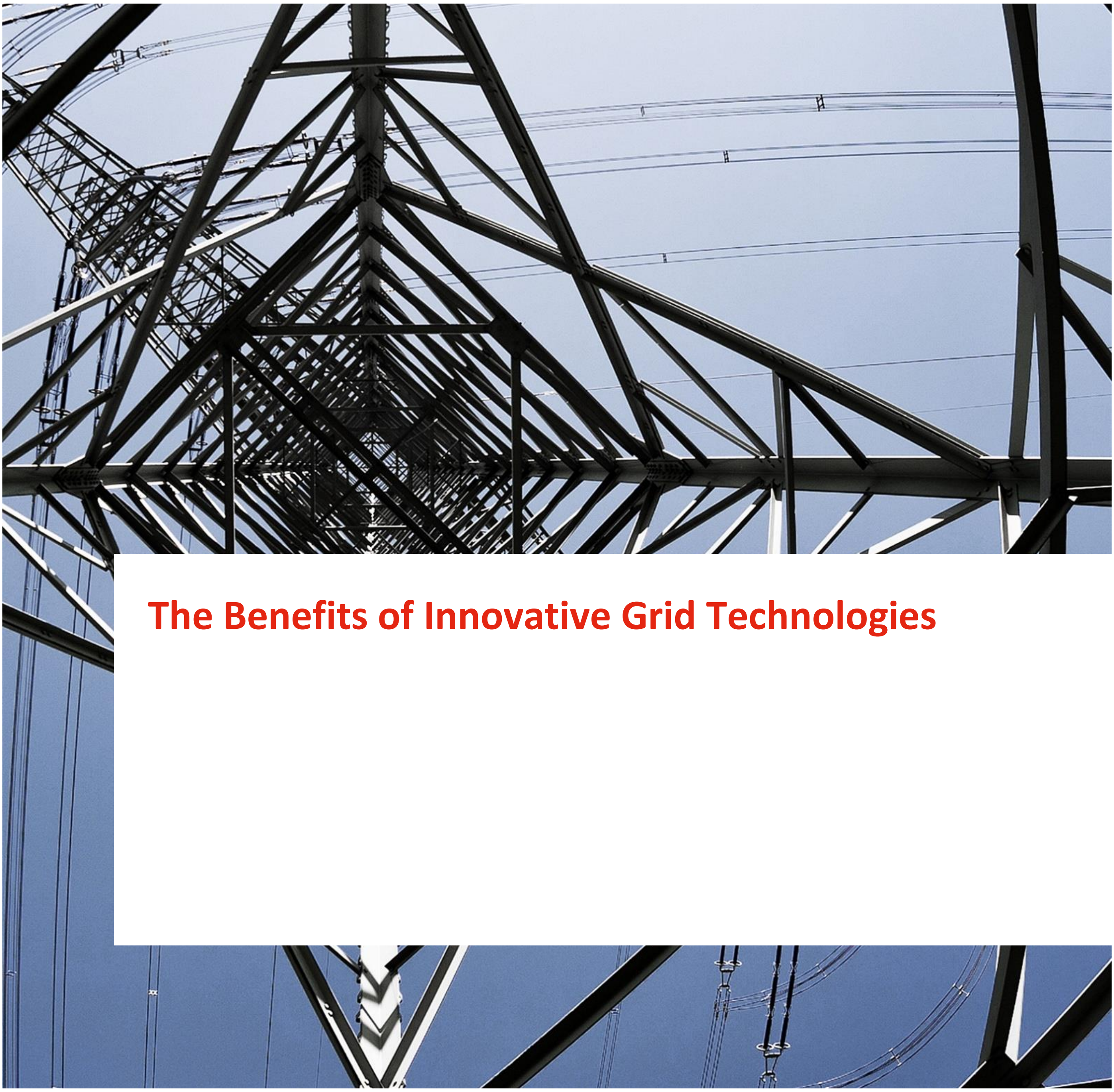

The Benefits of Innovative Grid Technologies

Final Report

commissioned by

currENT

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Key outcome

1 The ambitious energy transition towards net zero, with a 55% decrease in CO_2 emissions by 2030, rising electrification, and more than a 40% share of renewables require a fit for purpose affordable and secure power network that adapts and makes use of the best technologies available.

2 The study and the related scenario show that the combination of Dynamic Line Rating, M-SSSC and Superconductors reduces the congestion and redispatch costs by more than 90% and the congestion-related curtailment of renewables infeed by 3 TWh in 2030. The value of further benefits when using these innovative technologies that might range from improved integration of markets, reduced congestions, and price differences to faster employment of renewable generation, faster electrification of fossil fueled consumption and more emission cuts, have not been part of this study.

3 While each of the innovative technologies will help optimize the power network individually, our study shows in addition the complementary benefit of those technologies.

4 Efficiency and optimization using innovative technologies and the investments in reinforcement and expansion of networks, should be considered together to ensure a secure and cost-efficient green energy transition to society.

Summary

Long-distance transmission of electrical energy has increased significantly over the past decades and is expected to increase further. This development is driven by the rising electricity demand of electrifying the sectors heating, cooling and transport as well as the rapidly growing share of renewable energy power generation, which is often installed at long distances from load centers. Apart from that, an increasing domestic and cross-border electricity exchange can reduce the costs of electricity and foster security of supply.

It is widely recognized that transmission systems need reinforcement and expansion to cope with increasing demand of long-distance transmission and to achieve ambitious targets for the transformation of the electricity system (an inevitable component of the EU Green Deal). This is already reflected in European (TYNDP) and national network development plans (NDPs). However, the expansion of grid capacity has for some time fallen behind due to public resistance towards installing new power lines. Although grid expansion will still be required, reducing congestion on already existing infrastructure can contribute a lot to the energy transition. While most grid expansion projects continue to rely on traditional technologies, such as installing new and larger lines, the potential for proven smart grid technologies to optimize the operation of transmission systems has been widely recognized for some years now. currENT, the recently founded European industry association of suppliers of innovative grid technologies, stresses the need for optimization and sees room for ongoing improvement. Therefore, it has commissioned Consentec to examine the technical and economic potential of technologies that significantly reduce congestion and their associated costs in European transmission systems.

Furthermore, the study has investigated the potential for each of three innovative grid technologies, namely Dynamic Line Rating, Modular Static Synchronous Series Compensators (M-SSSCs), and superconducting Direct Current (DC) cables to reduce the need for congestion

management by Transmission System Operators (TSOs)[1] and its related costs. Our selected scenario is based on the future energy system in the year 2030, which reflects current expectations of the energy transition by implementing the "National Trends" (NT) scenario of the TYNDP 2020. In order to reflect recent changes in the level of ambition towards CO_2 neutrality, we increased the CO_2 emission certificate prices compared to the NT scenario. Projects already known with the aim of reinforcing the transmission grid and being reported in Network Development Plans (NDPs), were assumed to be commissioned on time. This ambitious setup already leads to a significant decrease in congestion in the power grid compared to today because significant transmission expansion anticipating increasing levels of sectoral integration, electrification, and RES infeed is already underway. However, for the purpose of performing a sensitivity analysis, we excluded the German "Suedlink" project, a 700 km high-voltage direct-current transmission corridor from Northern Germany to Southern Germany with a capacity of 2 x 2 GW, from the base case scenario. The geographic scope of the study covers the Central Western Europe region (France, Belgium, The Netherlands, Germany, Luxembourg, and Austria) together with Denmark West because this area covers most of the relevant congestions of the Core region.

Our base-case scenario shows a redispatch volume of 5.3 TWh in each direction (upward and downward regulation), of which 3.4 TWh of downward regulation are RES curtailment. The related redispatch costs amount to EUR 550 Mio./a.

A broad application of sensor-based Dynamic Line Rating, as well as modular static synchronous series compensator (M-SSSC) technology for load flow control can reduce the volume of redispatch and costs by roughly 40%-50% each, compared to the reference scenario. In addition, roughly an additional 1.5 TWh of RES generation can be integrated into the system and does not need to be curtailed.

To quantify benefits of superconducting cables, a realization of the Suedlink project with superconducting technology was assumed. According to currENT's data, necessary investment costs would be about EUR 1.4 billion lower than those of a comparable conventional HVDC system. Accordingly, a superconducting cable system with a total capacity of 2 x 4.5 GW could be installed without additional costs compared to a conventional HVDC system. With this configuration, we obtained a reduction of 50% in the volume of redispatch and costs savings of roughly 60%. The RES curtailment shrinks to 1.6 TWh.

When combining the three technologies and applying them to our scenario the redispatch volumes shrink to less than 1 TWh in upward and downward direction, with related annual costs dropping to as little as EUR 50 million, which is roughly a 90% reduction compared to the reference scenario. From these findings, we conclude that the benefits from the technologies considered are largely complementary rather than substitutive. In this scenario, the RES curtailment is only 0.4 TWh.

In addition to the predicted savings in congestion costs based on our modelling, applying innovative grid technologies to optimize utilization of the power system may bring additional benefits. Among these are an increased flexibility in operating the power grid, which in turn can help TSOs adapt to an increasing share of variable power infeed from renewable energy sources. Sensor-based Dynamic Line Rating and M-SSSCs can also be deployed quickly compared to building new transmission lines. The fast control capabilities of M-SSSC technology could also be part

[1] The benefits for Distribution System Operators' grids were out of scope here because we wanted to focus on the most obvious potential for costs savings. However, it should be noted that DSOs' power grids might also profit from the application of smart technologies, presented here.

of a reactive strategy for transmission system operation and thus contribute to a rapid congestion relief in contingency situations. Superconducting cables might not only reduce losses in long-distance power transmission but will also reduce land use conflicts because of significantly lower demand for right-of-way and possibility for agricultural use of the soil above cable trenches.

Table of Contents

1 Introduction

The demand for long-distance transmission of electrical energy has increased significantly over the past decades and is expected to increase over the next decades. This trend is driven by the rapidly growing share of renewable energy power generation which is often installed at long distances from load centers as well as the increasing desire for domestic and cross-border electricity exchange to reduce the costs of electricity and foster security of supply.

