand/Pages/Project2022-04EMTModeling.aspx.

[67] DOE Office of Electricity TRAC *Peer Review*, at https://www.energy.gov/sites/default/files/2022-05/DOE_OE_TRAC_Peer_Review_Project_dc_ac_Suman_Debnath.pdf

LCC based HVDC systems, and do not sufficiently capture the characteristics and capabilities of modern VSC and underground or submarine cable based HVDC systems.

As noted earlier, SPP has engaged EPRI to develop its criteria for HVDC system modeling, planning studies, and performance assessment for evaluating new HVDC project requests in its territory.[68] EPRI documented HVDC grid codes (or similar documents) in North America (California ISO, ISO-New England, ERCOT, and NERC); the European Union and 7 individual European jurisdictions; and 3 jurisdictions in the Asia-Pacific region. In addition, EPRI reviewed for SPP international standards such as IEEE 2800-2022 in the context of HVDC systems.

In North America, California ISO's Transmission Plan already includes specifications covering ratings and performance criteria.[69] Meanwhile, ISO-New England treats an HVDC system as an Elective Transmission Upgrade (ETU) following its planning procedure "New England Planning Procedure No. 5-6: Interconnection Planning Procedure for Generation and Elective Transmission Upgrades" that includes study, modeling, and other requirements for ETUs.[70] In Texas, ERCOT's Nodal Operating Guides have several sections that provide requirements for operation and control, network modeling, and disturbance monitoring and system protection.[71] NERC prescribes frequency and voltage performance standards and ride-through requirements for generators that can inform settings for HVDC converters.[72]

EPRI found that "the most developed requirements are from the European Union (and Great Britain), primarily driven by the European HVDC grid code, and its place in European and UK

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[68] EPRI, *HVDC Recommendations for SouthwestPower Pool: Review of performance standards, studies, and modelling of HVDC Grid Codes*, Interim Report, Technical Update, May 2023, posted with the SPP Transmission Working Group meeting materials for June 6, 2023 ("EPRI Report" at https://www.spp.org/spp-documents-filings/?id=18447.

[69] See EPRI report at p. 19 and California ISO/I&OP, "ISO 2021-2022 Transmission Plan - Appendix G Description and Functional Specifications for Transmission Facilities Eligible for Competitive Solicitation," California ISO/I&OP, 2022.

[70] See EPRI report at p. 19 and ISO-NE, "ISO New England Planning Procedure No. 5-6: Interconnection Planning Procedure for Generation and Elective Transmission Upgrades," ISO-NE, May 6, 2022.

[71] See EPRI report at p. 19 and ERCOT, "ERCOT Nodal Operating Guides - Section 2: System Operations and Control Requirements," February 1, 2023; "ERCOT Nodal Operating Guides - Section 5: Network Operations Modeling Requirements," November 1, 2018; "ERCOT Nodal Operating Guides - Section 6: Disturbance Monitoring and System Protection," March 1, 2022.

[72] See EPRI report at p. 20 and NERC, "PRC-024-3—Frequency and Voltage Protection Settings for Generating Resources," July 17, 2020; NERC, "Project 2020-02 SAR: Generator Ride-Through Standard (PRC-024-3 Replacement)," April 28, 2022.

Law."[73] The European Commission published regulations to establish a uniform grid code for HVDC systems in 2016. The European Network of Transmission System Operators for Electricity (ENTSO-e, the association of European grid operators) has published guidance notes to assist implementation of the EU code as a national code for HVDC in each of the member states.[74] The Great Britain Grid Code has incorporated the minimum technical, design, and operation criteria, compliance process, and planning code for new grid connections including HVDC.[75] GB Grid Code (OC9.4.5.1) defines the requirements for black start service providers.[76] Ireland has revised its EirGrid Code to align with the European HVDC Regulations and developed a document for simulation requirements.[77] Northern Ireland's SONI grid code includes provisions for HVDC systems.[78] Finland's system operator Fingrid has published the system technical requirements of HVDC systems.[79] The Danish system operator Energinet interpreted the grid code for HVDC systems for the requirements for voltage quality, simulation models, reactive control, etc.[80] The Netherlands's Authority for Consumers and Markets (ACM) published the electricity network code that aligns with the European HVDC Grid Code for new HVDC systems.[81] Similarly, the German Association for Electrical Engineers (VDE) published its version of the HVDC grid code.[82]

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73 See EPRI report at p. 113. The European Commission, "Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules," *Official Journal of the European Union*, August 9, 2016 at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32016R1447#d1e211-1-1.

74 ENTSO-e, "CNC—Implementation Guidance Documents" at: https://www.entsoe.eu/network_codes/cnc/cnc-igds/, Accessed 04/24/2023.

75 See EPRI report at p. 21 and NGESO, "EUROPEAN CONNECTION CONDITIONS—Issue 6 Revision 14,", October 6, 2022.

76 National Grid, Operating Code No. 9 (OC9) Contingency Planning, May 24, 2016 at https://www.nationalgrid.com/sites/default/files/documents/8589935287-OC9%20Contingency%20Planning.pdf

77 See EPRI report at p. 22 and Eirgrid Future Networks, Innovation and Planning, "Simulation Studies and Modelling Requirements for Compliance Demonstration—Version 1.0," EirGrid, March 23, 2021.

78 See EPRI report at p. 23 and SONI, "SONI GRID CODE," October 8, 2020.

79 See EPRI report at p. 23 and Fingrid, "Suurjännitteisten tasasähköjärjestelmien järjestelmätekniset vaatimukset,", 2018.

80 See EPRI report at p. 23 and Energinet, "Requirements set under EU regulation 2016/1447: Requirements for grid connection of high-voltage direct current systems and direct current—connected Power Park modules (HVDC), articles 11–54," October 14, 2019.

81 See EPRI report at p. 24 and De Autoriteit Consument & Markt , "Netcode elektriciteit," Overheid.nl , at https://wetten.overheid.nl/BWBR0037940/2022-12-18.

82 "Technical Connection Rule for the connection of HVDC systems and generation plants connected via HVDC systems", https://www.vde.com/en/fnn/topics/technical-connection-rules/tcr-hvdc

In the Asia-Pacific Region, the Australian Energy Market Operator (AEMO) publishes the Power System Model Guidelines that contain detailed requirements for power system models for load flow, short circuit, dynamic RMS and EMT models, and specific provisions for HVDC systems.[83] The Electricity Market Authority of Singapore publishes the Singaporean Transmission Code that includes requirements for LCC HVDC systems.[84] New Zealand's Electricity Industry Participation Code has extensive provisions for a single HVDC system.[85]

The existing grid codes and grid code requirements for HVDC systems typically apply to the performance and behaviour at the AC grid interface of the HVDC system, and do not cover the DC side. Currently, no grid code for the DC side of HVDC systems exists, and DC side performance and behavior is determined by the HVDC vendor, which complicates the creation of multi-terminal, multi-vendor HVDC grids.

For the international standards, the IEEE Standard 2800-2022 for *Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power* provides requirements for interconnection, capability, and performance of an IBR in transmission systems.[86] If a resource is connected to the AC grid via a VSC HVDC gen-tie then the HVDC system combined with the resource will be considered as an IBR, to which the IEEE standard 2800 will apply.[87] IEEE 1378-2022 provides general guidelines for commissioning HVDC converter stations and associated transmission systems.[88] The International Electrotechnical Commission (IEC) has published multiple standards for HVDC systems related to performance requirements, power quality requirements, power losses determination for HVDC converter stations, installation and system tests, audible noises, etc.[89]

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83 See EPRI report at p. 24 and Operational Analysis and Engineering, "Power System Modelling Guidelines," AEMO, 29 June 2018.

84 See EPRI report at p. 24 and Energy Market Authority of Singapore, "Transmission Code," Energy Market Authority of Singapore, 15 Dec 2022.

85 See EPRI report at p. 24 and Electricity Authority (of New Zealand), "Electricity Industry Participation Code 2010," Electricity Authority, November 2022.

86 IEEE, "IEEE 2800 Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems," IEEE, 2022.

87 See EPRI report at p. 25.

88 IEEE Standards Association, IEEE Guide for Commissioning Line-Commutated Converter (LCC) High-Voltage Direct-Current (HVDC) Converter Stations and Associated Transmission Systems, IEEE 1378-2022, April 28, 2023 at https://standards.ieee.org/ieee/1378/6945/

89 IEC TR 60919 Performance of high-voltage direct current (HVDC) systems with line-commutated converters; IEC 61000-4 IEC 61803 Determination of power losses in high-voltage direct current (HVDC) converter stations; IEC TS 61973 High voltage direct current (HVDC) substation audible noise; IEC 61975 High-voltage direct current (HVDC) installations—System tests; and IEC/TR 63411 Grid Connection of Offshore Wind via VSC-HVDC System.

The extensive experience with grid codes, modeling, and planning studies for HVDC systems provide valuable guidance to system planners in different regions to evolve their planning practice to incorporate HVDC systems in their planning.

IV. Considering HVDC Capabilities in Transmission Planning and Benefit-Cost Analyses

Capturing the unique capabilities that HVDC systems offer can challenge conventional transmission planning processes, which tend to be focused on the cost of meeting an identified incremental transmission need. Most transmission planning in North America is focused on individual transmission needs associated with maintaining system reliability, increasing market efficiency, facilitating clean energy and other public policy, or facilitating specific generation interconnection requests.[90] These siloed transmission planning processes make it challenging to consider any benefits and capability that HVDC transmission technology can offer beyond resolving individual "needs" identified through one of these planning processes. These planning processes make it virtually impossible to consider HVDC capabilities that may not be required to address the specific need (such as the need to interconnect large scale renewable generation in the near term), even if they can already be anticipated to be very valuable in addressing additional needs in the near future (such as providing power flow control, dynamic voltage control, mitigation of AC grid contingency and stability constraints, or blackstart and system restoration).

To consider in transmission planning today that HVDC technology can address multiple needs over time requires proactive planning processes that examine multiple needs (or multiple drivers/values) over both the near, medium, and long-term. Examples of such proactive, multi-value, and long-term planning processes exist, such as the multi-value planning processes used by MISO, CAISO, and others are listed in Table 14.[91]

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90 For example, see J. Pfeifenberger and J. DeLosa, *Transmission Planning for a Changing Generation Mix*, presented at OPSI 2022 Annual Meeting, Indianapolis, IN, October 2022 at https://www.brattle.com/insights-events/publications/transmission-planning-for-a-changing-generation-mix/.

91 This table is an updated version of Table 7 presented in Brattle-GridStrategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, October 2021 at https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/.

TABLE 14. EXAMPLES OF EFFICIENT PLANNING PROCESSES

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[92]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[93]	✓	✓	✓		
ERCOT CREZ (2008)[94]	✓			✓	
MISO RGOS (2010)[95]	✓	✓		✓	
EIPC (2010-2013)[96]	✓		✓	✓	✓
PJM renewable integration study (2014)[97]	✓		✓	✓	
NYISO PPTPP (2019)[98]	✓	✓	✓	✓	
ERCOT LTSA (2020)[99]	✓		✓		
SPP ITP Process (2020)[100]		✓		✓	
PJM Offshore Tx Study (2021)[101]	✓		✓	✓	
MISO LRTP-MVP (2022+)[102]	✓	✓	✓	✓	
Europe: ENTSO-e TYNDP and CBA[103]	✓	✓	✓	✓	✓
Australian Examples:					
- AEMO ISP (2022)[104]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[105]	✓	✓	✓	✓	✓

92 CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

93 American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007.

94 D. Woodfin (ERCOT), *CREZ Transmission Optimization Study Summary*, presented to the ERCOT Board of Directors, April 15, 2008 at https://www.ercot.com/files/docs/2008/04/08/item_6___crez_transmission_report_to_puc___woodfin_bojorquez.pdf.

95 Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010 at https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

96 See *Eastern Interconnection Planning Collaborative at https://eipconline.com/*, including Phase I and Phase II planning reports

97 GE Energy Consulting, *PJM Renewable Integration Study, Task 3A Part C: Transmission Analysis*, March 31, 2014 https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-c-transmission-analysis.ashx.

98 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019.

99 J. Bernecker (ERCOT), *2020 LTSA Review*, December 15, 2020 at https://www.ercot.com/files/docs/2020/12/14/2020_LTSA_Review_Dec2020.pdf and *2020 Long-Term System Assessment for the ERCOT Region*, December 20202, as posted at: Planning (ercot.com).

100 SPP, *2020 Integrated Transmission Planning Report*, October 27, 2020 at https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf. As noted in the report (at p 8), the (multi-value) objectives of the SPP ITP process are to: resolve reliability criteria violations; improve access to markets; improve interconnections with SPP neighbors; meet expected load-growth demands; facilitate or respond to expected facility retirements; synergize with the Generator

Unfortunately, such multi-value processes are not wide-spread and account for less than 10% of the average annual transmission investments approved in North America.[106] The large majority of North American transmission investments is in reaction to incremental, individual reliability needs and solutions that narrowly address these needs without considering the extent to which multiple near- and long-term needs could be addressed through broader-scale solutions at lower system-wide costs.

Where improved, multi-value planning frameworks are utilized—such as in MISO's LRTP and in new long-term planning processes envisioned by FERC[107]—they are uniquely capable of considering the multiple transmission needs that HVDC transmission systems are able to address at lower cost.

The next section of the report first discusses how values of different HVDC capabilities can be considered in multi-value transmission planning and then covers the unique opportunities of upgrading existing transmission lines to modern HVDC transmission technology.

Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Attachment AQ processes; address persistent operational issues as defined in the scope; facilitate continuity in the overall transmission expansion plan; and facilitate a cost-effective, responsive, and flexible transmission network.

[101] PJM, *Offshore Transmission Study Group Phase 1 Results*, presented to Independent State Agencies Committee (ISAC), July 29, 2021 at https://www.pjm.com/-/media/committees-groups/state-commissions/isac/2021/20210729/20210729-isac-presentation.ashx.

[102] Midwest ISO, Long Range Transmission Planning—Reliability Imperative at https://www.misoenergy.org/planning/transmission-planning/long-range-transmission-planning/

[103] See Entsoe, A European-wide vision for the future of our power network at https://tyndp.entsoe.eu/explore; https://2022.entsos-tyndp-scenarios.eu/; and Entsoe, What is the Cost-Benefit Analysis Framework? at https://tyndp.entsoe.eu/explore/what-is-the-cost-benefit-analysis-framework.

[104] AEMO, *2022 Integrated System Plan*, June 2022. https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf

[105] Transgrid, *Energy Vision: A Clean Energy Future for Australia*, October 2021 at https://www.transgrid.com.au/media/x4mbdody/transgrid_energy_vision.pdf.

[106] For example, see J. Pfeifenberger and J. DeLosa, *Transmission Planning for a Changing Generation Mix*, presented at OPSI 2022 Annual Meeting, Indianapolis, IN, October 2022 at https://www.brattle.com/insights-events/publications/transmission-planning-for-a-changing-generation-mix/.

[107] FERC's current Notice of Proposed Rulemaking (NOPR) on transmission planning (Docket No. RM21-17-000) envisions that all grid operators would employ proactive, multi-value, long-term planning processes in the near future.

A. Multi-Value Planning of HVDC Systems

Considering the benefits that HVDC capabilities can provide to the electricity grids beyond addressing a specific incremental system need requires that grid planners: (1) understand and recognize HVDC capabilities (as discussed above); (2) learn to consider these capabilities in the technical/reliability analyses used in grid planning (as discussed in Section III above); and (3) reflect the added value offered by HVDC capabilities when comparing the cost of both HVDC and AC transmission solutions that can address the immediate transmission needs identified by the planners. The latter ideally relies on a multi-value planning framework that recognizes the benefits of HVDC capabilities relative to the incremental costs of providing these capabilities through other technologies. When considering the value of the full set of capabilities that HVDC technologies can offer, it becomes apparent that HVDC transmission options can offer the lowest-cost or highest-value solution for addressing identified future transmission needs.

For example, when evaluating VSC-HVDC transmission options for transmission needs related to the integration of significant amounts of distant renewable resources in weak areas of the existing AC grid, HVDC solutions may be compared to 765 kV AC transmission solutions, as currently done by the Midcontinent ISO (MISO). This comparison requires the consideration of the capabilities, characteristics, and additional grid-integration equipment necessary under the two alternatives, as summarized in Table 15 below.

As shown, VSC-HVDC systems offer a number of advantages over HVAC options, such as providing AC grid stability in regions with high inverter concentration, lower-costs for long-distance transmission, power flow control, dynamic reactive power control and voltage response at each converter station, dynamic AC grid support, fault isolation, and less additional grid support equipment—consistent with the discussion of HVDC characteristics and use cases discussed earlier in this report.

TABLE 15. COMPARING VSC-HVDC AND 765KV AC ATTRIBUTES FOR SYSTEM INTEGRATION

Attribute	765 kV AC	VSC HVDC (±525 kV)
Power Transfer Capability	▪ Decreases substantially with line length/distance ▪ Enhanced with series/shunt reactive compensation	▪ Generally independent of line length/distance ▪ Main limitations associated with equipment ratings
Reactive Support and Voltage Control	▪ Generates large amount of reactive power at light load ▪ Consumes large amount of reactive power at high load ▪ Drastic swings require additional technologies & coordination (e.g. shunt reactors/capacitors, STATCOMs)	▪ Designed to produce or absorb reactive power at both converter stations ▪ Controls AC terminal voltages automatically for steady state and dynamic voltage regulation
Fault Performance: General AC System Faults External to the Transmission Line	▪ Generally do not trip for AC system faults but also do not provide significant additional support ▪ Low voltages may cause significant tripping of nearby renewable generation with long restart time	▪ Rides through AC system faults without blocking ▪ Designed to provide dynamic support during AC system faults, which can support improved system response ▪ Improved voltage response results in less tripping of nearby renewable generation
Fault Performance: Faults on the Transmission Line (765 kV or VSC HVDC)	▪ Fault impact will be seen broadly through the system ▪ Tripping results in significant rerouting of power onto the underlying system, increasing reactive requirements and potentially leading to overloading or voltage collapse ▪ Tripping the line results in loss of short circuit level in the area near the line, weakening the AC system	▪ Direct fault impact on AC system is minimized by HVDC connection configurations ▪ Vast majority of faults are single pole, meaning the remaining pole can continue to transfer real power and produce/absorb reactive power to support AC system ▪ Loss of VSC HVDC pole does not result in significant loss of system short circuit level

AC Transmission

For fair comparison of HVDC link costs versus AC-only solutions, all costs associated with the AC solution system integration need to be considered:

- New interconnection facilities
  - EHV and native voltage substations, buswork, circuit breakers, and instrument transformers
  - New autotransformers to stepdown to native voltage
- Voltage and reactive power control
  - Line shunt reactors, shunt capacitors
  - Series compensation, (if applicable)
  - STATCOMs or synchronous condensers
- Power flow control – *potentially*
  - Phase shifters or other technology
- Underlying system impacts
  - Short circuit level increases may require lower-kV circuit breakers to be replaced
  - Underlying AC transmission line upgrades & expansion

Final investment cost of AC-only solutions plus additional integration requirements becomes significant when all necessary support is considered.

VSC HVDC

VSC HVDC is considered costly primarily due the high cost of HVDC converters, however there is significantly less additional system integration support required:

- New interconnection facilities
  - AC (345kV) substations, buswork, circuit breakers, etc…
- New HVDC converter stations on each end
  - Inherent voltage and reactive power control
  - Inherent power flow control
  - Other grid-supporting attributes…
- Underlying system impacts
  - No impact on short circuit level
  - Impacts on underlying AC transmission system can be managed due to controllability and other features

System integration of VSC HVDC is much less complex. It has inherent value-added attributes and can usually be integrated with fewer changes to the existing system.

minnesota power RBJ Engineering Corporation

Source: Presentation by Minnesota Power and RBJ Engineering to the MISO Planning Advisory Committee, May 31, 2023 (slides 18–19) at https://cdn.misoenergy.org/20230531%20PAC%20Item%2008b%20MP%20RBJ%20Presentation629028.pdf

To assess the costs and benefits of transmission options that can address multiple transmission needs will additionally require an estimation of the monetary value of these transmission characteristics. Table 16 provides examples of how to quantify the monetary value of certain HVDC capabilities (on a case-by-case basis) for consideration in such multi-value transmission planning efforts that include benefit-cost analyses.[108] For example, the value of the grid operators' ability to optimize the dispatch of HVDC systems in power markets to reduce congestion and losses on the surrounding AC grid can be estimated by simulating the line with nodal production cost models that can simulate the optimization of HVDC lines.[109] The value of HVDC converters' dynamic reactive power and voltage control capabilities (if and when needed) can be estimated as the avoided cost of deploying traditional equipment used to address these needs, such as STATCOMs, SVCs, or synchronous condensers.

TABLE 16. QUANTIFYING THE VALUE OF HVDC CAPABILITIES FOR TRANSMISSION PLANNING

HVDC-VSC Capability	Planning Benefits / Options for Quantification
1. Flow control/market optimization	• Estimate value of congestion relief and loss reduction on AC grid with nodal production cost model that can optimize HVDC
2. Dynamic reactive power and voltage control	• Avoided cost of STATCOMs, SVCs, or synchronous condensers
3. Lower long-distance transfer losses	• Market value of avoided losses on transmitted energy
4. Smaller footprint/right-of-way (ROW), including for undergrounding option	• Lower cost for right-of-way (e.g., 50ft less than for 765kV AC); lower cost of undergrounding; lower permitting risks
5. Reliability benefits (fault ride-through, lower N-1 contingency for bipoles, voltage support)	• Increased transfer capacity; reduced cost of contingency reserves; avoided AC equipment costs (e.g., additional lines, STATCOMs)
6. AC dynamic stability; power oscillation dampening; mitigate stability constraints on AC grid	• Avoided cost of power system stabilizers/supplemental power oscillation damping (POD) controllers on batteries, SVCs, STATCOMs, switched shunt equipment, synchronous condensers, etc. • Value of congestion relief on proxy constraints
7. Grid forming, grid services, synthetic inertia, blackstart/restoration, etc.	• Market value or avoided cost of providing the grid services through conventional means

Source: Presentation by J. Pfeifenberger to the MISO Planning Advisory Committee, June 1, 2023 (slide 4) at https://cdn.misoenergy.org/20230531%20PAC%20Item%2011a%20Brattle%20Presentation629029.pdf

Figure 26 illustrates how to assess the relative attractiveness of HVDC and HVAC solutions that can address a specific transmission need, such as the long-distance transmission of renewable generation in sparsely populated areas to distant load centers in MISO.[110] In evaluating

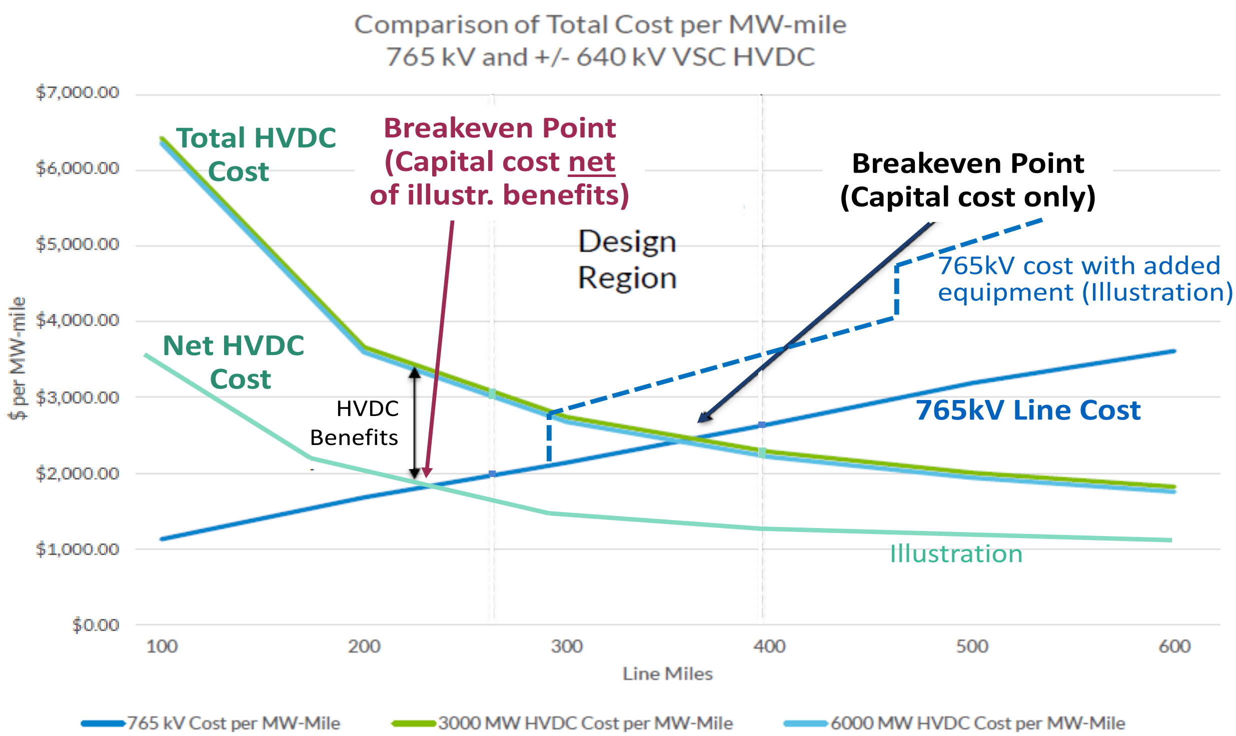
[108] This table was presented during a MISO Planning Advisory Committee (PAC) meeting on June 1, 2023. J. Pfeifenberger and L. Bai, HVDC Transmission: Multi-Value Planning Considerations and Experience, Slide 4 at https://www.brattle.com/insights-events/publications/hvdc-transmission-multi-value-planning-considerations-and-experience/.

[109] The ability to optimize the flow on HVDC lines to reduce congestion and losses when embedded in an AC grid, thereby enhancing the capability of the existing grid, typically offers substantial additional value. Because modern HVDC lines can be operated to behave like AC lines (i.e., in AC line emulation mode), the additional controllability will always be a (positive) net benefit.

[110] This example was presented during a MISO PAC meeting on June 1, 2023. Pfeifenberger and Bai, HVDC Transmission: Multi-Value Planning Considerations and Experience, Slide 5 at https://www.brattle.com/insights-events/publications/hvdc-transmission-multi-value-planning-considerations-and-experience/.

solutions for the identified transmission need, MISO compared the total capital cost of HVDC and 765kV AC solutions for different distances on a cost per MW-mile basis. That capital cost comparison identified a 360 mile "breakeven point" (see black arrow in Figure 26 below), indicating when the cost of HVDC transmission drops below the cost of the 765kV option.[111] This breakeven analysis, however, only reflects the benefit that HVDC offers for long-distance transmission. It does not consider other benefits and cost savings offered by HVDC technology relative to the AC solutions shown in Table 16, such as AC grid congestion relief and avoided AC equipment costs (e.g., for STATCOMs, synchronous condensers, or power system stabilizers). These HVDC benefits and avoided costs can be considered by netting them against HVDC investment costs, which shifts down the green HVDC line as illustrated in Figure 26.

FIGURE 26. CAPTURING OF HVDC BENEFITS IN THE COMPARION OF HVDC AND EHV-AC SOLUTIONS



This is a modified version of the chart in slide 29 of MISO, Discussion of Legacy, 765kV, and HVDC Bulk Transmission, March 8, 2023.

Source: Presentation by Johannes Pfeifenberger and Linquan Bai, HVDC Transmission: Multi-Value Planning Considerations and Experience, presented to the MISO Planning Advisory Committee, June 1, 2023, slide 5 at https://cdn.misoenergy.org/20230531%20PAC%20Item%2011a%20Brattle%20Presentation629029.pdf

[111] The original chart of this break-even analysis was presented at MISO's PAC meeting on March 8, 2023: MISO Planning Advisory Committee, Discussion of Legacy, 765 kV, and HVDC Bulk Transmission, March 8, 2023, Slide 29, at 20230308 PAC Item 07 Discussion of 765 kV and HVDC628088.pdf (misoenergy.org).

Under the HVDC benefits assumptions shown in the figure, this would yield a breakeven point of, for example, only 220 miles (as illustrated by the red arrow).[112] In the alternative, some of the additional AC equipment costs (such as the necessary reactive compensation for long HVAC lines at certain distances or the need for equipment to address stability concerns) can also be included in this comparison by shifting up the blue line for 765kV costs (as illustrated by the dashed blue line in the chart). While these adjustments to the MISO cost comparisons in Figure 26 are only illustrative, they highlight the distortions that would be created by comparisons that neither consider the added benefits of HVDC technology nor the potentially added costs incurred with conventional AC solutions. The importance of explicitly considering HVDC capabilities (or the additional cost of AC technologies needed to provide necessary capabilities) in such technology comparisons is also reflected in the European framework for planning and benefit-cost analysis discussed next.

B. European Transmission Planning, Benefit-Cost Framework, and Application to HVDC Projects

The multi-value framework discussed above is already formalized and extensively used for HVDC transmission in Europe. To facilitate the legislatively-mandated Europe-wide planning of regional and interregional transmission, the development of the required Ten Year Network Development Plans,[113] and the designation of "Projects of Common Interest,"[114] ENTSO-e has collaborated with the Agency for Cooperation of Energy Regulators (ACER) and the European Commission (EC) to develop a detailed framework for transmission planning and benefit-cost analyses. The proactive planning framework is based on scenario analyses with detailed scenarios defined specifically to "capture a plausible range of possible futures that result in different challenges for the grid" and a detailed "Guideline for Cost Benefit Analysis of Grid Development Projects."[115] The planning effort covers three different time horizons: mid-term (5–10 years), long-term (10–20 years), and very long-term (30–40 years). As summarized in Figure 27, the benefit-cost-analysis guideline assesses 15 different types of benefits in 9 benefit

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112 The actual magnitude of the HVDC benefits and resulting Net HVDC Costs will vary on a case-by-case basis.

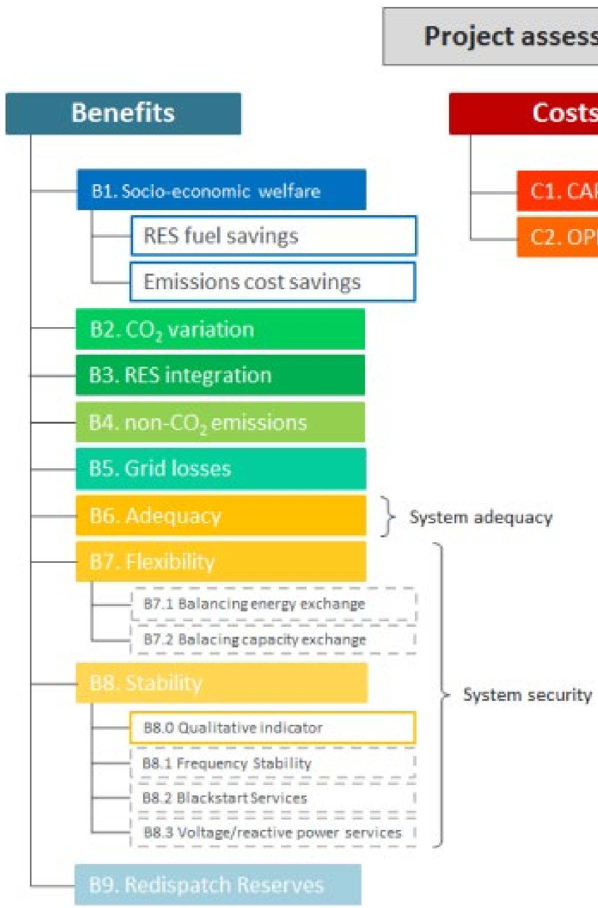
113 Entsoe, A European-wide vision for the future of our power network at https://tyndp.entsoe.eu/explore; https://2022.entsos-tyndp-scenarios.eu/.

114 Projects of Common Interest, https://energy.ec.europa.eu/topics/infrastructure/projects-common-interest_en

115 European Network of Transmission System Operators for Electricity, *Methodology for an energy system-wide cost-benefit analysis*, February 2023, at https://consultations.entsoe.eu/system-development/methodology-for-a-energy-system-wide-cost-benefit/

categories—six of which are monetized and defined to avoid double counting—along with costs and residual impacts.[116]

FIGURE 27. UNIFORM EUROPEAN BENEFIT-COST FRAMEWORK FOR REGIONAL AND INTERREGIONAL TRANSMISSION PLANNING



Source: ENTSO-e, *4th ENTSO-e Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version 4.0 for public consultation*, December 20, 2022, Figure 8 at 221215_CBA4-Guideline_v1.0_for-public-consultation.pdf (windows.net).

This planning framework and benefit-cost analysis—used for both regional (within countries) and interregional (between countries) planning—specifically addresses HVDC benefits that include cost savings achievable from optimized dispatch of HVDC lines,[117] the transient, voltage,

[116] Id., Section V.

[117] Id., pp. 86–87 and 112.

and frequency stability benefits of HVDC lines,[118] blackstart services,[119] and voltage and reactive power support.[120]

The review of benefit-cost analyses prepared for some of the transmission projects in the 2022 Ten Year Network Development Plan[121] shows that in addition to the grid resilience and energy market benefits of expanded transfer capabilities between countries (or within countries) provided by the HVDC projects, the projects offer a number of HVDC-specific benefits, such as:

- "Flexibility, transient and voltage stability, and ramping benefits; the project allows Ireland to take benefits from the more stable continental grid, participates in reactive power management and frequency management by quickly changing its active power." (Celtic Interconnector between Ireland and France)
- "The full controllability of the HVDC link facilitates the balancing of active and reactive power in the Belgian and UK grid" (Nautilus multi-purpose interconnector between the U.K. and Belgium)
- "Improves system flexibility and stability. Controllable HVDC connections stabilize the increasingly stressed German system. DC power lines can provide better controllability in the power grid and support especially voltage stability in the system, as the converters can provide both capacitive and inductive reactive power. The project will reduce unintended load flows significantly and will relieve the transmission grids of neighboring countries." (SuedOstLink between northern and southern Germany)
- "Improve system flexibility, improve system … local ramp rate, improve transient stability [to mitigate the] "flexibility/stability problems due to [weak] scarcely meshed grid" (Italy-Slovenia link)
- The "project reduces loop flows to Germany's neighboring countries [and] contributes significantly to security of supply and grid stability through the widespread integration of renewable energies in northern (wind offshore and onshore) and southern Germany (wind onshore); … the system flexibility is increased by the use of HVDC converter. (HVDC Ultranet between northern and southern Germany)

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[118] Id., Table 11.

[119] Id., pp. 83–84.

[120] Id., p. 85.

[121] ENTSO-e, TYNDP 2022 Project Collection, at https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission

- The "high capacity HVDC connection between the UK and Germany utilizes sophisticated Voltage Source Control (VSC) power converter technology enabling flexible grid services, including reactive power, and will provide both additional voltage stability and security of supply benefits, and support market integration" (NeuConnect between U.K. and Germany)

C. Planning the Conversion of Existing Lines to HVDC

It is critical that transmission planning consider the relative costs and capability of upgrading existing transmission lines with higher-capacity AC or HVDC technologies. Often, such upgrades of aging existing lines are the lowest-cost opportunities to expand transmission capacity. They also offer capacity expansion with only very limited environmental and community impacts as the additional capacity can be achieved through better use of existing rights of way. Here too, HVDC offers unique advantages.

Conversion of an AC overhead line to HVDC will require the addition of converter stations at either end of the line and (typically) the installation of new insulators. For large increases in transfer capability, it may also require upsizing of the existing conductors and tower and foundation reinforcements. The result is that in the same right of way of the existing AC overhead line, a conversion to HVDC can: (1) triple transfer capability; (2) reduce transmission losses; (3) mitigate AC stability constraints; (4) gain VSC-enabled grid support functions; and (5) achieve these benefits at one third to one half of the cost of building a new HVDC line.[122] As discussed in the Ultranet case study in Section V.16 below, hybrid AC and DC solutions are possible as well—by converting to HVDC only one circuit of a double circuit AC overhead line.

A significant number of studies have evaluated the feasibility and benefits of AC to DC conversions.[123] For example, Reed *et al*. pointed out in their 2019 research paper that too often

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[122] Cornelis Plet, *VSC-HVDC technology: European use cases, maturity, experiences and future plans*, ERCOT HVDC Workshop, June 2023, p. 10 at https://www.ercot.com/calendar/06262023-EHV-and-HVDC-Workshop.

[123] For discussions of the feasibility and advantages of converting existing AC lines to HVDC, see:

PTerra, AC to DC Line Conversion – It's time to think about it, October 2006 at https://www.pterra.com/transmission-systems/ac-to-dc-line-conversion-its-time-to-think-about-it/.

ABB Review, *Converting AC power lines to DC for higher transmission ratings*, March 1997 at https://library.e.abb.com/public/8345ed00181dda7bc1256ecc0034c069/04-11%20ENG%209703.pdf.

ABB, *Feasibility study for converting 380 kV AC lines to hybrid AC/DC lines*, 2009 at https://library.e.abb.com/public/724400579765e22cc1257720004100e5/Convertion%20of%20AC%20lines%20to%20hybrid%20AC_DC%20lines_09MP0519.pdf.