It is widely recognized that transmission systems need reinforcement and expansion to cope with increasing demand. This is also reflected in European (TYNDP) and national network development plans. However, the expansion of grid capacity has for some time been falling behind what is needed to achieve ambitious targets for the transformation of the electricity system (an inevitable component of the EU Green Deal). This includes grid expansion in the offshore environment where no grids have previously existed indeed. Offshore wind is growing in prominence and will require new grids to bring this power back to land. The European Commission estimates that EUR 800 billion must be invested in offshore renewable technology by 2050. Of this, it expects two thirds of the investments will be associated with grid infrastructure and one third for offshore generation assets. Annual investment in onshore and offshore grids in Europe need to double from EUR 30 billion per year to above EUR 60 billion per year in this decade, and then increase further after 2030, the European Commission believes[2]. The enormous cost of proposed investments in grid expansion as well as broader public acceptance issues weigh heavily in the minds of regulatory authorities and policy makers.

While it is widely recognized that grid expansion will be required, reducing congestion on already existing infrastructure can play a crucial role in accelerating and reducing the overall cost of the energy transition. Whereas most grid expansion projects continue to rely on traditional technologies, such as installing new lines or increasing the capacity of existing lines by installing additional circuits, the potential for proven smart grid technologies to optimize the operation of transmission systems has been widely recognized for some years now. Germany, Austria, and Switzerland, for example, require TSOs to consider optimization and reinforcement measures before planning new lines. Under the “NOVA principle”[3], regulators have approved adjustment of the capacity ratings for new and existing lines based on ambient temperature as well as the use of phase-shifting transformers for load-flow control.

Given the scale of the challenge of electrification and the change of the system, all solutions, i.e. more lines, reinforced lines but also the use of technologies for optimization are needed in combination.

currENT, the European industry association of suppliers of innovative grid technologies, founded in 2020, endorses such approaches but also sees room for improvement. Broad application of technologies such as Dynamic Line Rating (relying on sensor-based monitoring of actual line conditions and especially the cooling effect of wind), M-SSSC technology for load flow control, and superconducting lines could not only allow for a better utilization of the existing transmission system, but also reduce costs and enhance both operational flexibility and reliability for TSOs.

[2] European Commission Communication, COM (2020) 741 on a EU Strategy to harness the potential of offshore renewable energy for a climate neutral future.

[3] Stating that optimization should be done ahead of reinforcement, and both optimization as well as reinforcement should be done ahead of expansion of transmission lines.

currENT has commissioned Consentec to undertake a study to examine the technical and economic potential of these technologies to reduce congestion and its associated costs in European transmission systems. The study also examines how the various approaches to mitigate congestion can complement one another. In addition to a more qualitative analysis of the opportunities afforded by such technologies (see chapter 2, the study develops a quantitative assessment based on energy system modeling for a 2030 scenario including dispatch, load flow, and remedial action simulation (see chapter 3). The geographic scope of the study covers the Central West Europe region together with Denmark West.

2 Technical Description of Investigated Innovative Grid Technologies

This chapter describes the three innovative grid technologies that are considered in this study and analyzes them from a qualitative perspective. Each technology offers its individual qualities that can help to better utilize existing as well as new elements of transmission systems. These technologies are the basis for the modelling approaches implemented in chapter 3.

It should be noted that this study considers technologies that are currently in different states of maturity. Instead of considering distinct horizons for deployment within the quantitative calculations, in the following, we provide an overview on the technological readiness of the considered technologies to transparently document the differences. For that purpose, we rely on the information from ENTSO-E Technopedia[4], which categorizes technologies in nine so called Technology Readiness Levels (TRL):

- TRL 1 – Basic research: basic principles are observed and reported
- TRL 2 – Applied research: technology concept and/or application formulated
- TRL 3 – Critical function, proof of concept established
- TRL 4 – Laboratory testing of prototype component or process
- TRL 5 – Laboratory testing of integrated system
- TRL 6 – Prototype system verified
- TRL 7 – Integrated pilot system demonstrated
- TRL 8 – System incorporated in commercial design
- TRL 9 – System ready for full scale deployment

For the technologies considered here, Technopedia has TRL as listed in the table below.

[4] *ENTSO-E Technopedia - ENTSO-E (entsoe.eu)*

Dynamic Line Rating	Modul Static Synchronous Series Compensator	Superconductors
TRL 9	TRL 7 – TRL 9	AC: TRL 7 – TRL 8[5] DC: TRL 5 – TRL 6[6]

Table 1: Source: ENTSO-E Technopedia

2.1 Dynamic Line Rating (DLR)

As a first technology, this study considers the Dynamic Line Rating (DLR). To understand the benefits of DLR, one needs to consider (in a simplified manner) how the TSOs ensure a secure operation of the power grid. It is concretized by forecasting and monitoring the operational parameters of all elements in the transmission grid and comparing them to their respective technical limitations, which are provided by the manufacturer of each element. Highly relevant from a systemic perspective are the limitations on the current carrying capacity of transmission lines and transformers, which specify how much current a grid element can carry without being overloaded. Overloading means operating a grid element in an insecure state, where too much current increases the temperature of the considered grid element such that a failure might occur. Therefore, without DLR, when forecasting the state of the power grid, TSOs consider the static line ratings (SLR, i.e., the nameplate current carrying capacity)[7] and compare it to the projected operational currents. If the predicted currents are above the static line rating, there is a need for remedial actions to change the transmission grid's power flows in a way that reduces the actual power flow on lines in danger of being overloaded.

The SLR, however, is calculated for each grid element in a way that considers unfavorable ambient conditions. This means that SLRs must be set conservatively enough to allow line temperatures to be low enough to allow secure operation even when ambient temperatures are high and external cooling from wind is minimal. On the contrary, DLR allows TSOs to take those climatic cooling conditions into account and increase the grid elements' line ratings accordingly. DLR is already used by some TSOs operationally and/or considered in grid planning processes.

Sensor-based DLR, as offered by the member companies of currENT, provides accurate visibility of asset safety and cooling conditions. Such DLR is an established, well-proven technology, which is already employed by several TSOs (e.g., Belgian Elia, French RTE, Norwegian Statnett). Once implemented, such systems use sensors to provide measurements of the line's physical conditions like sag, conductor temperature, and ambient conditions like air temperature and wind speed. In general, the data measured by the DLR sensors can be obtained in real-time, meaning that live monitoring of line condition is provided. Hence, sensor-based DLR technology offers both a higher temporal as well as spatial resolution of weather conditions than any other data source available. In this regard, the obtained data is more accurate, which is essential for those TSOs that want to use it for dynamically adapting operational line limits to ambient conditions.

[5] Technopedia specifies a TRL of 7-8 on AC-Superconductor. There are, however, first projects that are fully commercial, which would allow for a TRL of 9. These projects are still limited to small scale applications with 50 MW of capacity and a length of 1 km.

[6] As most superconducting systems (including the commercial AC projects) are low ranged, several companies are developing DC systems based on superconductors designed for longer, transmission scale projects for both terrestrial and subsea applications. Therefore, we consider this technology for academic means in this study.

[7] Note that operational limits may be set by other concerns like voltage stability, protection relay setting, etc.

The TSOs need to be able to operate the transmission grid reliably within safe technical limits and therefore expect high data quality from DLR applications.

Other DLR approaches that rely on publicly available weather data are limited in their spatial and temporal resolution. Thus, applicants (e.g., TSOs) are lacking such confidence in the weather data at hand and are forced to apply large security margins (or "degradations") on-line ratings to account for uncertainty. This is relevant for wind speed based on weather modelling in particular because it is not verified with local measurements. Thus, the TSOs may degrade the impact of wind speed significantly or neglect the wind speed at all when calculating DLR if no sensors are installed locally.

In addition, information on the limits of secondary equipment may not be familiar to any operator. To account for the thermal limits in other equipment like switching components, a relative threshold is commonly applied to the line ratings. A further security margin may be needed to ensure that the current on a network element does not exceed stability limits. This margin is implemented in a way that DLR must not exceed an absolute cap.

To account for both beforementioned uncertainties two different types of caps, a cap relative to the static line rating and absolute cap, are jointly applied. The relative one is typically set to limit the usable capacity from DLR to 130%-150% of the static line rating[8], and the absolute one often caps at 3,600 Ampere for 380-kV transmission lines. Whichever limit is reached first, is considered. Figure 2-1 shows how the cap effects the capacity gain that is realized by several DLR approaches. The figure does not rely on actual data but rather gives a stylized example.

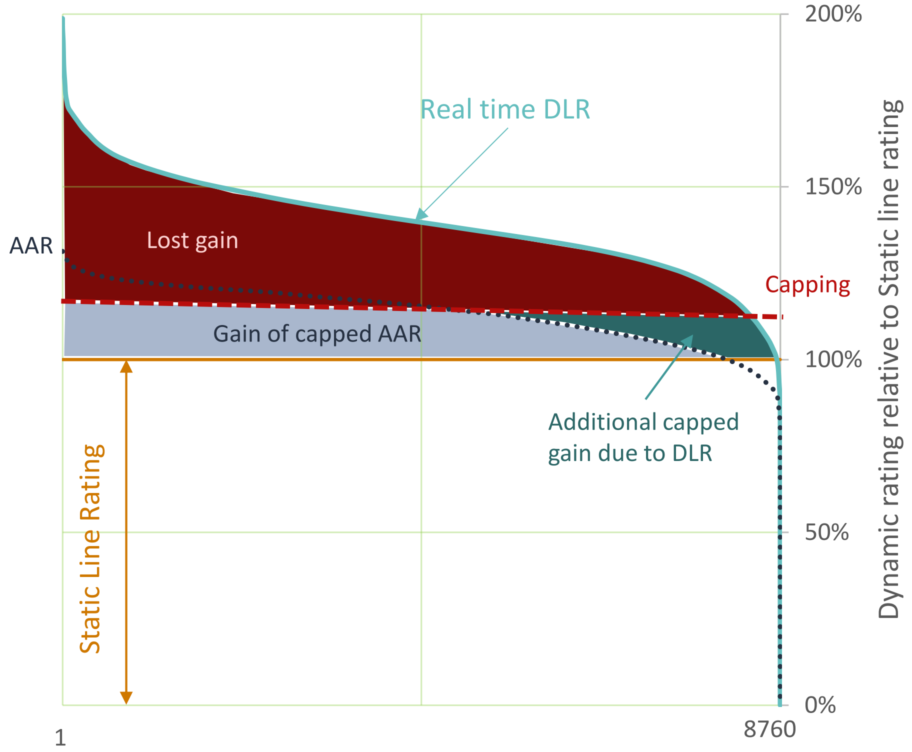

Figure 2-1: Illustration of capping mechanism

[8] Static line ratings are provided by the manufacturer of transmission lines and determined such that the equipment can also withstand rather conservative weather conditions, namely 35°C and a wind speed of 0.6 m/s.

The orange line shows the static line rating representing the 100% level. Applying ambient adjusted ratings (AAR, i.e., only considering cooling from air temperature) in this example increases the calculated line rating in most of the time (dotted blue line), whereas real-time sensor-based measurements allow for a further increase (green line). Capping both curves at a particular level (sliced red line) limits the capacity gain to either the greyish blue area (capacity gained by applying AAR), or, in addition, the green area (additional capped gain of DLR). The rest of the area between the static line rating and the real-time dynamic rating is lost (red area).

Consentec and Ampacimon, a currENT member company, analyzed the impact of these caps and the effect of wind speed on line ratings by calculating the amount of transmission capacity that is lost on several representative lines when the cap is set to various levels. The analysis was based on historical measurement data for three exemplary lines that are equipped with Ampacimon sensors. The impact of capping levels on the usable capacity gain for three real lines in Germany, France and Belgium are shown in Figure 2-2. The y-axis represents the sum of the hourly line rating increase due to real-time DLR in relation to the sum of the hourly static line rating and defines a yearly average increase of the static line rating. The horizontal axis reflects the considered capping levels in descending order.

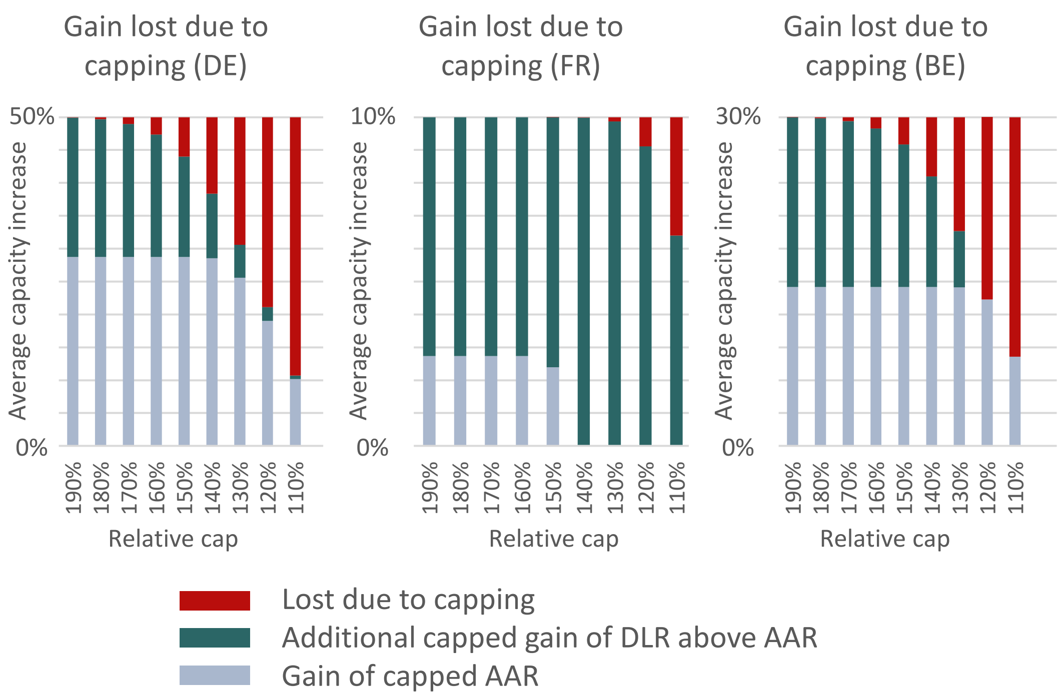

Figure 2-2: Impact of various levels set for capping on capacity gain of three different lines

The additional capacity if AAR are implemented are shown in blue, and the capacity gain by considering the wind cooling effect is indicated in green. As it can be seen, the higher the level at which line ratings are capped, the more DLR capacity can be used. However, if the wind cooling effect is neglected, increasing the capping beyond 130% does not bring a lot of additional value for the lines in Belgium or Germany. To extract most value from DLR technology, it is very important to consider the wind cooling effect. In the case of France, there is a tendency to set the SLR at a higher level than those in Germany or Belgium. This means that the wind cooling effect is the most important element to capture, to ensure safe assessment of available line capacity.

This analysis shows that – from the perspective of transmission lines alone – low caps might substantially limit the feasible thermal line ratings that could be applied in operation. We would therefore recommend evaluating whether the limits applied today might be increased by a more accurate assessment of actual limits (to which using more reliable data could contribute) or by relieving limits caused by secondary equipment (including, if needed, its replacement).

Even without such improvements, line-wise (or segment-wise) live monitoring as it is offered by sensor based DLR can strengthen TSOs confidence in temperature and wind speed measurements that they use to set line ratings in daily operation. Therefore, we assume for our simulation later in this report that they would accept lower security margins compared to today’s practice, when having access to high-resolution measurement data.

2.2 Modular Static Synchronous Series Compensator (M-SSSC)

One important characteristic of meshed transmission systems is that power flows in such systems cannot be directly controlled but follow Kirchhoff’s Laws. As a result, in highly loaded networks, single lines can be congested while other lines that run in parallel still have free capacity available. Having the possibility to control and manage power flows would allow to increase the overall capacity in an AC transmission system by shifting flows from congested lines to those which still have free capacity. For that purpose, phase-shifting transformers have been used for decades. Being bulky devices with limited capacity to control power flows, there are practical limits to their application, though.

Instead, modular static synchronous series compensator (M-SSSCs) are part of the FACTS tools and power electronics toolbox that allow controlling power flows in the altering current (AC) power grid by injecting a controllable voltage into a circuit. In the case of SmartValves, which are considered in this study, this can be done manually or automatically to dynamically control power flows. M-SSSCs can be used at any voltage level (‘voltage agnostic’ devices) and are scalable and adjustable. Hence, they can be applied in transmission as well as distribution systems. Due to their limited weight and compact dimensions, M-SSSCs can be physically deployed on towers and mobile platforms, in substations or near to the line. Compared to phase-shifting transformers, M-SSSCs offer some relevant benefits. They can be deployed within around one year’s time from order to installation. In addition, the compact design allows mobile applications. M-SSSCs can be redeployed to other locations or other voltage networks with no change to the device if location of congestion should shift over time. Mobile devices could also help with outage management. In addition, M-SSSCs can act as sources of reactive power. The expected lifetime of the device is 40+ years (see Annex C).

The key contribution of M-SSSCs resides in its capability to relief congested lines and redistribute flows to lines with lower utilization. This redistribution of flows has several advantages. First, TSOs are less dependent on conventional redispatch and therefore on power plant operators because they have more “redispatching” tools inhouse. Second, from a system perspective, less changes in the power plants scheduled infeed should decrease the cost of conventional redispatch.

Another application of M-SSSCs lies in operating them reactively. This means, that TSOs are able to manually or automatically change the injected voltages when it comes to special events in operation, most prominent, the outage of one grid element. Here, the reactive operation of

M-SSSCs can replace conventional and cost intensive redispatch and contributes to a higher utilization of the power grid. Due to timing constraints, we are not in the position to assess this quantitatively[9].

2.3 Superconductors (SC)

As the name suggests, superconducting cables utilize superconducting materials instead of copper or aluminum traditionally used to carry electricity in overhead power lines and underground cables. A superconducting material is any material, which, when cooled below a certain temperature, operates with zero resistance.

Superconductor materials provide two major advantages. First, wires made from superconductor materials conduct well over 150 times the amount of electricity that can be conducted by copper or aluminum wires of the same size. This means that a superconductor can carry increasing levels of power through a single cable, whereas conventional cables are limited and would require an increasing number of cables. This power density advantage drives system economics and can be a reason why underground superconductor cables can achieve cost parity with conventional cables over long distances. As a result of this property, superconducting cables can operate at a lower voltage than traditional HVDC cables while still maintaining high power capacities.

Second, when transmitting DC power, superconductors have close to zero resistance to the flow of electricity, which means that DC superconductor cables are literally perfect conductors and introduce no electrical losses of their own, again, reducing the costs of power transmission. Superconductor materials must be cryogenically cooled to exhibit their ideal electrical characteristics. The cables are cooled with conventional liquid nitrogen refrigeration systems that are widely used in a variety of industries[10]. While some power is required for the refrigeration — lowering the overall system efficiency — manufacturers claim that superconducting power cable systems still have much higher overall efficiency than any other long-distance transmission system.

Superconducting cable systems are already in operation today. While all previous installations are AC applications, applying this established technology to DC is straightforward according to currENT member companies. Because superconductor cables are compact, light, and emit no heat or electro-magnetic fields (EMF), they should be easy to install, even near further underground infrastructure. The absence of EMF allows for smaller distances between the cables of a superconducting cable system and, thus, leads to significantly lower trench width of the system.

It is also worth noting that the self-contained refrigeration inherent in superconductor cables eliminates depth-of-burial concerns associated with conventional cable technology, meaning that the soil above those superconducting cables it not heated up, where conventional cables dissipate heat into the surrounding soil, drying the soil in the process. Therefore, when using superconductor cables, the soil can still be used for agriculture and other uses.

In addition, superconducting cables could allow for combining the benefits of grid-stabilizing voltage-source converter technology (VSC) with transmission capacities that are available with

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[9] See *BMWi - Netzbetriebsmittel und Systemdienstleistungen im Hoch- und Höchstspannungsnetz* for reference.

[10] Liquid nitrogen is not an environmentally damaging element, constituting ~78% of air.

today's conventional line-commutated converter (LCC) technology only. VSC's technology provides greater control and flexibility and more simply enables DC lines to connect to multiple generation sources and multiple areas of electrical demand.