"converting existing transmission corridors to HVDC is an overlooked option for increasing transmission capacity."[124] The research assessed options to upgrade existing double-circuit 345kV lines and, as shown in Figure 28 below, found that:

- If the existing line's right of way cannot be expanded, AC solutions cannot increase capacity by more than 60%. In contrast, HVDC conversion can expand the capability by 250%. Even without considering VSC-related benefits, HVDC conversion is also least cost if the transfer capability needs to be increased by more than 60% or the distance is more than 200 km (135 miles).
- If the right of way can be expanded such that multiple 345kV or 500kV AC lines are possible, HVDC conversion is still lower cost if the capability needs to be increased by more than 60% and the distance is more than 300 km (185 miles)

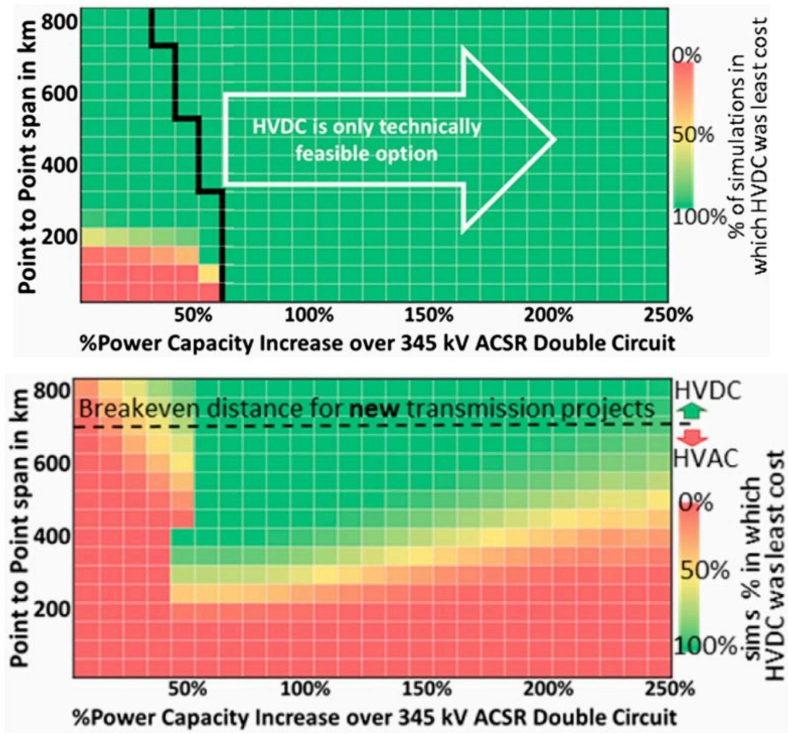
While the capabilities and costs of the HVDC and EHV-AC technologies assumed in the study and the resulting "break-even distances" would need to be updated given the rapid technological progress in recent years, these qualitative points raised in these results are important: the break-even point for conversions of existing lines to modern HVDC is substantially below the break-even distance for new transmission.

EPRI, *AC-to-DC Power Transmission Line Conversion*, November 2010 at https://www.epri.com/research/products/000000000001020114.

CIGRE, *Guide* to the conversion of existing AC lines to DC operation, TB583, 2014 at https://e-cigre.org/publication/583-guide-to-the-conversion-of-existing-ac-lines-to-dc-operation.

[124] Reed et al., *Converting existing transmission corridors to HVDC is an overlooked option for increasing transmission capacity*, *PNAS*, June 20, 2019 at https://www.pnas.org/doi/full/10.1073/pnas.1905656116

FIGURE 28. RELATIVE COST OF CONVERTING EXISTING 345KV LINES TO HVDC
(Green indicates HVDC is lower cost. Top figure is for retrofits within existing right of way, bottom figure applies when right of way can be expanded)



Source: Reed et al., *Converting existing transmission corridors to HVDC is an overlooked option for increasing transmission capacity*, *PNAS*, June 20, 2019. Note that, due to technological progress and cost trends, the "breakeven distance" for new HVDC transmission projects has already decreased since this study was undertaken.

Similar analyses can (and should) be done for AC transmission lines of other voltage levels as well as for opportunities to upgrade aging existing HVDC lines, all of which can offer substantially expanded transmission capabilities at lower costs and lower environmental and community impacts than building new greenfield transmission lines. Any "in-kind" replacement of aging existing lines potentially is a lost opportunity to better and more cost effectively utilize the existing right of way.

V. Case Studies of HVDC Transmission Experience

This section of the report presents twenty-one case studies that cover the planning, operational, and market experience with HVDC transmission systems. The case studies are meant as a resource for those interested in examples of available hands-on experience.

To make it easier to find the case studies that focus on a specific topic interest related to HVDC planning and operational experience, we have organized them into four groups:

- Experience with **developing large-scale HVDC transmission overlays** to enhance the capability of the existing AC grid and achieve long-term planning objectives, including procurement strategies aimed at building a robust and standardized HVDC supply chain;
- North American experience with **transmission planning** that includes modern HVDC solutions;
- **Operational experience** with HVDC transmission projects that utilize the specific capabilities discussed in Section II (such as frequency support and emergency energy, overhead fault clearing, mitigating AC grid contingencies and stability constraints, AC line emulation, black start and system restoration, synthetic inertia, and HVDC conversion of existing AC lines); and
- Experience with **market optimization** of both embedded and inter-regional HVDC lines.

A. Planned HVDC Overlays to Enhance the Capability of the AC Grid

A number of groups have called for the development of HVDC "macro grids" as a high-capacity overlay added to the existing AC grids in North America. Until recently, these macro grid initiatives have been largely conceptual.[125] However, with the advance of HVDC technology and

[125] For a listing of national transmission grid studies, see ACORE, Macrogrid Initiative, Report and Fact Sheet Library at https://acore.org/mgi-library/.

See also the national studies reviewed and summarized in Section VI of DOE, *National Transmission Needs Study: Draft for Public Comment*, February 2023 at https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.

quickly-growing system operator experience, such HVDC overlay proposals are no longer conceptual. A number of European grid operators have gained substantial experience with VSC-based HVDC systems—including TenneT, Energinet, RTE, National Grid, and Terna through the development of submarine HVDC transmission for delivering offshore wind generation and for interconnectors between countries. Based on that experience, several of them are now planning to use HVDC transmission to address the much broader set of future transmission needs. For example:

- In Germany three major backbone HVDC projects are currently under construction or in final permitting stages;
- The Dutch-German grid operator (TenneT), the Scottish grid operator (SSEN), and the Italian grid operator (Terna) have recently unveiled concrete plans—and already initiated procurement of standardized equipment for over 20 GW of HVDC transmission—to develop HVDC grid overlays that are co-optimized with AC grid expansion.

The TenneT and Terna case studies are based on both public information and interviews with the companies' grid planners.

1. Germany's 10 GW of Embedded HVDC Projects

Significant HVDC transmission planning and development experience has been accumulated in Germany to date. As Figure 29 shows, three major HVDC corridors that will add 10 GW of transfer capability between the wind-rich portions of northern Germany and the solar-rich areas of southern Germany. These VSC-based HVDC projects, all currently under construction or in final permitting stages, include:

- TenneT and 50Hertz's 4 GW **SuedOstLink** project (consisting of two 2 GW, 525 kV, 370 mile underground cables with a planned in-service date of 2027);[126]
- TenneT, Amprion, and TransnetBW's 4 GW **SuedLink** project (consisting of two 2 GW, 525 kV, 340 and 430 mile underground cables with a planned in-service date of 2028);[127]

[126] European Commission, Developing the SuedOstLink, 3.12-0009-DE-S-M-17, last modified March 2023 at https://ec.europa.eu/assets/cinea/project_fiches/cef/cef_energy/3.12-0009-DE-S-M-17.pdf

[127] European Commission, Internal line between Brunsbüttel/Wilster and Grgartach/Bergrheinfeld-West (DE) to increase capacity at northern and southern borders [currently known as "Suedlink"]: North-South electricity interconnections in Western Europe, last update March 2023 at https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.10.pdf.

- Suedlink is also proposed to be connected through the AC grid to the existing 1.4 GW, 525 kV, 380 mile **NordLink** HVDC interconnector between Norway (StatNet) and Germany (TenneT),[128] the world's longest subsea line commissioned in 2021;[129]

- A 2 GW **multi-terminal** VSC HVDC link consisting of:
  - Amprion's and TransnetBW's 2 GW **Ultranet** project (which converts one circuit of a multi-circuit AC overhead line to 380 kV HVDC over 200 miles with a planned in-service date of 2027, as further discussed in a case study below);[130] and
  - Amprion's 2 GW **A-Nord** link (an underground HVDC project with a planned in-service date of 2027),[131] which is planned to be supplemented (by 2032) with an additional 2 GW, 525 kV "Korridor-B" HVDC project between northeastern and central Germany.[132]

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[128] TenneT, Projects, NordLink at https://www.tennet.eu/projects/nordlink and Statnet, TenneT, and KFW, NordLink: Benefits of the NordLink interconnector, Factsheet, April 2021 at https://tennet-drupal.s3.eu-central-1.amazonaws.com/default/2022-07/NordLink%20Factsheets%20Benefits%20EN.pdf

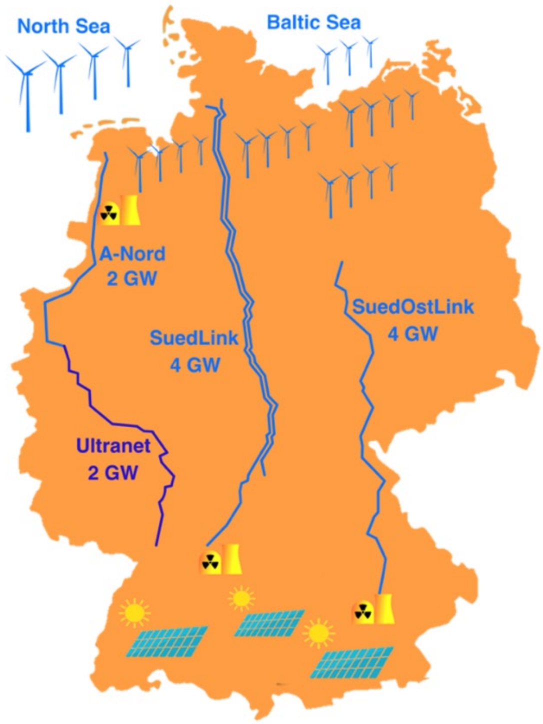
[129] U. Ellichipuram, "Germany and Norway commission NordLink power cable," *Power Technology*, May 28, 2021 at Germany and Norway commission NordLink power cable (power-technology.com).

[130] European Commission, Internal line between Osterath and Philippsburg (DE) to increase capacity at western borders [currently known as "Ultranet"]: North-South electricity interconnections in Western Europe, last update March 2023 at https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.9.pdf.

[131] European Commission, Internal line between Emden-East to Osterath to increase capacity from Northern Germany to the Rhineland: North-South electricity interconnections in Western Europe, last update March 2023 at https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.31.1.pdf.

[132] European Commission, Internal lines between Heide/West to Polsum to increase capacity from Northern Germany to the Ruhr-Area: North-South electricity interconnections in Western Europe, last update March 2023 at https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.31.2.pdf.

FIGURE 29. GERMAN HVDC TRANSMISSION PROJECTS WITH 2027–28 ONLINE DATES



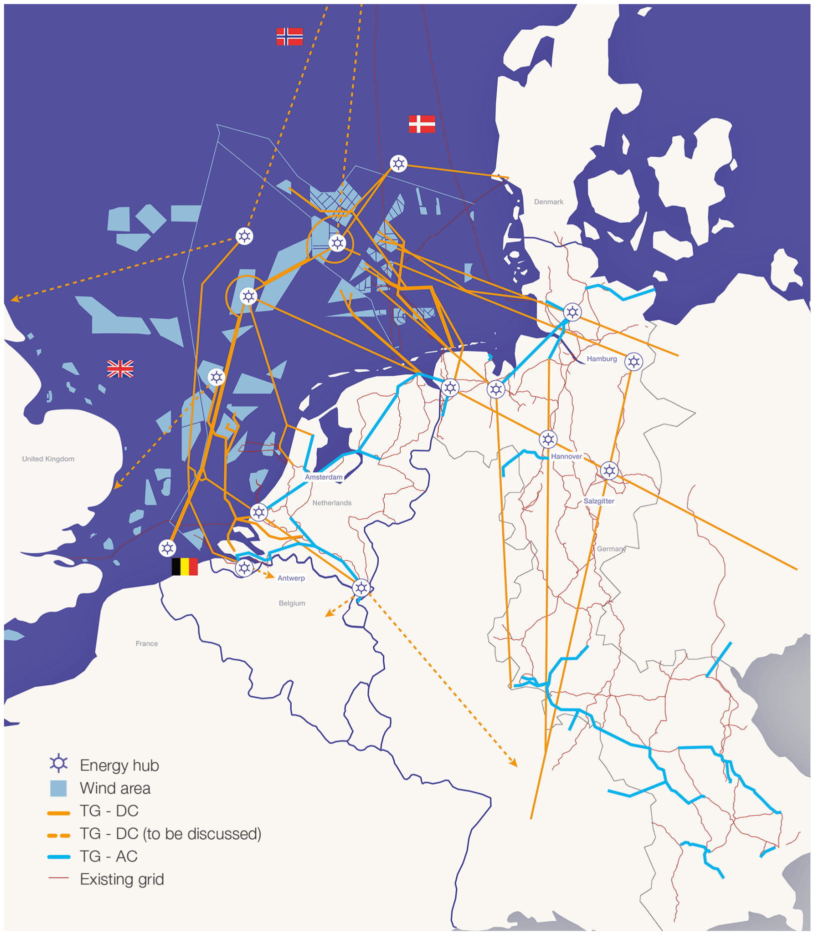
Source: INMR, PD Measurements for HVDC Cable Projects, December 30, 2022 at https://www.inmr.com/pd-measurements-for-hvdc-cable-projects/.

2. TenneT's "Target Grid" HVDC Overlay

In April 2023, TenneT proposed "Target Grid"—its vision of an integrated, onshore and offshore, cross-border electricity grid.[133] As shown in Figure 30 below, Target Grid will be a network of high-capacity AC and HVDC transmission lines and energy hubs to significantly supplement and improve the existing AC and HVDC grid. This set of energy hubs—connected by an HVDC transmission overlay—is planned to ensure that renewable electricity can be transported long distances from the wind-rich North Sea to consumers and industry, and that the electricity grid remains reliable.

[133] TenneT presents Target Grid, its vision for the electricity grid of 2045, April 14, 2023 at https://www.tennet.eu/news/tennet-presents-target-grid-its-vision-electricity-grid-2045.

FIGURE 30. TENNET'S "TARGET GRID"



As TenneT explains, the initiative addresses the fact that:

> [b]oth Germany and the Netherlands are faced with enormous and similar challenges: more than a doubling of electricity consumption, five to ten times larger generation capacity, significant levels of required flexibility and, for each country, approximately 70 GW of offshore wind energy that has to reach industries and households in Dutch, German and other European countries as efficiently as possible. Getting these large volumes of electricity to the right place in the future requires a new approach to realise the high-voltage grid of the future in a timely manner.[134]

[134] Ibid.

As TenneT's CEO emphasized, this planning effort was initiated

> so that TenneT can start working on what is needed on time, rather than ten or fifteen years from now when it is too late. We can no longer afford to work at a defined pace from 'bottleneck to bottleneck;' for grid development (onshore and offshore) at this scale and in a European context 2030 is tomorrow, 2040 is next week and 2050 is next month. (Interview with Alan Croes, June 8, 2023)

The announcement of the Target Grid initiative comes only weeks after TenneT awarded contracts worth €23 billion for 22 GW of HVDC grid connection systems, new standardized offshore platforms, onshore stations, and fourteen pairs of 2 GW HVDC converters.[135] These contracts are part of the Dutch-German system operator's procurement of standardized 2GW, 525 kV HVDC transmission technology.

The ambitious Target Grid and HVDC procurement initiative grew out of TenneT's positive experience with deploying HVDC transmission technology—the only feasible option to cost-effectively deliver generation from large, distant offshore wind plants to shore to major the load centers in central Germany, and to diversify it with southern Germany's substantial amount of solar generation. HVDC technology made it possible for TenneT to take on responsibility for 40 GW of grid connections to integrate offshore wind generation in the German and Dutch North Sea, which is around two-thirds of the 65 GW by 2030 offshore wind target agreed to by Germany, the Netherlands, Denmark, and Belgium in the May 2022 Esbjerg Declaration at the North Sea Energy Summit.[136]

Building on the experience with planning, designing, and developing this first set of HVDC projects, TenneT (in coordination with the German government and other grid operators) set out to develop the new 2 GW, 525 kV VSC-HVDC "standard" based on several key considerations:

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[135] "TenneT awards on and offshore converter stations and HVDC technology with a total capacity of 22 gigawatts," *energy-pedia.com*, March 30, 2023 at https://www.energy-pedia.com/news/general/tennet-awards-on--and-offshore-converter-stations-and-hvdc-technology-with-a-total-capacity-of-22-gigawatts-191051; Gail Rajgor, "TenneT awards €23 billion HVDC offshore grid contracts in Dutch and German North Sea," *Windpower Monthly*, April 6, 2003 at https://www.windpowermonthly.com/article/1818899/tennet-awards-%E2%82%AC23-billion-hvdc-offshore-grid-contracts-dutch-german-north-sea.

[136] Gregor Macdonald, "Big Yellow Box: Long-Distance HVDC Transmission Will Support Next Wave of Offshore Wind Off North Sea Coast," *Windfair*, May 10, 2023 at https://w3.windfair.net/wind-energy/pr/44044-ge-blog-story-hvdc-offshore-wind-transmission-grid-north-sea-mw-capacity-wind-farm-power-plant.

- The 2 GW size of bipole HVDC transmission links allows TenneT to limit its largest system contingency such that, when combined with 1 GW of demand response (automated through a system protection/remedial action scheme), TenneT did not need to increase its contingency-related generating reserves beyond the current 1 GW of operating reserve standard.
- The 525 kV voltage level allows for the use of both overhead HVDC lines as well as underground and submarine cables.[137]
- 2 GW is the largest converter station platform that could be reasonably transported and installed offshore.
- 2 GW is the largest capacity that currently can be transported through 525kV-rated polymer-insulated cables.
- The new VSC technology was the only HVDC option capable of integrating offshore wind generation, providing high-capacity connections at weak portions of the AC grid in northern Germany, and offering operations in grid-forming mode.
- The standard allows for the upfront procurement of a significant number of converter stations in an effort to mitigate manufacturer and supply chain risks.

While TenneT plans its generation links for N-0 contingencies (i.e., interconnected generation will not be able to operate if the transmission link fails), the rest of the grid is planned for N-1 contingencies. The 2 GW HVDC standard also facilitates TenneT's plans for the Suedlink project, consisting of two 2 GW HVDC lines from northern to southern Germany that are embedded in the regional AC grid, such that both HVDC lines can be fully loaded and the surrounding AC grid is able to balance the outage of a single 2 GW transmission HVDC link. This could be achieved by integrating the HVDC system through a multi-terminal configuration that transmits offshore generation to an onshore HVDC hub with converter stations in both northern and southern Germany. By embedding the onshore portion of the HVDC grid into the existing AC grid, the system design also allows: (1) the embedded HVDC lines to be optimized into the market and (2) substantial amounts of offshore wind generation to be transmitted to central and southern Germany and solar generation in southern Germany to be transported north without imposing parallel flows on the neighboring regional electricity grids (such as in Belgium, France, and the Czech Republic).

[137] While 800kV (and higher) HVDC transmission technology is available for overhead line, the higher voltage levels were not considered because they are not an option for submarine and underground cables.

For TenneT, the choice of HVDC was necessitated by the need for long-distance submarine transmission from offshore wind farms. Once chosen, however, TenneT found that that VSC-HVDC technology was also able to address emerging voltage stability and dynamic challenges in its AC grid that would have been challenging (if not impossible) to resolve through AC transmission technologies.

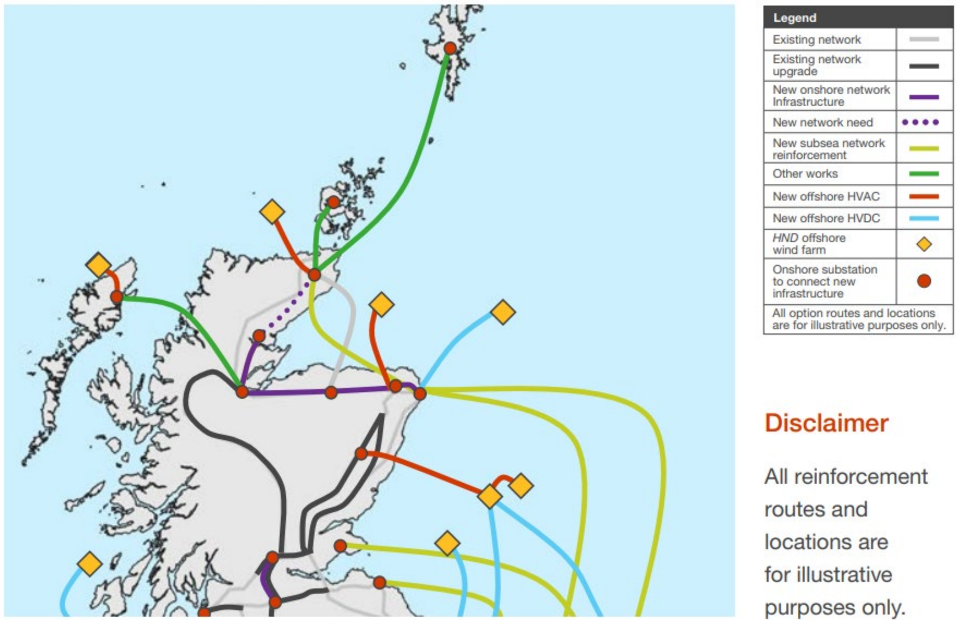
Based on this planning, development, and operational experience with the first generation of VSC-HVDC transmission lines, planning the Target Grid HVDC overlay was the logical next step. The plan allows TenneT to move beyond reacting to pressing current needs to prepare to more proactively address its most challenging scenario of long-term system needs through 2050. Even though some of the final planning decisions for Target Grid investments will not need to be made until 2030, it allows TenneT to collaborate with state policymakers and regulators in an effort to address near-term needs and mitigate the risk that a lack of sufficient infrastructure imposes high customer costs and significant delays in the countries' ability to achieve their energy policy goals in the long term.

3. Scottish & Southern Electricity Network's HVDC backbone

Scottish & Southern Electricity Networks (SSEN) Transmission has been at the forefront of developing multi-terminal HVDC transmission in Europe with their Caithness-Moray-Shetland[138] project, linking offshore wind resources around the Shetland Islands while reinforcing the onshore transmission grid in Scotland, both by means of submarine cable.

[138] Hitachi Energy, Caithness Moray HVDC Link at https://www.hitachienergy.com/about-us/customer-success-stories/caithness-moray-hvdc-link.

FIGURE 31. NORTH SCOTLAND TRANSMISSION OPTIONS FOR 2030



Source: National Grid ESO, Network Options Assessment 2021/22 Refresh, July 2022 at https://www.nationalgrideso.com/document/262981/download

The U.K. holistic network design approach[139] has identified the need for multiple HVDC links in Scotland in the 'Pathway to 2030,' as illustrated in Figure 31 above. They include:

- Two 2 GW subsea high-voltage direct current (HVDC) links from Peterhead to England:
  - Eastern Green Link 2 (EGL2), connecting to Drax for 2029
  - EGL4 connecting to South Humber
- A 2 GW subsea HVDC link from Spittal in Caithness, connecting to Peterhead
- A 1.8 GW subsea HVDC link from the Western Isles, connecting to the north of Scotland mainland

To support the realization of these transmission projects, SSEN Transmission has already procured five sets of 2 GW 525 kV HVDC systems to ensure delivery by 2030, even though 3 of the 5 sets of HVDC equipment still have to be assigned to actual projects.[140] By procuring the equipment now, SSEN Transmission is addressing supply-chain challenges to assure itself of the

[139] ESO, The Pathway to 2030 Holistic Network Design at https://www.nationalgrideso.com/future-energy/pathway-2030-holistic-network-design.

[140] Scottish and Southern Electricity Networks, News & Views, Major milestones in delivery of key contracts for 2030 Scottish electricity transmission network plans at https://www.ssen-transmission.co.uk/news/news--views/2023/7/major-milestones-in-delivery-of-key-contracts-for-2030-scottish-electricity-transmission-network-plans/

availability of a production slot for the timely delivery of the HVDC equipment it needs to realize the planned HVDC backbone necessary to achieve the 2030 clean energy policy goals.

For all of the UK, National Grid ESO's holistic network design recommends the realization of:

- 10 new, 525 kV high voltage direct current (HVDC) circuits with HVDC converter stations, offshore substations, and cables
- Two new multi-terminal HVDC systems.

Noting that the increased use of high voltage direct current (HVDC) technology in combination with proactive transmission planning enables significant customer cost savings along with "a reduction in the impact on the environment with up to a third smaller footprint from offshore cables connecting to shore and reducing the impact on the seabed."[141]

4. Terna's HVDC Experience and Hypergrid Proposal

Terna is the operator of the Italian transmission grid and the largest independent electricity transmission system operator (TSO) in Europe. Over the last several decades, Terna has been able to gain significant HVDC experience with the planning and development of several legacy projects:

- SACOI 1 (1967), a 200 MW, 200 kV link between Sardinia and Italy (with overhead line through Corsica to reduce length of submarine cable), utilizing mercury-arc-based LCC converters;
- SACOI 1 (1988), a 50 MW multi-terminal extension with a 3rd terminal in Corsica using thyristors-based LCC converters;
- SACOI 2 (1992), an upgrade to Sardinia and Italy converters, replacing mercury arc based LCC converters with thyristor-based LCC converters and increasing power rating from 200 MW to 300 MW;
- GRITA (2001), a 500 MW, 400 kV thyristor-based LCC interconnector between Greece and Italy; and
- SA.PE.I (2011), a 1 GW, 500 kV thyristor-based LCC transmission link between mainland Italy and Sardinia, the deepest cable in the world.

[141] National Grid ESO, *Pathway to 2030: A holistic network design to support offshore wind deployment for net zero*, July 2022 at https://www2.nationalgrideso.com/document/264656/download.

Recently, Terna has gained substantial experience with new HVDC technologies, including VSC-based converters, in projects such as:

- The 500 kV, 600 MW (expandable to 1,200 MW), 260-mile thyristors based LCC-HVDC submarine cable between Montenegro and Italy (MONITA, commissioned in 2019);[142]
- The 2×600 MW, 230-mile underground VSC-HVDC link between Italy and France (currently in final commissioning stages);[143]
- The conversion of the aging 200 kV, LLC-based HVDC submarine multi-terminal link between the mainland, Corsica, and Sardinia (SACOI 3) to utilize modern 400 MW VSC-HVDC technology (with a projected in-service date of 2027);[144] The SACOI 3 upgrade is envisioned to incorporate an HVDC circuit breaker to enable sufficiently quick fault clearing to avoid frequency instability in the Corsica and Sardinia grids;
- The development of the Tyrrhenian Link: two new 1,000 MW, 300-mile each VSC-HVDC submarine links between the mainland and Sicily (east branch) and Sicily and Sardinia (west branch); the full project will be completed by 2028;[145]
- The 600 MW, 125-mile TUNITA HVDC link between Sicily and Tunisia (with a projected in-service date of 2028);[146] and
- The Adriatic Link, a new 160-mile submarine HVDC link between the central-north and central-south portion of Italy (now under authorization with a projected 2028 in-service date), to strengthen the grid and address the security and flexibility requirements as part of the National Transmission Grid Development Plan.[147]

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[142] The MONITA HVDC line is now fully integrated into European energy markets (through market coupling) and also facilitates the sharing of ancillary services between Montenegro and Italy. Terna, Undersea cable between Italy and Montenegro Project and forthcoming market and power flow consequences, July 4, 2019 at https://gsm450601838.files.wordpress.com/2019/07/g0702-is01-monita_gsm-2019_lucerne.02.pdf).

[143] Terna, "Italy–France" Electrical Interconnection at https://www.terna.it/en/projects/projects-common-interest/italy-france-electrical-interconnection.

[144] Terna, Sardinia–Corsica–Italy Interconnection at https://www.terna.it/en/projects/projects-common-interest/sardinia-corsica-italy-interconnection

[145] Terna, The Tyrrhenian Link: The Double Underwater Connection Between Sicily, Sardinia And The Italian Peninsula at https://www.terna.it/en/projects/public-engagement/Tyrrhenian-link

[146] Terna, Italy-Tunisia Interconnection (#TUNITA) at https://www.terna.it/en/projects/projects-common-interest/italy-tunisia-interconnection.

[147] Terna, Adriatic Link: The New Centre-South And Centre-North Connection at https://www.terna.it/en/projects/public-engagement/adriatic-link.

The performance of the existing HVDC links has been satisfactory and Terna reports high availability of the converter equipment, although damage to submarine cables can be challenging to fix and lead to longer-duration outages (as discussed in section VI.A.2). Terna acknowledges that HVDC systems can be more expensive than AC transmission in some situations, but that the broad range of AC-grid benefits that HVDC can deliver often swing the decision in favour of HVDC.

Moreover, Terna has observed how submarine HVDC connections can be an effective solution to reduce land usage and avoid protected areas, improving social acceptability and mitigate the environmental impact of the electric infrastructure, while providing reliability and other grid benefits. The Adriatic Link mentioned above is an example of Terna's broader approach to benefits-based planning.

While Terna encountered a number of challenges during its first venture into VSC-based HVDC transmission, the challenges have mostly not been technology related but predominantly due to (1) the difficulties encountered in installing electrical infrastructure adjacent to an Alpine highway, and (2) the cross-border aspect of the project. VSC technology was chosen due to its excellent controllability and its ability to maintain power flow even if parallel AC lines trip due to contingencies, which was the reason for the 2003 black-out in Italy. In addition, VSC converters can deliver reactive power support, which is a much-needed attribute as conventional generators (which typically deliver such support) retire. Unlike LCC technology, VSC technology reverses power flow by reversing current rather than DC voltage polarity, which enables the use of modern XLPE insulated HVDC cables that have better thermal performance compared to legacy mass impregnated paper insulated cables. This allows unlimited power reversals, which is needed in a system increasingly dominated by variable generation.

The controllability of VSC technology, and in particular its ability to perform black-start services, was one of the main factors to consider it for connections to the Italian islands, such as the Tyrrhenian link and the upgrade of the SACOI system, given also the increasing renewable developments on the islands.

The control and protection systems of converters also bring with it new challenges, such as converter-control software, which has not traditionally been part of what a system operator had to consider in the procurement of transmission equipment. Different quality control processes are required during the development of software-based control and protection strategies and grid codes. In addition, new asset management approaches are needed to ensure the technical performance of the HVDC converters throughout their economic lifetime.

Different than the many standardized 2 GW offshore wind export systems which TenneT has contracted for, Terna experiences a much wider range of project-specific requirements in terms of ratings and functionalities due to the many different purposes of its HVDC projects. This leads to a more limited ability for large-scale procurement of standardized and modular converter equipment, and results in a more constrained supply chain.

Importantly, however, the lessons learned and positive operational experience gained with the already-installed projects, allowed Terna to be sufficiently confident to commit to the development of its €11 billion "Hypergrid",[148] which is part of a €30 billion long-term grid modernization plan (of which €21 billion in the next 10 years).[149]

As shown in Figure 32 below, this Hypergrid transmission overlay consists of a combination of (1) existing AC lines that are converted to high-capacity onshore HVDC lines; (2) high-capacity HVDC submarine cables; and (3) additional AC upgrades.

The Hypergrid project was announced by Terna in its 2023 National Electricity Grid Development Plan as the main feature of its grid development and modernization effort. It will leverage HVDC transmission technologies to modernize existing power lines on Italy's east and west backbones, down to the South and the islands, reinforced with new 500 kV HVDC submarine connections. The plan—consisting of 30 strategic transmission infrastructure projects to meet Italian and European decarbonization targets—enhances the capability of the existing lines where possible to minimize environmental impacts and doubles the power than can be transmitted from renewable generation in Southern Italy to high-load areas in the North (from today's 16 GW to over 30 GW) over the next 15 years,[150] enabling the development and integration of renewable generation to meet the country's renewable generation target of 85 GW by 2030 announced by Minister Gilberto Pichetto Fratin.[151]

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148 Terna, Terna: 2023 Development Plan for the National Electricity Grid Presented, Press Release, March 15, 2023 at https://www.terna.it/en/media/press-releases/detail/2023-development-plan.

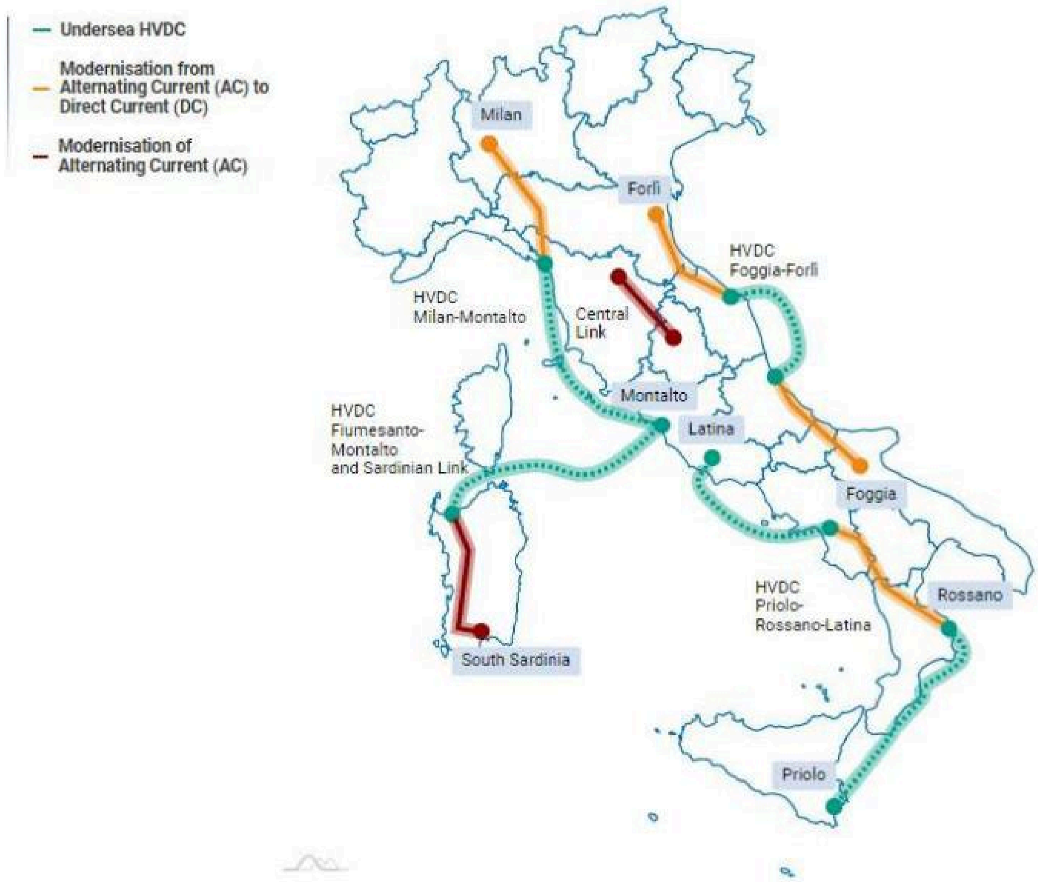
See also Y. Latief, "Italy's Terna invests €11bn in Hypergrid project," *Smart Energy International*, March 16, 2023 at https://www.smart-energy.com/industry-sectors/energy-grid-management/italys-terna-invests-e11bn-in-hypergrid-project/.

149 Terna Spa, Terna: 2023 Development Plan for the national electricity grid presented, Press Release, March 15, 2023 at https://www.terna.it/en/media/press-releases/detail/2023-development-plan.

150 Ibid.; and Terna, Terna and the Sicilian Region: 2023-2032 National Electricity Grid Development Plan meeting, Press Release, March 30, 2023 at https://www.terna.it/en/media/press-releases/detail/meeting-sicilian-region-national-electricity-grid-development-plan.

151 G. Navach and F. Landini, "Terna to invest over 21 bln euros in Italy power grid in 10 years *Reuters*," March 15, 2023 at https://www.reuters.com/business/energy/terna-invest-over-21-bln-euros-italy-power-grid-10-years-2023-03-15/.

FIGURE 32. TERNA'S "HYPERGRID"



Source: Terna, Terna: 2023 Development Plan for the National Electricity Grid Presented, Press Release, March 15, 2023 at https://www.terna.it/en/media/press-releases/detail/2023-development-plan.

The Hypergrid would also allow Italy to develop power lines with Northern African Countries to become an energy hub for southern Europe. In fact, the European Union is already committed to supporting the construction of a submarine HVDC line between Italy and Tunisia with around €307 million of funding.[152]

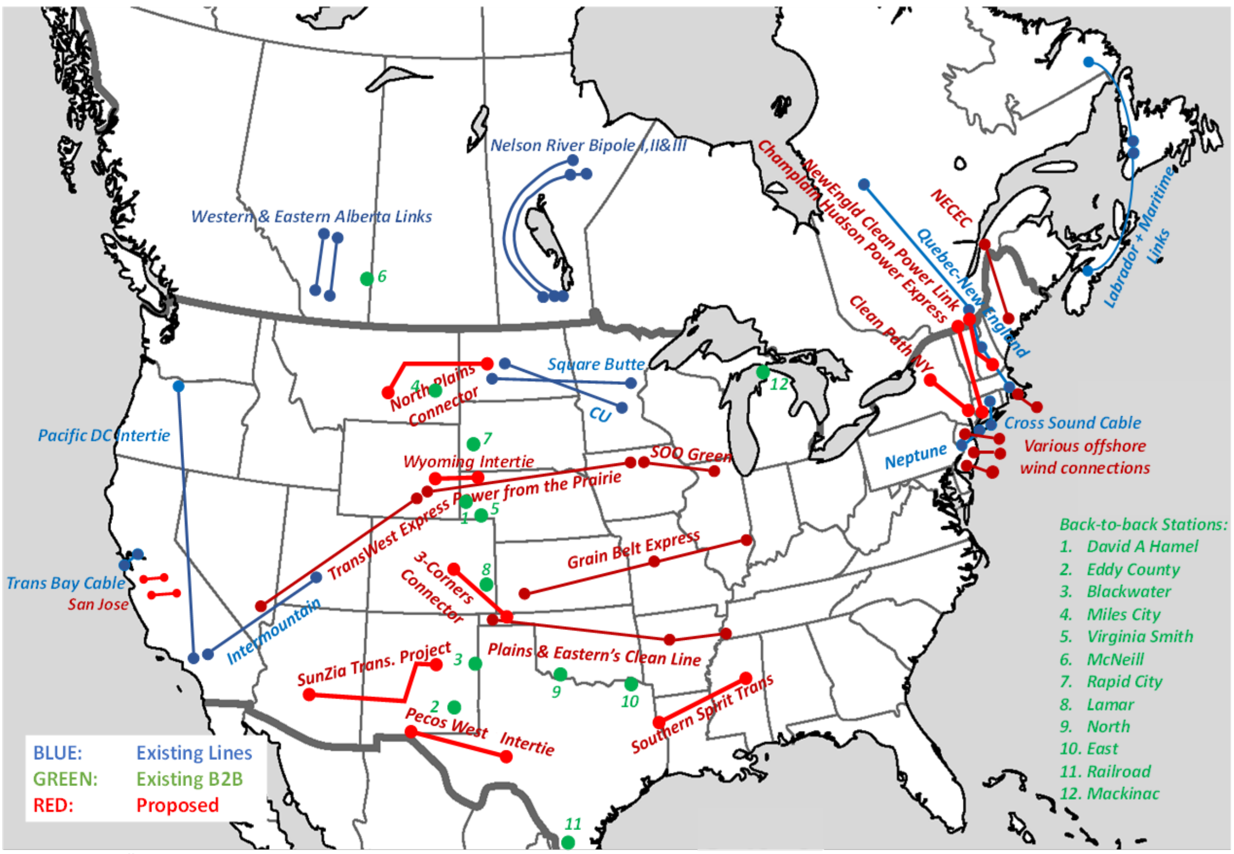
B. Planning Experience with HVDC Transmission in North America

While the use of VSC-HVDC technology to provide enhanced grid services is relatively new and several North American system operators are still in the process of gaining planning and

[152] Ibid.

operating experience with the new VSC technology, the use of HVDC transmission has a long history in North America, with several grid operators having planned and developed HVDC lines for several decades, with several VSC-based HVDC system already operational,[153] and both New York and New Jersey state regulators requiring HVDC transmission with at least 1,200 MW capacity to limit the number of cable landings necessary for the integration of offshore wind generation. As shown in Figure 33, numerous existing lines (shown in blue) already exist and an even larger number of new HVDC lines that have been proposed (shown in red, most of which are still actively under development).