Conventional HVDC cables are limited in their current carrying capacity, and as such, in order to increase the transmission capacity high operating voltages are necessary. With 525 kV technology available for DC cable systems with VSC converters, transmission capacity per system is limited to 2 GW. With superconductors, current carrying limits are practically irrelevant. Hence, even at low operating voltages (100 kV) transmission capacities can be higher than with conventional HVDC cable systems. Additionally, for conventional cables, transmitting high current over long distances through aluminum or copper conductors would result in considerable resistive losses. Here, superconductors could break through these limitations by providing the ability to transmit very high levels of current with zero electrical loss. The only losses in a superconducting system will be associated with the conversion losses of the AC/DC terminals (also occurring in the conventional copper cable scenario) and the losses of the cable's cooling system. Total system losses to move 5,000 MW are around 0.8% at a distance of 500 kilometres. This is roughly 0.5% less than that of other point-to-point conventional transmission technologies resulting in a more efficient method to transmit large amounts of power long distances.

Superconductors have a significantly reduced resistance, and as such, offer the ability to transmit larger quantities of power without significant increases in cost compared to conventional copper cables (in addition to the cost for additional AC/DC conversion technology). For the present study, capacities of up to 4.5 gigawatts per cable where considered.

The ability to scale the power carrying capacity could allow superconducting DC cable systems to accommodate future increase and changes in power flow at low cost. This might be especially important for the European transmission system where current grid planning deals with transmission demand until 2030 or 2035 but where it is obvious that more is yet to come. Therefore, even with conventional cable technologies today some kind of over-dimensioning of new DC cable systems (by laying additional cable systems beyond today's demand) is discussed. Superconducting cables could provide an interesting alternative to such additional cable systems by allowing a relatively easy capacity expansion (by installing additional converters) during the lifetime of a DC connection and having a significant lower demand for right-of-way than building multiple parallel conventional cable systems.

Whereas conventional DC cables with VSC converters are limited to a capacity of 2GW per system, superconducting cable systems could easily reach much higher capacities. The ability of superconductors to carry increasing levels of power capacity may require a review of system operational limits in the future. Currently, the largest single in-feed loss for Europe is 3,000 MW onshore. As with any system, losing a line should not result in the collapse of the system. The ability to build in redundancy to the superconducting cable subsystems ensures that – according to Supernode– reliability is on par with existing cable systems.

When comparing the total costs of installing a cable system, DC superconducting cable systems are less expensive than the comparable high voltage DC cable systems. Cost reductions are possible due to lower costs of cable systems (approximately EUR 1 million less per km), while the cost of the converters per MW of installed capacity remains similar (roughly EUR 0.25 million per MW).

2.4 Modelling Approach

Dynamic Line Rating (DLR), Load-Flow Control (e.g., M-SSSC technologies), and Superconducting DC cable systems are among the most promising technologies to enable an optimized operation of transmission systems. This chapter will focus on quantitative modelling and will point out technological benefits as well as potential consequences for system operation that can be deduced from our modelling.

Assessing the potential of DLR and M-SSSC technologies quantitatively is possible by modelling, first, the expected market-based dispatch of load and generation in the European electricity market, and second, the optimized operation of the onshore transmission system for this market outcome and the efforts necessary to manage congestion with and without those technologies applied. For superconductors, however, benefits cannot be directly assessed by electricity system modelling, as, from a system perspective, a superconducting and a conventional DC cable system with identical capacities also have an identical impact.

Thus, for assessing the benefits of superconducting cable systems we focused on cost savings that are possible by exchanging a future High Voltage Direct Current (HVDC) system with superconducting cables. Additionally, we evaluated the potential benefits of a superconducting cable system that comes at identical cost of a conventional HVDC system, but with increased capacity.

Therefore, for all three technologies, cost savings from a system perspective are the main results of our modelling work. To calculate these cost savings, we use a quantitative approach including a step-by-step analysis, which is based on a scenario for the expected development of the European energy system until 2030. Figure 2-3 shows the area that was considered in the models applied for this study.

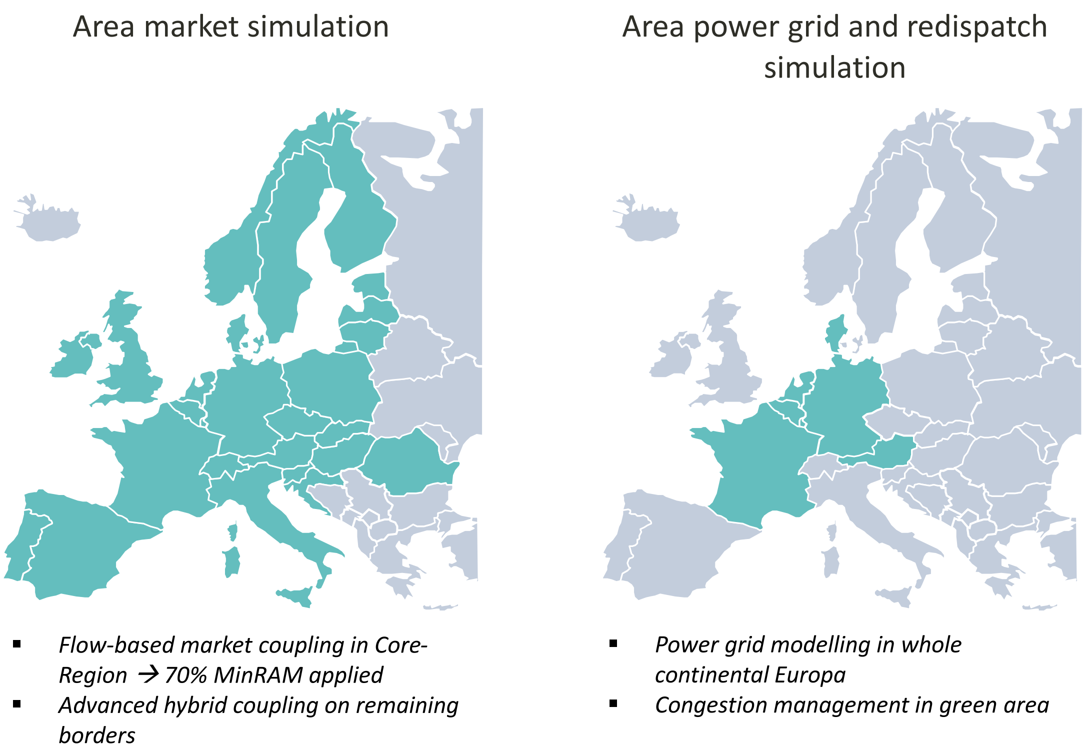


Figure 2-3: Considered area for dispatch and power grid simulation

Our market simulation model covers most parts of Europe from the Iberian Peninsula to the Nordic countries including Sweden, Norway, and Finland. Modelling such an extended area allows our analysis to account for the interdependencies of the European power markets that affect the generation output of power plants in each country, which in turn determine the utilization of the European interconnected power grid. In our power grid and redispatch simulation, however, we have focused on the closely interconnected power grids of France, Belgium, The Netherlands, Germany, Denmark, and Austria.

The considered scenario reflects a potential development of both the European power market and the related power transmission infrastructure until 2030 in line with current policies[11]. Relevant political targets being set out by the European Commission and individually defined by National Energy and Climate Plans (NECP)[12], have been considered by designing the scenario in a way that it resembles the "National Trends" scenario from the recent ENTSO-E Ten Year Network Development Plan (TYNDP). Our modelling further ensures a consistent pathway towards achieving the figures in the respective target years while considering the current state of the power market and grid. Concerning the transmission grid, we have assumed that grid expansion projects will be commissioned according to the timeline as foreseen in the TYNDP 2020 (European projects) and the German network development plan 2019 (German projects). In cooperation with currENT, we decided to deviate from these general principles and to adjust the assumptions in two regards:

- We adjusted the level of commodity and carbon prices to let them reflect recent policy decisions, namely the European Green Deal. The price of carbon emission certificates for 2030 was set to EUR 80 per ton of CO_2[13]. EU emission allowances have been traded for about EUR 50 to EUR 60 between May and October 2021.
- For our reference scenario, we assumed a delay in the realization of one of the currently planned HVDC systems in Germany, namely SuedLink, leading to a commissioning date beyond 2030. Currently, commissioning of Suedlink is planned for 2026/2027 with recent indications that ongoing delays might be expected. It should be noted that this assumption in no ways reflects an expectation from our side that SuedLink might be delayed beyond 2030. Instead, Suedlink is an arbitrarily chosen example to assess whether intelligent grid technologies as investigated here might be able to mitigate consequences of delayed grid expansion.

Our study focusses on the costs for relieving congestion in Germany, Belgium, The Netherlands, Luxembourg, Denmark, and Austria. In order to calculate those costs, we use the modelling sequence as described in the following. For details on our approach on flow-based market coupling, we refer to Appendix A.

Modelling sequence

For our quantitative assessment, we apply two different simulation models. The first one covers the European power market with its wide interconnectivity and the second one models the European transmission grid, while ensuring consistency between the models. This enables to link

[11] This also includes assumptions on existing offshore power-system infrastructure and installed offshore capacities, which are based on publicly available sources (e.g., TYNDP).

[12] Underlying NECPs and related installed power plant capacities are not yet adopting the European Green Deal. Nonetheless, we assumed a higher CO2 price than in the TYNDP to change power generation to less carbon intensive primary energy sources.

[13] All prices are real prices assuming 2021 as the reference year.

the results of power market scenario directly to the power-grid utilization and necessary remedial actions resp. redispatch. The models are applied in the sequence displayed in Figure 2-4. Please note that we use the same input data for the power market model for each of the various scenarios. Therefore, changes only occur in the power grid simulation.

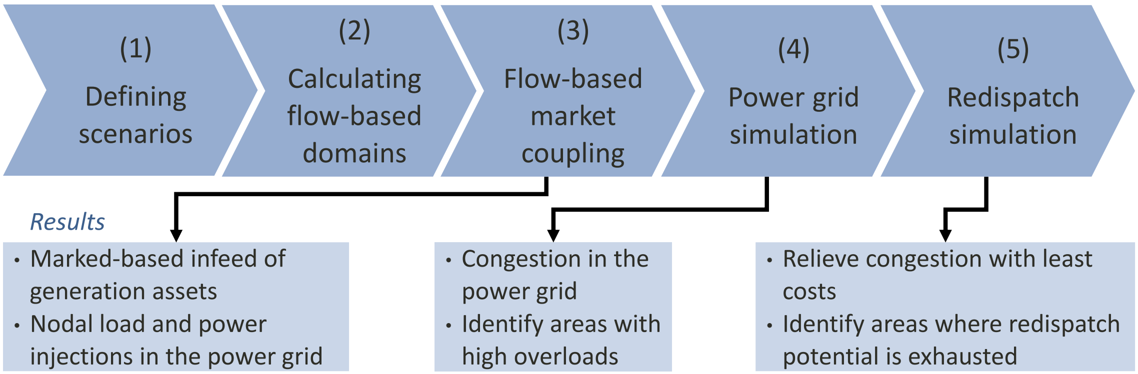


Figure 2-4: Sequential modelling approach

(1) **Defining scenarios**: In a first step we have defined one reference scenario to assess the power markets state in 2030. For further information on the power market scenario, we refer to chapter 3.1.

(2) **Calculating flow-based domains**: In the European power market, electricity can be traded without limitations while cross-border exchange is determined by the market coupling process. The latter represents an algorithm that determines net import and export position of countries (and exchange over potentially congested borders, respectively) in order to optimize the overall socio-economic welfare in the market-coupling region, subject to capacity constraints of the power grid. For the Core region, comprising major parts of continental Europe including the countries which are in focus of this study, until 2030 those constraints will be defined by so-called flow-based domains.[14] To consider this adequately, we have calculated respective flow-based domains with an hourly resolution, performing the following steps.

    a. In a first step, we have calculated an operating point of the power system, i.e., approximate all generators infeed as well as market-based exchanges for each hour. This was done by simulating the power market with simplified capacity restrictions that were based on NTCs (net transfer capacity), which are publicly available[15].

    b. In a second step, PTDF, PSDF, and $PTDF_{HVDC}$ values were computed for each bidding zone and for each individual hour based on the operating point in this particular hour (see excursus below). These factors are calculated for each CNEC. Afterwards, the CNEC selection takes place where only those CNECs are further considered that are impacted by cross-border trade. Current regulation assumes that network elements are significantly impacted by cross-border trade if the maximum difference of two PTDFs of a respective CNEC lies beyond a threshold of 5%.

[14] Flow-based capacity calculation is already applied today in Central Western Europe.

[15] The actual NTCs for our simulation year 2030 are calculated by using historic NTCs s of 2020 and adding to them NTC enhancements of cross-border grid-enforcement projects that are published by the ENTSO-E in its TYNDP 2020.

c. Finally, we calculate the hourly flow-based domains as a system of linear constraints. These constraints require the flows on each CNEC resulting from cross-border trade to be below a CNEC-specific margin (RAM). The Clean Energy Package Electricity market regulation 2019 (CEP) now states that a minimum remaining available margin (MinRAM) of at least 70% of a CNECs maximum flow are to be made available to market. Therefore, we apply the MinRAM of 70% before restricting the market-coupling through flow-based domains.

(3) **Flow-based market coupling**: With these hourly flow-based domains we recalculate the market simulation with higher accuracy by changing capacity restrictions from NTC-based to flow-based.

(4) **Power grid simulation**: The generation and load patterns resulting from our power-market model define the transmission demand that has to be served by the transmission system. As the flow-based domains are only able to approximate resulting flows on network elements (GSK approximation) and do not fully consider flows which are not controllable by FBMC (filtering of CNECs in CNEC selection, application of MinRAM), actual physical flows might still be high enough to cause congestion. We use a nodal load-flow model of the continental European power system[16] to calculate actual flows and detect congestion for each of the 8760 hours of one year. This calculation requires generation and load to be disaggregated on a nodal level. We determine nodal dispatch by mapping the generation of each generator to the power-grid node which it is connected to. Total load per bidding zone is allocated to nodes within this zone by application of a distribution factor, load shift-key, which we have specified for each bidding zone individually. Detected congestion is transferred to our remedial actions simulation model to determine appropriate remedial actions.

(5) **Redispatch/remedial action simulation**: Congestion in the power grid is managed by TSOs by applying remedial actions, namely countertrading and redispatch. With redispatch, TSOs request downward regulation of power plants on one side of a congested network element and the same amount of upward regulation on the other side. Thus, system balance is maintained while each congestion is relieved. With more than one congested element an impact of particular generators on load flow on congested lines depending on “electrical distance”, the basic principle is maintained. However, the actual determination of sufficient and cost-optimal redispatch becomes a complex optimization problem. We approximate the outcome of such process with our linear programming based redispatch simulation model, which is also adopted for the 8760 hours of the year. As the Clean Energy Package (CEP) established Regional Coordination Centers (RCCs) that in the future will coordinate remedial actions optimizations among TSOs, our model simultaneously considers hourly congestions in the entire power grid. It checks which power plants are available to potentially relieve these congestions. This information is then used to compute remedial actions (domestic and cross-border) in a manner that minimizes the costs of redispatch measures while resolving all congestions throughout the considered region, which consists of in Germany, Belgium, The Netherlands, Luxembourg, Denmark, and Austria. As a result, we retrieve redispatch volumes at a level of power-grid nodes and gain information about how necessary redispatch is distributed geographically. The tool typically applies coordinated upward and downward regulation of power plants (prices at marginal cost level) but includes modules for

[16] Our model used in this project covers the voltage levels 380kV, 220kV and 150kV of the CWE+ region, which consists of roughly 1,500 nodes and their connecting lines, respectively.

non-costly remedial actions, such as M-SSSCs, DLR, and Superconducting cable systems. The amount of remedial actions required and the respective costs (difference between additional costs for upward regulations and cost savings for downward regulations) are the main outcome of the analysis and the main result of our modelling in this study.

Considered technology scenarios

Together with currENT we agreed on considering the following five different technology scenarios which combine the application of intelligent power grid tools in various ways.

Scenario	DLR	M-SSSC	Superconductors
Base	inactive	inactive	inactive
DLR only	active	inactive	inactive
M-SSSC only	inactive	active	inactive
SC only	inactive	inactive	active
DLR, M-SSSC, and SC	active	active	active

For each scenario we have re-calculated the minimal costs as well as the related amount of redispatch necessary in Step 5 of the modelling sequence above and compared the results between the scenarios. In comparing the results, we have been able to provide data on the benefits of the DLR, M-SSSCs and superconductor technology for the European transmission grid.

3 Impact of Innovative Grid Technologies

This chapter discusses the quantitative benefits that the considered technologies can deliver to the power system. Chapter 3.1 starts with a description of the electricity market scenario and its results followed by the results of the reference scenario for the grid modelling (chapter 3.2). In subsequent sections, we describe the modelling results for the various technology scenarios with each technology being individually considered (chapters 3.3, 3.4, and 3.5) before looking at the combined potential of all three technologies (chapter 3.6).

3.1 Power Market Scenario

This section submits the input and results of our electricity market simulation model, the output of which was used as an input for the grid modelling. The market simulation was applied to a likely 2030 scenario which closely resembles the ENTSO-E's National Trends scenario[17] from the TYNDP 2020 [1]. Taking this as basis and extrapolating the actual time series for variable renewable generation and load from historic data taken from the climate year 2012, the share of RES generation in total electricity generation is 64%. The share of variable renewable energy generation only (wind, solar) is at 42% of the considered area's total power supply. These figures are roughly in line with typical expectations on what the RES share in electricity generation in 2030 would have to be for reaching the European Green Deal's targets. Compared to the National Trends scenario, however, we also modified the assumptions on carbon and commodity prices to reflect the increased ambition of the Green Deal:

[17] Data available here: *Maps & Data (entsoe.eu)*

	CO_2	Lignite	Nat. Gas	Hard coal	Oil
	EUR/t	EUR/MWh$_{th}$	EUR/MWh$_{th}$	EUR/MWh$_{th}$	EUR/MWh$_{th}$
NT 2030	27	4	25	15	53
This Study	***80***	***6***	***28***	***9***	***51***

With assuming these prices, we observe that gas-fired electricity generation is actually cheaper than coal-fired generation, resulting in a fuel-switch compared to the traditional merit order of electricity generation. Hence, we find a significantly less carbon-intensive electricity generation in total, with a reduction of roughly 80% of the power sectors emissions compared to 1990[18].

Figure 3-1 shows generation capacities not being modified compared to the National Trends scenario. For reference, we also included the maximum load of each country.

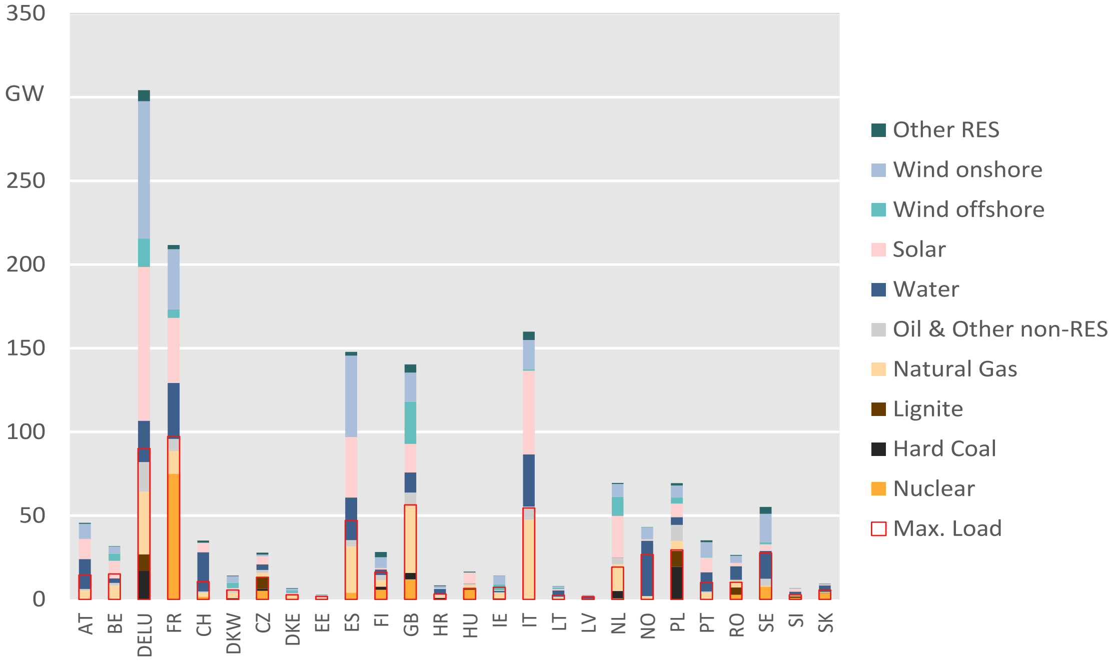


Figure 3-1: Installed capacities per country

Capacity-wise, there is still a significant share of conventional power generation. Coal capacities are still in operation in Germany, Poland, and the Czech Republic, whereas the nuclear phase-out will already be completed in Belgium and Germany.