FIGURE 33. NORTH AMERICAN HVDC PROJECTS (EXISTING AND PLANNED)



Source: Jim McCalley, Iowa State University

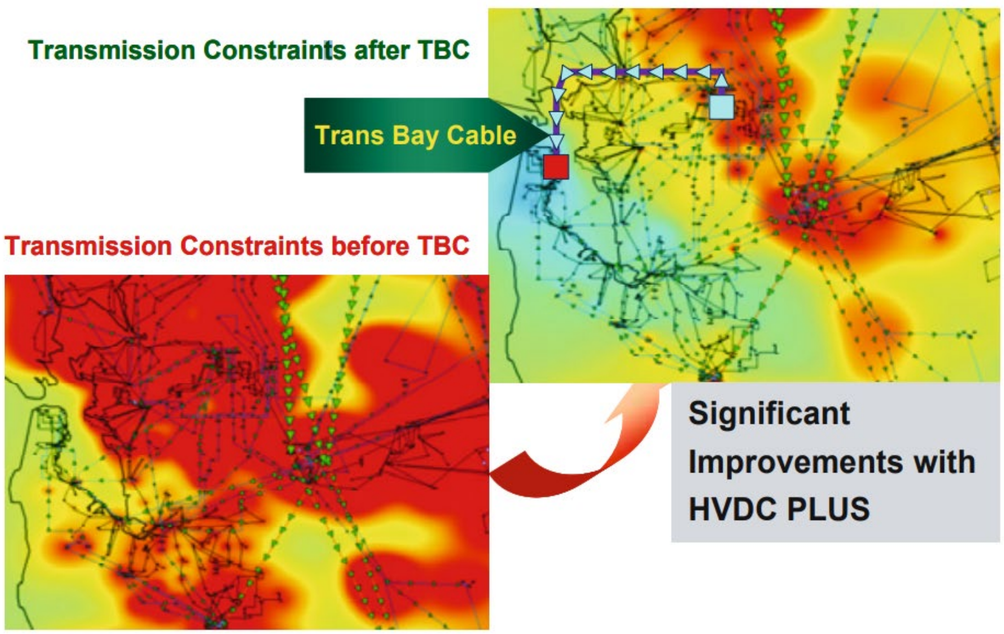
The three case studies below focus on examples of North American system operators' experience with and initiatives at considering VSC-HVDC solutions in their transmission planning efforts. The case studies are focused on three such planning efforts by CAISO, MISO, and SPP.

[153] Operational VSC-based HVDC lines in North America include Cross Sound Cable, TransBay Cable, and Maritime Link.

5. CAISO Transmission Planning and HVDC Projects Considered

CAISO has led the U.S. in considering HVDC solutions in transmission planning. CAISO already operates the Trans Bay Cable, a 200 kV, 400 MW HVDC underwater interconnection between San Francisco and Pittsburg in California, which was the world's first commercially operated HVDC system using VSC-MMC technology. Figure 34 shows that, through market-optimized scheduling of Trans Bay Cable, CAISO was able to relieve AC transmission constraints. (CAISO's market design that allows for the co-optimization of generation and controllable transmission facilities is discussed in Section III-C below).

FIGURE 34. TRANSMISSION CONSTRAINTS RELIEVED BY THE TRANSBAY CABLE



Source: M. Davies, M. Dommaschk, J. Dorn, J. Lang, D. Retzmann, D. Soerangr (Siemens), *HVDC PLUS—Basics and Principle of Operation*, 2009 at https://edisciplinas.usp.br/pluginfile.php/1589087/mod_folder/content/0/hvdc-plus-basics-and-principle-of-operation.pdf?forcedownload=1.

Based on the positive experience with integrating TransBay Cable into its AC grid, CAISO's 2022 Transmission Planning Process (TPP) approved two VSC-HVDC- systems to address reliability needs in the San Jose area south of San Francisco: (1) a 500 MW HVDC line from PG&E's Newark 230 kV station to SVP's NRS 230 kV station, and (2) a 500 MW HVDC line from Metcalf 500 kV station to San Jose B 115 kV station. In selecting these HVDC options as preferred solutions, the CAISO noted that:

> the HVDC alternatives resulted in better performance from the power flow perspective as a result of controllability of the HVDC source. The HVDC alternative also provides benefits in reducing local capacity requirements in the San Jose subarea and overall Greater Bay Area that reduces reliance on the local gas generation.[154]

CAISO's 2022 TPP Report also discussed a number of VSC-HVDC-related benefits that it considered in its Transmission Planning Process:[155]

- "Transmission over long distances with overhead lines or underground/subsea cables; there is no practical limit on how far power could be transmitted with HVDC lines"
- "smaller rights-of-way" than AC transmission
- "Power flow on the line is set by the operator"
- "The AC system the VSC-HVDC converters are connected to does not need specific minimum short circuit levels"
- "Does not require reactive power support at the converter station"
- VSC-based "Multi-terminal configuration is less complicated" than for LLC systems
- "VSC-HVDC is suitable for delivering power to urban areas and systems with low short-circuit levels"
- "The converter stations [of VSC systems] are physically smaller compared to LCC HVDC stations and therefore more suitable to deliver power to urban centers"
- VSC HVDC lines can be combined with other technologies: e.g., to create a "hybrid AC and HVDC solution" to connect 14,428 MW of wind with two VSC-HVDC, two LCC-HVDC, and two 500kV AC lines

CAISO's most recent 2023 TPP considered ten VSC-HVDC solutions (in multi-terminal configuration) for addressing identified reliability needs in southern California:[156]

- Three variants of a Diablo South Multi-Terminal VSC-HVDC Line:

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[154] CAISO, 2021–2022 Transmission Plan, March 17, 2022, p. 103 at http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

[155] Ibid.

[156] Kaitlin McGee (CAIS), Reliability Assessment and Study Updates, presented-at the 2022-2023-Transmission-Planning-Process Stakeholder Meeting, Nov 17, 2022.pdf at http://www.caiso.com/InitiativeDocuments/Presentation-2022-2023-Transmission-Planning-Process-Nov%2017,%202022.pdf.

  - 2,000 MW at Diablo Canyon, 1,000 MW at Alamitos, and 1,000 MW at Huntington Beach
  - 2,000 MW at Diablo Canyon, 1,000 MW at Redondo Beach, and 1,000 MW at Encina
  - 2,000 MW at Diablo Canyon, 500 MW at Redondo Beach, 750 MW at Alamitos, and 750 MW at San Onofre

- Alberhill—Suncrest VSC-HVDC Line (1,000 MW)
- Vincent—Del Amo VSC-HVDC line (1,000 MW)
- Imperial Valley—Serrano VSC-HVDC line (2,000 MW)
- Devers—La Fresa VSC-HVDC line (1,000 MW)
- Imperial Valley—Del Amo VSC-HVDC line (2,000 MW)
- Two variants of an Imperial Valley multi-terminal VSC-HVDC:
  - Imperial Valley (2,000 MW)—Inland (normal flow at 1,000 MW with converter capability up to 2,000 MW for emergency condition)—Del Amo (1,000 MW normal flow with converter capability up to 2,000 MW for emergency condition)
  - Multi-terminal VSC-HVDC: Imperial Valley (2,000 MW)—Sycamore Canyon (1,000 MW normal flow with converter capability up to 2,000 MW for emergency condition)—Del Amo (1,000 MW normal flow with converter capability up to 2,000 MW for emergency condition)

While CAISO has not (at this point) selected any of these ten HVDC options to address identified transmission needs, their evaluation of these options clearly documents the role that HVDC solutions have now started to play in the ISO's grid planning process. Importantly, CAISO is still in the process of improving its planning process for HVDC. For example, CAISO notes that it continues efforts of finding and promoting standard models and approaches for assessing VSC-HVDC technologies and is in the process of assessing applicable models for dynamic stability analysis. To inform this effort, California Western Grid Development LLC has been working with industry experts to develop dynamic stability models for VSC-HVDC lines and to find modeling solutions that work in a PSLF™ environment. They are now able to perform dynamic analysis of VSC-HVDC lines using PSLF™.[157]

[157] California ISO, Comments on 2022–2023 Transmission planning process, November 17–December 5, 2022 at https://stakeholdercenter.caiso.com/Comments/AllComments/6cdb6ed2-f22c-4064-96e1-739c8db239ef.

As discussed further in Section III-C below, CAISO has combined its HVDC transmission planning efforts with market design modification that allow for the full co-optimization of the dispatch of controllable transmission facilities and generation in its nodal day-ahead and real-time energy markets, and do so on an intra-regional and inter-regional basis for both regulated and merchant HVDC lines.

6. MISO's Renewable Integration Impact Assessments and HVDC Planning Efforts

The Midcontinent ISO is currently considering both HVDC and 765 kV AC transmission solutions as the system operator is in the process of designing a "Tranche 2" portfolio of Multi-Value Projects (MVPs) to meet projected future transmission needs that require the integration and long-distance transmission of significant amounts of renewable generation in its Midwestern footprint.[158] While MISO has not yet enhanced its planning tools and operational processes to fully assess and integrate HVDC solutions, MISO has previously recognized in its Renewable Integration Impact Assessment (RIIA) the unique advantages that HVDC transmission solutions offer for addressing the integration challenges expected at higher renewable generation levels as shown in these quotes:[159]

> New Stability Risks: The grid's ability to maintain stable operation is adversely impacted, primarily when renewable resources are clustered in one region of the transmission system. As inverter-based resources displace conventional generators, the grid loses the stability contributions of physically spinning conventional units. A combination of multiple technologies—such as high-voltage direct current (HVDC) lines, synchronous condensers, motor-generator sets and emerging technology such as grid-forming inverters—are needed to provide support, along with operational and market changes to identify and react to this risk as it occurs.[160]
>
> Traditional transmission solutions, such as synchronous condensers and Flexible AC Transmission System (FACTS) devices, help stabilize the local system; however, the

158 For example, see MISO Advisory Planning Commission, "Discussion of Legacy, 765 kV, and HVDC Bulk Transmission," March 8, 2023 at https://cdn.misoenergy.org/20230308%20PAC%20Item%2007%20Discussion%20of%20765%20kV%20and%20HVDC628088.pdf.

159 MISO, *Renewable Integration Impact Assessment (RIIA) Summary Report*, February 2021 at https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

160 Id. at 3.

large magnitude of the need for these solutions causes additional challenges. Two viable solutions are presented: high-voltage direct current (HVDC) lines to isolate a portion of the new renewable resources and connect them to a stronger part of the system; and the commercialization of advanced technology such as grid-forming inverters.[161]

Achieving stability becomes a significant challenge beyond the 30% milestone as the amount and location of renewable generation stresses the system. Various technologies, including HVDC, synchronous condensers, STATCOMs, and batteries, were implemented to provide appropriate support, which changed as the generation profile changed at different milestones. **A more significant number of HVDC lines had to be distributed in regions where wind generation increased while transmission capacity was limited**.[162]

For the purposes of RIIA analysis, **the only workable solution found was addition of Voltage Source Converter (VSC) HVDC transmission lines** (Figure OR-DS-7). Utilizing the older LCC HVDC technology in weak areas was found inadequate and indicated further system enhancements needed to keep the system stable (Figure OR-DS-8). **The need for VSC HVDC technology to successfully solve a myriad of issues (reducing curtailment, ensuring power delivery, solving weak-area instability) demonstrates dynamic stability will become increasingly important for any large or small transmission expansion project in high renewable penetration scenarios**, and the transmission design needs to be specifically vetted for dynamic performance. To port power from wind-rich zones located in weak-area, building a VSC-HVDC line into those weak areas may be more economical than incrementally installing a combination of AC transmission lines with many synchronous condensers and mitigating the small signal stability issues created by installing the rotating masses of those synchronous condensers (Figure OR-DS-9). It also re-emphasizes the desire to **develop new technology, such as grid-forming inverters and pilot projects, to demonstrate their effectiveness to bring down the cost of grid-integration of renewable resources**. Modern VSC-HVDC technology does not require filter banks. Modern HVDC systems can be tapped to form multi-terminal systems.[163]

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[161] Id. at 14–15

[162] Id. at 24–25 (emphasis added).

[163] Id. at 118 (emphasis added).

7. SPP's HVDC Engagement with EPRI

Similarly, the Southwest Power Pool's existing planning, performance, study, and modelling criteria are primarily focused on AC transmission solutions and, thus, and do not yet fully address the requirements for HVDC transmission and HVDC interconnections (including with merchant HVDC developers). SPP expects that HVDC transmission will play an increasingly important role in SPP's planning processes due to the system operator's expansion into the Western Interconnection—which is currently connected to the eastern SPP footprint only through a number of aging back-to-back DC converters.

Because SPP is already evaluating several HVDC transmission and interconnection options, it has engaged the Electric Power Research Institute (EPRI) to:

- Review the performance, study, and modelling criteria used by system operators and other entities within and outside the United States; and
- Make recommendations on HVDC grid codes and the performance, study, and modelling criteria that SPP should adopt for HVDC systems.[164]

For this effort, EPRI has already undertaken (1) a review of other system operators' HVDC grid codes; (2) a benchmarking analysis of HVDC performance standards; (2) a benchmarking analysis of system studies required for HVDC interconnections; and (3) an analysis of modeling and simulation tools.[165] EPRI's preliminary recommendations to SPP include:[166]

- Grid code recommendations addressing twelve HVDC performance elements (as shown in Figure 35 below)
- Recommendations for feasibility, planning, and design studies (including for load flow, dynamic performance, and power quality analyses)
- Recommendations on power system data and models provided by SPP
- Recommendations on building analytical tools necessary to analyze HVDC options

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[164] EPRI, *HVDC Recommendations for Southwest Power Pool*, Interim Report, posted with the SPP Transmission Working Group meeting materials for June 6, 2023 at https://www.spp.org/spp-documents-filings/?id=18447.

[165] See Geoff Love and Alberto Del Rosso, *Project Overview to TWG*, March 28, 2023. Posted with the SPP Transmission Working Group meeting materials for March 24, 2023 at https://www.spp.org/spp-documents-filings/?id=18447.

[166] Geoff Love and Alberto Del Rosso, *HVDC Recommendations Southwest Power Pool*, Project Update to TWG, May 31, 2023. Posted with the SPP Transmission Working Group meeting materials for June 6, 2023 at https://www.spp.org/spp-documents-filings/?id=18447.

FIGURE 35. EPRI'S HVDC GRID CODE RECOMMENDATIONS TO SPP

Source: Geoff Love and Alberto Del Rosso, *HVDC Recommendations Southwest Power Pool*, Project Update to TWG, May 31, 2023. Note: SSO = sub-synchronous oscillation; UVRT = undervoltage ride-through; TOV = temporary overvoltage; EPC = emergency power control.

In the development of these grid code recommendations, EPRI reviewed and made available to SPP and its Transmission Working Group a number of HVDC grid codes from system operators in Europe and Australia as well as HVDC performance standard issued by IEEE as summarized in Table 17 below.

TABLE 17. HVDC GRID CODES AND STANDARDS REVIEWED BY EPRI FOR SPP

Organization	Title Description	Link
EU / ENTSOE	**COMMISSION REGULATION (EU) 2016/1447** European Grid Code	https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32016R1447
IEEE	**IEEE-2800-2022** Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems	https://standards.ieee.org/ieee/2800/10453/
EPRI/IEEE	**Webinar on 2800-2022** click on attachments for slides and recording of webinar	https://www.epri.com/research/programs/027570/events/621D26F1-00A5-4F90-8AA8-C68959393DBC
NGESO	**GB Grid Code;** *European Connection Conditions* and *European Compliance Process* contain the performance and study requirements for new HVDC links	https://www.nationalgrideso.com/industry-information/codes/grid-code/code-documents
EirGrid	Ireland Grid Code	https://www.eirgridgroup.com/site-files/library/EirGrid/GridCode.pdf
EirGrid	Simulation Requirements v1.0 Version 1.0	https://www.eirgridgroup.com/customer-and-industry/general-customer-information/simulation-studies/
AMEO	Power System Modelling Requirements (Australian NEM)	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/modelling-requirements
Energinet (Denmark)	Annex B – Requirements for Simulation Models for HVDC Facilities - Rev. 0	https://en.energinet.dk/media/5b5hhrey/hvdc-annex-b-requirements-for-simulation-models.pdf

Source: Geoff Love and Alberto Del Rosso, Project Overview to SPP's TWG, March 28, 2023.

C. Experience with Specific Capabilities of HVDC Transmission

Operational experience with HVDC transmission systems—including the utilization of advanced VSC-based capabilities and coordination needs—has already been documented in detail by European grid operators for both embedded HVDC links and interties between balancing areas.[167] The following case studies show that HVDC transmission systems have successfully demonstrated multiple technical capabilities in system operation:

[167] See, for example, ENTSO-e, HVDC Links in System Operations, Technical paper, December 2, 2019 at https://www.entsoe.eu/Documents/SOC%20documents/20191203_HVDC%20links%20in%20system%20operations.pdf.

- The British-Belgian NEMO link provides frequency support and emergency energy to the continental European grid during a system event;
- The German-Norwegian NordLink demonstrated its capabilities of fast transition from bipole to monopole operation and auto-reclosure for fault clearing on overhead HVDC lines;
- HVDC runback schemes of Manitoba Hydro and Nova Scotia Power prevent the overloading of AC lines during critical contingencies;
- The Fenno-Skan HVDC system is used to mitigate AC stability constraints and improve system transfer capability;
- France's HVDC links with Spain and Italy successfully operate in "AC line emulation," stabilize voltage, and reduce losses and congestion on the AC grid;
- Caithness-Moray, EWIC, and Skagerrak 4 HVDC links provide black-start and system-restoration services;
- The U.K.'s HVDC Centre documented in detail the capabilities and effectiveness of using HVDC links to address black-start and system-restoration needs;
- The potential role of VSC-HVDC transmission in providing inertia and frequency responses is demonstrated by system operators' experience with synthetic inertia from inverter-based resources; and
- The German Ultranet project illustrate the attractive features of converting existing AC circuits to HVDC to substantially increase transfer capability and allow for full power flow control without the need to upgrade existing towers or conductors.

8. The British-Belgian NEMO Link: Frequency Support and Emergency Energy

The NEMO Link is a 400 kV, 1 GW, 140 km submarine link connecting the British and Belgian grids.[168] It is based on multi-level modular voltages sourced converters (MMC-VSC) in symmetrical monopole configuration—with converters provided by Siemens Energy and cross-linked polyethylene (XLPE) insulated cables provided by Sumitomo. It was the first HVDC system and the first offshore system procured by the Belgian grid operator ELIA. The NEMO link still is the highest-voltage-rated XLPE insulated cable in operation today, although this will soon be surpassed by the installation of 525 kV cable systems.

[168] Nemo Link at https://www.nemolink.co.uk/.

NEMO Link is the first merchant interconnector project that utilized the U.K.'s "cap and floor" regulatory framework that offers project risk sharing to facilitate the development of this type of merchant interregional transmission projects.[169] The project is exemplary in terms of its on-time[170] and on-budget[171] delivery, as well its exceptional performance. Since its commissioning in 2019, NEMO link has had a total annual availability of 96%, 99%, and 99% in 2020, 2021, and 2022,[172] without any unplanned outages or maintenance need. In 2020, Nemo Link also reviewed its observed transmission losses and lowered its loss factor from 2.6% to 2.372%.[173] Altogether, NEMO Link transmitted 17.65 TWh in its first three years, and provided vital support to the security of and reliability of supply to the interconnected grids.

For example, during the European "system split" event on January 8, 2021, the NEMO Link's automatic frequency support functionality was activated by the sudden drop of frequency on the continental grid. The line immediately (within a small fraction of a second) decreased its export of real power to Britain to help stabilize the frequency of the continental European grid, as shown in Figure 36 below.[174] In another example, the controllability of the link helped avoid

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169 Ofgem, Cap and floor regime: unlocking investment in electricity interconnectors, May 2016, available at https://www.ofgem.gov.uk/sites/default/files/docs/2016/05/cap_and_floor_brochure.pdf

170 NS Energy Staff, "Siemens, J-Power to construct 1GW Nemo link between UK and Belgium," *NS Energy*, March 10, 2015 at https://www.nsenergybusiness.com/news/newssiemens-j-power-to-construct-1gw-nemo-link-between-uk-and-belgium-100615-4597527/; and NS Energy Staff, "Siemens connects HVDC Nemo Link between UK and Belgium," *NS Energy*, December 6, 2018 at https://www.nsenergybusiness.com/news/siemens-nemo-link-uk-belgium/

171 OfGem, Consultation - Post Construction Review of the Nemo Link interconnector to Belgium, September 12, 2019 at https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/pcr_consultation_-_final.pdf.

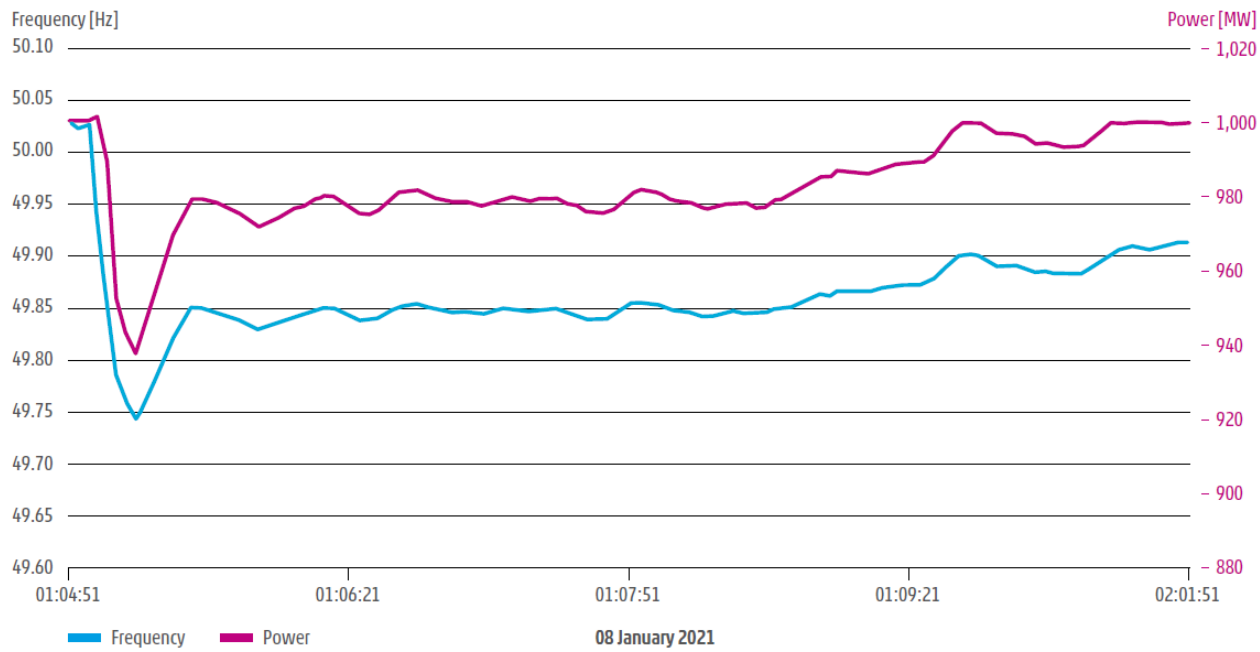
172 Nemo Link celebrates strong performance in its first full year of operation, Press Release, February 4, 2020 at https://www.nemolink.co.uk/news-news/nemo-link-celebrates-strong-performance-in-its-first-full-year-of-operation/; Nemo Link celebrates another outstanding performance in the extraordinary year of 2020, Press Release, January 12, 2021 at https://www.nemolink.co.uk/news-news/nemo-link-celebrates-another-outstanding-performance-in-the-extraordinary-year-of-2020/; and Nemo Link celebrates its fourth anniversary with exceptional operational performance, supporting security of supply in both the UK and Belgium, Press Release, January 31, 2023 at https://www.nemolink.co.uk/news-news/nemo-link-celebrates-its-fourth-anniversary-with-exceptional-operational-performance-supporting-security-of-supply-in-both-the-uk-and-belgium/.

173 Nemo Link announces its new Loss Factor effective from 1 September 2020, Press Release, Press Release, July 2, 2020 at https://www.nemolink.co.uk/news-news/nemo-link-announces-its-new-loss-factor-effective-from-1-september-2020/.

174 Entsoe, Final report on the separation of the Continental Europe power system on 8 January 2021, Press Release, July 15, 2021 at https://www.entsoe.eu/news/2021/07/15/final-report-on-the-separation-of-the-continental-europe-power-system-on-8-january-2021/.

major supply problems in London during the generation shortage in July 2022.[175] Amidst planned line outages and forced generation outages due to a heat wave, UK grid operators relied on NEMO's power flow control capability to procure emergency power in Belgium to avoid a black-out in London.

FIGURE 36. NEMO LINK AUTOMATIC FREQUENCY SUPPORT DURING EUROPEAN SYSTEM SPLIT EVENT



Source: Continental Europe Synchronous Area Separation on 08 January 2021[176]

[175] Nemo Link celebrates its fourth anniversary with exceptional operational performance, supporting security of supply in both the UK and Belgium, Press Release, January 31, 2023 at https://www.nemolink.co.uk/news-news/nemo-link-celebrates-its-fourth-anniversary-with-exceptional-operational-performance-supporting-security-of-supply-in-both-the-uk-and-belgium/

[176] ENTSO-e, Final report on the separation of the Continental Europe power system on 8 January 2021, July 15, 2021 at https://www.entsoe.eu/news/2021/07/15/final-report-on-the-separation-of-the-continental-europe-power-system-on-8-january-2021/

9. The German-Norwegian NordLink: VSC Converters with Fast Transition from Bipole to Monopole Operation, STATCOM mode, and Overhead Line Fault Clearing Capability

NordLink is a 525 kV, 1,400 MW, 390 mile VSC-HVDC link comprised of overhead lines, subsea cables, and underground cables between Ertsmyra in Norway and Wilster in Germany.[177] It is jointly owned by TenneT (Germany) and Statnett (Sweden) and was commissioned in 2020. During the commissioning, two functionalities of the NordLink were tested: (1) fast transition from bipole to monopole operation when a fault occurs in either converter pole, and (2) auto-reclosure for fault clearing in the overhead line of the HVDC link.[178]

NordLink has a rigid bipole converter configuration, which means it does have a dedicated metallic return. The NordLink mainly operates in the bipole mode but was designed to be able to transition to monopole mode using the DC bypass arrangement with high-speed switches installed on the converter stations. This function enables transition from bipole to monopole operation within one second. During monopole operations, one pole is operated in power transmission mode and the other pole is operated in STATCOM mode.

A converter fault that causes the outage of one HVDC pole triggers the transition from bipolar operation to monopolar metallic return operation for power transmission with the line's total transmission capacity reduced by half. The AC circuit breakers are opened to isolate the faulty transmission segment while the healthy converter on the other end of the disconnected line will remain connected to the AC grid and transition to STATCOM mode. This function reduces the risk of a bipole trip that would result in the loss of the entire 1,400 MW of transfer and associated impacts on the AC power system. The commissioning test of this fast transition function was performed in 2021.[179]

The overhead line of NordLink is located in Norway between the Vollesfjord submarine cable to overhead line transition station and Ertsmyra converter station and is routed through mountains exposed to challenging conditions including snow, ice, salt spray from the sea, and

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[177] TenneT, Projects, NordLink at https://www.tennet.eu/projects/nordlink.

[178] M. Meisingset, S. Bødal, K. Koreman, A. Vinoth, "B4 - Transmission system testing of a VSC based HVDC System," CSE-27, CIGRE, January 2023 at https://cse.cigre.org/cse-n027/b4-transmission-system-testing-of-a-vsc-based-hvdc-system.

[179] S. Bødal, M. Meisingset, C. G. A. Koreman, A. Vinoth, H. S. Andersson, "Commissioning of VSC HVDC converters for STATCOM operation," B109-2020, CIGRE 2020 E-Session Papers and Proceedings, Paris, France, 2020 at https://e-cigre.org/publication/SESSION2020_B4-109.

lightning strikes, which may cause temporary pole-to-ground faults on the overhead HVDC line. To address such events, an automatic reclosure functionality was designed and deployed on the NordLink for fault clearing.

If the protection system of the NordLink system detects a pole-to-ground fault on the overhead HVDC line based on the current measurements from the transition station and the Ertsmyra converter station, the automatic reclosure functionality is activated. The grid operator, Statnett, performed a full-scale staged-fault field test to verify this functionality. After an intentional pole-to-ground fault was applied to the negative pole, the fault was detected, which activated the differential protection and auto-reclosure functionality to restore power transmission. The auto-reclosure function de-energized the faulty converter pole and cleared the fault by blocking the HVDC converter valves and opening the AC circuit breaker in the faulty converter pole at both ends of the HVDC link. After 400 milliseconds, the HVDC pole was re-energized by closing the AC circuit breakers and de-blocking the valves in the faulty converter pole. NordLink is designed to be capable of restoring the active and reactive power of both converter stations to at least 90% of pre-fault level within 1 second after the fault is cleared.

Another two full-scale short-circuit field tests with 50 MW of power flow from Norway to Germany were performed. The first test in November 2020 was unsuccessful because the HVDC link tripped without being able to restart after the fault was cleared. After protection settings were adjusted, the automatic reclosure functionality worked properly during the second test in December 2020.

Real-time operational data from data loggers installed on the NordLink system was used in a first-of-a-kind proof of concept to determine the dynamic capacity of HVDC systems. It was found that depending on operating conditions, the real power transfer could temporarily be increased by 26.9% over the rated power to enable grid operation services, as shown in Section V.C.9.

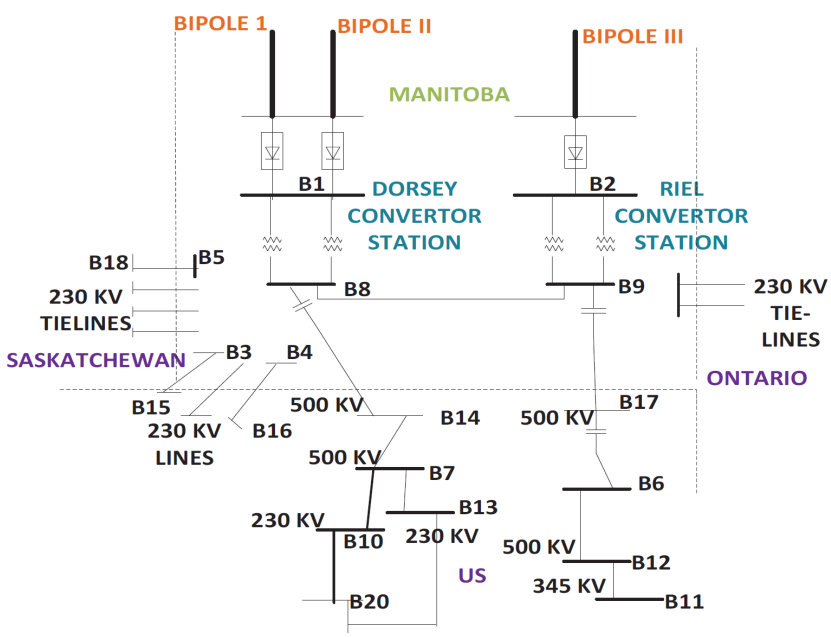
10. Manitoba and Nova Scotia: “Runback” HVDC Controls to Increase AC Grid Capacity

The HVDC controls implemented for Manitoba Hydro and Nova Scotia HVDC systems are an example of how the fast controllability of HVDC lines can be used to enhance the capability of the AC grid. In these examples, the immediate and automatic reduction of DC power injection is able to prevent overloads of AC transmission lines during contingencies on the surrounding AC grid through so-called “runback” schemes—utilizing the ultra-fast controllability of HVDC lines to eliminate the contingency constraint that would otherwise prevent the full utilization of the AC grid.

Manitoba Hydro's HVDC Reduction Remedial Action Scheme (RAS): The Manitoba Hydro HVDC Reduction RAS leverages the fast-control properties of HVDC transmission (and asynchronously-connected hydro generators) to maximize the export capability of Manitoba Hydro's AC transmission system to the MISO market.

The interconnection between Manitoba Hydro and MISO currently consists of 5 AC transmission lines, three 230 kV and two 500 kV, as shown in the bottom half of Figure 37 below. This interconnection with MISO is used to export hydropower delivered from northern Manitoba to the southern Manitoba AC grid over three bipole LCC HVDC lines (shown at the top of the figure).

FIGURE 37. MANITOBA GRID AND AC INTERCONNECTIONS WITH MISO



Source: Narinder S. Dhaliwal, J. Brett Davies, David A. N. Jacobson, Richard Gonzalez, "Use of an integrated ac/dc special protection scheme at Manitoba Hydro," CIGRE (2006).

Manitoba Hydro had implemented its HVDC Reduction Scheme prior to the construction of the 500-kV Manitoba–Minnesota AC Transmission Project in 2020. At that point, there were only three 230 kV lines and one 500 kV line in service.

The HVDC Reduction Scheme allowed Manitoba Hydro to export over its AC links to MISO— the then-existing three 230 kV lines and single 500 kV line—a total of 2,100 MW from Manitoba's hydro resources, which is delivered to the AC grid by means of the bipole HVDC transmission systems shown in Figure 37. Without the HVDC Reduction Scheme, the AC grid's transfer capacity to MISO would be much lower.[180]

The enhanced transfer capability results from the HVDC control's ability to mitigate contingency-related overloads of the AC grid. If the then-existing three 230 kV lines and single 500 kV line were loaded at their maximum transfer capacity, the trip of any of these lines would trigger the immediate reduction of inflows from the HVDC system, which is automatically determined based on the AC line loadings caused by the fault. This is a very fast process (less than 50 milliseconds from the tie line trip signal to the actual HVDC power reduction), which means it is able to prevent AC overloads, cascading outages, and uncontrolled separation of the AC grid.

By contrast, if the system had to be operated without the HVDC Reduction Scheme, the power previously flowing over the outaged AC line would start to flow on and overload the parallel AC paths, which could cause the cascading tripping of all Manitoba Hydro tie lines to the USA, Ontario, and Saskatchewan. In order to avoid this poor contingency response, without the HVDC Reduction Scheme, the transfer capability to MISO over the AC lines would have to be limited to only a few hundred MW.

A 2019 study documented this AC grid benefit of the HVDC control feature for the planned addition of the second 500 kV line, simulating the impact of losing either one 230 kV line or one 500 kV AC line in Manitoba Hydro's interface with MISO due to a three phase fault.[181] In the simulation of the 500 kV line outage (labeled B8-B14 in the line diagram of Figure 37 above), the fault occurs at 0.1 seconds and is cleared by removing the impacted line after 0.06 seconds (4 cycles) as shown in Figure 38 below. The power flow on the parallel 500 kV line (B9-B17) immediately exceeds its emergency overload rating after the fault is cleared by tripping the impacted line. In response to the detected fault, however, a power reduction control signal is sent instantaneously to reduce the HVDC lines' injection into the AC grid. As shown in Figure 38, this HVDC control function lowered the AC flow on the impacted 500 kV line below its emergency rating within one second of the fault and below the line's normal ratings within approximately three seconds of the fault.

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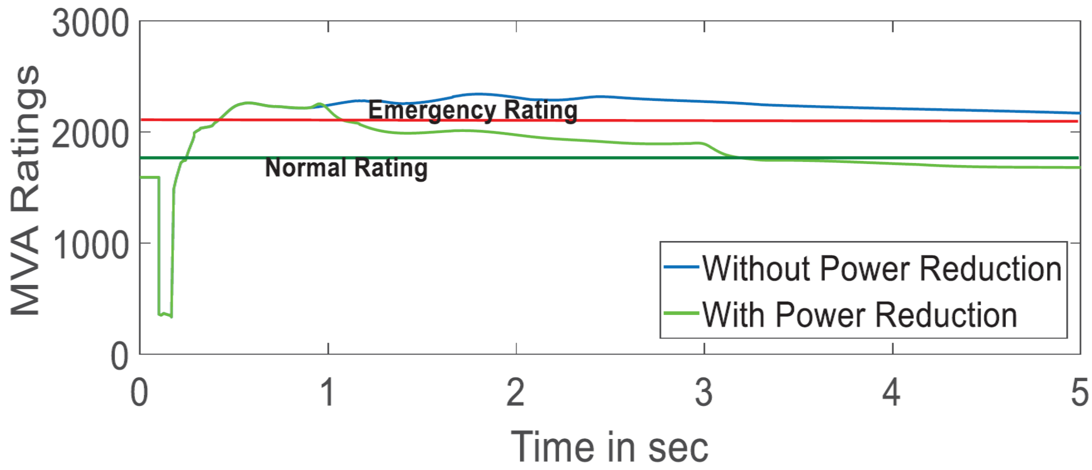
[180] Manitoba Hydro, *Long-Term Development Plan—2016 for Manitoba Hydro's Electrical Transmission System*, April 2017 at http://www.oatioasis.com/woa/docs/MHEB/MHEBdocs/Trans_LongTermDevlpmtPlan_2016_final1.pdf.