Figure 3-2 shows the results of our power market simulation in terms of electricity generation per country. Electricity generation from renewable, mostly variable energy sources is the most relevant generation technology with a total share of 64%, as mentioned above.

Among conventional power plants, nuclear power plants have the largest share in generation, with a total generation of roughly 525 TWh. Out of this nuclear generation, 310 TWh are produced in France, providing the highest installed capacity in nuclear power plants by far. The

[18] Reference: 1360 Mt CO2 equivalents, retrieved from Eurostat's data set "Greenhouse gas emissions by source sector: Fuel combustion in public electricity and heat production" (note that Bulgaria, Greece, Cyprus, Malta, and Iceland were excluded from the data set because they are not considered in our model)

output of gas-fired power plants comes close with approximately 510 TWh of total electricity generation. This generation is distributed more widely across the considered area, with the main contributors being Germany and Italy, each of which generates more than 100 TWh of electricity from natural gas. Electricity generation from coal-fired power plants is significantly lower than it is today, with a total output of roughly 100 TWh.[19] The main reasons for this result are reduced capacities and high generation costs due to increased carbon prices.

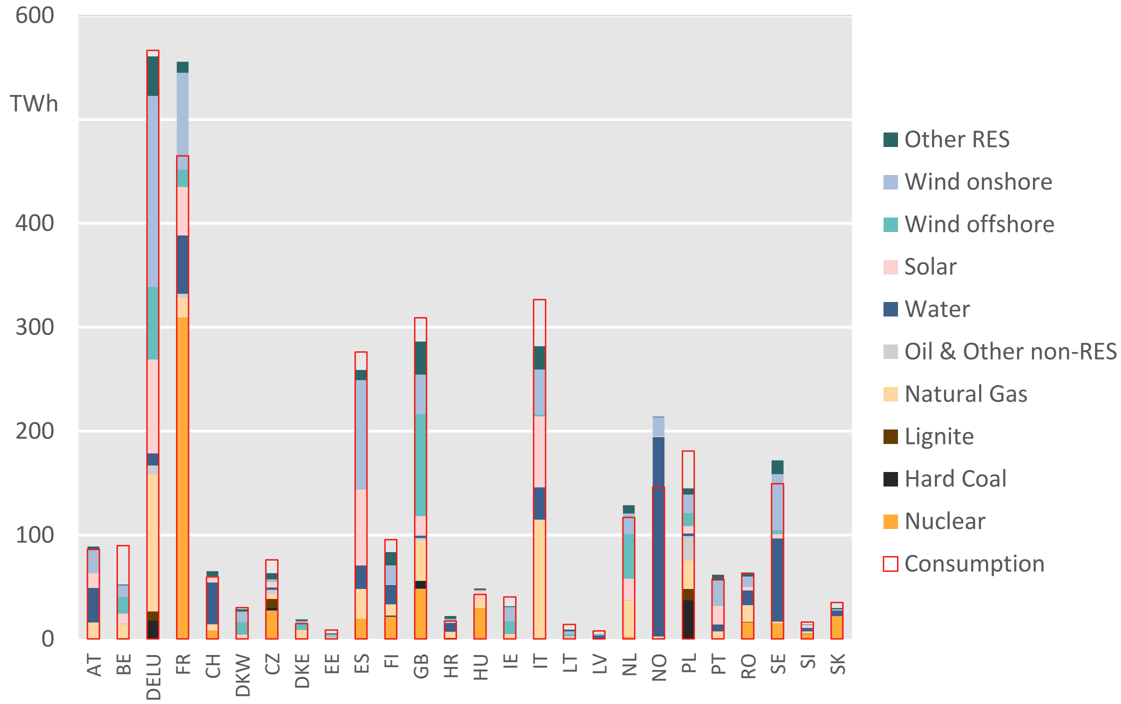


Figure 3-2: Results of the power market simulation

3.2 Reference Scenario (RC)

This section introduces the reference technology scenario for the transmission grid calculations (which all take the output of the power market model as an input). In this reference scenario as well as in all other grid modelling, we have considered the power grids of France, Belgium, The Netherlands, Germany, Denmark, and Austria. Congestion on all grid elements within and between these countries was detected and appropriate remedial actions were determined. Congestion on interconnection lines to third countries, however, was not explicitly dealt with in our calculations. This observability area is kept constant in each of the following scenarios.

Regarding the power grid topology, we have assumed that planned grid reinforcement projects with an expected commissioning date before 2030 will be commissioned on time. This assumption is rather ambitious as the younger history shows that grid reinforcement projects are often delayed. It is also worth noting that the resulting transport capacity of the power grid significantly exceeds the today's capacity because it is designed by TSOs in a way that already considers growing RES infeed as well as an increasing electrification in the future. Our parametrization of the power grid will, therefore, lead to significantly lower figures in redispatch volume and

[19] For reference, according to [1] and [2], the power generation from coal-fired plants in the EU amounts to 450 TWh up to 650 TWh between 2018 and 2019.

related costs than those observed today or in studies with a nearer modelling horizon.[20] The single exception to this is the German high voltage DC project “Suedlink”, which was not included in the reference scenario. Please note that this is not a specific assumption about “Suedlink”. Instead, this well-known project here rather serves as a proxy for potential delays in grid expansion and is exemplarily used to investigate the application of superconductors (see section 2.4).

In the power grids of the observation area, there are not yet any definitive plans for the deployment of M-SSSCs or superconducting cable systems. Consequently, these technologies are not included in the reference scenario. The situation is slightly different for DLR, which is partially applied today and where further applications are planned on a limited basis by some TSOs. However, the different TSOs pursue various approaches and processes, which cannot be covered all in the detailed modelling. Thus, together with currENT we have decided to implement the reference scenario in a way that reflects a broad, but rather conservative DLR approach. This reflects that relevant national grid development plans suggest that the TSOs are mostly relying on approaches that are not based on sensor-based DLR, and therefore will have to apply higher security margins than would be possible with sensor-based equipment. We have implemented the following approach in our reference scenario:

- DLR is applied for all lines[21] within the considered region. This assumption is rather ambitious, but we chose it out of the following two reasons:
    - We deem it reasonable that TSOs would apply DLR at lines, where they expect the most impact. Doing so would in turn reduce the levels of necessary redispatch to a good share of the technical limit (i.e., applying DLR to all lines in the system). Therefore, DLR on the rest of the lines, does not change the amount of redispatch very much and is, hence, justifiable in our modelling.
    - Even with our model being able to differentiate whether a line is equipped with DLR or not, restrictions in the time schedule forbid an extensive study on which lines would contribute most from DLR. Therefore, we had to choose a uniform approach for all lines.
- Actual rating is determined based on ambient temperature only. Wind speeds are not considered.
- With DLR, actual rating is capped at 140% of the respective static line rating or at 3,600 Ampere, whichever is lower. Actual rating is determined based on historic data on ambient conditions[22] for each individual grid node. For each line, the actual rating reflects the least favorable conditions among starting and end node.

Using the market simulation’s results as an input to our nodal power grid model, we pursued load flow and contingency analysis for each of the year. As a first indicator for the level of congestion, frequency and congestion energy of overloaded grid elements are calculated. The results are shown in Figure 3-3. There are a high number of lines where congestion might occur. But the frequency of congestion events is low (500 h/a maximum) for most of those lines. There are only a limited number of lines with high frequency of congestion and a congestion energy of

[20] E.g., study from IAEW Aachen for the year 2023: *RWTH Aachen University - Modular Power Flow Control Enhancing German Transmission Grid Capacity*

[21] Including the three voltage levels 380kV, 220kV, and 150kV.

[22] In line with the inputs for the market model, we apply data taken from the climate year 2012, reflects a rather average year compared to the last 40 climate years with regard to most typical parameters.

more than 1000 GWh/a. Those highly congested lines are mainly located in Germany, where the western parts and border regions with the Netherlands and Denmark, respectively, are most severely affected.

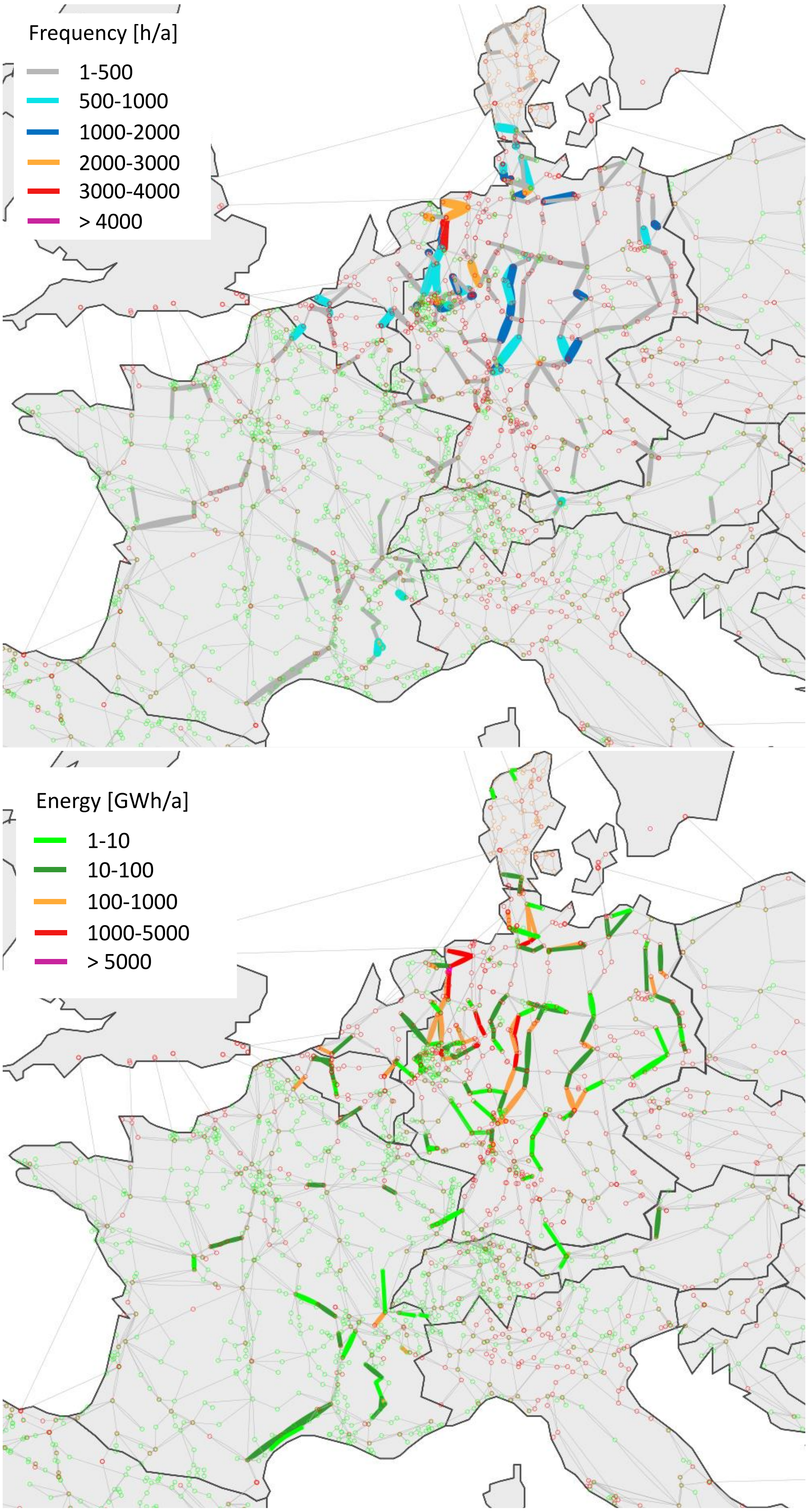
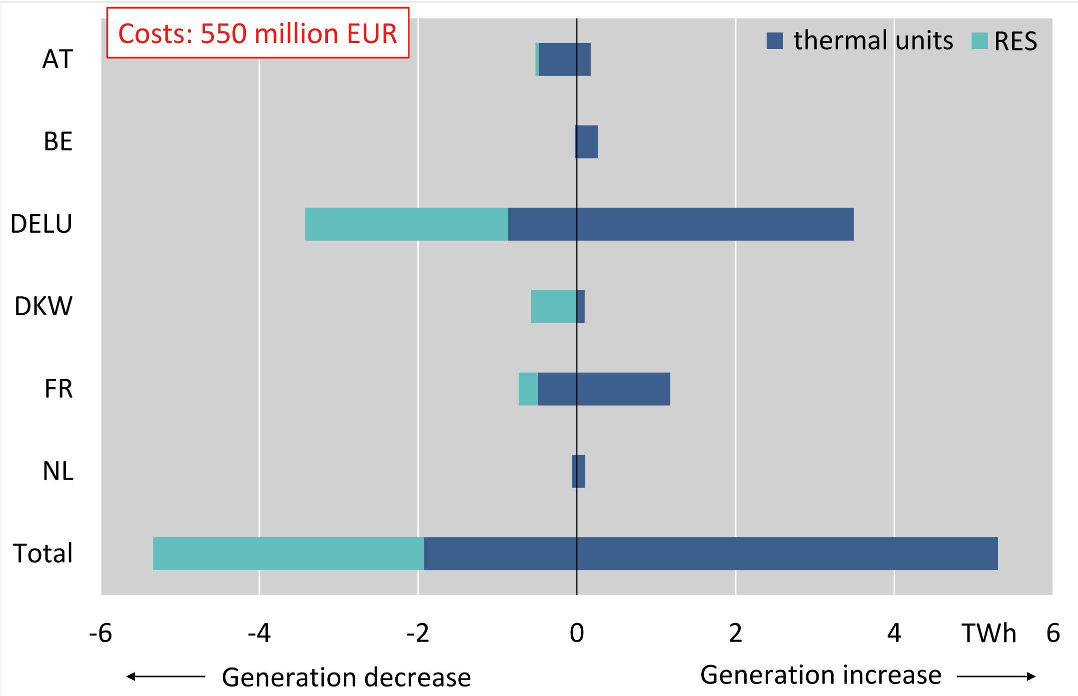


Figure 3-3: Frequency of congestions and congestion energy in the considered scenario

Necessary efforts to relieve this observed level of congestion were then calculated by applying a remedial action simulation. This simulation preferably relies on non-costly remedial actions but uses costly remedial actions as a remedy to congestion where necessary. Hence, the level of costly remedial actions (namely redispatching, and, with lower priority, RES curtailment) needed, can be taken as an indicator of the severity of congestion in a given technology scenario. Figure 3-3 shows the total volume and costs of remedial actions for the reference scenario. Most of the redispatching needed is located near the location of congestions, namely in Germany. This holds true also for RES curtailment, which is mostly necessary for wind farms in Northern Germany. Redispatching in the other countries has a significantly lower volume than in Germany. Whereas volumes for downward and upward redispatching (which have to level out within the entire region) are similar in Germany, patterns are different in other countries. In France and Belgium, upward regulation of generation is dominant. In contrast, Austria and Denmark show higher levels of downward regulation. The overall costs for remedial actions in the region amount to EUR 550 million. These figures lie significantly below today's redispatch volumes and costs due to the at the time of scenario ambitious assumptions regarding (timely) grid development as well as DLR penetration (see section 3.2).



3.3 DLR Scenario (DLR)

In the technology scenario DLR we have assumed a wide-spread application of sensor-based DLR equipment. With line sensors in place, hence more certainty about actual conditions, a higher confidence in the security margins will be possible. Furthermore, we would expect that with DLR being able to consider real-time wind-speed measurements the TSOs should have a more secure understanding concerning cooling effects while calculating line-ratings. And this is just as true when wind speeds are low. Therefore, we have applied the following changes to the reference scenario.

- Wind speed is fully considered when calculating actual line ratings.
- We increase the caps applied to the actual rating to 150% of static line rating and 4,000 Ampere, respectively.

With these modified assumptions, Figure 3-4 demonstrates that the redispatch volumes and related costs significantly decrease by roughly 50%. The geographical patterns observed in the reference case, though, remain more or less unchanged. Volume-wise, applying the advanced DLR reduces necessary RES curtailment significantly by roughly 1.6 TWh (or 47%); most of it located in Germany.

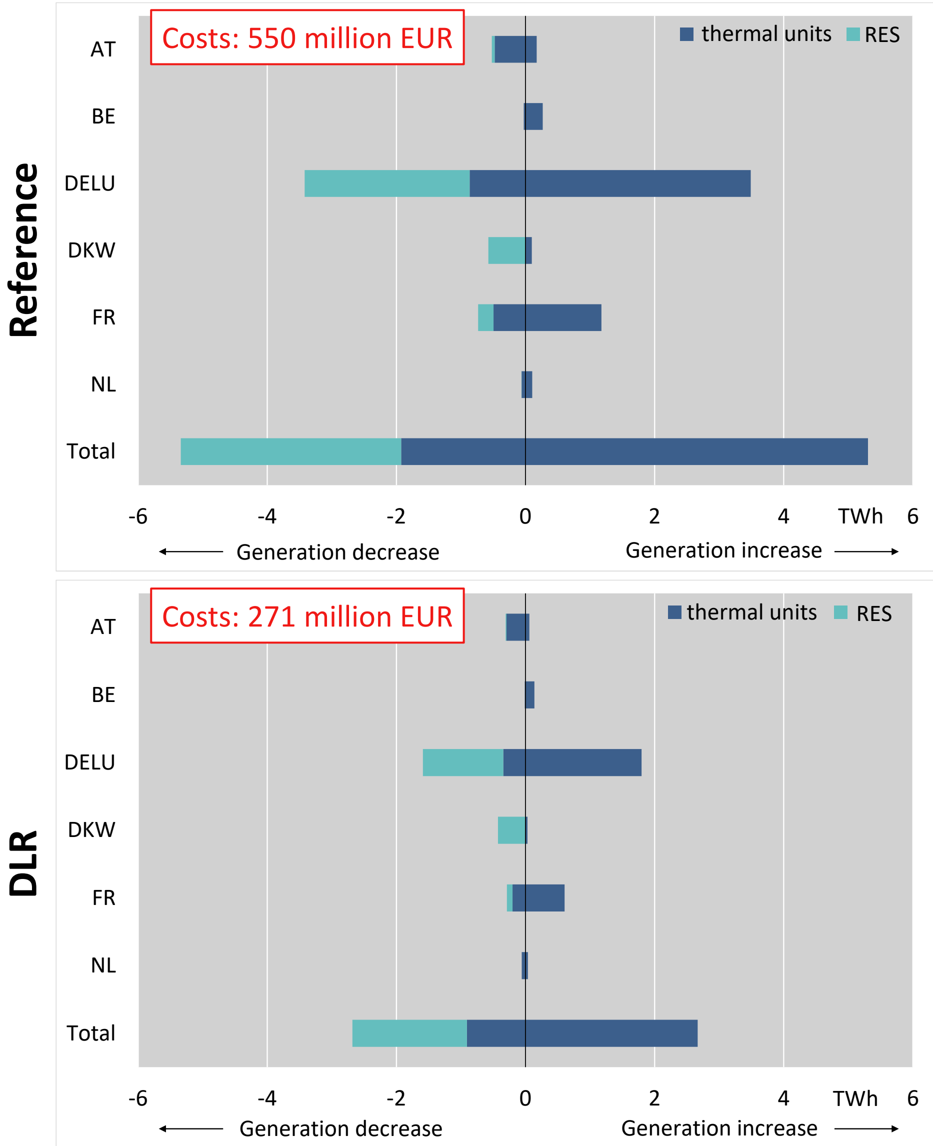


Figure 3-4: Changes in redispatching volumes and costs due to advanced DLR application