[181] N. V. Raju, A. D. Rajapakse, I. T. Fernando and D. Diakiw, "Wide area synchrophasor measurements based ac/dc integrated remedial action scheme for overload prevention," presented at 15th IET International Conference on AC and DC Power Transmission (ACDC 2019), Coventry, UK, February 5–7, 2019, pp. 1–6, doi: 10.1049/cp.2019.0038 at https://ieeexplore.ieee.org/document/8690251.

FIGURE 38. VARIATION OF POWER FLOW IN LINE B9-B17 WITH AND WITHOUT HVDC POWER REDUCTION



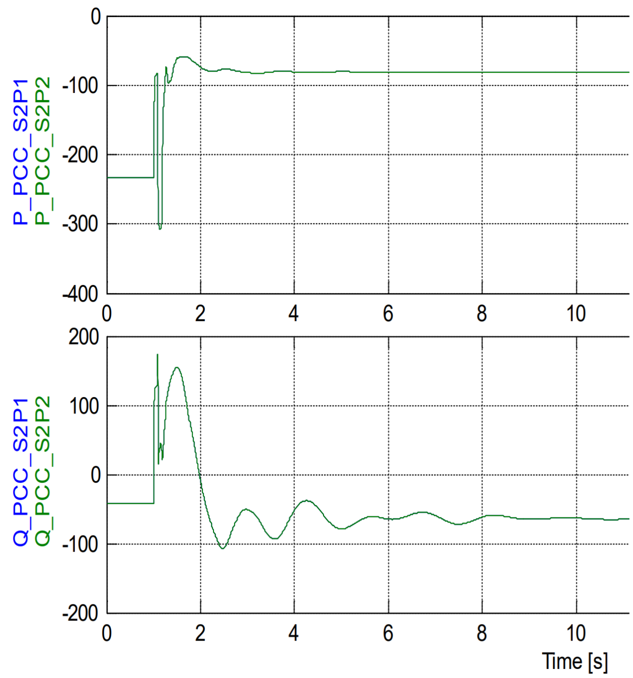
Source: N. V. Raju, A. D. Rajapakse, I. T. Fernando and D. Diakiw, "Wide area synchrophasor measurements based ac/dc integrated remedial action scheme for overload prevention," presented at 15th IET International Conference on AC and DC Power Transmission (ACDC 2019), Coventry, UK, February 5–7, 2019, Figure 12 at https://ieeexplore.ieee.org/document/8690251.

Nova Scotia Maritime Link HVDC Special Protection Scheme. The Maritime Link is a 200 kV, 500 MW HVDC line with bipolar VSC converter stations that transmits hydro power generation from Newfoundland to the grid in Nova Scotia. The HVDC line controls are designed with a runback scheme that can rapidly adjust the power transfer to mitigate AC grid imbalances during severe disturbances in the interconnected AC networks.

A 2017 study simulated a severe contingency in Nova Scotia's AC grid—assuming a three-phase fault at a node in "Hopewell" followed by a permanent trip of the Hopewell-Onslow line. To avoid interrupting the thermal units whose generation would otherwise need to be reduced under the fault conditions, a HVDC Special Protection Scheme (SPS) initiates the fast runback on the Maritime Link to avoid the overloading of AC transmission lines without the need to curtail local generation.

Figure 39 below shows the simulated system behaviors under the fault conditions. The fault occurred at 1 second, at which point the HVDC link's real power injection (top chart) was reduced immediately due to the detected voltage dip. After 150 milliseconds, when the fault was cleared, active power from the HVDC converter increased back to the pre-fault level. Meanwhile, the SPS sent signals to the HVDC converters to trigger their emergency power control (EPC) function. The control function quickly reduced the active power of Maritime Link to avoid overloads of the surrounding AC transmission grid and regulated both real power (top chart) and reactive power (bottom chart) to dampen transient power oscillations. The system reached a new stable operating point a few seconds after the fault without the need to ramp down any of the thermal generators in East Nova Scotia.[182]

FIGURE 39. ACTIVE AND REACTIVE POWER CONTROL OF THE WOODBIEN CONVERTER STATION OF THE MARITIME LINK DURING AC SYSTEM FAULT



Source and notes: P. Lundberg, F. Johansson, O. Vestergaard, J. Brake, Maritime link–enabling high availability with a VSC HVDC transmission, CIGRE Study Committees A, September 2017, Figure 4 at https://search.abb.com/library/Download.aspx?DocumentID=HVDC0008&LanguageCode=en&DocumentPartId=&Action=Launch. The top curve shows the active power injections of Maritime Link's Woodbine converter and the bottom curve shows its reactive power injections.

11. Fenno-Skan HVDC: Mitigating AC Stability Constraints

The Fenno-Skan HVDC line connects South Finland and Sweden. AC power transfer capability from South Finland is limited by inter-area oscillations and power transfer capability to South Finland is limited by voltage stability issues. Power oscillation damping (POD) implemented in the control systems of the Fenno-Skan HVDC system is able to effectively mitigate the 0.3 Hz inter-area oscillations that conventional Power System Stabilizers (PSSs) would not be able to address. In addition, the Fenno-Skan HVDC line contributes to mitigating voltage stability issues

[182] P. Lundberg, F. Johansson, O. Vestergaard, J. Brake, Maritime link–enabling high availability with a VSC HVDC transmission, CIGRE Study Committees A, September 2017, at https://search.abb.com/library/Download.aspx?DocumentID=HVDC0008&LanguageCode=en&DocumentPartId=&Action=Launch.

by relieving AC grid loading through emergency power control that is triggered by weakened voltage stability. By mitigating these dynamic stability concerns on the AC grid, the Fenno-Skan HVDC project was able to increase the transfer capability between the two areas beyond the capability of the HVDC project itself.[183]

Similarly, a 2007 ABB study documented in detail the ability of VSC-HVDC lines to mitigate AC stability constraints, thereby improving the transfer capability of the AC grid.[184] The study demonstrated that the instant power control capability of VSC-HVDC is effective at mitigating transient stability constraints to improve the transfer capability of the AC system. In one studied scenario, it showed that adding a 350 MW VSC-HVDC line between the areas affected by the stability constraint increased the total power transfer capability of the underlying AC grid between the two areas from 1,060 MW to 1,270 MW by means of a control mode that allows for instant full power reversal.

Voltage stability could similarly constrain the loading level of the AC lines. The ABB study also documented the benefit of VSC-HVDC for improving voltage stability through its reactive power support capability, which can prevent voltage collapse and, consequently, allow for increased utilization of AC lines. The simulation results (in Figure 40 below) show that the active power in one AC line could be increased (first curve) by reducing the reactive power of the HVDC converter (second curve) to maintain voltage stability (third curve), without affecting the active power control of the HVDC (fourth curve).

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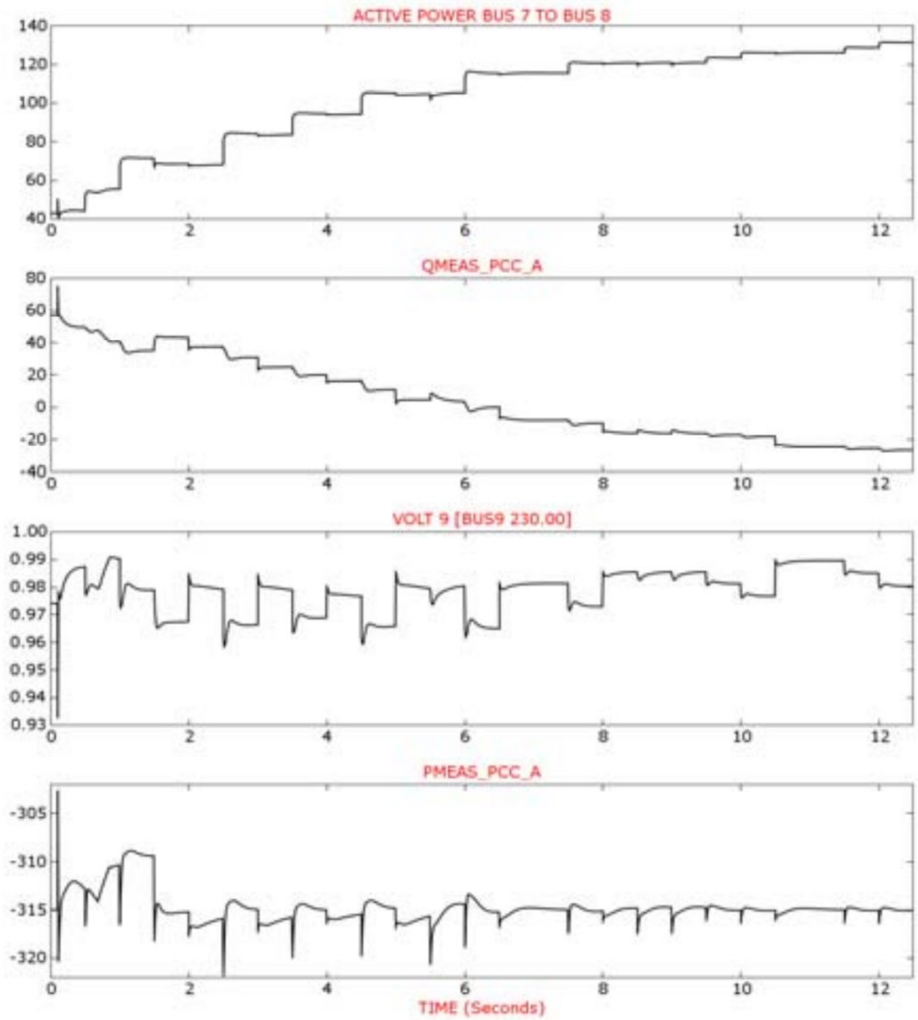
[183] CIGRE Joint Working Group C4/B4/C1.604, Influence of Embedded HVDC Transmission on System Security and AC Network Performance, April, 2013, p. 28 at https://cigreindia.org/CIGRE%20Lib/Tech.%20Brochure/536.pdf.

[184] L. Zhang, L. Harnefors, P. Rey, "Power System Reliability and Transfer Capability Improvement by VSC HVDC," presented at Security and Reliability of Electric Power Systems, CIGRÉ Regional Meeting, Tallin Estonia, June18–20 2007 at https://library.e.abb.com/public/158b677a7b207f5bc125731d00477d6a/Power%20system%20reliability%20and%20transfer%20capability%20improvement%20by%20VSC%20-%20HVDC%20Light.pdf.

FIGURE 40. VOLTAGE STABILITY IMPROVEMENTS BY VSC-HVDC



Source: L. Zhang, L. Harnefors, P. Rey, "Power System Reliability and Transfer Capability Improvement by VSC HVDC," presented at Security and Reliability of Electric Power Systems, CIGRÉ Regional Meeting, Tallin Estonia, June18–20 2007, Figure 6 at https://library.e.abb.com/public/158b677a7b207f5bc125731d00477d6a/Power%20system%20reliability%20and%20transfer%20capability%20improvement%20by%20VSC%20-%20HVDC%20Light.pdf.

12. France-Spain INELFE Link and France-Italy Link: AC Line Emulation, Black Start Capability, and External Power Control to Minimize System Losses

INELFE is a VSC-HVDC link with underground and tunnel installed cable embedded in synchronous and meshed AC network between France and Spain that was commissioned in 2015. It is designed as two identical but independent voltage source converters (VSC) links between Santa Llogaia (Spain) and Baixas (France), with a nominal active power of 1,000 MW each and a rated DC voltage of ±320 kV (positive–negative pole).[185] A 2019 study documented the real-time operational experience and control features of the INELFE link during the first 3 years after commissioning, noting that "[f]rom this operational point of view, the commissioning of the HVDC link has provided very positive results, impacting more directly [not only] the TSOs involved but also to the whole Continental Europe synchronous system."[186]

The 3-year review of operational experience confirmed a number of important operational characteristics:

- The INELFE link increased the total (contingency-constrained) transfer capacity between both countries from 1,400 MW to 2,800 MW.
- AC-line emulation control and special protection through angle difference control (ADC) of the INELFE link provided enhanced dynamic responses after contingencies. For example, during an April 2017 forced outage of a nearby 1,000 MW nuclear power plant, the active power control of the HVDC line immediately increased the power transfer by around 250 MW to support the affected system, eliminating the risk of overloading the parallel AC lines.
- The reactive power control of the INELFE link was able to mitigate the significant voltage fluctuations on the AC grid caused by large variations in power exchange schedules between Spain and France. After the commissioning of the HVDC link, the high volatility in AC grid voltage at interconnecting substation has been reduced significantly. For example, when the power exchange decreased from 1,300 MW to 300 MW during an hour in April 2017, voltage in the area where the INELFE link is located was much more stable than other areas of the grid.187

As noted, the INELFE link's VSC converters are operated in AC line emulation control. AC line emulation—which is also utilized by MISO for the Mackinac back-to-back interconnector in Michigan and the Piedmont-Savoy France-Italy interconnector between France and Italy—controls the HVDC line so it behaves like an AC transmission line. While the feature does not optimize real and reactive power flows of the HVDC line, it has the benefit of emulating the

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185 INELFE — Europe's first integrated onshore HVDC interconnection | IEEE Conference Publication | IEEE Xplore

186 P. L. Francos, S. S. Verdugo, H. F. Álvarez, S. Guyomarch and J. Loncle, "INELFE — Europe's first integrated onshore HVDC interconnection," 2012 IEEE Power and Energy Society General Meeting, San Diego, CA, USA, 2012, pp. 1-8, doi: 10.1109/PESGM.2012.6344799 at https://ieeexplore.ieee.org/abstract/document/6344799; also presented at AEIT HVDC International Conference 2019: Operational Experience and Technological Development for Application Worldwide, Cigre, Italy.

187 Id, p. 6.

transmission line behaviour that transmission system operators are already familiar with.[188] It is implemented through angle difference control (ADC) to reproduce the behavior of an AC line, such that it produces active power flow based on the differences of voltage angles at the two converter stations. In the second example for dynamic response after contingency in the INELFE study above, ADC was also utilized for active power control in real-time operation to increase power transfer after a contingency.[189]

Another 2019 study tested and validated the black start and other capabilities of the INELFE link by implementing a VSC-HVDC control and protection system on a real-time simulator for a realistic testbed that is a replica of the INELFE link.[190] The study simulated a blackout in the power network at one end of the INELFE link. INELFE's HVDC controls automatically energized the converter station in the energized area in DC voltage control mode and then energized the converter in the blacked out area using synchronous machine inertia control. The VSC-HVDC link set the voltage and frequency references. The simulation results show that the INELFE link can support passive load recovery, synchronize a 1,000 MW thermal generator, and restore the balance between the synchronous machine and supporting network through inertia emulation control. This study confirmed the effectiveness of the INELFE VSC-HVDC link and associated control scheme in the black start and restoration process.

In addition, a "tracking control" or "external power control" functionality has been implemented in the INELFE link, which can reduce system losses by regulating the active power of the HVDC as a percentage of total flows between the interconnected AC power grids.[191] This control feature is only possible for embedded HVDC links, with one or more parallel AC lines in service during synchronous network operation. The 400 kV Vic-Baixas AC line is operated in parallel to the INELFE link. The active power set-point of the INELFE link can be set as a function of the active power flow on the Vic-Baixas line or the corridor as a whole, such that total

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[188] Javier Renedo, Lukas Sigrist, Luis Rouco and Aurelio Garcia-Cerrada, "Impact on power system transient stability of AC-line-emulation controllers of VSC-HVDC links," Proc. 14th IEEE/PES PowerTech Conference,Madrid, Spain, June 28–July 2, 2021, pp. 1–6.

[189] L. Coronado, C. Longás, R. Rivas, et al., "INELFE: main description and operational experience over three years in service", 2019 AEIT HVDC International Conference (AEIT HVDC), Florence, Italy, May 9–10, 2019, doi: 10.1109/AEIT-HVDC.2019.8740447, p. 5 at https://ieeexplore.ieee.org/document/8740447.

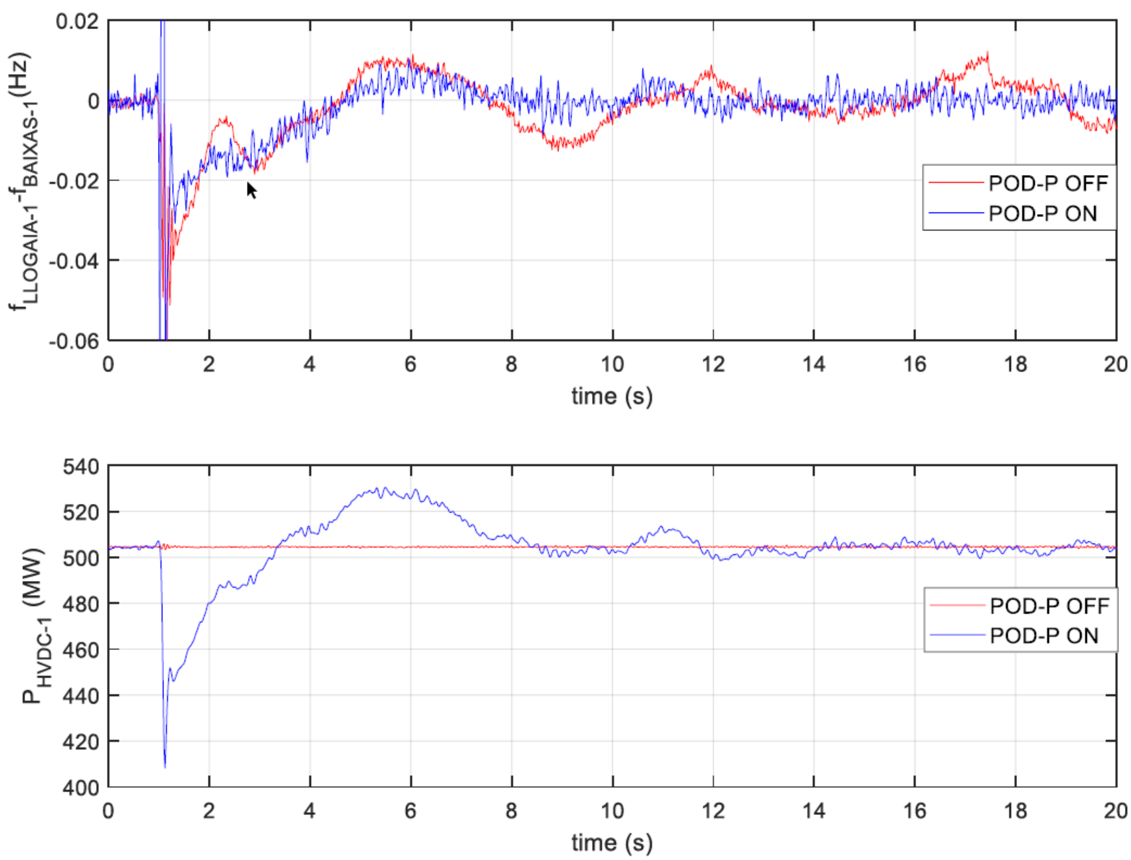
[190] C. Pisani, G. Bruno, H. Saad, P. Rault, B. Clerc, "Functional validation of a real VSC HVDC control system in black start operation," 2019 AEIT HVDC International Conference (AEIT HVDC), May 9–10, 2019 at https://ieeexplore.ieee.org/document/8740646.

[191] Siemens Energy, *HVDC PLUS linking France and Spain: a milestone for Europe's energy market*, p. 12 at https://assets.siemens-energy.com/siemens/assets/api/uuid:83dc80ed-cbd6-4027-9e48-83a87eab8e0b/263_160390_ws_hvdcplususlowres.pdf

transmission losses of the corridor are minimized. It was found that total losses are minimized when the active power of the INELFE link is set to 60%-70% of the total active power flow on the corridor.[192]

The INELFE link also is equipped with an active power oscillation damping (POD-P) controller, which can act to damp interarea oscillations due to unstable modes which are known to exist in the European grid. Even though it is hard to exactly quantify the impact of such a controller due to varying and unobservable system conditions, a field test carried out by the system operators on each side of the link in December 2022 (shown in Figure 41) documented a clear improvement in damping interarea oscillations.[193]

FIGURE 41. FIELD TEST OF THE INELFE POWER OSCILLATION DAMPING CONTROLLER DECEMBER 2022



192 P. L. Francos, S. S. Verdugo, and S. Guyomarch, S., New French-Spanish VSC link, B4-110_2012, CIGRÉ 2012 Session, Papers and Proceedings, p. 10 at https://e-cigre.org/publication/B4-110_2012-new-french-spanish-vsc-link.

193 J. Renedo et al., "*Tests on the POD-P controller of INELFE Spain-France VSC-HVDC interconnector*", CIGRE B4 Colloquium, 11th – 15th September 2023, Vienna, Austria

The France-Italy Link is another VSC-HVDC link between France and Italy that is currently undergoing final commissioning tests, consisting of underground- and tunnel-installed cables embedded in the synchronous and meshed AC network.[194] It is designed as two identical but independent VSC links between Piossasso (Italy) and Grande Ile (France) with a nominal active power of 600 MW each and a rated DC voltage of ±320 kV (positive–negative pole). The link has been equipped with the same AC line emulation control functionality[195] as the INELFE link.

13. Caithness-Moray, EWIC, Caprivi and Skagerrak 4: HVDC Black Start Services

Caithness-Moray: The Caithness-Moray is an embedded HVDC link in the Great Britain grid between Spittal in the Caithness area (North Scotland) and Blackhillock in Moray. The Caithness-Moray link uses VSC-HVDC technology to also provide black start and system restoration services to address blackouts in North Scotland. The line's AC voltage control, reactive power support, and frequency control capabilities of VSC-HVDC are needed during the black start.

During the commissioning process, the black start capability of the Caithness-Moray HVDC was successfully tested for energizing the 275 kV AC Spittal substation in Caithness. The Caithness-Moray link could support broader system restoration by energizing 275 kV AC circuits and interconnecting more resources such as the Foyers pumped hydro station and other smaller generators in the area, combining the Peterhead Station to form a network with sufficient generation. After Blackhillock converter station is re-energized, power can be transferred by HVDC circuit to restore power supply in the Caithness area. Finally, it can progressively pick up loads and other renewables in the area. The controllability of VSC-HVDC ensures that transient stability issues are fully mitigated in the restoration process and facilitate the energization of most of main transmission routes.[196]

[194] GE Grid Solutions, *RTE and TERNA Piedmont-Savoy HVDC Line: A New Power Highway Through The Alps To Build Europe's Energy Grid*, 2018 at https://www.gegridsolutions.com/products/applications/hvdc/france-italy-hvdc-link-casestudy-en-2018-02-grid-pea-1641.pdf.

[195] L. Michi, E. M. Carlini, et al., "AC Transmission Emulation Control Strategy in VSC-HVDC systems: general criteria for optimal tuning of control system," 2019 AEIT HVDC International Conference (AEIT HVDC), Florence, Italy, 2019, pp. 1–6, doi: 10.1109/AEIT-HVDC.2019.8740356 at https://ieeexplore.ieee.org/document/8740356.

[196] National HVDC Centre, Maximising HVDC Support for GB Black Start and System Restoration, April 12 2019, p. 23 at https://www.hvdccentre.com/wp-content/uploads/2019/12/HVDC-BS-001-041219-v2.0.pdf.

EWIC and Skagerrak 4: Black start tests on the East–West Interconnector (EWIC) between Great Britain and Ireland, and on Skagerrak 4 between Demark and Norway, are well documented. In the black start test in Ireland, results show that EWIC successfully picked up active and reactive loads at each switching operation, and facilitated synchronization of generators with the surrounding AC network.[197] Meanwhile, a live black-start capability test was performed on Skagerrak 4 during its commissioning in 2014. The full-scale test was executed by control centers of the TSO. A small AC testing grid was disconnected from the rest of the Nordic system. The results show that Skagerrak 4 was able to energize and synchronize the islanded testing AC grid to the Nordic system and restore normal operation.[198]

The Caprivi link between Zambia and Namibia is equipped with the ability to detect whether the AC grid it is connected to in Zambia becomes islanded due to AC grid contingencies and automatically adjust its control mode and output real and reactive power to maintain supply to the islanded grid.[199]

In addition, the HVDC links can limit the system outages by serving as a "firewall" against cascading failures during system events. The 2003 North America blackout and 2006 Europe Blackout demonstrated that HVDC links could effectively perform as a "firewall" against the system collapse propagating across the interconnected networks and prevented larger blackouts.[200]

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[197] N. Macleod, N. Cowton and J. Egan, "System restoration using the "black" start capability of the 500MW EIRGRID East- West VSC-HVDC interconnector," IET International Conference on Resilience of Transmission and Distribution Networks (RTDN) 2015, Birmingham, 2015, pp. 1–5, doi: 10.1049/cp.2015.0871 at https://ieeexplore.ieee.org/document/7447234.

[198] T. Midtsund, A. Becker, J. Karlsson, KA Egeland, "A live black-start capability test of a voltage source HVDC converter," 2015 CIGRE Canada Conference, Winnipeg, Manitoba August 31–September 2, 2015 at https://library.e.abb.com/public/97ac6612486f42dcbe4e5342edd41a01/A%20Live%20Black%20Start%20Capability%20test%20of%20a%20Voltage%20Source%20HVDC%20Converter.pdf.

[199] T.G.Magg, "Zambezi (previously Caprivi) Link HVDC Interconnector: Review of Operational Performance in the First Five Years," 2016 CIGRE Paris Session, Paper B4-108 at https://search.abb.com/library/Download.aspx?DocumentID=9AKK106930A0396&LanguageCode=en&DocumentPartId=&Action=Launch.

[200] Union for the Coordination of Transmission of Electricity (UCTE). Final report on system disturbance on 4 November 4, 2006 at https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/publications/ce/otherreports/Final-Report-20070130.pdf and U.S.-Canada Power System Outage Task Force. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004 at http://bh.brattle.net/sites/Collaboration/General/ELEC/Lists/Calendar/calendar.aspx.

14. HVDC-Based Black Start and System Restoration Plans

The National HVDC Centre in Great Britain—part of Scottish & Southern Electricity Networks—has analyzed in detail the extent to which HVDC system can support black start and system restoration.[201] The study was motivated based on the recognition that the changing profile of generation not only creates challenges for maintaining reliable system operations (voltages and frequency), but also makes re-energizing the network more difficult. With costs of providing black start services through conventional means forecast to potentially increase by a factor of 10 over the next 10 years, the HVDC Centre investigated the capabilities of HVDC technologies, technically evaluated how to use HVDC systems for black start processes, reviewed international experience, and identified necessary modification to existing codes and obligations.

The HVDC Centre's black start study specifically concluded that:

- HVDC-based provision of black start and system restoration services was a unique opportunity given that 26 GW of HVDC transmission system had already been proposed in Great Britain.
- Great Britain's black start capability can be improved and system restoration times can be reduced at significant overall cost savings by utilizing and maximizing the black start capabilities of proposed HVDC systems.
- HVDC interconnectors based on voltage source converter technology are inherently able to provide excellent Black Start capabilities as well as other areas of system support able to increase system stability and reduce the impact of network disturbances. This capability of HVDC lines to energize network and load is more than equivalent to that from conventional resources previously available.
- There is an opportunity to not only support black start services in Great Britain with HVDC interconnectors to other countries (such as Norway, Ireland, and continental Europe), but also—in combination with embedded (GB-internal) HVDC links—leapfrog areas of more problematic network restoration, energizing large geographic areas more rapidly and provide a faster and more flexible approach to restoring demand.

More importantly, black-start capability of VSC-HVDC converters has been quite well documented, tested, and even been put into practice. While the rated current of VSC-

[201] National HVDC Centre, Maximising HVDC Support for GB Black Start and System Restoration, HVDC-BS-001, April 12, 2019, at https://www.hvdccentre.com/wp-content/uploads/2019/12/HVDC-BS-001-041219-v2.0.pdf

converters is more limited than that of conventional generators, its excellent controllability means that this does not necessarily limit the scope of HVDC-based system restoration—as long as the other end of the HVDC link is connected to a strong AC grid or generation resource, including inverter-based resources, such as an offshore windfarm.[202]

The excellent voltage control capabilities of VSC-HVDC converters enable it to significantly speed up recovery time and reduce demands on black-start units by using the "soft-energization" system restoration technique.[203] Instead of black-starting one unit, and then sequentially switching in sections of the black-out network, it relies on closing all circuit breakers, interconnecting network, and then slowly ramping up the voltage to avoid inrush currents and transformer saturation. The National HVDC Centre's work was undertaken in collaboration with EPRI, which published its own report, specifically confirming VSC-HVDC's suitability for soft-start restoration that includes simulation results validating the approach.[204] Today, black start capability from HVDC links is quite well accepted as an ancillary service by most EU system operators and is specifically provided for in the ENTSO-e grid code, stating:

> An HVDC system with black start capability shall be able, in case one converter station is energised, to energise the busbar of the AC-substation to which another converter station is connected, within a timeframe after shut down of the HVDC system determined by the relevant TSOs. The HVDC system shall be able to synchronise within the frequency limits set out in Article 11 and within the voltage limits specified by the relevant TSO or as provided for in Article 18, where applicable. Wider frequency and voltage ranges can be specified by the relevant TSO where needed in order to restore system security.[205]

202 While LCC converters similarly can black-start an AC system, they need additional components such as synchronous condensors.

203 DNV-GL, *Reducing The Risks Of Network Restoration: DNV GL's 'soft energisation' approach*, July 2016.

204 EPRI, *Coordination of ac protection settings during energisation of AC grid from a VSC HVDC interconnector*, June 2020 at https://www.hvdccentre.com/wp-content/uploads/2020/06/EPRI-Black-Start-from-HVDC-Project-final-report_reviewed_clean.pdf

205 The European Commission, "Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules," *Official Journal of the European Union*, August 9, 2016 at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32016R1447#d1e211-1-1.

That VSC-HVDC is very well suited to perform such a task through its excellent voltage control abilities has also been operationally confirmed with a number of existing VSC HVDC transmission projects. For example, in addition to the INELFE example[206] discussed earlier:

- **Skagerrak 4**: "To confirm that the soft start capability is working as intended for energization of larger networks, a live black start test of parts of the Danish 400 kV and 150 kV network was performed with the Norwegian grid as the only power source. The test included 400 kV cable, several transformers and reactors, and was performed both with sequential and soft start energization. A 25 MW district heating boiler unit was also connected after energization of the transmission network to validate the HVDC performance under load and in an islanded condition. Lastly, the energized island was synchronized to the rest of the transmission network."[207]
- **Cross-Sound Cable**: Following the Northeast blackout of 14 August 2003, the CSC was started up under an emergency order from the U.S. Department of Energy. The CSC was used to help restore service to Long Island, and it was the first Long Island interconnection in service following the blackout. Despite its not being furnished with black start control, the CSC was able to operate with a minimal system intact on Long Island in the vicinity of Shoreham. In addition to providing power for system restoration, converter dynamic reactive power capability was instrumental in stabilizing system voltage during the restoration process as lines and transformers were energized, generators were restarted, and cold loads were picked up. Dynamic voltage support from the converters operating with ac voltage control helped the system ride through three major disturbance events on Long Island during restoration.[208]
- **Caprivi Link**. Electric system tests were undertaken in which the AC network at the sending end is opened. The HVDC link automatically detects islanded operation at the sending end and reduces its power transfer to maintain the frequency of the islanded network. If more

[206] C. Pisani, G. Bruno, H. Saad, P. Rault and B. Clerc, "Functional validation of a real VSC HVDC control system in black start operation," 2019 AEIT HVDC International Conference (AEIT HVDC), Florence, Italy, 2019, pp. 1–6, doi: 10.1109/AEIT-HVDC.2019.8740646 at https://ieeexplore.ieee.org/document/8740646.

[207] T. B. Sorensen, J. B. Kwon, J. M. Jorgensen, G. Bansal, P. Lundbert, *A live black start test of an HVAC network using soft start capability of a voltage source HVDC converter*, No. 140, CIGRE Symposium Aalborg, Denmark, June 4–7, 2019 at https://e-cigre.org/publication/SYMP_AAL_2019-symposium-aalborg-2019.

[208] NYISO, *Blackout August 14, 2003: Final Report*, February 2005 at https://www.nyiso.com/documents/20142/3059489/blackout_rpt_final.pdf/8fde000f-6b73-82a0-2c5d-1c599f8fe056

load were connected on the island, power flow over the DC link could actually reverse. In this manner, the DC link remains ready for restoration of the AC interconnection.[209]

- **Kriegers Flak**: The transmission system operators 50Hertz and Energinet as well as the coal-fired power plant Rostock successfully performed a live simulation of a restart of the power grid after a power outage in Continental Europe with voltage supplied from Denmark. For the first time, a land and sea cable connection between two countries as well as offshore wind power were used in real conditions to restart a power plant.[210]

15. Frequency and Inertial Response from HVDC Lines and Inverter-Based Resources

As noted in the discussion of grid services, the ability of HVDC transmission lines to rapidly adjust their real power output enables it to provide frequency response—including inertial control (needed during the first 12 seconds of a system disturbance) and primary frequency control (or frequency governor response, during 10-60 seconds after a disturbance, prior to the availability of secondary frequency or regulation response) as defined by NERC.[211] Such frequency response (along with emergency energy support) can be provided over HVDC lines either by importing real power from asynchronous neighboring systems, as discussed in the NEMO Link case study above, or from interconnected generating or storage resources.

The UKs and ENTSO-e's European HVDC grid code specifically provides for frequency response, requiring activation as fast as technically possible (but with delays of no longer than 0.5 seconds).[212] ENTSO-e's HVDC grid code also requires that "[i]f specified by a relevant

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[209] T G Magg, F Amputu, M Manchen, E Krige, J Wasborg, K Gustavsson, *Zambezi (previously Caprivi) Link HVDC Interconnector: Review of Operational Performance in the First Five Years*, 2016 CIGRE Paris Session, Paper B4-108 at https://search.abb.com/library/Download.aspx?DocumentID=9AKK106930A0396&LanguageCode=en&DocumentPartId=&Action=Launch.

[210] 50hertz, *'Black start' with wind power: Rostock power plant successfully started up via cable Germany – Denmark*, September 2020 at https://www.50hertz.com/en/News/FullarticleNewsof50Hertz/id/7313/black-start-with-wind-power-rostock-power-plant-successfully-started-up-via-cable-germany-denmark.

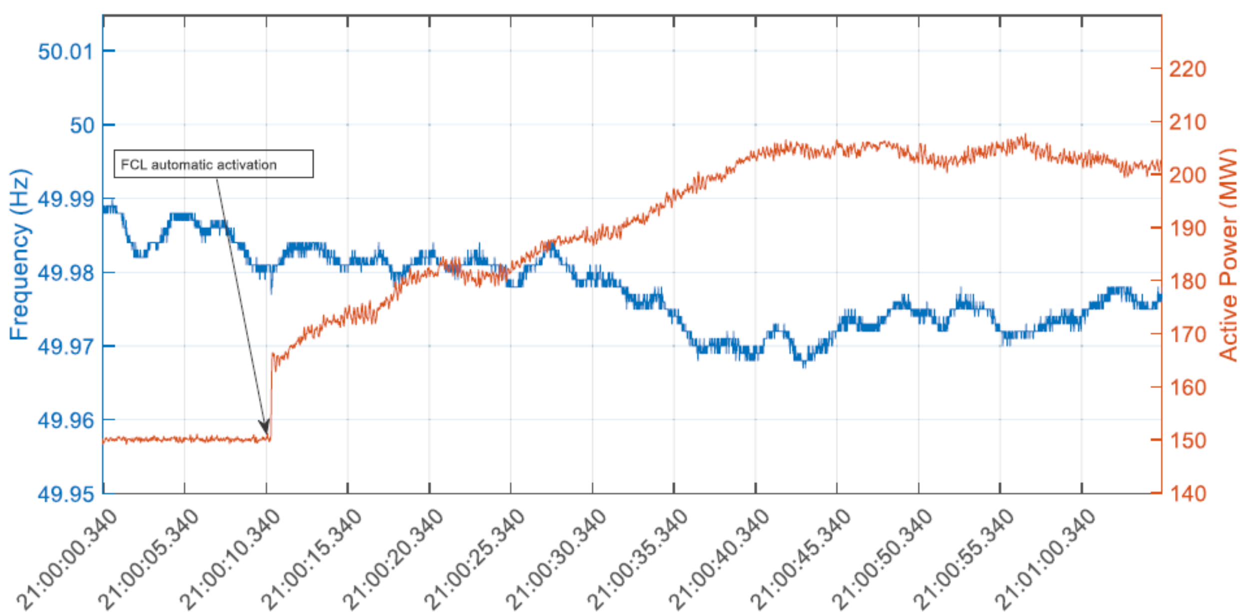
[211] See NERC, *Balancing and Frequency Control Reference Document*, May 11, 2021 https://www.nerc.com/comm/OC/ReferenceDocumentsDL/Reference_Document_NERC_Balancing_and_Frequency_Control.pdf.

[212] The European Commission, "Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules," *Official Journal of the European Union*, August 9, 2016, Articles 39, 47 and Annex II at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32016R1447#d1e211-1-1.

[transmission system operator], an HVDC system shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency."[213] During the ENTSO-e system split event in Europe on the 8th of January 2021, HVDC links to neighbouring asynchronous systems automatically imported an additional 592 MW of supportive power. The HVDC links that were equipped with this functionality and participated in providing support were Skagerrak (Norway-Denmark West), Kontiscan (Sweden – Denmark West) and Kontek (Denmark East – Germany).

An example of an automatic frequency response is given in the case study on the NEMO link in section V.C.8, which shows the automatic adjustment of real power flow in response to a sudden frequency drop in the European continental grid following the 2021 system split. Automatic frequency response can also provide benefit during normal operation (as opposed to just during contingencies) and support system operators by stabilizing frequency during fast changes in loads or generation. An example of this is shown in Figure 42 which shows the automatic increase in power flow on the MONITA link between Italy and Montenegro in response to an excessive frequency excursion during the evening 8-9 pm.

FIGURE 42. FIELD TEST OF 'FREQUENCY LIMITATION CONTROL' IN THE MONITA LINK BETWEEN ITALY AND MONTENEGRO ON JUNE 26, 2019[214]



[213] Id., Article 14.

[214] E. M. Carlini, "*Active and Reactive Power control of Italy – Montenegro HVDC First year of operation*", AEIT 2021

For HVDC links, frequency and inertial control will generally be provided by importing real power from a neighboring asynchronous system or connected resources, including storage systems. While it is theoretically possible to provide synthetic inertia directly from each VSC converter—by adding capacitor- or battery-storage capability to the VSC converters—doing so may not be economic for high-capacity HVDC systems because of the expense of capacitors or battery systems that are able to operate at the converters' high voltage levels. It also needs to be noted that frequency and inertial response from HVDC lines (and any inverter-based resources) will differ from those of conventional generating resources and synchronous condensers by the lower magnitude of short-circuit current the converters can deliver, which is limited to by current rating of the power semi-conductors.

While we are not aware of examples of synthetic inertia with real power provided from the VSC HVDC converters themselves, the provision of primary frequency response and synthetic inertia through VSC HVDC lines (by relying on imports from neighboring systems or connected resources, as discussed in the earlier case studies) and other inverter-based resources is now well established. The operational experience from inverter-based resources includes synthetic inertia provided from wind generators, battery facilities, and STATCOMs.[215] For example, ERCOT has required since 2012 that all new interconnecting generators, including wind and solar farms, be able to provide "primary frequency response" and increase or decrease real power output immediately to stabilize frequency.[216] As a result, ERCOT has observed a major improvement in its primary frequency response capability, as well as a reduced need for "secondary" frequency regulation services provided by conventional resources.[217]

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[215] J. St. John, "Solving the Renewable Energy Grid's Inertia Problem," Dispatches from the Grid Edge, *GreenTech Media (gtm²)*, August 7, 2020 at https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/solving-the-renewable-powered-grids-inertia-problem-with-advanced-inverters.

See also Siemens Energy, Frequency and voltage support for dynamic grid stability: SVC PLUS (STATCOM) Frequency Stabilizer at https://www.siemens-energy.com/global/en/offerings/power-transmission/portfolio/flexible-ac-transmission-systems/svcplus-frequency-stabilizer.html.

[216] Ibid.

[217] S. Sharma (ERCOT), *Frequency Control and Grid Resiliency*, presented July 2018 at https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.2%20Frequency%20Response%20Panel%20-%20Sharma%2C%20ERCOT.pdf.

Similarly, Hydro Quebec has required since 2010 that wind farms be capable of providing synthetic inertia.[218] A 2015 transformer failure that forced offline about 1,600 megawatts of generation on Hydro-Québec's 40,000-megawatt grid showed that this synthetic inertia capability was able to stabilize grid frequency just like synchronous generators, although controls needed to be adjusted to avoid a "double dip" of frequency during post-inertia recovery.[219]

High shares of renewable generation in portions of the Australian grid have required additional sources of system inertia, which is now also provided synthetically through batteries such as Tesla's Hornsdale and Wallgrove projects, General Electric's Solar River system, and Hitachi's Dalrymple ESCRI (Energy Storage for Commercial Renewable Integration) project.[220] Commissioning and testing reports validate the operational effectiveness of synthetic inertia provided through these battery storage systems.[221] For example, Tesla's "virtual machine mode" has been added to the controls of the 150 MW (195 MWh) Hornsdale battery to provide 3,000 MW-seconds of inertial response (which is half of the entire inertia required to operate the grid in South Australia), with test results confirming that the facility has been able to successfully demonstrate an inertial response to real system events.[222]

SINTEF has partnered with multiple European TSOs including Statnett, Statoil, RTE and ELIA to work on the "HVDC Inertia provision" project for enabling HVDC interconnectors to deliver inertia support.[223] They have demonstrated the capability of HVDC converters to provide

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[218] See P. Fairley, "Can Synthetic Inertia from Wind Power Stabilize Grids? Wind farms can emulate the rotational inertia that conventional power plants provide to stabilize power grids. Next-generation technology will do it even better," *IEEE Spectrum*, November 7, 2016 at https://spectrum.ieee.org/can-synthetic-inertia-stabilize-power-grids and J. Brisebois and N. Aubut,. Wind farm inertia emulation to fulfill Hydro-Québec's specific need. Proceedings of IEEE PES General Meeting, 2011 pp. 1–7: 10.1109/PES.2011.6039121 at https://www.researchgate.net/publication/224261524_Wind_farm_inertia_emulation_to_fulfill_Hydro-Quebec%27s_specific_need

[219] J. St. John, "Solving the Renewable Energy Grid's Inertia Problem," Dispatches from the Grid Edge, *GreenTech Media (gtm²)*, August 7, 2020 at https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/solving-the-renewable-powered-grids-inertia-problem-with-advanced-inverters.

[220] Ibid. See also Tesla, *Transgrid: Meeting System Strength requirements in NSW*, submission to PSCR, March 2023 at https://www.transgrid.com.au/media/kelpxss5/tesla-submission.pdf.

[221] See for example Transgrid/Lumea, *Commissioning Report: CPEOI190025 Wallgrove Grid Battery*, October 2022 at https://www.lumea.com.au/media/441ozmkp/2022-commissioning-report.pdf.

[222] N. Hicks and E. Green (Neoen), *Hornsdale Power Reserve Expansion: VIrtual Machine Mode Test Summary Report*, September 3, 2022 at https://arena.gov.au/assets/2022/03/hornsdale-power-reserve-virtual-machine-mode-testing-summary-report.pdf .

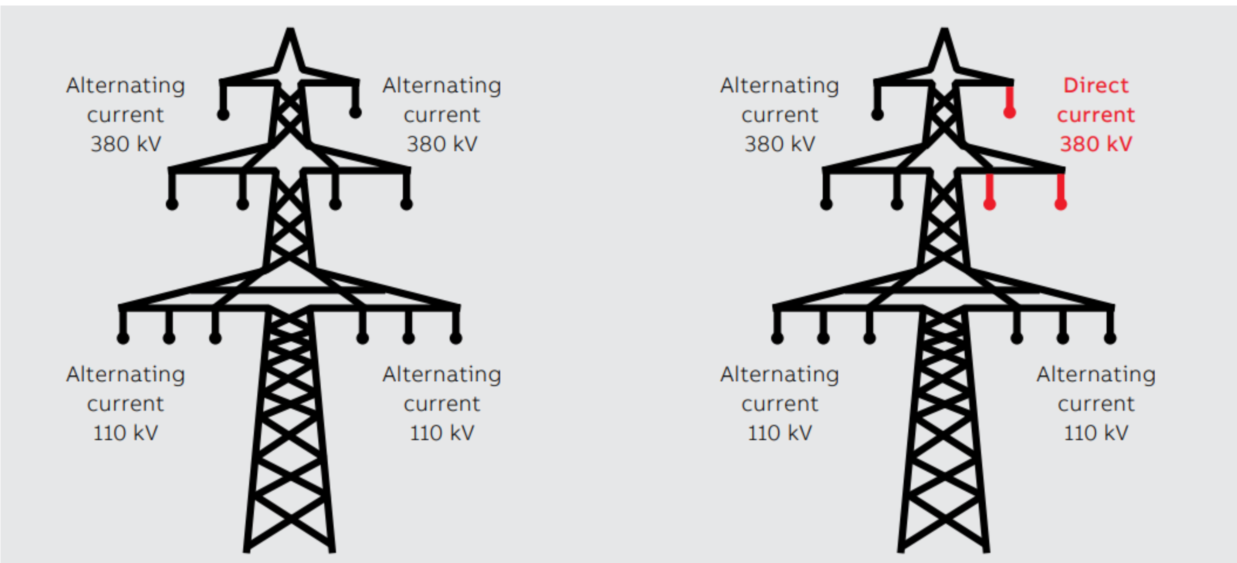
[223] J. Are Suul (SINTEF Energy Research), *Introduction to the "Hvdc Inertia Provision" Research Project*, at https://www.sintef.no/globalassets/project/hvdc-pro/suul_hvdc_inertia_provision_project_28042022.pdf.

synthetic inertia to the Nordic power system through Power-Hardware-in-the-Loop lab tests with an MMC converter.[224]

16. Ultranet: EHV-AC to HVDC Conversion

The German Ultranet project, developed jointly by Amprion and TransnetBW, is a 2 GW 380 kV VSC-HVDC overhead transmission project that will be combined with Amprion's 2 GW, 380 kV, A-Nord link in a bipolar multi-terminal configuration.[225] As shown in Figure 43 below, the 2 GW, 380 kV VSC HVDC UltraNet project is developed as 200 mile overhead line by converting to HVDC an existing 380 kV circuit on multi-circuit towers that currently carry two 380 kV AC and two 110 kV AC circuits.

FIGURE 43. ULTRANET'S AC OVERHEAD LINE CONVERSION TO HVDC



Source: ABB, *Convert from AC to HVDC for higher power transmission*, December 6, 2018 at https://new.abb.com/news/detail/11828/convert-from-ac-to-hvdc-for-higher-power-transmission.

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[224] S. D'Arco, T. D. Duong, and J. Are Suul, "P-HiL Evaluation of Virtual Inertia Support to the Nordic Power System by an HVDC Terminal," 2020 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe), The Hague, Netherlands, 2020, pp. 176–180, doi: 10.1109/ISGT-Europe47291.2020.9248905 at https://ntnuopen.ntnu.no/ntnu-xmlui/bitstream/handle/11250/2773794/ISGT_Europe_Virtual_Inertia_N44_PHiL_Final_Paper_Submitted.pdf?sequence=2

[225] Amprion Connects, Project Description, Ultranet: Bbplg Project No. 2 | Osterath–Philippsburg at https://www.amprion.net/Grid-expansion/Our-Projects/Ultranet/ and European Commission, Internal line between Osterath and Philippsburg (DE) to increase capacity at western borders [currently known as "Ultranet"]: North-South electricity interconnections in Western Europe, last update March 2023 at https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.9.pdf.

The HVDC conversion of the 380 kV AC circuit has a planned online date of 2027. It will significantly increase the capability of the existing lines and facilitate 2,000 MW of flow-controlled transfers from wind farms in the North Sea to the industrial towns in the south of Germany. The Ultranet project is the first VSC HVDC project outside China to use full-bridge submodules[226] to achieve DC fault current control capability, which enables high reliability due to the ability to quickly and effectively clear temporary overhead line faults.

As noted by ABB, Ultranet is the world's first example of this type of AC to HVDC conversion, which requires careful consideration of a range of environmental, engineering and economic factors as shown in Table 18 below.[227] As further noted by ABB:

> When a decision has been made to proceed with the conversion, the HVDC configuration must be decided: symmetric/asymmetric monopole or bipole or a hybrid that suits the tower configuration and the clearances available. For example, a horizontal single-circuit AC transmission line can be replaced with either one or two symmetrical monopole HVDC lines. A bipole configuration is also an option. In the case of a double circuit or multi-circuit, either one or several AC systems can be converted to HVDC. … However, replacement is not straightforward and modifications may have to be made to the tower structure, insulators and conductors. The AC ceramic insulators are generally replaced with high resistivity toughened glass (HRTG) or composite insulators to meet the clearance requirements.[228]

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[226] Siemens, Siemens presents new technology for reliable power highways, Press Release, December 8, 2015 at https://assets.new.siemens.com/siemens/assets/api/uuid:9d1f5be1-c468-434c-b596-3bbebceeed62/pr20151208-reliable-power-highway.pdf.

[227] ABB, *Convert from AC to HVDC for higher power transmission*, December 6, 2018 at https://new.abb.com/news/detail/11828/convert-from-ac-to-hvdc-for-higher-power-transmission.

[228] Ibid.

TABLE 18. CONSIDERATIONS IN CONVERTING AC TRANSMISSSION TO HVDC

Environmental	Engineering	Economic
The pollution zone in which the AC system to be converted is located decides the creepage requirements of DC insulators.	The conversion can be a monopole, bipole or hybrid HVDC configuration.	In spite of converter station losses, operating expense is often lower for DC compared to AC owing to low line losses and enhanced transmission capacity.
Weather conditions determine the audible noise and radio interference level generated by the converted line.	DC voltage selection is based on the clearances in the transmission line towers. Current, based on the thermal limit of the conductor, decides the maximum power transmission capacity of the conversion.	Capital expenditure mainly depends upon the type of AC transmission tower, HVDC converter station and configuration planned, along with the transmission distance.
Corona and field effects depend on the voltage and current levels, and the configuration and positioning of the conductors.	To achieve the desired DC voltage and current, modifications to the insulator, and possibly the tower or conductor, may be required .	Time for conversion is shorter than the time taken to obtain permits and construct a new line, even if towers have to be modified or conductors or insulators replaced.

Source: ABB (2018).

Ultranet will also be the first HVDC system using full bridge converters whose ability to control HVDC fault currents enables it to maintain high reliability under the occurrence of temporary DC line faults, which is more common for overhead line systems compared to insulated cable based systems in which faults tend to be uncommon and permanent.

D. Experience with Regional and Interregional HVDC Market Integration

As the following case studies shows, market operators have gained significant experience with HVDC lines that are co-optimized with generation dispatch. The optimization of transfers on interregional HVDC transmission links represents an additional challenge—the need for neighboring system operators to coordinate in that optimization. The case studies below cover:

- CAISO and NYISO market optimization of controllable HVDC transmission lines;
- European “market coupling” to optimally utilize inter-regional transmission, including HVDC lines;
- The optimization of inter-regional transmission (including HVDC lines) in the Western energy imbalance markets;
- The importance of similarly optimizing intertie capacity in the rest of North America, as noted by market monitors; and

- The CAISO's proposed market optimization of interregional merchant HVDC lines.

17. Market Optimization of Controllable HVDC Transmission Lines

The full value of the exceptional power flow control capability offered by VSC-HVDC transmission systems can be captured most completely if the "dispatch" of the HVDC facility is co-optimized with the region's generation dispatch, both on a day-ahead basis (to optimize generation unit commitment and bilateral trading) and in real-time (during actual system operations). The opportunity to co-optimize HVDC transmission with regional generation dispatch is particularly valuable in regions with nodal energy markets with security-constrained economic dispatch, which already optimize generation dispatch against the transmission constraints in the AC grid.

CAISO is the only U.S. system operator that co-optimizes HVDC transmission and generation dispatch in its nodal day-ahead and real-time energy and ancillary services markets. CAISO has utilized HVDC transmission for decades and, since 2013, has been operating its first VSC-based HVDC line, the Trans Bay Cable in San Francisco. In response to the positive operational experience with that VSC-based HVDC line, CAISO addressed the optimization of "controllable transmission devices" (which also includes phase shifters) to its "Market & Operational Excellence" effort, through which full optimization of HVDC and other controllable transmission was added to the CAISO day-ahead and real-time nodal energy markets in 2017.

Section 3.1.12 of CAISO's business practice manual for market operations now specifically states that:

> The CAISO controlled grid includes controllable transmission devices that enable the CAISO as the balancing authority area and transmission operator to monitor and adjust the power flow on the CAISO controlled grid. (An example of these devices include but not limited to ISO controlled HVDC, Phase Shifting Transformer, and any other controllable devices). Controllable transmission devices are designed to ensure the reliable and secure operation of the grid is maintained. Controllable transmission devices help control the power flow through transmission lines. The CAISO market systems optimizes the controllable transmission devices as part of its security constrained economic dispatch and security constrained unit commitment. The CAISO market systems will calculate and issue the optimal position for the controllable device to the transmission owner. Pursuant to operating procedures,

> the transmission owner modifies the controllable device pursuant to the CAISO market instruction.[229]

Through the WECC-wide Western Energy Imbalance Market (WEIM) and the introduction of an Extended Day-ahead Market (EDAM), this co-optimization of generation and HVDC transmission dispatch is now also being applied to HVDC transmission lines between CAISO and other Balancing Areas in the Western U.S. (as discussed in more detail below).

In addition to CAISO, NYISO is currently modifying its market design to similarly implement the optimization of "Internal Controllable Lines" in its energy and capacity markets.[230] This effort is in response to the selection of the "Clean Path NY" HVDC line, which was selected in a recent state procurement effort in part because of its congestion-relief benefits to New York's AC grid.[231] The concept of market-optimization of dispatchable HVDC lines is also included in MISO's market roadmap for implementation by 2031.[232]

In power system where such an optimization of internal HVDC lines is not undertaken, the owners of HVDC lines will have to try to maximize the value of their transmission facility through self-scheduling hourly (or sub-hourly) flows. Such self scheduling, however, tends to be quite inefficient—particularly during real-time operations where nodal price differences between the interconnection points vary on a 5-minute basis, are growing more volatile as more intermittent renewable generation is added to the AC grid, and where even modest delay

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229 CAISO, *Business Practice Manual for Market Operations*, Version 89, Revised April 6, 2023 (emphasis added), at https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/BPM_for_Market%20Operations_V89_Clean.doc

230 M. Swider and A. Myott (NYISO), *Internal Controllable Lines: Market Design Concept Proposal*, presented at ICAPWG/MIWG, August 04, 2022 at https://www.nyiso.com/documents/20142/32552857/Internal%20Controllable%20Lines_Market%20Design%20Concept%20Proposed_FINAL.pdf/a36c7967-9959-777a-879e-370fc30c4318

231 NYPSC Case 15-E-0302, Order Approving Contracts for the Purchase of Tier 4 Renewable Energy Certificates, April 14, 2022, noting that "the HVDC line … would relieve congestion that inhibits renewable upstate power from reaching downstate loads, [with NYISO controlling dispatch of the line, thereby] minimizing costs for ratepayers" (at pp. 41-42) at https://www.cleanpathny.com/sites/g/files/ujywhv376/files/2022-06/NYS%20Public%20Service%20Commission%20Order%20Approving%20Contracts%20for%20the%20Purchase%20of%20Tier%204%20Renewable%20Energy%20Certificates.pdf

232 MISO, *Markets of the Future*, November 2021, p. 29 at https://cdn.misoenergy.org/MISO%20Markets%20of%20the%20Future604872.pdf

See also MISO, *New Planning Approaches Workshop: Market Dispatchable HVDC*, February 16, 2021 at https://www.misoenergy.org/past-events/2021/new-ideas-approaches-and-technologies-to-be-considered-in-planning-for-a-renewable-heavy-market---february-16-2021/

in rescheduling real-time flows mean the loss of a significant share of the full value that controllable HVDC facilities can provide to the market.

18. European "Market Coupling"

In Central and Western Europe (CWE), cross border trading among different markets was initially facilitated through separate cross-border auctions based on traders' expected market prices. This could result in uneconomic transactions with power flows from high-priced to low-priced areas.[233] To mitigate that inefficiency and more effectively utilize the available transfer capability between national power markets, the European "market coupling" process was implemented in 2006 and improved over time:

- In 2006, Belgium, France, and the Netherlands "coupled" their day-ahead markets to better utilize the cross-border transmission capacity.[234]
- In 2010, the available transfer capacity (ATC) approach was added to market coupling and implemented in the entire CWE region. Under the ATC-based approach, the neighboring TSOs coordinate with each other bilaterally to determine a Net Transfer Capacity (NTC) value for each direction on the border based on historical data that represent the maximum available commercial exchange capacity.
- In May 2015, the CWE region transitioned to a flow-based market coupling (FBMC) mechanism, which has been expanded to more countries in Europe.[235] The FBMC method is based on detailed representations of the AC network using Power Transfer Distribution Factors (PTDFs) to determine the linear relationship between the net energy exchange and flows on critical grid elements.[236]

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[233] T. Kristiansen, "The flow based market coupling arrangement in Europe: Implications for traders," *Energy Strategy Reviews*, Vol. 27, 100444, January 2020 at https://www.sciencedirect.com/science/article/pii/S2211467X19301373

[234] Belgian Power *Exchange, Belpex and Trilateral Market Coupling: Energy Exchanges and Transmission System Operators working together towards European Market Integration*, Belpex Conference Day, January 12, 2006 at https://inis.iaea.org/collection/NCLCollectionStore/_Public/38/045/38045713.pdf.

[235] June 08, 2022–Launch of Flow-Based Market Coupling in the Core region enhances energy transition at https://www.jao.eu/sites/default/files/2022-06/Core%20DA%20FB%20MC%20go-live%20press%20release.pdf

[236] C. Müller, A. Hoffrichter, H. Barrios, A. Schwarz, and A. Schnettler, "Integration of HVDC-Links into Flow-Based Market Coupling: Standard Hybrid Market Coupling versus Advanced Hybrid Market Coupling," Cigré International Symposium, Dublin, Ireland, June 2017 at https://www.researchgate.net/publication/317957636_Integration_of_HVDC-Links_into_Flow-Based_Market_Coupling_Standard_Hybrid_Market_Coupling_versus_Advanced_Hybrid_Market_Coupling.

- To further optimize the trading over cross-border interties including HVDC links in intra-day markets, a cross-border intraday trading platform, known as the Single Intraday Coupling (SIDC), was launched in 2018 across 15 countries and then expanded to 23 countries in 2021 to facilitate the optimal use of interties and 15-minute to hourly trading across the borders of participating markets.[237] SIDC is based on "order matching"[238] and has employed a flow-based approach since 2022.[239] From 2018 through the first quarter of 2022, SIDC has matched 151 million intra-day trades.

Today, flow-based market coupling is used by the TSOs to optimize cross-border energy exchanges and market-to-market transactions in both day-ahead trading and intra-day trading. For market-based scheduling of available capacity on **cross-border HVDC links**, the same flow-based market coupling algorithm is used to maximize economic surplus by optimizing the set points for any HVDC links that connect two binding zones—which could be two regions within a synchronous AC network or two regions with asynchronous AC networks. There are two ways to manage HVDC links in the FBMC-based market coupling approach:

- In the "standard hybrid" coupling of AC and DC systems, HVDC links are modeled with their Net Transfer Capacities (NTC) with HVDC transactions receiving priority access to the AC grid.
- In the "advanced hybrid" market coupling approach, PTDF factors at the end nodes of HVDC lines are calculated and the two nodes act as virtual bidding zones, which are linked to the flow-based constraints. In this case, flows from HVDC lines compete for capacity with all other trades and no AC grid capacity is reserved for HVDC.[240]

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[237] ENTSO-e, Single Intraday Coupling (SIDC) at https://www.entsoe.eu/network_codes/cacm/implementation/sidc/.

[238] Ibid. SDIC creates a single "order book" for all buy and sell bids from all the participating markets; it then continuously matches the orders from sellers and buyers until one hour before delivery time. TSOs make any intraday cross-border capacities available to allow the bids submitted by a market participant in one market to be matched with bids in other markets. The trade is done on a first-come-first-served basis with the highest buy and lowest sell bids matched first until the available transmission is fully utilized.

[239] Acer, ACER to consult on the methodology for electricity intraday flow-based capacity calculation in the Core region, Press Release, April 26, 2023 at https://www.acer.europa.eu/news-and-events/news/acer-consult-methodology-electricity-intraday-flow-based-capacity-calculation-core-region

See also ENTSO-e, *Market Report 2022*, p. 83, at: https://ee-public-nc-downloads.azureedge.net/strapi-test-assets/strapi-assets/2022_ENTSO_E_Market_report_Web_836ec0a601.pdf.

[240] ENTSO-e, *HVDC Links in System Operations*, Technical Paper, December 2, 2019, pp. 75–76 at https://eepublicdownloads.entsoe.eu/clean-documents/SOC documents/20191203_HVDC links in system operations.pdf.

A few studies have documented the benefits of the FBMC approach and its ability to better optimizes the operation of interties, including HVDC links, compared to the earlier ATC-based approach. The European TSOs tested the FBMC approach in parallel off-line runs from 2013 to 2015 and compared its performance to the actual cross-border exchange volumes and prices using the ATC-based approach, as documented in a 2015 report.[241] The report shows that the FBMC approach increased cross-border exchange volumes and improved price convergence, enabling an increase of €95 million in economic savings in 2013. A 2023 study empirically estimated the effect of introducing the advanced FBMC approach for cross-border arrangements that include HVDC links, finding that the FBMC approach has increased the cross-border exchange volumes by 1,000 MWh per hour and decreased the average market price difference between different countries by 2 €/MWh. It estimated that the welfare gain associated with optimizing cross-border exchanges by the FBMC in the CWE region is currently around €116 million per year.[242] The FBMC methodology is being expanded to the Nordic power markets, which is scheduled to launch in Q1 2024.[243] Nordic power markets have started external parallel runs to evaluate the market results of the FBMC methodology in comparison to their current method.[244]

19. Western EIM: Full Co-Optimization of Transmission and Generation

As noted earlier, the Western Energy Imbalance Market (WEIM) now co-optimizes in real-time both AC and HVDC transmission capability with the dispatch of generation resources across the market seams of the 19 balancing areas (including CAISO) in the nearly WECC-wide WEIM footprint.

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[241] Amprion et al., *CWE Flow Based Market- coupling project: Parallel Run performance report*, Technical Report May 2015 at https://www.jao.eu/sites/default/files/2020-04/Parallel%20Run%20performance%20report%2026-05-2015.pdf.

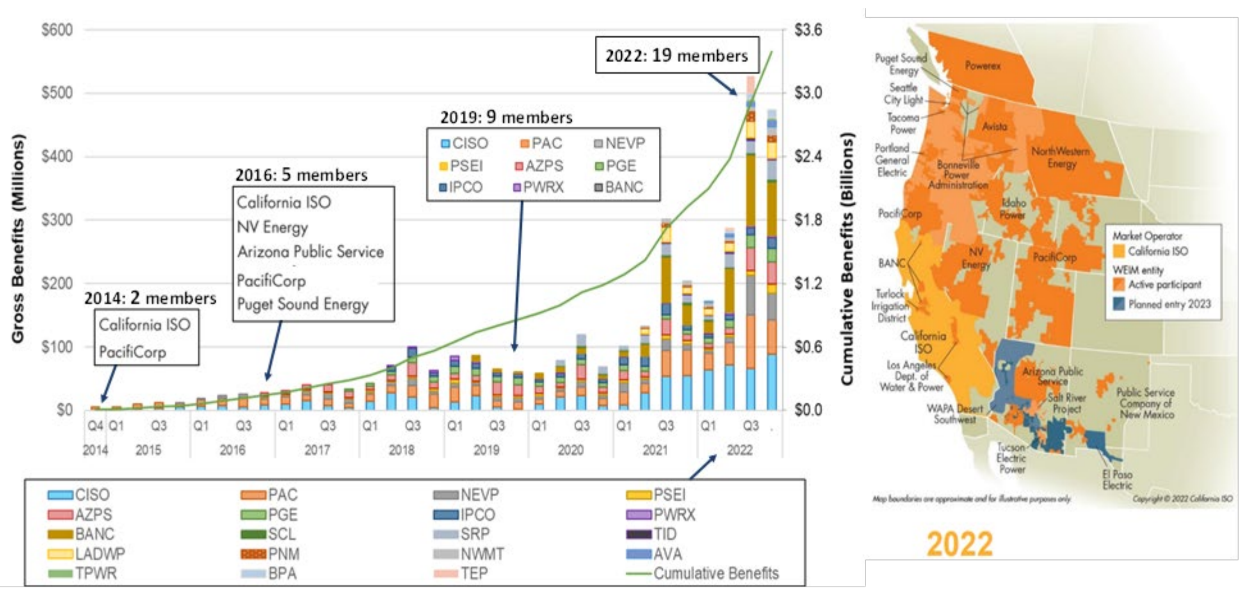
[242] M. Ovaere, M. Kenis, K. Van den Bergh, K. Bruninx, and E. Delarue, "The effect of flow-based market coupling on cross-border exchange volumes and price convergence in Central Western European electricity markets," *Energy Economics*, February 1 2023. https://www.researchgate.net/publication/359210561

[243] Statnett, Go-live of Nordic flow-based CCM delayed to Q1 2024, November 18, 2022 at https://www.statnett.no/en/for-stakeholders-in-the-power-industry/news-for-the-power-industry/go-live-of-nordic-flow-based-ccm-delayed-to-q1-2024e/#:~:text=The%20implementation%20of%20the%20flow,January%202023%2C%20at%20the%20earliest.

[244] Nordic TSOs, External parallel run evaluation report—For assessment by the NRAs of the Nordic CCR, as required by the Nordic DA/ID CCM, June 12, 2023 at https://nordic-rcc.net/wp-content/uploads/2023/06/Parallel-run-report_final_public.pdf.

As shown in Figure 44 below, the WEIM-based co-optimization of generation and transmission within its footprint—including interregional HVDC and AC transmission—has achieved cumulative savings of over $3 billion since its introduction in 2014, with quarterly savings increasing exponentially as the footprint is expanded to optimize more market seams and cover a broader and more diverse geographic area.

FIGURE 44. QUARTERLY AND CUMULATIVE WEIM BENEFITS 2014–2022



Source: based on https://www.westerneim.com/Pages/About/QuarterlyBenfits.aspx

The planned introduction of the Extended Day Ahead Market (EDAM) expands this co-optimization of interregional transmission and generation dispatch, which includes the optimization of HVDC transmission schedules, to day-ahead market transactions between CAISO and other participating Balancing Areas in the Western U.S.[245]

20. U.S. Market Monitors Calls for Intertie Optimization

This type of intertie optimization between market regions does not currently exist in the rest of North America, which leads to inefficient utilization of interregional transmission capacity, including existing HVDC lines. Even though the flows on existing HVDC lines could be controlled precisely and optimized by the system operators to maximize their benefits to both day-ahead

[245] See California ISO, EDAM: Extended Day-Ahead Market at http://www.caiso.com/Documents/extended-day-ahead-market-edam-fact-sheet.pdf and California ISO, Initiative: Extended day-ahead market at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

and real-time markets, they currently carry only bilateral trades based on schedules that need to be finalized well ahead of the day-ahead and real-time periods to which they apply.

For example, PJM's independent market monitoring unit (MMU) has long been pointing out inefficient utilization of interregional transmission capacity. For example, in 2022 the price difference across the MISO-PJM seam exceeded $10/MWh during 3,182 hours; yet during 1,570 of these hours, market flows were inconsistent with those price differences, exporting power from the higher-priced market to the lower-priced market.[246] Similarly, on interties between PJM and NYISO, price differences exceeded $10/MWh during 4,178 hours with inconsistent market flows during 1,667 of these hours.[247] Importantly, this pattern of inefficient utilization of available interregional transmission capacity is not limited to the total interface between the market areas. It also applies to power flows on existing merchant HVDC interties, which could be controlled to avoid inefficient flows. For example, during 2022, power flows on the Neptune HVDC line between New Jersey (PJM) and Long Island (NYISO) flowed from the higher-priced market to the lower-priced market during 1,385 hours of the year.[248] Similarly, on the Hudson DC line, 2022 power flows were inconsistent with market price differentials during 2,217 hours of the year.[249]

To address the inefficient utilization of interregional transmission capacity between PJM and its neighboring power markets, the PJM MMU has yet again repeated the recommendation it has made since 2014:

> The MMU recommends that PJM explores an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves

[246] Monitoring Analytics, *2022 PJM State of the Market Report*, Vol. II, Section 9: Interchange Transactions, Table 9-27, p. 502 at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec9.pdf. Access the entire report at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022.shtml.

[247] Monitoring Analytics, *2022 PJM State of the Market Report*, Vol. II, Section 9: Interchange Transactions, Table 9-29, p. 504 at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec9.pdf.

[248] Id., Table 9-33, p. 506.

[249] Id., Table 9-35, .p. 508.

> and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.[250]

A co-optimization of interregional transmission capability, including HVDC lines, similar to that achieved by the Western EIM, is particularly important during real-time market operations, where large differences in wholesale power prices are often large and changing frequently. For example, while PJM MMU observed that in 2022 the average (absolute) value of PJM-NYISO price differences was $12.91/MWh in the day-head markets, with price differences changing signs 3.1 times per day on average, the average value of real-time price differences was $115.35/MWh, with real-time price differences changing sign 47.9 times each day.[251]

Inefficient utilization of available interregional transmission capacity is of course not limited to PJM. Potomac Economics—the market monitor for MISO, NYISO and ISO-NE—has first documented inefficient intertie utilization in 2003, recommending that interchange transactions are actively coordinated by the neighboring system operators.[252] In 2010, Potomac Economics estimated that optimizing interties between MISO, PJM, NYISO, ISO-NE, and Canadian system operators would conservatively yield between $160-300 million in annual cost savings.[253] Yet, despite repeated calls for implementation of intertie optimization,[254] the inefficiency has yet to be addressed and little has changed over the last decade. For example, in the MISO 2021 State of the Market Report, Potomac Economics yet again notes that bilateral trading between MISO and PJM "has produced very little of the sizable savings it could generate" and that "more than 40 percent of the current … transactions are ultimately unprofitable."[255] To address this inefficiency, Potomac Economics (similar to the PJM MMU) recommends that the market operators address these continued inefficiencies and

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[250] Monitoring Analytics, *2022 PJM State of the Market Report*, Vol. II, Section 2: Recommendations, at p. 105 at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec2.pdf.

[251] Monitoring Analytics, *2022 PJM State of the Market Report*, Vol. II, Section 9: Interchange Transactions, Table 9-30 at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec9.pdf.

[252] David Patton, Coordinated Interchange Recommendations, March 13, 2003 (Presentation to New England RTO Working Group).

[253] Potomac Economics, *Analysis of the Broader Regional Markets Initiatives*, September 27, 2010, pp. 10–13 at https://www.nyiso.com/documents/20142/1394342/BRM_Analysis_Presentation_to_RTOs_9-27-10.pdf/a83ea814-22e3-c754-e90d-99ac0b967029.

[254] See, for example, NYISO and ISO-NE, *Interregional Interchange Scheduling (IRIS) Analysis and Options*, ISO white paper, January 5, 2011 at https://www.iso-ne.com/static-assets/documents/pubs/whtpprs/iris_white_paper.pdf.

[255] Potomac Economics, *MISO 2021 State of the Market Report*, June 2022 at xx and 90. https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

approximate intertie optimization by clearing "transactions every five minutes through [the Unit Dispatch System] based on the most recent five-minute prices in the neighboring RTO area."[256]

These observations and recommendations by the market monitors of PJM, NYISO, ISO-NE and MISO clearly highlight the importance of intertie optimization, since bilateral trades are unable to capture a large part of intertie value as demonstrated by the above statistics. The value and feasibility of such intertie optimization has been demonstrated impressively by the success of the Western EIM. Given that power flow can be precisely controlled on a minute-by-minute basis, intertie optimization is particularly valuable for interregional HVDC transmission links.

21. Market Integration of Interregional Merchant HVDC Lines

U.S. federal regulations provide to holders of transmission rights on privately-funded merchant transmission projects priority access to the physical transmission capability of the merchant line. This differs from the "open access" requirement to provide non-discriminatory access to all transmission facilities with regulated (not merchant) cost recovery. While these regulations also require that any unused capacity on merchant transmission lines be made available to third parties at an owner-determined rate,[257] there is no requirement that any merchant transmission capacity that becomes available be offered to market operators so they can integrated the HVDC capacity with the regulated grid and co-optimized in the regional wholesale power market.

However, because it is valuable to do so, CAISO is in the process of developing a "Subscriber Participating Transmission Owner" (SPTO) framework that specifically promotes the integration and optimization of unutilized capacity on merchant transmission lines into the regional and interregional day-ahead and real-time energy markets.[258] The SPTO framework will first be applied to TransWest Express (TWE), an interregional HVDC line from Wyoming to Utah and Southern California, whose costs are recovered primarily from "subscribers" rather than from CAISO transmission customers at CAISO's regulated transmission rates.

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256 Id., at p. 89.

257 See, for example, *PJM Open Access Transmission Tariff*, Schedule 14 (transmission service on the Neptune HVDC line), Section 3.7 at https://agreements.pjm.com/oatt/4427.

258 See CAISO, *Initiative: Subscriber Participating TO Model, Final Proposal*, June 22, 2023 at http://www.caiso.com/InitiativeDocuments/Final-Proposal-Subscriber-Participating-Transmission-Owner-Model-Jun292023.pdf.

The SPTO proposal recognizes that fully integrating interregional merchant lines into DA and RT energy markets (and compensating the holders of the transmission rights for market-based use) offers substantial benefits to CAISO, its customers, and the larger western power market. The proposed SPTO design includes the following elements:

- Unscheduled merchant transmission capacity (held by subscriber or project owner) is made available for regional and interregional optimization in both day-ahead and real-time markets
- CAISO will co-optimize with generation dispatch the SPTO capacity that is made available, including inter-regionally within the Western EIM and EDAM (e.g., to optimize day-ahead and real-time market transactions on TWE between PacifiCorp's balancing area in Wyoming and Utah and the CASIO balancing area.)
- CAISO will pay a "Non-Subscriber Usage Rate" to compensate the owner or subscriber of transmission on the merchant facility for releasing unscheduled capacity for market use. The Usage Rate will be paid from CAISO transmission access charge to load and exports in order to avoid rate pancaking.

The proposal currently still leaves unspecified how market congestion revenues (accruing to the contributed transmission capacity beyond Usage Rates) are allocated, even though in EIM/EDAM these market-based revenues are distributed to those who contribute the transmission capacity to the regional market.

VI. Barriers to the Utilization of HVDC Capabilities

This section of the report identifies a number of barriers to the adoption of HVDC transmission technologies and VSC-based HVDC transmission specifically. These barriers are related to (a) misconceptions about the HVDC-VSC technology; (b) the lack of sufficient technology standardization; (c) current supply chain challenges; and (d) various planning, regulatory, and market-design challenges, including the lack of detailed "grid codes" that clearly define interconnection standards and take advantage of the operational capabilities of HVDC facilities. Each of these four categories of barriers is discussed in more detail below.

A. Misconceptions about VSC-HVDC Technology

Attractive HVDC solutions often may not be sufficiently considered because of misconceptions about the technology and the capabilities of modern VSC-based system. These misconceptions are generally based on outdated information or problems that were encountered when implementing new technology for the first time. We address eleven such misconceptions that we have become aware of in discussions with industry participants.

1. Myth: VSC technology is not yet sufficiently mature

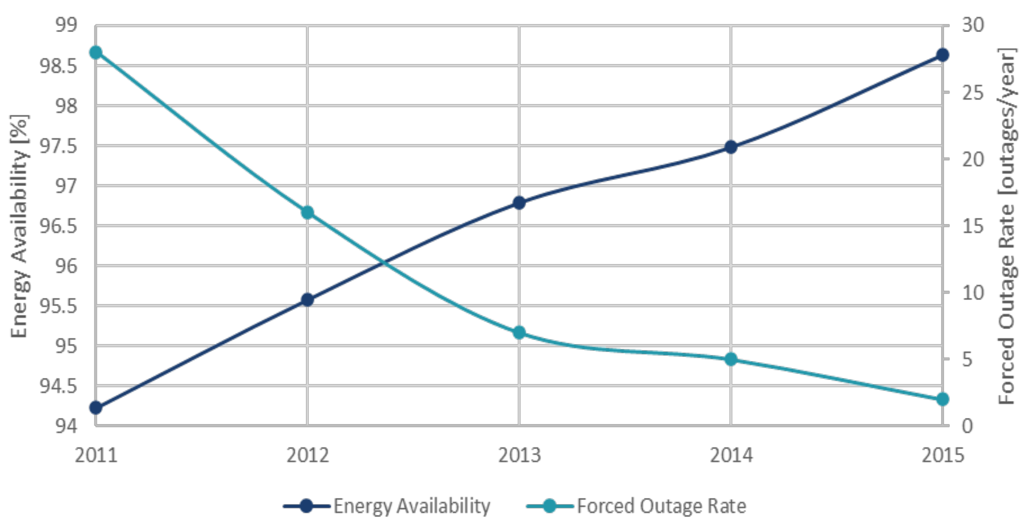
VSC-based HVDC technology has long been portrayed as an emerging or still developing technology—and this perception still exists in some regions. This perception is inconsistent with the rapid technology development and valuable lessons that been learned from the already-installed VSC systems.[259] While it is correct that early VSC-based HVDC projects encountered delays, cost overruns, and/or sub-par performance, those challenges no longer apply or were not related to the technology itself. Rather, the challenges encountered related to:

- Challenges associated with building large linear infrastructure projects. These challenges are not HVDC technology specific, but relate to permitting, routing and rights of way, logistics of offshore projects, and the financing of large infrastructure projects

[259] See, for example, ModernPowerSystems, "Navigating the North Sea learning curve," September 2, 2014 at https://www.modernpowersystems.com/features/featurenavigating-the-north-sea-learning-curve-4359059/.

- Challenges arising from the first-of-a-kind applications of new HVDC technologies. For example:
  - In the first large-scale application of VSC-HVDC technology (Caprivi link), the converters were suffering from a high Forced Outage Rate, leading to insufficient energy availability.[260] After investigating the root cause of the issue, both technology and operational adaptations substantially improved in availability, as shown in Figure 45. Importantly, high availability is now expected for VSC-HVDC systems. Based on the DNV co-authors' experience, a 98.5% guaranteed energy availability is now standard for HVDC converters, reflecting 0.5% of unplanned outages and 1% of planned outages. But 99% total availability (including planned outages) have been achieved by newer VSC-based HVDC lines, such as NEMO Link (discussed in Section 1 above). It is also worth noting that the overall availability for bipole HVDC systems is the same from an overall system perspective, they offer the important advantage that planned and unplanned outages will generally only affect one pole at a time, which is less costly as it allows for the continuation of "baseload" flows of up to 50% of the line's total capacity.

FIGURE 45. PERFORMANCE IMPROVEMENTS IN CAPRIVI LINK



[260] T G Magg, F Amputu, M Manchen, E Krige, J Wasborg, K Gustavsson, *Zambezi (previously Caprivi) Link HVDC Interconnector: Review of Operational Performance in the First Five Years*, 2016 CIGRE Paris Session, Paper B4-108 at https://search.abb.com/library/Download.aspx?DocumentID=9AKK106930A0396&LanguageCode=en&DocumentPartId=&Action=Launch.

- In the first application of MMC-type VSC-HVDC technology in the Transbay project, the failure rate of the submodules exceeded the design value.[261] After forensic analysis, replacement of the submodules and operational mitigations, performance has been satisfactory.
- The first application of HVDC cables with extruded polymer insulation (the SouthWest Link in Sweden) encountered issues with the accessories (splices) leading to the need to replace all splices.[262]

- Challenges arising from offshore application:
  - The first offshore application of VSC-HVDC technology in German transmission projects experienced significant delays[263,264] and cost overruns[265] due to challenges encountered when connecting islanded offshore wind[266] and project management and logistics challenges associated with the first-in-kind offshore installation.

The suppliers involved in these projects have incorporated the lessons-learned and, since then, avoided significant cost overruns and delays. Today, over 40 GW of VSC-HVDC converter capacity is in operation, both onshore and offshore, and by all major vendors. Lessons-learned in these projects have led to a maturity of technology that avoids the challenges initially encountered. For example, new generations of valve designs have been introduced, improved control & protection designs have been developed, and new logistics and project management approaches are used. In addition, standardization for testing VSC-HVDC equipment has been completed and implemented, and sufficient experience exists to design adequate redundancy margins and enable appropriate quality control strategies to achieve desired project performance. MMC-based VSC-HVDC technology is now considered to be a mature technology

[261] J. Boyle (SteelRiver Infrastructure Partners), "An Introduction to Trans Bay Cable An Introduction to Trans Bay Cable," February 2011 at https://www.nfma.org/assets/documents/asfeb11boyle.pdf.

[262] Svenska Kraftnät, Press Release, "SydVästlänken's cable joints are being replaced," August 2, 2019 at https://www.svk.se/utveckling-av-kraftsystemet/transmissionsnatet/avslutade-transmissionsnatsprojekt/sydvastlanken/byggnation/sydvastlankens-kabelskarvar-byts-ut/.

[263] offshoreWIND.biz, Germany Deals with Further Grid Connection Delays, June 25, 2012 at https://www.offshorewind.biz/2012/06/25/germany-deals-with-further-grid-connection-delays/.

[264] B. Radowitz, "Siemens installs BorWin2 platform," Wind, *Recharge*, April 29, 2014 at https://www.rechargenews.com/wind/siemens-installs-borwin2-platform/1-1-865692

[265] P. Winters, "ABB Says DolWin1 Project On Time After $50 Million Delay," *Bloomberg*, May 28, 2013 at https://www.bloomberg.com/news/articles/2013-05-28/abb-says-dolwin1-project-on-time-after-50-million-delay#xj4y7vzkg

[266] C. Buchhagen, C. Rauscher, A. Menze and J. Jung, "BorWin1 - First Experiences with harmonic interactions in converter dominated grids," International ETG Congress 2015; Die Energiewende—Blueprints for the new energy age, Bonn, Germany, 2015, pp. 1–7 at https://ieeexplore.ieee.org/document/7388457.

with high technology readiness ratings, as discussed in Section II.B—although due diligence effort must be applied when working with new suppliers of the technology or when utilizing new generations of the technology.

2. Myth: VSC converters have lower reliability and availability

Modern VSC-HVDC systems are reliable by design. Several updated design characteristics combined with experience in quality assurance reduced the number of forced outages encountered in the first applications of the technology, which now ensures a high availability. They include:

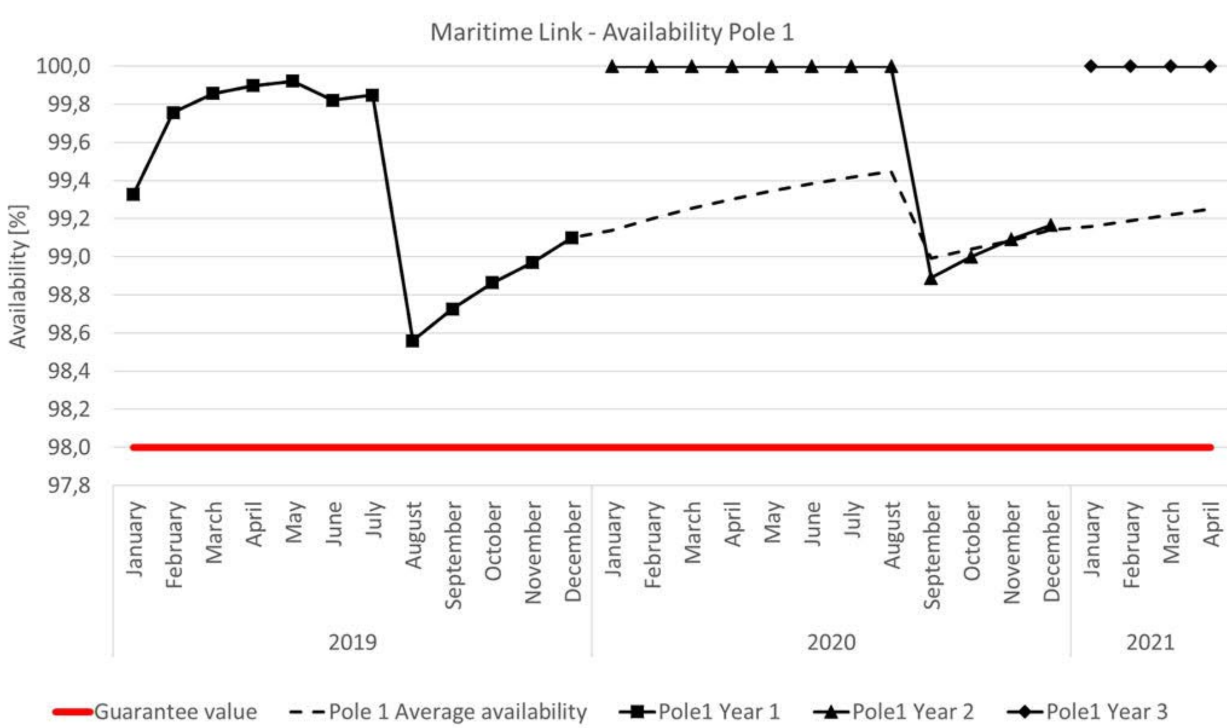
- Redundant submodules with blast proof transistor casings and bypass switches that ensure seamless continuation of operation in case of a submodule failure;
- Spare/redundant interface transformers with provisions for quick replacement of busbars;
- Non-flammable or low smoke materials in the valve room (e.g., no oil-filled equipment) to avoid fire or smoke damage in case of failures;
- Duplicate control and protection systems on hot stand-by;
- Duplicate cooling pump and water filtration systems;
- Arrangements that facilitate straightforward and quick component replacement and minimize downtime;
- Optimized O&M strategies to minimize the occurrence of maintenance periods and reduce their duration; and
- O&M agreements with vendors and spare parts managements to ensure rapid response in case of outages.

Of course, these measures come at a cost. In modern VSC HVDC systems, the Energy Availability is typically designed to be 98% or higher with a maximum number of typically 2 permitted forced outage events and planned maintenance outages each year.[267] The availability value is contractually guaranteed by the vendor for a certain period after commissioning and subject to fines if performance is less. In addition, outages due to cable or line faults and damages are typically monitored separately.

[267] A 98.5% availability is typically guaranteed by the OEM, but actual availability is expected to be higher.

Figure 46 illustrates the cumulative moving average of the annual energy availability performance of pole 1 of the Maritime Link, a recently completed HVDC link in North America using VSC technology in bipole configuration and both insulated cable as well as overhead line sections.[268] The indicator is computed on an annual basis from January to December, which explains the 'reset' every January. As can be seen, after initial challenges in the beginning of 2019, the link operates at 100% availability for significant parts of the year. The chart clearly shows the impact of annual maintenance on the availability. However, the performance at all times is better than the contractually-agreed 98% (marked in red). It should be noted that today VSC systems can be designed with two or even three yearly maintenance windows.

FIGURE 46. ENERGY AVAILABILITY OF POLE 1 OF THE MARITIME LINK

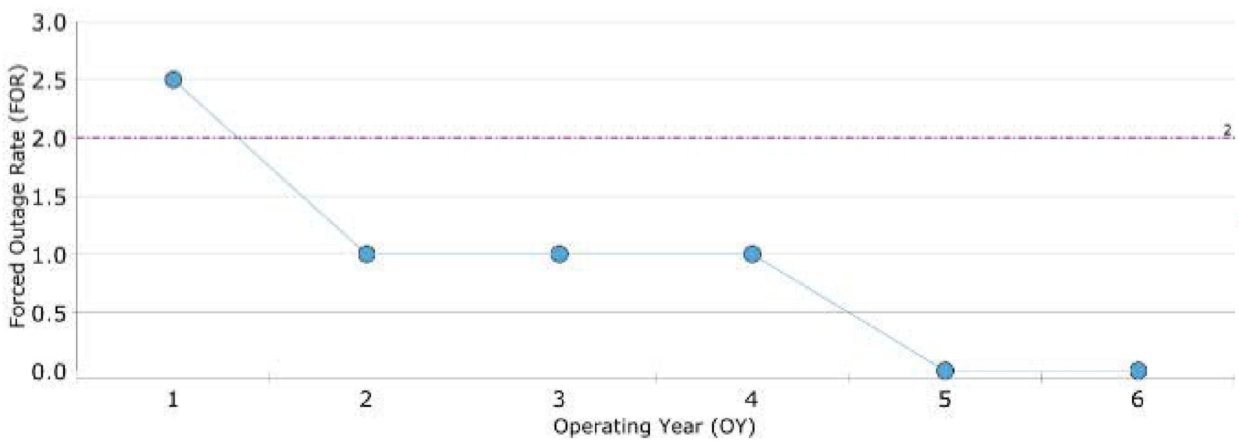


It is common to observe a 'bathtub' curve of reliability events for transmission equipment throughout its lifetime, where number of outages is higher during the first few years, then reduced steadily to a low level for the majority of the equipment's lifetime, only to increase again towards the end of life as ageing-related effects increase the failure rate again. The first phase is often referred to as the "burn in" phase in which the first high-load testing is done and the system is thermally stressed. This first phase often coincides with the trial-run period and is

[268] P. Lundberg et al., "Design and operational experience of Voltage Source Converter HVDC Bipolar solutions", AEIT 2021.

typically under warranty. Figure 47 shows averaged data from the real-world projects of one vendor that illustrate how the forced outage rate is reduced during the first few years of operation.

FIGURE 47. IMPROVEMENT OF RELIABILITY IN AN HVDC SYSTEM'S FIRST YEARS[269]



Well-documented techniques for monitoring the performance of converter stations have been standardized and adopted by North American[270] and European[271] standardization bodies. In Europe, TSOs of the Nordic and Baltic states have been collecting and annually publishing the utilization and availability statistics of their HVDC systems since 2011.[272] Figure 48 shows the total annual TWh capacity utilization of converters by technology type and by use type. The chart shows the growth of VSC converter capacity over the years and the absence of new-built LCC. The orange slice of the bars also shows that, on an annual basis, a substantial margin is reserved on the links, presumably for reliability purposes, although that margin seems to be diminishing over the years. The unavailability of the HVDC links is small as shown by the brown and dark blue slices at the very bottom of the bars.

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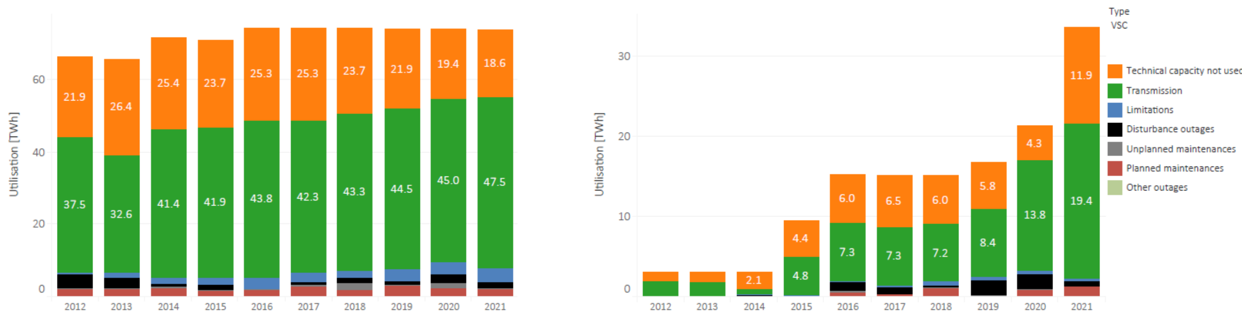
269 J. Lange et al., "Innovative Converter Testing Technology and Overall Reliability and Availability Performance of HVDC Solutions", 2021 AEIT HVDC International Conference

270 "IEEE Guide for the Evaluation of the Reliability of Hvdc Converter Stations," in IEEE Std 1240-2000 , vol., no., pp. i, February 13, 2001, doi: 10.1109/IEEESTD.2001.245621 at https://ieeexplore.ieee.org/document/905229.

271 CIGRE Technical Brochure 590, "Protocol for Reporting the Operational Performance of HVDC Transmission System (Line Commutated Converters and Voltage Sourced Converters)," 2014 at https://e-cigre.org/publication/590-protocol-for-reporting-the-operational-performance-of-hvdc-transmission-systems.

272 ENTSO-e, *ENTSO-E HVDC Utilisation and Unavailability Statistics 2021*, August 16, 2022 at https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/Nordic/2021_ENTSO_E_HVDC_Utilisation_and_Unavailability_Statistics.pdf.

FIGURE 48. ANNUAL UTILIZATION PER TYPE OF CONVERTER



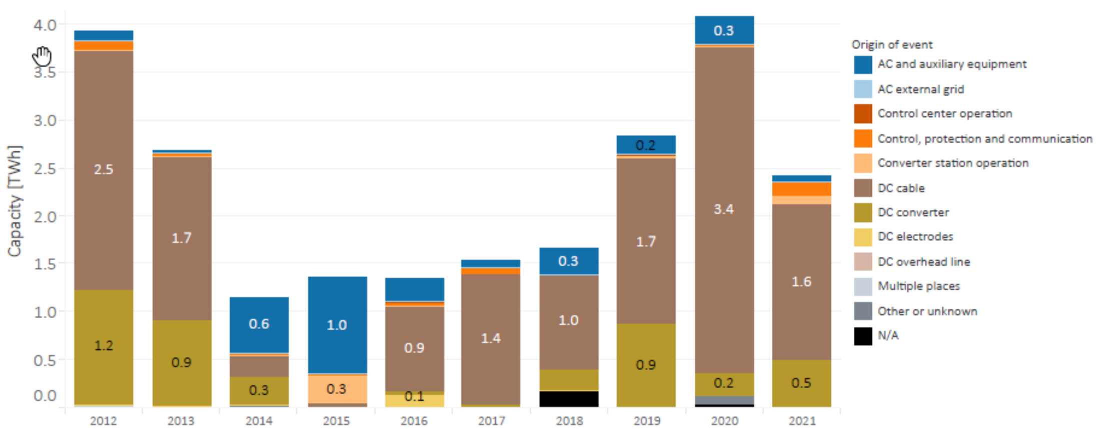
a) LCC converter utilization

b) VSC converter utilization

Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2021

A look at the causes of unavailability of HVDC links in Figure 49 below shows that (1) the large portion of unavailability is driven by outages of the submarine or underground HVDC cables (the dark brown slices of the bar), and (2) unavailability caused by outages of converters (light brown slices) have generally been less than 0.5% recently and outage of DC overhead lines are minimal. This is due to the fact that even though outage events are rare, cable failures (and especially submarine cable failures) when they happen take a significantly longer time to repair than resolving converter or overhead line outages.

FIGURE 49. ANNUAL UNAVAILABLE CAPACITY BY ORIGIN OF EVENT



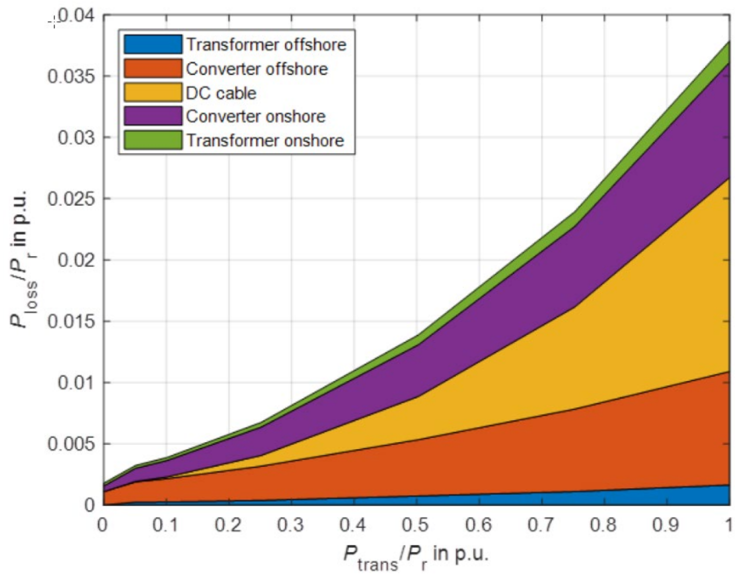
Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2021

From these statistics it can be seen that HVDC systems (both VSC and LCC) can, with appropriate quality control and operational measures, have very high availability.

3. Myth: VSC converters have high losses

Early versions of VSC converters, such as 2 and 3-level topologies, had relatively high valve losses, equal to several percent. These losses were strongly related to the high semi-conductor switching frequency that was used in these topologies to synthesize AC waveforms. Modular multi-level converter topologies use a low-switching frequency and, thus, have low switching and total losses. An example of the breakdown of losses for the major items of equipment in an offshore MMC VSC HVDC system with approximately 125 miles cable length is shown in Figure 50 below.

FIGURE 50. EXAMPLE OF LOSSES VS. LOADING IN AN OFFSHORE VSC MMC HVDC SYSTEM



Source: CIGRE TB 844 – Feasibility study for assessment of lab losses measurement of VSC valves

As shown, converter losses are less than 1% per converter station. In fact, using smart switching patterns, both switching and conduction losses in the valve can be reduced to less than 0.5%, enabling total losses to be as low as 0.7% per converter station. Similar to availability, the efficiency of converter stations typically is contractually guaranteed by the vendor, subject to penalties if stated performance requirements are not met.

The chart also shows that, at full load, the DC cable losses are the largest part of the total system losses. Depending on the line length, a similar statement can be made for overhead HVDC lines. The DC cable and line losses, however, will be substantially below the line losses of a typical AC system and are a design parameter and can be reduced by increasing the conductor size or by increasing the transmission voltage.

4. Myth: Placing VSC-HVDC converters from different vendors close to one another is not reliable

Challenges regarding interoperability of HVDC converter stations from different vendors have led to concerns that having converter stations from different vendors in electrically close vicinity of each others could lead to adverse interactions of their controllers. These concerns are valid and require due attention. The concerns are addressable, however, and do not prevent the installation of multiple converters from different vendors—provided that they are connected to a strong AC grid.[273] In Germany, clusters of several onshore HVDC converter terminals of offshore wind export links are already connected to the same AC busbar at multiple locations. For example, Figure 51 shows the Dörpen West substation in Germany where three HVDC converter stations from two different manufacturers are used by DolWin1 (800 MW, Hitachi Energy), DolWin2 (916 MW, Hitachi Energy) and DolWin3 (900 MW, GE Vernova)—all of which connect to the same substation on the AC grid. To address compatibility concerns, however, it is recommended to perform grid integration studies with the vendor-specific models of each converter to ensure that any adverse interactions can be identified and mitigated prior to commissioning.

FIGURE 51. AC GRID VONNECTION OF THREE HVDC CONVERTERS FROM TWO DIFFERENT VENDORS

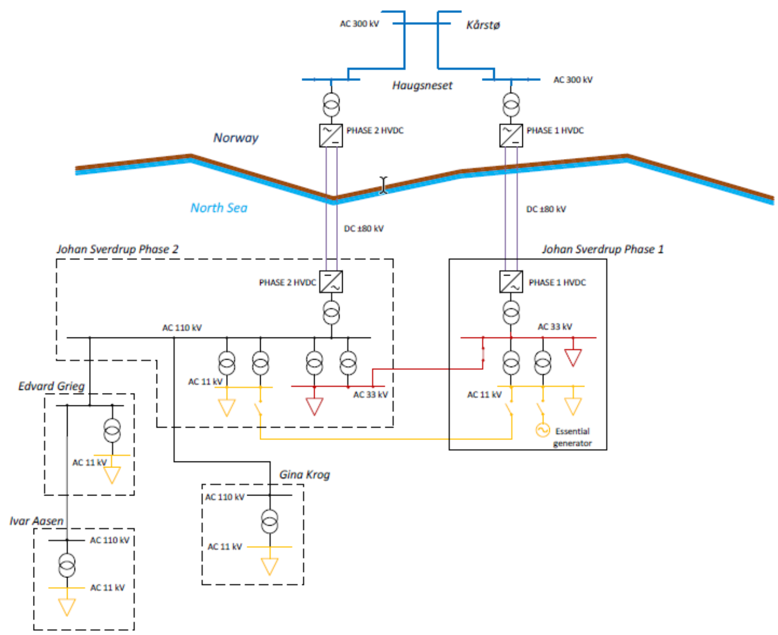
Source: Google Maps

[273] C. Yin, X. Xie, S. Zu, and C. Zou, "Review of oscillations in VSC-HVDC systems caused by control interactions," *The Journal of Engineering,* Vol. 16, 2019 (presented at 14th IET International Conference on AC and DC Power Transmission, 2018) at https://www.researchgate.net/publication/328478842_Review_of_oscillations_in_VSC-HVDC_systems_caused_by_control_interactions.

Even in cases where converters from different vendors are connected to a weak or even islanded AC grid, this is technically possible. The Johan Sverdrup system of offshore oil and gas platforms in Norway, shown in Figure 52, is supplied with power from shore by parallel 100 MW and 200 MW HVDC links which are connected at the offshore end by means of a submarine cable connection. The HVDC links are supplied by Hitachi Energy and Siemens Energy, respectively, and utilize different VSC technologies.[274]

Limits on the ability to exchange information between the two vendors, and the timing in the different project phases required a new, iterative approach towards solving the multi-vendor interoperability, through an independent 3rd party consultant and real-time simulations using controller hardware in the loop.[275]

FIGURE 52. PARALLEL OPERATION OF MULTI-VENDOR HVDC SYSTEMS IN JOHAN SVERDRUP SYSTEM



Source: RTE HVDC Webinar; The Johan Sverdrup HVDC project: First multivendor HVDC system in grid forming operation

Similarly, four multi-terminal HVDC networks with converters from different vendors are successfully in operation in China today. This shows that multi-vendor interoperability is

[274] K. Sharifabadi, et al., "Parallel operation of multivendor VSC-HVDC schemes feeding a large islanded offshore Oil and Gas grid," B4-104_2018, in CIGRE 2018 Paris Session, Paper and Proceedings at https://e-cigre.org/publication/SESSION2018_B4-104.

[275] RTE International, Webinar sessions on HVDC interaction studies with EMT simulation tools, 3rd Session: "The Johan Sverdrup HVDC project: First multivendor HVDC system in grid forming operation" at https://www.rte-international.com/webinar-sessions-on-hvdc-interaction-studies-with-emt-simulation-tools/?lang=en

technically feasible within a conducive regulatory and intellectual property framework that enables the necessary exchange of converter characteristics. This typically also means that the TSO or the developer of the HVDC network needs to play a more prominent role in the DC system integration and, accordingly, take on a larger responsibility (and liability) than is currently the case for single-vendor point-to-point applications.

5. Myth: VSC-HVDC technology is not suitable for overhead transmission lines

A common misconception regarding VSC-HVDC systems is that they cannot be used in conjunction with overhead lines. Worldwide, at least ten VSC-based HVDC links containing overhead lines have been in operation since 2000, indicating the technical feasibility of such systems:

- Caprivi Link, Namibia-Zambia, 300 MW, 350 kV, 2L-VSC, Hitachi Energy, asymmetrical monopole, 950 km, 2000
- Maritime Link, Canada, 500 MW, 200 kV, CTL-VSC, Hitachi Energy, Bipole with ground return, 190/170 km overhead/cable, 2017[276]
- Hokkaido-Honshu, Japan, 300 MW, 250 kV, MMC-VSC, Toshiba, Asymmetrical monopole, 98/24 km overhead/cable, 2019[277]
- Southwest link, Sweden, 2 x 720 MW, 300 kV, MMC-VSC, GE, Symmetrical monopole, 63/197 km overhead/cable, 2021
- Thrissur-Pugalur, India, 2x1000 MW, 320 kV, MMC-VSC, Siemens Energy, Symmetrical monopole, 165/27 km overhead/cable, 2021[278]
- NordLink, Germany-Norway, 1400 MW, 515 kV, CTL-VSC, Hitachi Energy, Rigid bipole with by-pass switches, 53/570 km overhead/cable, 2021[279]

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[276] "Maritime Link–enabling high availability with a VSC HVDC transmission," B4-088, CIGRÉ SC A3, B4 & D1 Colloquium—Winnipeg 2017 Colloquium, COLL_WIN_2017.

[277] "The Construction of New Hokkaido-Honshu HVDC Link Project," Cigre 2018 Paris Session, Papers and Proceedings, B4-132_2018 at https://e-cigre.org/publication/SESSION2018_B4-132.

[278] "DC Fault Recovery Capability of the Pugalur-Thrissur HVDC Project," Cigre 2018 Paris Session, Papers and Proceedings, B4-132_2018, at https://e-cigre.org/publication/SESSION2018_B4-132.

[279] M. Meisingset, S. Bødal, K. Koreman, A. Vinoth, B-4.10979, "Transmission system testing of a VSC based HVDC System," CSE 027, Cigre 2022 Paris Session at https://cse.cigre.org/cse-n027/b4-transmission-system-testing-of-a-vsc-based-hvdc-system.

- Ultranet, Germany, 2000 MW, 380 kV, FB-MMC-VSC, Siemens Energy, Bipole with DMR, 340 km overhead line, 2024
- Nanao, China, 160 kV, MMC-VSC, multi-vendor, symmetrical monopole, radial multi-terminal with HVDC circuit breaker[280]
- Zhangbei, China, 500 kV, MMC-VSC, multi-vendor, bipole with DMR, meshed multi-terminal with HVDC circuit breakers[281]
- WuDongDe, China, 800 kV, hybrid VSC-LCC, hybrid HB-FB, multi-vendor, bipole with DMR, radial multi-terminal[282]

Many more VSC-based overhead HVDC projects are currently in construction or development such as Sunzia (U.S.), TransWestExpress (U.S.), Yanbu-NIC (Saudi Arabia), Grain Belt Express (U.S.) and Southern Spirit (U.S.).

However, designing VSC-HVDC links with overhead lines presents a different set of challenges compared to cable-based systems due to the exposed nature of the overhead lines. This opens up the possibility of lightning strikes and the occurrence of associated electrical surges, as well as the occurrence of regular (but temporary) faults. Three such challenges are sometimes perceived as barriers to the implementation of VSC-HVDC systems with overhead lines as discussed in the following three subsections.

6. Myth: HVDC power electronic switches cannot handle the surge voltages from lightning strikes

The process of studying how much overvoltage protection is needed to ensure that lightning impulses do not damage sensitive equipment is called insulation coordination and is a well-understood, mature, and standardized process.[283] So-called surge arrestors are placed at

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[280] H. Rao, "Architecture of Nan'ao multi-terminal VSC-HVDC system and its multi-functional control," in CSEE Journal of Power and Energy Systems, vol. 1, no. 1, pp. 9–18, March 2015, doi: 10.17775/CSEEJPES.2015.00002 at https://ieeexplore.ieee.org/document/7086151.

[281] G. Tang et al., "Characteristics of system and parameter design on key equipment for Zhangbei DC grid," B4-121_2018, Cigre 2018 Paris Session at https://e-cigre.org/publication/SESSION2018_B4-121.

[282] H.Rao, "Research and development of Ultra-High-Voltage VSC for the multi-terminal hybrid ±800kV HVDC project in China Southern Power Grid," B4-120_2018, Cigre 2018 Paris Session at https://e-cigre.org/publication/SESSION2018_B4-120

[283] IEC 60071-11:2022: Insulation co-ordination - Part 11 ： Definitions, principles and rules for HVDC system at https://webstore.iec.ch/publication/66648

strategic locations in the converter stations to absorb any energy stemming from lightning strikes before it can cause damage to station equipment. Specifically, in MMC-VSC systems, the power electronic switches are connected in modules that each have a large parallel capacitor, which is a very effective overvoltage protection as it absorbs the energy of a lightning surge.[284]

7. Myth: MMC-VSC HVDC systems cannot handle overhead line faults

For half-bridge converters with converter-breaker-reclosing capability, several projects have been commissioned (NordLink, SouthWestLink, Pugalur-Thrissur) that include the capability to clear temporary arc-based faults on the DC overhead line by opening the AC converter breakers long enough to de-ionize the arc (a few 100 milliseconds) and re-close them to resume full power operation within 0.7-1.8 seconds, with fast-acting grounding switches installed to assist in speeding up the operation.[285] The operation of the reclosing functionality has been validated by means of staged fault testing.[286] In case of a single-pole fault in a bipolar system, the power typically is only interrupted on the affected pole, while the other pole continues operation, leaving half of the line's total capacity unaffected by the outage (which means more than half of the power can continue to flow, unless the line was fully loaded).

In addition, HVDC circuit breakers can be used to clear temporary or permanent faults in cases where reclosing the AC converter breakers is not fast or selective enough. For example, several multi-terminal HVDC systems are already in operation in China that utilize HVDC circuit breakers for this purpose. In Europe, several projects under development, such as the Heide and Rastede HVDC hubs in Germany and the SACOI 3 upgrade in Italy, are underway that envisage the use of HVDC circuit breakers.

Full-bridge converters (or converters that have a ratio of >50% of full-bridge modules) are designed to be capable of blocking DC fault currents and of rapidly reducing (or even reversing)

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284 K. Sharifabadi, L. Harnefors, H.-P. Nee, S. Norrga, R. Teodorescu, *Design, Control, and Application of Modular Multilevel Converters for HVDC Transmission Systems*, John Wiley & Sons/IEEE Press, 2016 at https://www.amazon.ca/Control-Application-Multilevel-Converters-Transmission/dp/1118851560

285 "DC Fault Recovery Capability of the Pugalur-Thrissur HVDC Project," B4-10466_2022, Cigre 2022 Paris Session, at https://e-cigre.org/publication/b4-10466_2022.

286 M. Meisingset, S. Bødal, K. Koreman, A. Vinoth, B-4.10979, "Transmission system testing of a VSC based HVDC System," CSE 027, Cigre 2022 Paris Session at https://cse.cigre.org/cse-n027/b4-transmission-system-testing-of-a-vsc-based-hvdc-system. See also PROMOTioN, *D4.2 – Broad comparison of fault clearing strategies for DC grids,* n.d, at https://www.promotion-offshore.net/fileadmin/PDFs/D4.2_Broad_comparison_of_fault_clearing_strategies_for_DC_grids.pdf

the DC voltage to deionize any temporary arc based fault.[287] This technology is currently being applied in the Ultranet project in Germany in which an AC circuit of an existing overhead line is converted to DC (see case study in Section V.16).

8. Myth: HVDC transmission systems have no overload capability

Traditional AC transmission equipment's temporary overloading capability is well understood. The relatively slow thermal inertia of components, such as transformers or overhead lines, allows for a temporary increase in loading above the rated values without leading to excessive loss of life or failures. In HVDC converters, the electronic valves have a very low thermal inertia, leading to the impression that no headroom is available for temporary overloading or dynamic loading. However, HVDC converters are typically rated for extreme conditions in terms of ambient temperatures and grid voltages, but spend most of the time operating well below these boundaries. As a result, overload capability is inherently available without having to upsize any of the converter components. This is further explained in Section II.4.b above. Experimental measurements on the NordLink system between Germany and Norway show that up to 14% and 27% of additional "overload" capacity is available for durations of 90 minutes to 30 minutes, respectively.[288]

9. Myth: VSC-HVDC converters have the same fault-related issues as legacy inverters, such as "momentary cessation"

During transient voltage disturbances, VSC-HVDC stations can inject current throughout, even during events with transient AC voltage drops well below 50% of nominal. This is in contrast to LCC-based HVDC converters and many inverter-based resources that generally suspend current injections when riding through especially low voltage events. When weighing dynamic stability considerations of converter technologies, it is consequently important to differentiate VSC-HVDC capabilities from other HVDC technologies.

Some inverter-based generation resources ride through voltage disturbances using a mode called "momentary cessation," in which they temporarily suspend current injections when

[287] Siemens, Siemens presents new technology for reliable power highways, Press Release, December 8, 2015 at https://assets.new.siemens.com/siemens/assets/api/uuid:9d1f5be1-c468-434c-b596-3bbebceeed62/pr20151208-reliable-power-highway.pdf.

[288] "Online Estimation of Dynamic Capacity of VSC-HVDC Systems–Proof of Concept in NordLink," No. 11089,.Cigre 2022 Paris Session at https://e-cigre.org/publication/session2022b4-session-2022-sc-b4-package.

voltage is well outside normal ranges (e.g., IEEE Std. 2800 allows momentary cessation for voltage below 10% of nominal). They suspend normal current injection until a few hundred milliseconds after the AC voltage returns to normal. Because legacy inverters used higher voltage thresholds for entering momentary cessation mode, or had lengthy return-to-service periods of several minutes, NERC has observed delayed recovery from faults in the WECC system starting in 2016.[289] In that report, NERC recommended that “Inverters that momentarily cease active power output for these voltage excursions should be configured to restore output to pre-disturbance levels in no greater than five seconds, provided that the inverter is capable of these changes.” NERC went on to recommend in 2018 that “Momentary cessation should not be used within the voltage and frequency ride through curves specified in PRC-024-2. Use of momentary cessation is not considered “ride through” within the “No Trip” zone of these curves.”[290] As IEEE Std. 2800 becomes mandatory, momentary cessation from applicable inverter-based generators will be allowed only for voltages below 10% of nominal, essentially eliminating its use.

As thyristors require a line voltage to commutate the valve currents, LCC-based HVDC stations have technical limitations to riding through low voltage conditions. This is particularly important for the inverter side of LCC links (as opposed to the rectifier side). To avoid commutation failure and keep reactive power demand within limits, the converters will reduce DC current and thus power output by issuing a voltage dependent current order limit. For very low AC voltage magnitudes, the converter may be blocked altogether. For the inverter side, even moderate unbalanced AC voltage drops can lead to commutation failures, and preventative blocking of the entire converter.[291]

VSC stations, however, offer a significant advantage over LCC in terms of performance during transient voltage disturbances. Unlike LCC, VSC stations maintain controllability over the output current even under very low and/or unbalanced voltage events, during which they are capable of injecting reactive current up to the rated current. Therefore, VSC converters are immune to commutation failures, and can actively contribute to system stability during faults and support restoration following fault clearing. Depending on the use case and the AC grid requirements,

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289 NERC, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*: *Southern California 8/16/2016 Event*, June 2017 at https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

290 NERC, *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*, September 2018, p. 68 at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf.

291 EPRI, High-Voltage Direct Current Handbook, EPRI TR-104166S, 1994.

the VSC station can be designed to inject either positive or negative sequence components. Recently, there has been a specific demand for negative sequence current injection to enhance fault detection on the grid side, especially in offshore applications that are inverter dominated grids (wind generators and HVDC converters).

Relatedly, the NERC issued an alert and recommendations to solar generators in March this year, following a series of disruptions to inverter-based resources and a growing number of instances where inverter-based resources tripped offline or reduced output in response to geographically-distant grid disturbances.[292] In response, NERC issued reliability guidance noting that electromagnetic transient (EMT) domain analysis simulations are necessary to adequately identify and mitigate bulk power system reliability risks associated with some inverter-based resources moving forward.[293] Such EMT studies, however, are already an integral component of HVDC project design by OEMs. These HVDC-related EMT studies encompass both offline analyses and real-time simulations to thoroughly verify various scenarios. This approach is well-established for HVDC project design and serves to ensure comprehensive validation without anticipated system reliability issues. Nonetheless, it is crucial for the buyer of HVDC systems—whether they be the developer and system operator—to provide explicit instructions regarding the scenarios they require the OEM to analyze. In the absence of specific guidance, OEMs typically rely on their expertise and judgment to determine the most relevant scenarios for study. Therefore, the precision and clarity of the buyer's instructions play a pivotal role in ensuring that the EMT studies effectively address the desired aspects of the HVDC project.

10. Myth: Inverter-based resources, such as HVDC lines, cannot provide black-start services because of large in-rush currents

As discussed in the case study in Section V.13, the black-start capability of VSC-HVDC converters is well documented, tested, and used in practice. While the rated current of VSC-converters is more limited than that of conventional generators, this does not limit the scope of HVDC-based

[292] R. Walton, *NERC issues alert, recommendations to solar resources following inverter-based grid disturbances*, *Utility Dive*, March 15, 2023 at https://www.utilitydive.com/news/nerc-solar-inverter-grid-disturbances-bulk-electricity-systems/645097/.

[293] NERC, *Reliability Guideline: Electromagnetic Transient Modeling for BPSConnected Inverter-Based Resources—Recommended Model Requirements and Verification Practices*, March 2023 at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline-EMT_Modeling_and_Simulations.pdf.

system restoration—as long as the other end of the HVDC link is connected to an AC grid or generation resource, including inverter-based resources such as an offshore windfarm.[294] In fact, the excellent voltage control capabilities of VSC-HVDC converters enable it to significantly speed up recovery time and reduce demands on black-start units by using the "soft-energization" system restoration technique.[295] Instead of black-starting one unit, and then sequentially switching in sections of the black-out network, it relies on closing all circuit breakers, interconnecting network, and then slowly ramping up the voltage to avoid inrush currents and transformer saturation.

Today, black start capability from HVDC links is quite well accepted as an ancillary service by most EU system operators and is specifically provided for in the ENTSO-e grid code, stating:

> An HVDC system with black start capability shall be able, in case one converter station is energised, to energise the busbar of the AC-substation to which another converter station is connected, within a timeframe after shut down of the HVDC system determined by the relevant TSOs. The HVDC system shall be able to synchronise within the frequency limits set out in Article 11 and within the voltage limits specified by the relevant TSO or as provided for in Article 18, where applicable. Wider frequency and voltage ranges can be specified by the relevant TSO where needed in order to restore system security.[296]

That VSC-HVDC is very well suited to perform such a task through its excellent voltage control abilities has also been operationally confirmed with a number of existing VSC HVDC transmission projects as discussed in Section V.13.

11. Myth: HVDC circuit breakers do not yet exist

AC circuit breakers rely on the current's zero crossings that are inherently present in AC grids to interrupt AC short circuit currents. In DC grids, no such current zero crossings are available, which means different ways (e.g., full-bridge converters or DC circuit breakers) are needed to

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[294] While LCC converters similarly can black-start an AC system, they need additional components such as synchronous condensors.

[295] DNV-GL, *Reducing the Risks of Network Restoration: DNV GL's 'soft energisation' approach*, July 2016.

[296] The European Commission, "Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules," *Official Journal of the European Union*, August 9, 2016 at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32016R1447#d1e211-1-1.

interrupt a DC short circuit current. Development of DC circuit breakers dates back several decades,[297] with an increased interest during the last decade.[298] Modern HVDC circuit breakers typically use a combination of power electronics and mechanical switching devices to create artificial local zero current conditions. During the last five years, several prototypes have been built, tested, and put into operation with voltage ratings up to 500 kV.

Currently, HVDC circuit breakers have been fully commissioned and are in operation only in three multi-terminal HVDC systems, all of which are located in China with limited public information about their operational performance:

- Nanao, radial 3-terminal, symmetrical monopole system, 160 kV, cable and overhead line, partially selective fault clearing
- Zhoushan, radial 5-terminal, symmetrical monopole system, 200 kV, cable only, partially selective fault clearing
- Zhangbei, meshed 4-terminal, bipole with DMR system, 500 kV, overhead line only, fully selective fault clearing

In addition, multiple HVDC circuit breaker designs have been tested at full scale and qualified in Europe during the PROMOTioN project as shown in Figure 53.[299] As a result, several projects in Europe are currently being developed that include HVDC circuit breakers, such as (1) the Heide[300] and Rastede[301] HVDC hubs in Germany, multi-terminal HVDC hubs connect offshore wind export links with onshore HVDC transmission links to bring power to load centers, (2) the Aquila project in Scotland (discussed earlier), and (3) the SACOI3 upgrade,[302] which connects the islands Corsica and Sardinia to the mainland grid in Italy.

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[297] CIGRE Technical Brochure 114: Circuit breakers for meshed multi-terminal HVDC systems at https://e-cigre.org/publication/114-circuit-breakers-for-meshed-multiterminal-hvdc-system-final-report.

[298] CIGRE Technical Brochure 873: Design, test and application of HVDC circuit breakers at https://e-cigre.org/publication/873-design-test-and-application-of--hvdc-circuit-breakers.

[299] N.A. Belda et al., "Recent HVDC Circuit Breaker Development and Testing," No A3_10545, CIGRE 2022 Paris Session, SESSION_2022_A3 at https://e-cigre.org/publication/session2022a3-session-2022-sc-a3-package

[300] 50 Hertz and TenneT, 50Hertz and TenneT to jointly bring wind power from the North Sea into the extra-high voltage grid for the first time , Press Release, January 17, 2022 at https://netztransparenz.tennet.eu/fileadmin/user_upload/Company/News/German/Fischer/2022/20220117_PM_50Hertz-TenneT_multi_terminal_hub_Heide_EN_TenneT.pdf.

[301] REGlobal, Germany's Network Expansion Plans: BNetzA confirms NEP, Policy Watch, March 12, 2022 at https://reglobal.co/germanys-network-expansion-plans-bnetza-confirms-nep/.

[302] Terna, Sardinia–Corsica–Italy Interconnection at https://www.terna.it/en/projects/projects-common-interest/sardinia-corsica-italy-interconnection.

If procured from a single vendor in combination with the converters, HVDC circuit breakers can now be considered commercially available. Multi-vendor integration remains a challenge, however, which is currently being addressed by the InterOpera project in Europe.[303]

Alternatively, HVDC short circuits can also be handled by full-bridge converters. HVDC fault currents can be controlled and suppressed with full-bridge converters either to non-selectively interrupt HVDC short circuits or, with strategically-placed HVDC switchgear, to selectively disconnect any faulty element in an HVDC grid. The optimal choice of technology will depend on total equipment cost, operating cost (including the cost of frequency reserves and losses), and permissible impact on the surrounding AC grid.[304]

FIGURE 53. FULL POWER TESTING OF A 350 KV HYBRID HVDC CIRCUIT BREAKER DURING THE PROMOTION PROJECT

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[303] See WindEurope.org/Windflix, Workstream for the development of multi-vendor HVDC systems and other power electronics interfaced devices at https://windeurope.org/intelligence-platform/product/workstream-for-the-development-of-multi-vendor-hvdc-systems/.

See also Plet et al., *Compatibility & interoperability framework to facilitate the step-wise organic development of multi-terminal offshore HVDC grids*, No C1-10351_2022, Cigre 2022 Paris Session at https://e-cigre.org/publication/c1-10351_2022.

[304] PROMOTioN, "Deliverable 4.7: Preparation of cost-benefit analysis from a protection point of view"

12. Myth: HVDC is "more complicated" than AC transmission

HVDC technology is still new for many grid operators and the apparent complexity and steep learning curve might seem overwhelming. But in many ways, the fact that power flows are precisely controllable makes HVDC systems easier to operate than the AC grid. In fact, the perception that HVDC technology is "more complicated" ignores the high complexity of operating the existing AC grids—although that is a level of complexity the industry is used to and experienced with.

Just as city roads managed with traffic lights are more efficient, even though they may seem to be more complex than "free-flowing" roads, HVDC transmission will be a critical part of a future grid that can more efficiently support the energy transition. We should thus embrace HVDC and other advanced transmission technologies and the capabilities they offer. While seemingly more complex initially, a grid that is enhanced with HVDC technology will ultimately be easier to operate. Of course, implementing technical standards and gaining planning and operational experience with HVDC technology will be a critical first step in that transition.

B. Technology Standardization Challenges

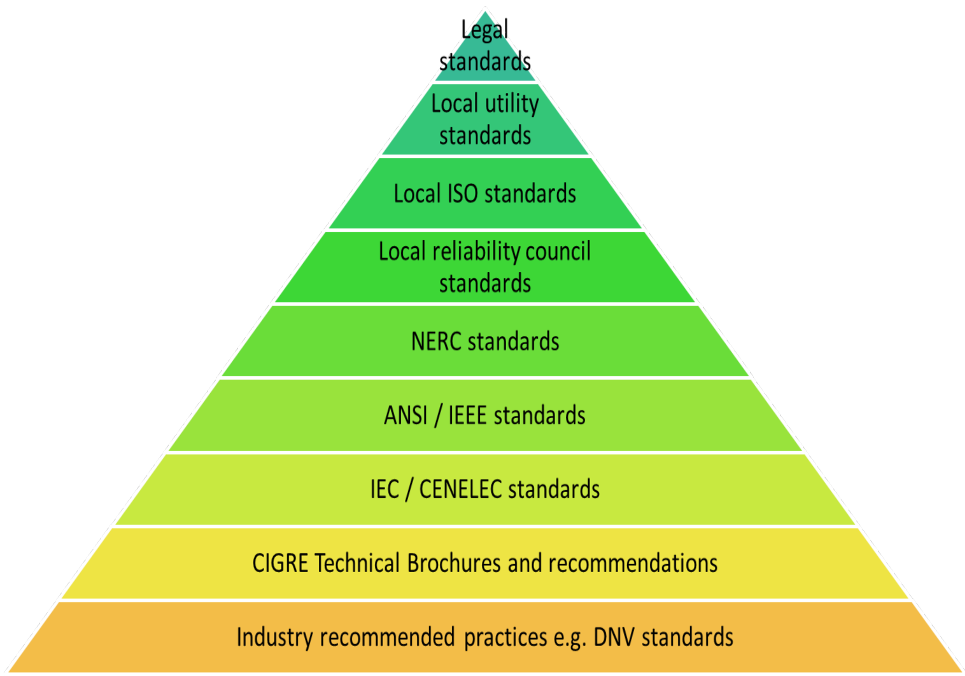
An important indicator of the maturity of a technology is the availability of a stable and comprehensive set of standardizations to guide the user through the required performance, design, specification, quality assurance (e.g., testing), and operation stages. Generally, technical standards address the following categories:

- Health, safety, and environment
- System performance
- System design
- Technology & equipment
- Test, measurement, & analysis
- Communication
- Cyber security

The creation of standards is often a time-consuming process including representatives from multiple stakeholders such as governmental bodies, system operators, OEMs, users, academics, and others. Depending on the technology, location, and aspect under study of an HVDC project, different sets of standards may apply that can be issued by different organizations. These are typically presented in a standards hierarchy pyramid as shown in Figure 54, ranging from legal requirement to "nice to have" rules.

In North America, the NERC reliability standards[305] and ANSI/IEEE suite of standards, recommended practices, and guides are leading,[306] whereas in Europe the IEC[307] and CENELEC[308] suite of standards are used. As standards often take a long time to develop and implement, several pre-standardization activities exist—including through industrial associations, such as the CIGRE B4 study committee for DC systems,[309] or industry-led recommended practices, such as DNV standards for offshore HVDC platform project certification[310].

FIGURE 54. ILLUSTRATIVE STANDARDS HIERARCHY PYRAMID



305 NERC, Program Areas & Departments, Standards at https://www.nerc.com/pa/Stand/Pages/Default.aspx.

306 IEEE Power & Energy Society, Technical Activities, Standards, IEEE PES Standards Process at https://ieee-pes.org/technical-activities/standards/.

307 International Electrotechnical Commission (IEC) at https://iec.ch/homepage.

308 Cenelec, European Standardization, European Standards a thttps://www.cencenelec.eu/european-standardization/european-standards/.

309 Cigre, B4–DC systems and power electronics at https://www.cigre.org/article/GB/knowledge-programme/study-committees/b4---dc-systems-and-power-electronics

310 DNV, DNV-ST-0145 Offshore substations: Standard, Edition 2020-10 - Amended 2021-09 at https://www.dnv.com/energy/standards-guidelines/dnv-st-0145-offshore-substations.html.

HVDC technology historically had a much more limited use than AC technology and has also typically been implemented as a bespoke turn-key solution in which the DC side characteristics were largely determined by the technology supplier to achieve the desired high-level performance requirements. As a result, the body of standardizations available to guide the realization of new HVDC infrastructure is significantly smaller than for AC systems—and in some places, particularly in North America, outdated and incomplete. Some specific examples of outdated or incomplete North American standards include:

- HVDC technology, and specifically the characteristics of modern VSC technology, are often not or only incompletely included in the transmission providers open access transmission tariffs;
- NERC standards include provisions for LCC based HVDC converter technology but do not include the characteristics of modern VSC technology and underground/submarine cable-based transmission projects. For example, Requirements (e.g., cable spacing) for parallel underground or submarine circuits are seen as separate from a contingency definition perspective, especially for systems with bipole converter configuration and capable of operating in single pole mode
- IEEE standards do not yet cover testing of modern VSC equipment (valves) and control & protection;
- The recently published IEEE P2800 standard for the performance of the AC side of inverter interfaced resources applies to HVDC, but excludes the offshore (rectifier) HVDC terminals of HVDC links connecting offshore wind farms;
- No North American standards cover HVDC cables with extruded polymer insulation;
- There are currently no standards describing the DC side ratings and performance of HVDC converters. For example:
  - There are no standardized DC voltage classes (although some progress is being made in the IEC TC115 on this topic).[311] Currently, voltage levels are typically chosen by the party procuring the HVDC line and are often based on legacy voltage levels, leading to differences (and hence incompatibility) between different regions and different HVDC projects within regions. Differences in voltage designations for different component groups can lead to misunderstandings between nominal, rated, and maximum continuous operating voltage. Unfortunately, the U.S. National Committee of IEC

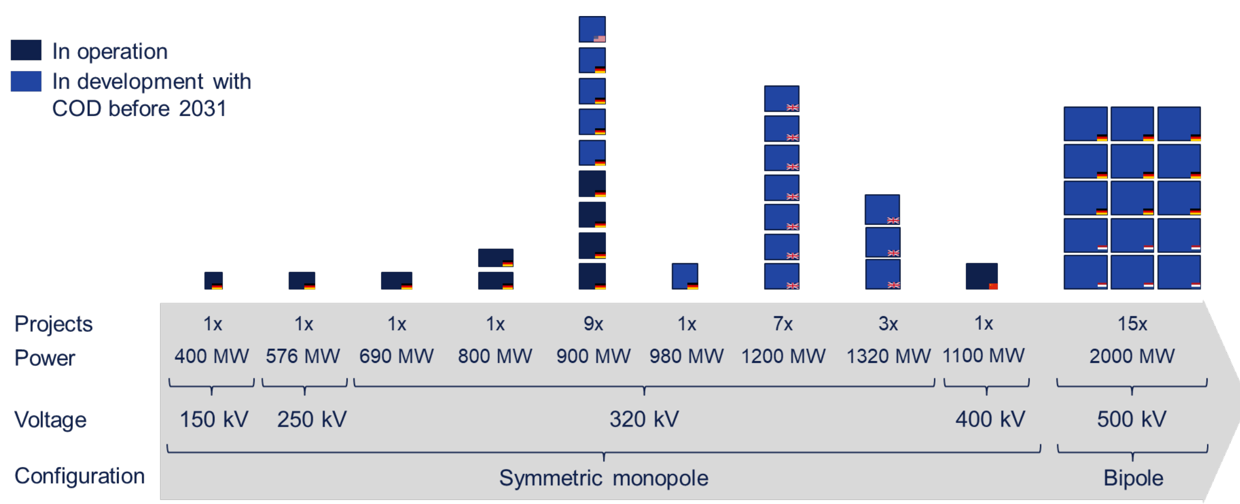
[311] International Electrotechnical Commission, TC 115 High Voltage Direct Current (HVDC) transmission for DC voltages above 100 kV at https://iec.ch/dyn/www/f?p=103:30:::::FSP_ORG_ID:3988.

withdrew from participation in this TC a few years ago, illustrating the lack of sufficient U.S. interest in the development of international HVDC Standards.

- There are no standardized DC system configuration (e.g., converter configurations, system grounding configurations, DC busbar configurations). Currently, these aspects are often determined by HVDC converter system vendors and often are subject to specific IP limitations, leading to incompatibility between different vendors.
- There is no standardized approach towards DC system protection.[312]
- There is no standardized DC performance requirements (i.e., DC grid codes specifying permitted operating voltage range, DC fault ride through, energization sequences, etc.).

- Modular HVDC design standards (e.g., based on a standardized power rating, nominal voltage, and system configuration) do not yet exist. For example, in Europe, offshore HVDC system planners are converging around two main voltage levels and three power ratings as shown in Figure 55. As shown, they include monopole HVDC systems with a design capacity of 900 MW operating at a voltage of 320 kV, 1,320 MW at 320 kV, and bipole system transmitting 2,000 MW at 500 kV. This modularization, originating from specific European transmission planning needs for offshore wind generation, is now driving the market and supply chain. While originating from offshore developments, the modularization is now being applied onshore as well, as demonstrated by the over 40 GW worth of recent 500 kV, 2 GW bipole HVDC orders by both TenneT and SSEN (as discussed earlier).

FIGURE 55. MODULARIZATION OF OFFSHORE HVDC RATINGS



[312] PROMOTioN, *D4.2 – Broad comparison of fault clearing strategies for DC grids,* n.d, at https://www.promotion-offshore.net/fileadmin/PDFs/D4.2_Broad_comparison_of_fault_clearing_strategies_for_DC_grids.pdf

In Europe, the CENELEC committee has made some progress in providing technical guidelines[313] and defining parameters[314] for the development of functional specifications of HVDC grid systems and these guidelines are now being converted to IEC standards. While in North America such standardization initiatives are not yet in place, progress could be made quickly by leveraging the more extensive European experience. It is important, however, that the development of technology standards and grid codes does not take on an overly "defensive" stance—focused mostly on possible HVDC-related problems that might occur without taking full advantage of modern VSC-based HVDC capabilities. HVDC technology should not be held to a "higher" standard than other technologies without understanding how its capabilities can best be utilized.

Modularization of HVDC equipment—with ratings suitable for U.S. application and coordination of requirements between the different hierarchical standardization layers, and ideally compatible with the emerging European standards—would dramatically benefit the development of a project pipeline that would support the development of an HVDC supply chain for cost effective HVDC systems in North America.

C. Supply Chain Challenges

Similarly to the supply chain challenges of other electrical equipment (such as a scarcity of large power transformers) and clean-energy generation technologies (such as a scarcity offshore wind generation installation vessels), HVDC technology is currently experiencing similar, if not more severe, supply chain challenges.

HVDC systems consist of several main components, several of which can be large and heavy and require special transport & installation (T&I) equipment. Historically, the HVDC market has been rather small and with limited production capacity, and as a result, the strong current worldwide growth in uptake of HVDC technology is straining the existing supply chains for both HVDC system components as well as T&I equipment. HVDC systems are typically realized with a single supplier for the core converter system solution from AC to DC terminals of both stations, alternative suppliers for civil works and platforms design and construction, and one or more suppliers for the transmission by overhead line or cable system. HVDC systems are typically

[313] CENELEC - TS 50654-1 - HVDC Grid Systems and connected Converter Stations - Guideline and Parameter Lists for Functional Specifications - Guidelines

[314] CENELEC - TS 50654-2 - HVDC Grid Systems and connected Converter Stations - Guideline and Parameter Lists for Functional Specifications - Parameter lists

realized with a single supplier for the core converter system solution from AC to DC terminals of both stations, different suppliers for civil works and platforms design and construction, and one or more suppliers for the transmission by overhead line or cable system. As a result of the relatively small market, technical complexity, and high-risk nature of HVDC projects, the number of vendors capable of delivering converters and cables is limited, and is further constrained by:

- The technical maturity of the vendor's HVDC technology solution at the required HVDC system ratings and functionality
- The project management experience of the vendor in terms of track-record of successfully completed projects
- The country of origin of the vendor and any resulting export restrictions
- The subsupplier/partnership strategy of the vendor, i.e.,
  - all-inhouse production of converter components or ability to source on a competitive basis from 3rd party vendors
  - strategic partnerships with 3rd party vendors to deliver offshore platforms and/or offshore T&I services
- The production capacity of the vendor in terms of engineering staff, number of factories, number of production lines, number and capacity of T&I equipment and the availability of testing facilities

Currently, there are only three main Western converter vendors and original equipment manufacturers (OEMs) for HVDC converter equipment: Siemens Energy, Hitachi Energy, and General Electric (GE) Vernova. These vendors in many cases rely on sub-suppliers and partners for components such as cables, converter subcomponents, and services such as transport and installation. Many of these supply chains are currently experiencing constraints due to the recent, large-scale European HVDC developments, exceeding 40 GW of HVDC system as discussed earlier. The European cable vendors' available capacity is almost entirely used up by the European demand for power cables alone.[315] As a result, current delivery dates for new orders of HVDC converters and cables are in the early 2030s. As the *Financial Times* recently confirmed, "[l]ead times for electricity parts have 'gone through the roof', with waits of three to four years for large power transformers…manufacturing slots are booked up, and … [total

315 EUROPACable, Demand and Capacity for HVAC and HVDC underground and submarine cables, September 2019.

delivery] times for HVDC converter stations have jumped to up to seven years" with grid operators competing with offshore wind generation and other developers for HVDC equipment.[316]

The HVDC supply-chain challenges are perhaps worse in the U.S., due to the lack of domestic manufacturing of HVDC converters and components.[317] As the U.S. DOE already noted in early 2022:[318]

> Because of a small number of HVDC projects in the United States, demand for converters, DC breakers, DC filters, AC switchyard and IGBTs is almost non-existent. This leads to no significant domestic manufacturers for those components. Leading global suppliers such as Hitachi Energy, GE, and Siemens Energy have a U.S. presence in other areas, but their HVDC facilities are in Asia and Europe. [However, w]ithout a significant domestic demand, HVDC manufacturers lack incentive to establish U.S. based manufacturing facilities.
>
> As the world seeks to adopt more carbon-neutral energy sources, demand for HVDC devices will increase and procuring these devices with no domestic manufacturing may be more challenging. There may be a higher risk of failed projects due to delays associated with a heavy dependence on foreign markets and limited global production capacity.
>
> The major bottleneck of this supply chain is a lack of domestic HVDC transmission system manufacturing due to low demand. There are two main reasons for not having high HVDC demand in the United States. First, large transmission projects require collaboration from multiple Regional Transmission Organizations (RTOs) which proves to be difficult. Second, cost recovery aspect of an HVDC project needs a new customer base—similar to a tollway project business model—that is hard to forecast due to competition with existing, lower cost transmission systems. The short-term opportunity to increase HVDC domestic manufacturing is through

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[316] *Financial Times*, Will there be enough cables for the clean energy transition?, July 30, 2023 at https://www.ft.com/content/c88c0c6d-c4b2-4c16-9b51-7b8beed88d75

[317] Manufacturing facilities for HVDC cables have now been established in North America. See, for example: https://www.prysmiangroup.com/en/insight/projects/prysmian-group-awarded-900m-dollars-soo-green-hvdc-link-project-a-key-milestone-in-building-a-us-clean-energy-grid

[318] U.S. Department of Energy, *Electric Grid Supply Chain Review: Large Power Transformers and High Voltage Direct Current Systems*, February 24, 2022, at pp. ix and 54–55 at https://www.energy.gov/sites/default/files/2022-02/Electric%20Grid%20Supply%20Chain%20Report%20-%20Final.pdf

> enhancing collaborations among RTOs and developing government policies to stimulate demand. The medium-term opportunities are to increase research activities and train the workforce in this field. Stable demand and skilled workforce provide security for manufacturers to locate facilities in the United States to reduce costs in the long-term.

The increased strain on the supply chain has a number of detrimental effects on HVDC system development such as increase in costs (coupled with inflation), increase in lead time, and a decrease in vendor flexibility towards delivering desired project characteristics as well as terms and conditions. Recognizing these supply chain challenges, European grid operators, regulators, and governments have been coordinating, recognizing: (1) that the limited supply chain needs a more centralized strategy to ensure that countries and their grid operators can meet the scale and pace of HVDC project delivery that is required,[319] and (2) their important role in supporting and developing the HVDC industry and its supply chain.[320] While the resulting procurement of over 40 GW of HVDC equipment by the Scottish, Dutch, and German grid operators (in coordination with their governments and regulators) will be effective in building and supply chain mitigating their own HVDC supply-chain challenges, these procurements only serve to increase the near-term supply chain challenges for other grid operators and countries, including the U.S., until manufacturing capability of critical HVDC components can be increased to meet demand.

Today, the supply chain issues are so pronounced that they are often seen as the number one risk to an HVDC project. To overcome or mitigate this risk, HVDC project developers have resorted to a number of measures:

- Project developers enter into partnerships with vendors[321]

[319] National HVDC Centre (U.K.), *HVDC Supply Chain Overview (Co-ordinated Offshore)*, July 28, 2021 at https://www.hvdccentre.com/wp-content/uploads/2021/07/Offshore_Co-Ordination_Supply_Report_v2.0.pdf.

[320] For example, see National Grid*, UK Electricity Interconnection: Driving competition and innovation in the HVDC supply chain, November 2016*, at https://www.ofgem.gov.uk/sites/default/files/docs/2016/12/national_grid_hvdc_supply_chain_nov16_public.pdf.

[321] TenneT and partners to develop innovative solutions for IJmuiden Ver, 14 February 2021, https://www.rivieramm.com/news-content-hub/news-content-hub/tennet-and-partners-to-develop-innovative-solutions-for-ijmuiden-ver-57992

- Guarantee availability of production slots[322] and supply vessels before project details are finalized[323]
- Ensure availability of desired technology, e.g., TenneT's 525 kV HVDC cable program[324]

- Large, centralized European Transmission System Operators (TSO) place mega-orders to ensure availability of manufacturing slots for long term grid plans
  - E.g., TenneT procured 14 (28 GW) of HVDC systems (EUR 23 billion for converters alone)[325]
  - E.g., SSEN Transmission procured 5 (10 GW) of HVDC systems[326]
- Developers build / procure own manufacturing facilities to satisfy project needs and serve competitive market afterwards
  - E.g., Xlinks (3.6 GW, 2,400 miles) invests in own cable factory in technology partnership with cable OEM[327]
- TSOs and developers are exploring multi-contracting to open up supply chain
  - Increased interface risk
- Supply chain constraints presents opportunity for market entrants
  - E.g., Mitsubishi, Toshiba

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[322] Invenergy Transmission, Prysmian Announce Long-Term Supply Agreement and Manufacturing Facility Expansion, May 1, 2023, https://www.tdworld.com/digital-innovations/hvdc/article/21265013/invenergy-transmission-prysmian-announce-longterm-supply-agreement-and-manufacturing-facility-expansion

[323] TenneT awards transport and installation slots for 2GW offshore platforms to Allseas and Heerema, May 17, 2023, https://www.tennet.eu/news/tennet-awards-transport-and-installation-slots-2gw-offshore-platforms-allseas-and-heerema

[324] TenneT develops innovative submarine cable with suppliers, April 20, 2020, https://netztransparenz.tennet.eu/tinyurl-storage/detail/tennet-develops-innovative-submarine-cable-with-suppliers

[325] Around €30 billion: Europe's largest-ever contracting pack-age for security of supply, the energy transition and climate protection launched, April 20, 2023, https://www.tennet.eu/news/around-eu30-billion-europes-largest-ever-contracting-pack-age-security-supply-energy

[326] Major milestones in delivery of key contracts for 2030 Scottish electricity transmission network plans, August 2023, Major milestones in delivery of key contracts for 2030 Scottish electricity transmission network plans - SSEN Transmission (ssen-transmission.co.uk)

[327] XLCC obtains planning approval to build UK's first HVDC cable factory in North Ayrshire, June 30, 2022, XLCC obtains planning approval to build UK's first HVDC cable factory in North Ayrshire

- E.g., GEIRI/C-EPRI project in Germany[328]

- Drive towards standardized & modularized designs

The increased supply chain pressure is also providing an impetus for vendors to invest in increased production capacity and open up new factories as illustrated by the following (incomplete) list of announcements:

- New Hitachi Energy valve facilities in Sweden[329] and India[330]
- New GE valve production and testing facilities in Stafford[331]
- New Infineon IGBT manufacturing facilities[332]
- New NKT plant in Karlskrona and new installation vessel[333]
- New Nexans cable plant in U.S.[334]
- New Prysmian cable plant in U.S.[335]
- New Sumitomo cable factory in Scotland[336]

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328 TenneT awards land and sea station of grid connection project BorWin6 to international consortium, November 7, 2022, TenneT awards land and sea station of grid connection project BorWin6 to international consortium

329 Hitachi opens new factory in Smedjebacken - "Hundreds of new employees", September 3, 2022, Hitachi opens new factory in Smedjebacken - "Hundreds of new employees" - Teller Report

330 Hitachi Energy inaugurates advanced power system factory in Chennai to meet the growing electricity demand, February 9, 2023, Hitachi Energy inaugurates advanced power system factory in Chennai to meet the growing electricity demand

331 HVDC VALVES Power Electronics for HVDC Schemes, GE, https://www.gegridsolutions.com/products/brochures/powerd_vtf/hvdc-valves-brochure-en.pdf

332 Infineon opens high-tech chip factory for power electronics on 300-millimeter thin wafers, September 17, 2023, https://www.infineon.com/cms/en/about-infineon/press/press-releases/2021/INFXX202109-098.html

333 NKT will invest EUR 1bn in high-voltage capabilities and capacity at Swedish factory, May 24, 2023, https://www.nkt.com/news-press-releases/nkt-will-invest-eur-1bn-in-high-voltage-capabilities-and-capacity-at-swedish-factory

334 Nexans Charleston, a world class facility uniquely positioned to serve the rapidly expanding U.S. offshore wind market, November 9, 2021, https://www.nexans.com/en/newsroom/news/details/2021/11/2021-11-09-pr-nexans-charleston-world-class-facility-positioned-to-serve-rapidly-expanding-us-offshore-wind-market.html

335 Prysmian Group: New Cable Plant in the U.S.A, February 17, 2023, https://na.prysmiangroup.com/press-release/prysmian-group-new-cable-plant-in-the-usa

336 Sumitomo Electric Establishes Power Cable Factory in Scotland, U.K., April 27, 2023, https://sumitomoelectric.com/press/2023/04/prs021

As noted, there are only three western OEMs for HVDC converters: Siemens Energy, Hitachi Energy, and GE. The new added production capacity is still likely to be insufficient to meet the future demand. Without the prospect of sufficiently large-scale commitments, the OEMs will be hesitant to invest in more domestic U.S. and additional world-wide manufacturing capabilities. While new OEMs from Asia (Toshiba, Mitsubishi, Hyosung) have qualified and tested HVDC converter designs and may play a role and multiple OEMs from China (NR, C-EPRI, GEIRI, XD, XJ, RXHK, TBEA) offer HVDC equipment, they have not yet gained customer acceptance in North America. The U.S. DOE has already developed in 2022 a number of recommendations to address these supply chain challenges, as summarized in Section VII below.

D. Planning, Regulatory, and Market Design Challenges

The utilization and development of HVDC transmission technologies also face a number of regulatory and wholesale power market design challenges. These challenges are similar to those faced by proactive planning for clean energy policy needs, as we had previously discussed in Section III of our report, *The Benefit and Urgency of Planned Offshore Transmission* (January 2023).[337] The challenges are similar because large-scale offshore wind generation developments increasingly rely on HVDC technologies as more cost-effective transmission solutions that offer lower environmental and community impacts through high-capacity lines that utilize less right of way than conventional solutions.

These regulatory and market design challenges that often prevent the selection of HVDC technology to address identified transmission needs include:

- **Incremental generation interconnection processes**: the current processes to evaluate transmission needs for clean energy resources are not sufficiently proactive to be able to identify larger-scale HVDC solutions that, over the longer-term, could integrate generation in more cost-effective, reliable, and timely fashion. The current processes used by the regional grid operators only consider individual or annual clusters of generation

[337] J. Pfeifenberger, J. Delosa, L. Bai (Brattle), and C. Plet (DNV), Brattle Consultants Highlight the Benefits of Collaborative Planning Process for Offshore Wind Transmission in New Report, January 24, 2023 at https://www.brattle.com/insights-events/publications/brattle-consultants-highlight-the-benefits-of-collaborative-planning-process-for-offshore-wind-transmission-in-new-report/.

interconnection requests, which means they will only identify incremental solutions for a subset of future needs.[338]

- **Lack of interregional planning**: The absence of effective planning processes for interregional transmission will necessarily foreclose many HVDC solutions. As we noted before,[339] numerous studies have confirmed the significant benefits of expanding interregional transmission in North America. Building new interregional transmission projects can lower overall costs, help diversify and integrate renewable resources more cost effectively, and reduce the risk of high-cost outcomes and power outages during extreme weather events.[340] Yet, despite broad consensus that the benefits and value of expanding interregional transmission capabilities often exceed its costs, thereby reducing overall system-wide costs, these studies are not integrated with any actionable transmission planning processes of the regional grid operators. In fact, there is still a lack of actionable planning processes that could holistically identify interregional transmission needs, and approve projects that could address such needs,[341] as had been noted in FERC's 2021 Advance Notice of Proposed Rulemaking (ANOPR)[342] and at least 32 reply comments, most of which recommended improving interregional planning processes.[343] In addition to the near-total absence of actionable interregional planning processes, cost effective interregional transmission solutions are often pre-empted by the design and sequencing of existing local and regional transmission planning processes under which local reliability needs are met through local projects, followed by regional transmission addressing regional

[338] See J.P. Pfeifenberger, *Generation Interconnection and Transmission Planning*, presented at ESIG's August 9-11, 2022, Joint Generator Interconnection Workshop, August 9, 2022 at https://www.brattle.com/insights-events/publications/generation-interconnection-and-transmission-planning/ .

[339] J.P. Pfeifenberger, *et al.*, A Roadmap to Improved Interregional Transmission Planning, November 30, 2021 ("Interregional Planning Roadmap") at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[340] For a summary of interregional transmission studies, see Interregional Planning Roadmap, at 2 (Table 1) and Appendix B at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[341] For a survey of interregional transmission planning barriers, see Interregional Planning Roadmap, Appendix A at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[342] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

[343] Interregional Planning Roadmap, p. 3 at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

reliability needs.[344] Almost by definition, this means there is no reliability need for interregional transmission projects left to address.

- **Siloed regional grid planning processes:** most regional planning processes are siloed by type of transmission need, utilizing separate planning effort for projected reliability needs, market efficiency needs, and public policy needs. Less than 10% of U.S. transmission investments currently are planned using a multi-value planning framework, which means the traditional planning processes may not consider the added value of HVDC capabilities relative to the lowest-cost AC solutions that can address individual needs.[345] Similar to the incremental generation interconnection processes, these siloed regional grid planning processes are less likely to identify larger-scale HVDC solutions that could lead to more cost-effective and reliable long term solutions capable to address the full set of reliability, economic, and public policy transmission needs.

  In addition, where multi-value planning processes are utilized, the scope of regional planning processes tends to consider too narrowly transmission-related benefits and their geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits, considering only benefits that accrue to that particular region without considering the broader set of interregional benefits, and typically are not designed to consider HVDC-specific benefits. This means that quantified benefits are frequently understated, HVDC-related capabilities and their benefits are not considered. Moreover, regional projects near interregional seams often fail to meet applicable benefit-cost thresholds for region-specific market efficiency and public policy needs, simply because the planning process ignores the benefits that accrue on the other side of the seam.

  The lack of effective interregional planning processes (discussed above) in combination with siloed regional planning also means that most of the regional grid operators' transmission planning processes are simply not designed to identify transmission solutions that could simultaneously and more cost-effectively address multiple regional and interregional needs—something for which HVDC transmission technology is uniquely capable.

- **Undefined regulatory, contractual, and market frameworks for optimized, shared operation of merchant HVDC transmission projects.** Many of the currently-proposed North American HVDC transmission projects are being developed on a "merchant" basis (i.e., without traditional cost recovery through regulated based on the facilities' cost-of-service).

[344] Id., at 10–11.

[345] See J.P. Pfeifenberger and J. DeLosa III, *Transmission Planning for a Changing Generation Mix*, presented at OPSI 2022 Annual Meeting, Indianapolis, IN, October 18, 2022, Slide 2 at https://www.brattle.com/wp-content/uploads/2022/10/Transmission-Planning-for-a-Changing-Generation-Mix.pdf.

With the exception of the CAISO's "subscriber participating transmission owner" (Subscriber PTO) proposal discussed in the case studies of Section V.21 above, none of the North American grid and wholesale power markets operators have implemented the regulatory and contractual frameworks necessary to integrate merchant HVDC facilities into regional power markets to take full advantage of the energy market, resource adequacy, and overall resilience benefits that these merchant HVDC facilities would be able to provide to the respective regions. Rather, these merchant HVDC facilities typically have to resort to self scheduling, which leads to inefficient market utilization of the lines.

- **Lack of HVDC Market Optimization Capability.** As also discussed in the case studies of Section V.D, the market clearing engines of most regional wholesale market operators are not yet designed to co-optimize regional or interregional HVDC links with generation dispatch. Only CAISO is already able to do so in its nodal day-ahead and real-time wholesale energy market, including on an interregional basis through its WECC-wide Energy Imbalance Market (EIM) and its proposed Extended Day Ahead Market (EDAM). Beyond NYISO, which is currently in the process of implementing this capability, we are not aware of similar efforts to implement such HVDC co-optimization capability by any of the other North American regional market operators.
- **The Need to Update Reliability Standards, Planning Tools, and Grid Codes:** As already discussed in Section VI.B (technology standardization challenges) the currently applicable regulations and standards set out by the North American Electric Reliability Council—which is regulated by FERC—do not yet address the unique capabilities of VSC-based HVDC transmission technologies. This lack of clear standards and reliability regulations makes it significantly more challenging to rely on modern HVDC technology and the grid management capabilities and resilience benefits it can provide. As SPP's effort with EPRI (discussed in Section V.7) shows, the planning tools utilized by regional transmission planners similarly need to be updated—along with staff training—to address HVDC-related operational characteristics. It is critical, however, that these tools are not just focused on HVDC-related challenges, but also on how to be able to take advantage of HVDC-related opportunities.

VII. Recommendations for Addressing the Identified Barriers

To address the barriers and challenges discussed in Section VI above, we offer the nine recommendations discussed below. Implementing them will require close collaboration between grid planning authorities, collaborate with transmission owners, HVDC equipment manufacturers, the North American Electric Reliability Corporation (NERC), industry groups, and the U.S. Department of Energy (DOE) and its National Labs—as well as a willingness to embrace and build on the already substantial HVDC experience documented throughout this report, including the case studies presented in Section V and industry organizations, such as CIGRE.

These recommendations are ordered roughly by priority and time sensitivity, recognizing that the first six recommendations significantly affect the planning and development of HVDC systems, while the last three recommendations are focused on their operations and market integration necessary once the HVDC facilities are placed in service.

1. Develop and implement "grid codes" for interconnecting and embedding HVDC transmission

It will be important that North American system operators and NERC develop technical guidelines for the performance and behavior of HVDC systems at their AC interfaces that can accommodate and take advantage of HVDC capabilities. This effort can take advantage of the ENTSO-e and other European grid code development efforts[346] and progress the CENELEC committee has made In Europe by providing technical guidelines[347] and defining parameters[348] for the development of functional specifications of HVDC grid systems (guidelines, which are now being converted to IEC standards). These grid codes and interconnection standards need to be broad enough to accommodate all HVDC use cases such as gen ties as well as the

[346] See ENTSO-e, "CNC—Implementation Guidance Documents" at: https://www.entsoe.eu/network_codes/cnc/cnc-igds/, Accessed 04/24/2023.

See also HVDC-supporting grid codes developed in the U.K., Ireland, Finland, Denmark, the Netherlands, Germany, and Australia as summarized by EPRI for SPP and discussed in Section III.C of this report.

[347] CENELEC - TS 50654-1 - HVDC Grid Systems and connected Converter Stations - Guideline and Parameter Lists for Functional Specifications - Guidelines

[348] CENELEC - TS 50654-2 - HVDC Grid Systems and connected Converter Stations - Guideline and Parameter Lists for Functional Specifications - Parameter lists

interconnection of interregional (and often merchant) HVDC transmission lines and the integration of HVDC lines that are entirely embedded within a single regional market and balancing area. As noted earlier, it is important that the development of these grid codes and guidelines allow grid operators to take full advantage of the available HVDC technologies, system configurations and ratings, and the advanced HVDC capabilities and not take an overly “defensive” stance that is focused mostly on possible HVDC-related challenges, making it challenging to utilize such capabilities.

This effort will require close collaboration between grid operators, NERC, HVDC manufacturers, and DOE, which has already started initiatives in support of these efforts. DOE, through its roles of investing, convening and influencing is organizing workshops on HVDC technology, funding R&D projects such as the FOA 2828: HVDC Standards, MTDC Controls & Functional Requirements, Education & Workforce Development and the FY23 Appropriations: HVDC Moonshot. In selecting these programs, it is important to consider the industrial participation and the disseminations strategy to ensure that findings are diffused to the appropriate channels such as NERC and IEEE standardization initiatives in an effective and timely manner.

2. Adapt grid planning tools and multi-value transmission planning frameworks to take full account of modern HVDC capabilities

As discussed in Sections III and IV, transmission planners and grid operators should adapt grid planning models and tools that can accurately simulate the full capabilities of the modern HVDC systems and their impacts on the AC transmission network. The planners need to establish standard processes and a range of simulation scenarios to verify these grid planning models and tools for HVDC in different control modes and operation conditions, such as contingencies and restorations used in different stages of the studies that meet the performance requirements and comply with applicable reliability standards. Similar to the effort SPP is currently undertaking with EPRI (as summarized in Section V.7), performance requirements and study criteria would need to be established by the grid operators and NERC for interconnection and integration of HVDC transmission systems, especially VSC HVDCs. In undertaking this effort it will be critical to adopt planning tools and criteria that allow grid operators to take advantage of the advanced capabilities of VSC-based HVDC systems and not take a “defensive” stance that would hold HVDC system to a higher standard and make it difficult to take advantage of the technology’s capabilities.

In particular, as discussed in Section IV above, transmission planning processes should be improved to:

- Be more proactive and holistic by considering the full set of transmission needs (reliability, resilience, market efficiency, and public policy, load serving, and generation interconnection needs) for the near-term while simultaneously considering long-term needs under a range of plausible future scenarios;[349]
- More systematically and holistically evaluate interregional transmission needs and the extent to which interregional transmission expansion (including through merchant transmission lines) can increase reliability and reduce customer costs;[350] and
- Consider the value and avoided AC grid costs of the full set of advanced VSC-based HVDC capabilities as discussed in Sections II and IV above.

In improving these planning processes to be able to take full advantage of the HVDC capabilities discussed in Section II and demonstrated by the case studies in Section V of this report, the regional grid operators and planning authorities will have the most important role to play. However, their efforts can be encouraged and supported through grid planning and HVDC technology-related efforts by the DOE, FERC, and NERC. Independent transmission monitors, as contemplated in industry discussions,[351] could also play a helpful role in assisting FERC and grid operators in the ongoing evaluation and analysis of transmission needs, planning reforms, and the consideration of HVDC capabilities and their value.

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[349] See Brattle-GridStrategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, October 2021 at https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/

See also recommendations for improving regional transmission planning in in Section VI.9 of https://www.brattle.com/insights-events/publications/brattle-consultants-highlight-the-benefits-of-collaborative-planning-process-for-offshore-wind-transmission-in-new-report/

[350] See Interregional Planning Roadmap, available at https://www.brattle.com/insights-events/publications/brattle-economists-author-report-on-the-benefits-of-expanding-interregional-transmission/

See also recommendations for creating effective inter-regional transmission planning processes in Section VI.10 of https://www.brattle.com/insights-events/publications/brattle-consultants-highlight-the-benefits-of-collaborative-planning-process-for-offshore-wind-transmission-in-new-report/

See also DOE National Transmission Needs Study (Draft), February 2023, for a summary of interregional transmission needs that a number of studies have found to be cost-effective.

[351] See, for example, FERC, state regulators consider independent monitors as way to boost transmission oversight 'gap' | Utility Dive (November 16, 2022); and Item No. 5 of Notice Inviting Post-Technical Conference Comments - Docket No. AD22-8-000 | Federal Energy Regulatory Commission (ferc.gov) (December 23, 2022).

In addition, the U.S. DOE recommends that as part of improving transmission planning processes, such planning efforts should also:

> …identify corridors that have priority for developing transmission projects. This will help reduce the number of stakeholders required to approve a transmission project. One example cited by stakeholders is that a multi country HVDC project in Europe only requires half of the stakeholders needed for an HVDC project that spans two U.S. states. Due to a reduced number of stakeholders, Europe can bring certainty of construction to award projects. In addition, if RTO collaboration challenges are not solved, it is very likely that large-scale onshore U.S. HVDC demand will stay stagnant for the next decade. A National Transmission Plan could also be leveraged to identify which existing transmission HVAC lines could better benefit the bulk power system by being converted to HVDC lines. The process of converting existing HVAC lines to HVDC would be simpler and faster compared to constructing new HVDC lines. This conversion would also increase transmission capacity, reduce system losses, and improve overall system stability.[352]

3. Provide training for planning, engineering, and grid operations staff so they are able to take advantage of modern HVDC capabilities

To be able to plan, design, and operate modern HVDC transmission facilities such that the full set of their capabilities can be utilized will require knowledgeable transmission planning, grid design, and grid operations staff—which in turn will require that the necessary educational and training resources be developed and made available to the industry. This will require the close collaboration between industry groups with the necessary technical expertise (or are able to convene the necessary experts for training efforts), experienced grid operators who are able to share their expertise, HVDC manufactures, academia and standards-setting groups. We recommend that entities such as DOE, its National Labs, NERC, IEEE, and CIGRE coordinate and collaborate to make sure the necessary training resources are broadly available and focused on North American challenges in grid planning and design as well as grid and market operations. For example, CIGRE has already convened a “B4 study committee” that focuses specifically on DC power systems and electronics.[353] It would also be advisable to establish an entity similar to

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[352] DOE, *Supply Chain Strategy Report*, February 2022, at 57, available at https://www.energy.gov/policy/articles/americas-strategy-secure-supply-chain-robust-clean-energy-transition.

[353] Cigre, B4 - DC systems and power electronics at https://www.cigre.org/article/GB/knowledge-programme/study-committees/b4---dc-systems-and-power-electronics.

the National HVDC Centre in the UK, which established a testing facility that hosts detailed models (and control/protection hardware) from multiple suppliers and from grid operators and has the expertise (and technology infrastructure) to undertake technical studies, to support the deployment of HVDC projects and mitigate any associated risks to the reliable operation and control to ensure a resilient grid. The Centre also offers a range of HVDC-related services, technical and operational support and training.[354]

Table 19 below provides an overview of HVDC-related training topics and examples of resources available for those training needs. Additional resources can be found in the technical discussions, case studies, and references throughout this report.

TABLE 19. OVERVIEW OF AND EXAMPLES FOR HVDC-RELATED TRAINING

Topic	Audience	Specificity	Trainer	Examples
HVDC technology & systems	System planners, technologists, project engineers, researchers	Generic, could be focused on different technology groups, or systems	Consultants, universities, industry associations, vendors, etc.	• HVDC Converter Technologies training course (dnv.com) • Training – The National HVDC Centre • Services - TransGrid Solutions (myftpupload.com)
HVDC modelling & analysis	System planners, project engineers, researchers	Generic	Consultants, universities, industry associations, vendors,…	• Training & Support - RTDS Technologies • HVDC Control & Project Management | PSCAD • HVDC-VSC System Training - RTE international (rte-international.com)
HVDC project management	Project teams	Generic	Consultants, industry associations, vendors,…	
HVDC operation (operator training)	Grid Operators	Vendor specific	Vendors, consultants,…	• Training | Hitachi Energy • High Voltage Direct Current (HVDC) Systems e-learning – GE Grid Solutions
HVDC maintenance	Maintenance teams	Vendor specific	Vendors, consultants,…	
Market operations	Market Operators	TSO specific	TSO, market operator, consultants	• Controllable Lines Proposal (nyiso.com)

[354] The National HVDC Centre at https://www.hvdccentre.com/our-centre/our-services/.

4. Address current supply chain challenges by building manufacturing capability through clear long-term commitments

Significant investments, such as investments to expand HVDC manufacturing, transport and installation capabilities, will be necessary to address the supply chain challenges currently faced by the industry. Existing and potential new manufacturers of HVDC equipment, however, will not be able to justify the necessary investment until there is reasonable certainty about the magnitude and long-term needs for HVDC equipment. This requires a sufficient "pipeline" of HVDC projects.

In Europe, this pipeline has been created through the pre-orders and long-term commitments made by several European grid operators in collaboration with their local governments. While such close coordination between grid operators and government agencies may be more difficult to achieve in North America, progress is already being made and more can be done. For example, New York and New Jersey have already required that the transmission facilities used to deliver offshore wind generation to shore employ HVDC technology, taking advantage of the smaller environmental and community impact of HVDC technology that can deliver 3 to 4 times the capacity of AC transmission on same right-of-way. As regional grid operators endeavor on new long-term transmission planning efforts, they too have the ability to evaluate and approve HVDC transmission solutions wherever cost effective, particularly when considering the advantages and full range of capabilities that modern HVDC offers for grid operations and power market efficiencies. The reliance on standardized HVDC equipment would also facilitate the advance procurement (pre-orders) of HVDC equipment, which would be an important driver of building a local manufacturing base.

DOE also provided a number of supply chain recommendations in its 2022 E*lectric Grid Supply Chain Review*[355] and *America's Strategy to Secure the Supply Chain for a Robust Clean Energy Transition*[356] reports (both February 2022) to address the current supply chain challenges for HVDC transmission equipment:

[355] "Supply Chain Review." Available at https://www.energy.gov/sites/default/files/2022-02/Electric%20Grid%20Supply%20Chain%20Report%20-%20Final.pdf

[356] "Supply Chain Strategy Report," available at https://www.energy.gov/policy/articles/americas-strategy-secure-supply-chain-robust-clean-energy-transition

- **Short-term efforts** should be focused on increasing the domestic HVDC demand. HVDC is a key transmission technology supporting the 30 GW of offshore wind deployment by 2030. Near term growth in HVDC projects supporting connection of offshore wind is expected. From a national grid perspective, at some point, offshore wind will need to connect with the rest of the grid on land, which would require onshore HVDC systems as the backbone not only for delivering energy to distant users but also improving grid resilience, security, and flexibility.[357]
- **Medium-term efforts** should be focused on increasing R&D investment and workforce training. Areas of R&D investment include HVDC grid interconnection, cost feasibility, HVDC grid stability, grid control & protection and resilience, HVDC grid maintenance, and life cycle management. HVDC equipment such as the HVDC breaker (switchgear) and multi-terminal HVDC systems also need further R&D support to accelerate commercialization. Additionally, it is important to train the workforce for design, installation, maintenance, and eventually manufacturing, especially focusing on >100 kV high-voltage power system/equipment with on-site experiences. During this time frame, there might be growth in HVDC demand. However, foreign friendly suppliers can be utilized for HVDC component sourcing.[358]
- **Long-term efforts** should be focused on increasing the domestic HVDC component manufacturing in the United States. Once demand is substantial, it will make the business case for manufacturers to locate their facilities in the United States to reduce distribution and related costs. Additionally, supply chain vulnerabilities can be reduced by increasing domestic production of HVDC components. One such example is semiconductors. Using the U.S. domestic manufacturer GE as an example, the IGBT manufacturers for GE (and Hitachi Energy and Siemens Energy) are still mainly from Europe because of the high demand of European HVDC markets and the completeness of the EU supply chain. It is important to support U.S. domestic downstream semiconductor manufacturing serving HVDC systems through demand stimulation, tax breaks during production ramp-up period, and other policy means that do not violate the World Trade Organization fair-trade agreement similar to ARRTA of 2009.[359]
- The short-term opportunity to increase HVDC domestic manufacturing is through enhancing collaborations among RTOs and developing government policies to stimulate demand.[360]

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[357] Supply Chain Review at 57.
[358] *Id.*
[359] *Id.*
[360] Supply Chain Review, p. ix

- Expand mechanisms such as competitive grants, direct loans, and loan guarantees that support domestic manufacturing capabilities and job creation. These funding mechanisms will focus on key areas that build on U.S. capabilities and developing markets. Possible topics will include electric vehicles (EVs), rare earth magnets, Grain Oriented Electrical Steel (GOES)—critical for electrical grid, semiconductors, batteries, solar PV processed materials and components, large power transformers, HVDC transmission systems, fuel cells and electrolyzers, nuclear reactor components, and other advanced materials and chemicals key to energy. The funding mechanisms will also focus on other opportunities to strengthen U.S. manufacturing capabilities, including support of casting and forgings, equipment and machine tools, and advanced manufacturing technologies, such as additive manufacturing. An example of an existing program that can be leveraged for these purposes is LPO Title XVII.[361]
- DOE will collaborate with GSA, DOD, and SBA to leverage DOD experience and GSA and SBA authority to support strong investment in clean energy. Specific actions will include:[362]
  - Incentivize domestic production of energy components on government supported projects.
  - Whenever possible, require domestic content standards for Federal procurement of electronics (including those in electric vehicles), batteries, solar inverters, and grid components such as HVDC converters.
  - Where appropriate, provide specific domestic content incentives.
- Incentivize domestic production of energy components on government supported projects through requiring domestic content standards for Federal procurement of grid components including HVDC, wherever possible. By increasing domestic HVDC component manufacturing, the business case is improved for manufacturers to locate their facilities in the United States.[363]

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[361] Supply Chain Strategy Report, p. 28.

[362] Supply Chain Strategy Report, p. 34.

[363] DOE, *Achieving American Leadership in the Electric Grid Supply Chain*, p. 2, available at https://www.energy.gov/sites/default/files/2022-02/Electric%20Grid%20Supply%20Chain%20Fact%20Sheet.pdf

Federally funded research and innovation programs similar to the European Horizon[364] program which funded the BestPaths[365], PROMOTioN[366] and the ongoing InterOpera[367] projects should also be considered, bringing together industry and academia to address technology and policy gaps, build workforce, and promote innovation and diffusion of knowledge and technologies through interstate collaboration.

As the domestic supply chain grows, so will domestic research and innovation, and the need for HVDC testing facilities in which new technologies can be tested and qualified. Such facilities can be distinguished between conventional high voltage and high power testing labs in which physical performance of HVDC equipment can be assessed, as well as state-of-the-art real-time simulation facilities in which the functional performance of HVDC control & protection systems can be validated, its impact on the stability of the grid can be assessed and which can be used for operator training. An example of such a center in Europe is the National HVDC Centre in Scotland.[368]

5. Develop standardized HVDC functional requirements, interface definitions, and vendor compatibility standards, taking advantage of experience gained in similar European efforts

As noted in Sections V.2 and V.3 above, European grid operators TenneT and SSEN have ordered over 40 GW of HVDC equipment, specifying 2 GW, bipole, VSC-HVDC converters that operate at a voltage of 525 kV and are multi-terminal ready. While, Terna is planning to procure HVDC solutions that can be more customized (as discussed in Section V.4), these orders effectively create a well-defined standard for the HVDC equipment that will facilitate scaling up of manufacturing capacity and maintain the option value of future HVDC grid expansion. Other European transmission operators have adopted the use of the new 2 GW, 525 kV standard and—recognizing that HVDC components from different suppliers have not been compatible to date—TenneT and its collaborating partners have developed a vendor-neutral standard for next-generation HVDC technology, asking the EU Commission to support this effort by granting

[364] Horizon Europe, https://commission.europa.eu/funding-tenders/find-funding/eu-funding-programmes/horizon-europe_en

[365] Best Paths: Transmission for Sustainability, Best Paths - Home (bestpaths-project.eu)

[366] Progress on Meshed Offshore HVDC Transmission Networks, PROMOTioN - Home (promotion-offshore.net)

[367] Interopera: Enabling multi-vendor HVDC grids, Home - interOPERA

[368] The National HVDC Centre, Our Services – The National HVDC Centre

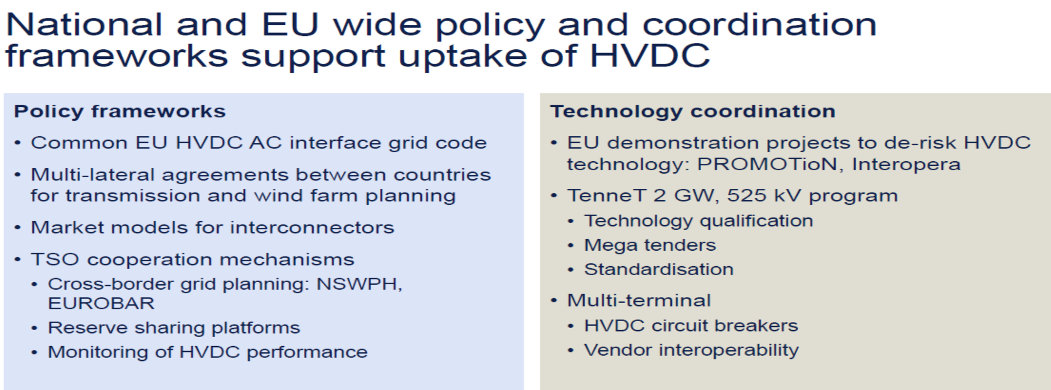
rapid approval. [369] These standardization efforts are critically important to make networked HVDC links (i.e., HVDC grids) possible. They are also important for the point-to-point HVDC developed initially, to create the option to network them with other HVDC links in the future.

We believe that efforts to standardize the functional requirements and ratings of HVDC equipment and ensuring vendor compatibility through the definition of standardized interfaces are critical for the larger-scale and cost-effective development of HVDC transmission solution, recognizing that customized solutions will likely need to be required and remain available. Given that the considerations that led TenneT to the 2 GW, 525 kV, bipole, multi-terminal ready HVDC specification are also meaningful for HVDC applications in North America—such as defining bipole contingencies as two separate 1 GW contingencies or the ability to use HVDC cables, as discussed in Section V.2—we recommend that U.S. transmission developers and system operators adopt the same/similar specifications or work towards defining standard system ratings and functionalities which may fit the specific US conditions .

Adopting the emerging 2 GW, 525 kV standard would not only take advantage of the experience gained in Europe, it would also increase competition, lower costs, facilitate vendor compatibility and inter-operability, and help grow manufacturing capacity, and address the significant supply-chain bottlenecks discussed earlier. We also recommend that activities complementary to this technology standardization effort—such as those summarized in Table 20—be initiated and take advantage of the European experience.

[369] "Making 2 GW the new standard for HVDC offshore wind connections," *Modern Power Systems*, April 28, 2023 at https://www.modernpowersystems.com/features/featuremaking-2-gw-the-new-standard-for-hvdc-offshore-wind-connections-10798364/

TABLE 20. NATIONAL AND EU-WIDE POLICY AND COORDINATION FRAMEWORKS TO SUPPORT THE UPTAKE OF HVDC[370]



6. Update grid operations to be able to take advantage of HVDC capability

As the technical discussion in Section II of this report summarizes, modern HVDC technology can provide a wide range of grid services. The case studies of HVDC experience in Section V show that a number of grid operators are already taking advantage of these capabilities. As the case studies show, the industry can look to European grid operators for a broad range of relevant experience, as well as some of the Canadian and U.S. grid operators (such as CAISO) who are already familiar with VSC-based HVDC capabilities.

To take advantage of HVDC capabilities, grid operators will have to modify their operational processes so they can in fact utilize the grid-support functionality offered by modern HVDC technology. This update to grid operations is focused on the actual operational utilization of the capabilities, which means it is separate from the grid codes that define the design parameters of HVDC systems so they are compatible with the surrounding AC grid and able to provide these capabilities.

Many capabilities of VSC-based HVDC systems are based on fast automatic response functionalities. Operator confidence and intuitive understanding of these functionalities is of utmost importance, which can be achieved through appropriate operator training. We thus recommend the creation of a dedicated national operator training center in which the real-time

[370] VSC-HVDC Technology: European use cases, maturity, experiences, and future plans, June 26, 2023, Cornelis Plet, ERCOT EHV and HVDC workshop, https://www.ercot.com/files/docs/2023/06/27/3_VSC-HVDC%20technology-Europe_DNV_Plet_20230626.pdf

behavior of the U.S. power grids, including HVDC links' advanced capabilities, can be simulated to familiarize and train operators on how to handle grids with HVDC lines during contingency and other challenging operating conditions.

7. Develop new regulatory and cost-recovery paradigms that can take advantage of the controllable nature of HVDC technology and merchant lines

The regulatory paradigms that apply to interregional transmission lines, and merchant transmission development in particular, will have a significant impact on the feasibility of expanding interregional transmission. This has been demonstrated by the experience in the U.K., where few interconnectors to neighboring power markets were proposed or built until the U.K. regulator—the Office of Gas and Electricity Markets (Ofgem)—introduce its new "cap and floor" regime.[371] Ofgem recognized that interconnectors and cross-border flows to neighboring power markets offer significant benefits to consumers:

> Through allowing the trade of energy into and out of the GB energy market they can lower electricity bills, improve security of supply and support decarbonisation. Electricity interconnectors also have the capability to enhance the European energy market and enable the efficient integration of new renewable energy sources.[372]

Ofgem cap and floor regime was designed to encourage investment in interregional transmission by striking a balance between commercial incentives and offer risk mitigation for project developers. As Ofgem explains:[373]

> Electricity interconnectors developed under the cap and floor regime will earn revenue from the allocation of capacity to users who want to flow electricity between GB and our neighbours. Interconnectors may also earn additional revenue streams, such as from participating in the GB capacity market or providing services to system operators. The floor is the minimum amount of revenue that an electricity interconnector can earn. This means that, if an interconnector does not receive enough revenue from its operations, its revenue will be 'topped up' to the floor level. The funds will be transferred from the GB system operator (National Grid),

[371] Ofgem, *Cap and floor regime: unlocking investment in electricity interconnectors*, May 2016, available at https://www.ofgem.gov.uk/sites/default/files/docs/2016/05/cap_and_floor_brochure.pdf

[372] Id. at p. 2.

[373] Ibid.

> which will in turn recover the sum from transmission charges applied to all users of the national electricity transmission system.
>
> The cap is the maximum amount of revenue for an electricity interconnector. This means that, should an interconnector's revenue exceed the cap, the interconnector will transfer the excess revenue to the GB system operator, which will in turn reduce transmission charges.

With a floor set to cover the project debt and operating costs, customers paying regulated transmission rates are essentially backstopping the commercial investment. In exchange, any revenues earned above the cap benefits customers in return for their exposure in underwriting the floor, but "[t]here is a wide band of 'merchant' exposure between the cap and the floor."[374] NEMO link between the U.K. and Belgium (the case study in Section V.8 above) was the first interconnector to which the cap and floor regime was applied; it applies to the whole interconnector and is split 50:50 between the U.K. and Belgium.

The Subscriber PTO (SPTO) proposal currently under development by the CAISO is another example of an innovative and necessary regulatory regime that facilitates the market optimization and cost recovery of regional and interregional merchant transmission lines. As discussed in the case study in Section V.21, the SPTO proposal offers a framework under which the owners of merchant transmission lines will be compensated by the grid operator for making any unsubscribed capacity available for market optimization, which applies to both within-region and interregional transactions.

We recommend that the independent system operators, in collaboration with industry stakeholders and FERC, develop and implement these types of innovating regulatory risk and cost sharing mechanisms to facilitate the development of interregional transmission, including through competitive processes such as those offered through merchant transmission development efforts. Facilitating financial risk sharing through improved market integration of merchant transmission developments, both regionally and interregionally, will yield more efficient outcomes and (as the U.K. experience shows) facilitate the development of the interregional transmission that DOE and others have found to be cost effective.

[374] Ibid.

8. Update market designs so system operators can co-optimize controllable embedded transmission with generation

Similar to the necessary updates to grid operations, updates will be necessary to the market design and market-optimization engines of the regional system operators. The highly controllable nature of modern HVDC systems offers unique advantages to the nodal day-ahead energy, real-time energy, and ancillary services markets of the regional system operators in North America. Yet, at this point, only CAISO has implemented market enhancements that allow it to co-optimize HVDC transmission with generation unit commitment and dispatch on a security-constrained basis in the hourly nodal day-ahead energy markets, ancillary service markets, and the 5-minute nodal energy imbalance markets—which provides important improvements to overall market efficiency.[375] While NYISO is currently in the process of implementing similar market enhancement to be able to take advantage of controllable HVDC lines, these updates to the design and operations of regional power markets will still need to be initiated and implemented by other North American market operators.

9. Implement optimization of interregional transmission capabilities that can accommodate merchant HVDC transmission

As noted in Sections V.20 and VI.D, existing interregional transmission capabilities are often poorly utilized, relying solely on prescheduled bilateral trades to schedule energy flows between regions during normal system operations. These pre-scheduled bilateral trades are too latent to be able to fully utilize the available interregional transfer capability in the volatile real-time power markets, where high price differences between regions may change direction between 50 and 60 times each day.

To ensure more efficient utilization of interregional transmission facilities, we recommend that neighboring system operators implement intertie optimization processes that automatically schedule transactions between the markets if opportunities to do so remain after all bilateral trading opportunities have closed, which is typically at least 20 minutes prior to each real-time operating period. As noted in Section V.20, U.S. market monitors have pointed out that doing so would offer substantial cost savings; and the successful Western EIM experience has

[375] See Section V.1

similarly shown the substantial cost savings that can be achieved with optimizing real-time transactions across neighboring Balancing Area.

When implementing such interregional intertie optimization frameworks, making the optimizations available to HVDC transmission links and merchant transmission facilities is important because: (1) HVDC systems have unique advantages in addressing the high-capacity and (often) long-distance transmission needs between regional market areas, and the high controllability of power flows on HVDC facilities makes them especially well-suited for interregional optimization during real-time market operations; and (2) many large interregional HVDC proposals in North America—as shown, for example, in the map of Figure 33 above—are being pursued by merchant transmission developers.

As discussed in the case study of Section V.19, the Western Energy Imbalance Market and Extended Day-Ahead Market are already designed to be able to co-optimize interregional HVDC transmission lines across the seams between the participating Balancing Areas. As further discussed in Section V.21, this interregional transmission optimization is now being combined with the CAISO-led Subscriber PTO proposal, which would fully integrate into the regional and interregional market optimizations any merchant transmission capacity that remains unutilized by the “subscribers” that have long-term transmission rights on the merchant lines.

We recommend that other North American system operators consider and implement—possibly with encouragement by FERC—equivalent intertie optimization processes that allow for the efficient utilization of interregional transmission capabilities, including HVDC facilities and merchant transmission lines.

VIII. Conclusions

HVDC technology has evolved dramatically, and the technology is playing a critical role in grid modernization efforts around the world. However, the U.S. is lagging behind in deploying HVDC lines, despite the need to dramatically expand the nation’s transmission capacity to meet increased demand, ensure reliable power, and efficiently move low-cost power long distances.

Deploying HVDC technology provides substantial benefits and unique grid management capabilities. As demonstrated through the quickly-growing body of commercial experience, HVDC transmission is a proven cost-effective solution for many bulk-power transmission needs that offers important advantages compared to the conventional AC grid technologies. Modern HVDC technology can enhance the AC grid by allowing it to run more efficiently, better control power flows, address grid stability and flexibility challenges, and increase grid resilience.

As the numerous individual case studies presented in this report show, most of the unique capabilities of modern HVDC transmission technology are already utilized successfully by grid operators. This is particularly true for HVDC systems based on “voltage-source converters” (VSC), which is quickly replacing the line-commutated converter (LCC) technology that accounts for nearly all of North American HVDC projects.

European grid operators in particular have taken advantage of advanced VSC capabilities. VSC-based HVDC technology has become the dominant HVDC choice over the last 5–10 years, with approximately 50 GW of VSC-based HVDC transmission projects in operation today and approximately 130 GW planned or under development through the end of the decade. The extensive planning and operational experience with modern HVDC transmission technology gained in recent years provides a substantial resource for North American grid operators who are seeking cost-effective solutions to address project future transmission and grid operational needs.

Despite the substantial and rapidly growing planning and operational experience, deploying modern HVDC transmission technology is still challenging for a number of reasons related to misconceptions, a lack of experience, technology standardization, supply chain challenges, and regulatory and market design challenges. However, as our recommendations lay out, grid planning authorities can collaborate with transmission owners, HVDC equipment manufacturers, the North American Electric Reliability Corporation (NERC), industry groups, regulators, states, and the U.S. Department of Energy (DOE) and its National Labs to address and overcome these challenges.

List of Acronyms

€	Euro
2L	Two Level
3L	Three Level
AC	Alternating Current
ACER	Agency for Cooperation of Energy Regulators
ACM	Authority for Consumers and Markets (Netherlands)
ADC	Angle Difference Control
AEMO	Australian Energy Market Operator
ANOPR	Advance Notice of Proposed Rulemaking
ANSI	American National Standards Institute
ATC	American Transmission Company or Available Transfer Capacity
AVA	Avista Utilities
AZPS	Arizona Public Service
BA	Balancing Authority
BEIS	Department for Business, Energy & Industrial Strategy
BIGT	Bi-Mode Insulated Gate Transistor
bln	Billion
BPA	Bonneville Power Administration
CAISO or CISO	California Independent System Operator
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CCC	Capacitor Commutated Converter
CENELEC	European Electrotechnical Committee for Standardization
CIGRE	International Council on Large Electric Systems
CO_2	Carbon Dioxide
CREZ	Competitive Renewable Energy Zone
CSC	Current-Sourced Converters
CTL	Cascaded Two-Level
CWE	Central and Western Europe
DA	Day Ahead
DC	Direct Current
DCCB	HVDC Circuit Breaker

DOD	Department of Defense
DOE	Department of Energy
EC	European Commission
EDAM	Extended Day-ahead Market
EGL	Eastern Green Link
EHV	Extra-High-Voltage
EHV-AC	Extra-High-Voltage Alternating Current
EIPC	Eastern Interconnection Planning Collaborative
EMI	Electro-Magnetic Interference
EMT	Electromagnetic Transient
ENTSO-e	European Association for the Cooperation of Transmission System Operators
EPC	Emergency Power Control
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESCRI	Energy Storage for Commercial Renewable Integration
ETU	Elective Transmission Upgrade
EU	European Union
EV	Electric Vehicles
EWIC	East West Interconnector
FACTS	Flexible AC Transmission System
FB	Full-bridge (converter)
FBMC	Flow-Based Market Coupling
FERC	Federal Energy Regulatory Commission
GB	Great Britain
GE	General Electric
GOES	Grain Oriented Electrical Steel
GRITA	Greece-Italy
GSA	General Services Administration
GW	Gigawatt
HB	Half-bridge (converter)
HV-AC	High-Voltage Alternating Current
HVDC	High-Voltage Direct-Current
Hz	Hertz (1 Hz = one event per second)
IBR	Inverter-Based Resource
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers

IEGT	Injection Enhanced Gate Transistor
IGBT	Insulated-Gate Bipolar Transistor
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ISP	Integrated System Plan
IPCO	Idaho Power Company
ITP	Integrated Transmission Planning
km	Kilometers
kV	Kilovolt
LADWP	Los Angeles Department of Water and Power
LCC	Line-Commutated Converter
LRTP	Long-Range Transmission Planning
LTSA	Long-Term System Assessment
MISO	Midcontinent Independent System Operator
MMC	Modular Multi-Level Converter
MMU	Market Monitoring Unit
MSSC	Most Severe Single Contingency
MTDC	Multi-terminal DC
MVP	Multi-Value Project
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NEVP	Nevada Energy
NREL	National Renewable Energy Laboratory
NTC	Net Transfer Capacity
NWMT	Northwestern Energy
NYISO	New York Independent System Operator
O&G	Oil and gas
OEM	Original Equipment Manufacturer
OHL	Overhead Line
OPEX	Operational Expenditure
ORNL	Oak Ridge National Laboratory
P	Real Power
PAC	Planning Advisory Committee or PacifiCorp
PGE	Portland General Electric
PJM	PJM Interconnection

PLL	Phase-Locked Loop
PMU	Phase measurement units
PNAS	Proceedings of the National Academy of Sciences
PNNL	Pacific Northwest National Laboratory
PNM	Public Service Company of New Mexico
POD	Power Oscillation Damping
PPTPP	Proposed Public Policy Transmission Planning Process
PROMOTioN	Progress on Meshed HVDC Offshore Transmission Networks
PSEI	Puget Sound Energy
PSLF™	Positive Sequence Load Flow
PTDF	Power Transfer Distribution Factor
PTO	Participating Transmission Operator
PWM	Pulse Width Modulation
Q	Reactive Power
R&D	Research & Development
RAS	Remedial Action Scheme
RGOS	Regional Generation Outlet Study
RIIA	Renewable Integration Impact Assessment
RMS	Root Mean Square
RT	Real Time
RTO	Regional Transmission Organization
SACOI	Sardinia–Corsica–Italy
SA.PE.I	Sardinia-Italian Mainland
SBA	Small Business Administration
SCC	Short Circuit Capacity
SCL	Seattle City Light
SIDC	Single Intraday Coupling
SPP	Southwest Power Pool
SPS	Special Protection Scheme
SPTO	Subscriber Participating Transmission Owner
SRP	Salt River Project
SSEN	Scottish & Southern Electricity Networks
SSO	Sub-Synchronous Oscillation
TEAM	Transmission Economic Assessment Methodology
TEP	Tucson Electric Power
TID	Turlock Irrigation District

TOV	Temporary Overvoltage
TPP	Transmission Planning Process
TPWR	Tacoma Power
TRAC	Transformer Resilience and Advanced Components
TRL	Technology Readiness Level
TSO	Transmission System Operator
TUNITA	Italy-Tunisia Interconnection
TWE	TransWest Express
Tx	Transmission
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
UVRT	Undervoltage Ride-Through
VSC	Voltage-Sourced Converter
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
XLPE	Cross-Linked Polyethylene