3.4 M-SSSC Scenario (M-SSSC)

The next technology scenario analyzes how utilizing M-SSSCs can contribute to reducing the overloading of elements in the power grid by rerouting flows from congested to uncongested lines. As M-SSSCs, once installed, can adapt to multiple load flow situations with their ability to operate in pulling as well as pushing mode (see chapter 2.2), we integrated M-SSSCs in a way that ensures a situation-specific optimal set-point for each hour of the year. The actual modelling of M-SSSCs has been done here with a model of phase-shifting transformers. While this modelling is simplified with regard to capabilities of M-SSSCs to impact reactive power flows, e.g., it is sufficiently accurate to model the active power flow control capabilities. For our quantitative assessment we had to define locations, where M-SSSCs could have a relieving effect on congested power lines and do an appropriate dimensioning. This was done using a heuristic approach using location and intensity of congestions in the reference case as a proxy to where M-SSSCs could be beneficial, which lead to an initial list of sites[23]. Afterwards, we checked whether either of those lines were in series to each other and, if so, only applied M-SSSCs at the starting point of the series. In a last step, we excluded all sites where phase shifting transformers were already installed[24]. This last step was mostly relevant at the Dutch-German borders. It is important to note that this heuristic should lead to sensible assumptions regarding the beneficial deployment of M-SSSCs but will not replace a full cost-benefit analysis which could test various factual and counterfactual scenarios. Figure 3-5 provides the final set of M-SSSCs considered here.[25]

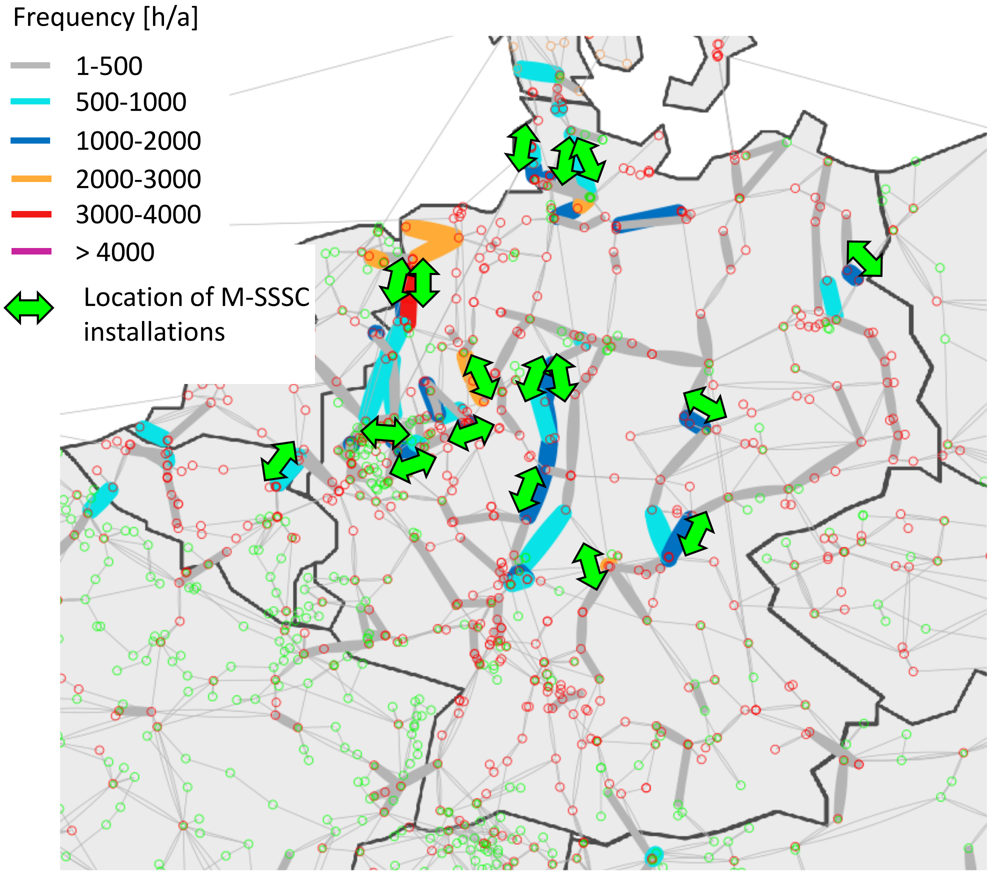


Figure 3-5: Location of M-SSSC installations

With the configuration shown above we have re-calculated all steps of the grid modelling. The results from the remedial action simulation appear in Figure 3-6. The necessary redispatching volume decreases by roughly 40% and the costs by roughly 45% compared to the reference scenario. Notably, also some changes in the geographical pattern of redispatching have been observed. M-SSSCs are located at sites close to the most severe congestions in the power gird, thus relieving those lines foremost. With those lines located mostly in Germany, the decrease in redispatching is most pronounced there. Redispatch volumes in other countries, however, do not

[23] Note that in the reference scenario already a basic amount of FLM is assumed to be in place.

[24] This led us to exclude M-SSSCs at this point.

[25] All M-SSSCs are installed at the 380kV level due to the obtained congestions.

change significantly, except for Denmark, where the impact of M-SSSCs is also measurable. RES curtailment is reduced by 1.5 TWh (roughly 45%).

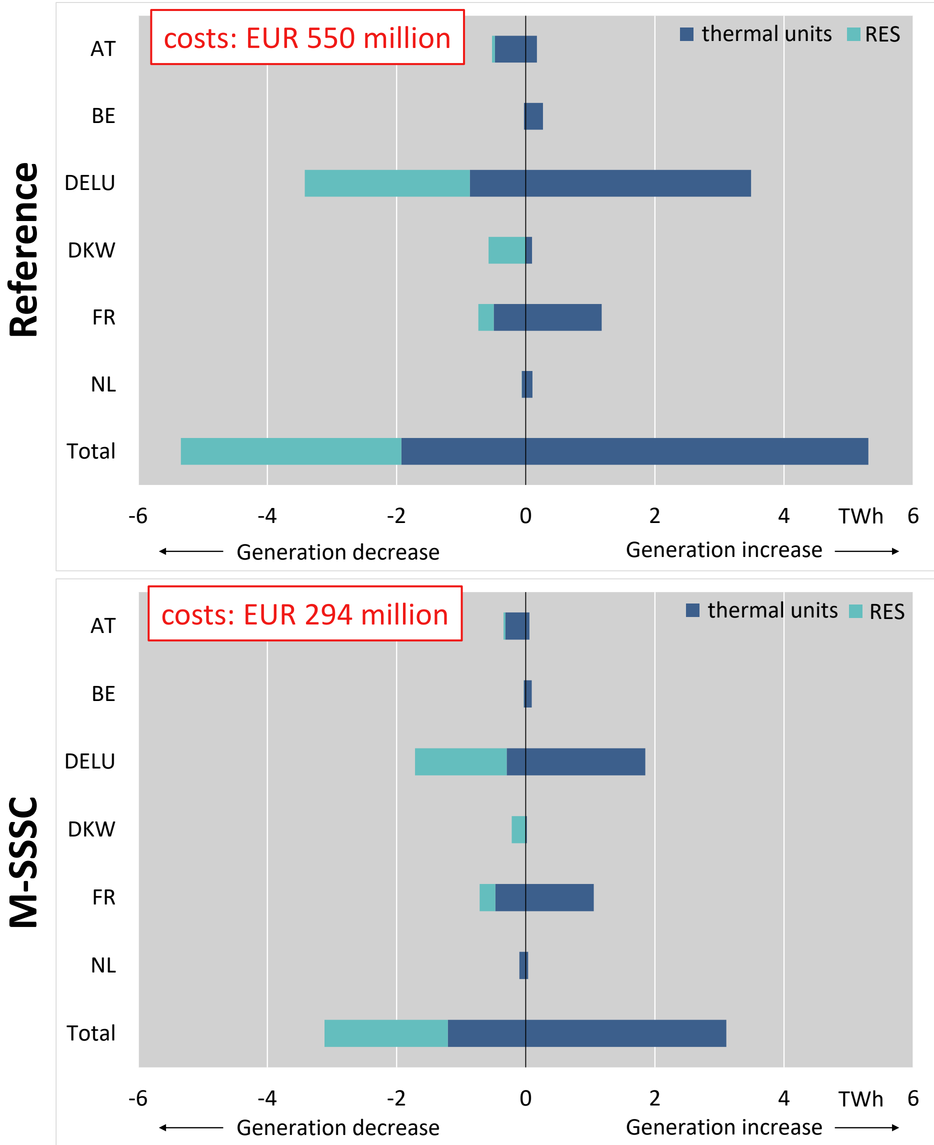


Figure 3-6: Redispatching volumes and related costs in the M-SSSC scenario

3.5 Superconductors Scenario (SC)

In addition to evaluating the effects of DLR and M-SSSCs, in a third technology scenario we analyze how superconducting cables could be used to increase the transmission capacity of given transmission corridors in the power grid. The application of superconducting technology in the European electricity systems is still limited to pilot and demonstrator applications. Hence, there are no existing scenarios employing superconducting technology commercially which could be compared. Additionally, from a system perspective, superconducting DC cables will operate in the same manner as equally dimensioned conventional DC cables while costing less on a GW per km basis.

To reflect this, we investigate two sub-scenarios. In the first scenario we calculate the congestion-relieving effect of an additional DC connection compared to the reference scenario. Here, a 2 x 2 GW connection resembling the “Suedlink” project, which is not included in the reference scenario, is considered (same grid connection points). In a second sub-scenario we then evaluated the effect of a superconducting DC cable system which would have identical investment costs as a conventional DC cable but come at higher capacity (due to lower specific costs for the cable).

In the first sub-scenario (2 x 2 GW transmission capacity) we obtain a cost reduction from reduced redispatch of roughly 40% compared to the reference scenario. Figure 3-7 shows that redispatch is, once again, mostly reduced in Germany, with other bidding zones being also affected but to a significantly lesser degree. RES curtailment is reduced by 1.3 TWh (38%). The cost savings as well as the reduction of redispatch volume and curtailment are achieved by the increased transmission capacity in the “Suedlink” corridor. To this extent, there should be no major differences in the results between conventional HVDC lines and superconducting cables if the same capacity is assumed. Changes would only stem from lower losses of a superconducting system or from lower investment costs (see chapter 2.3).

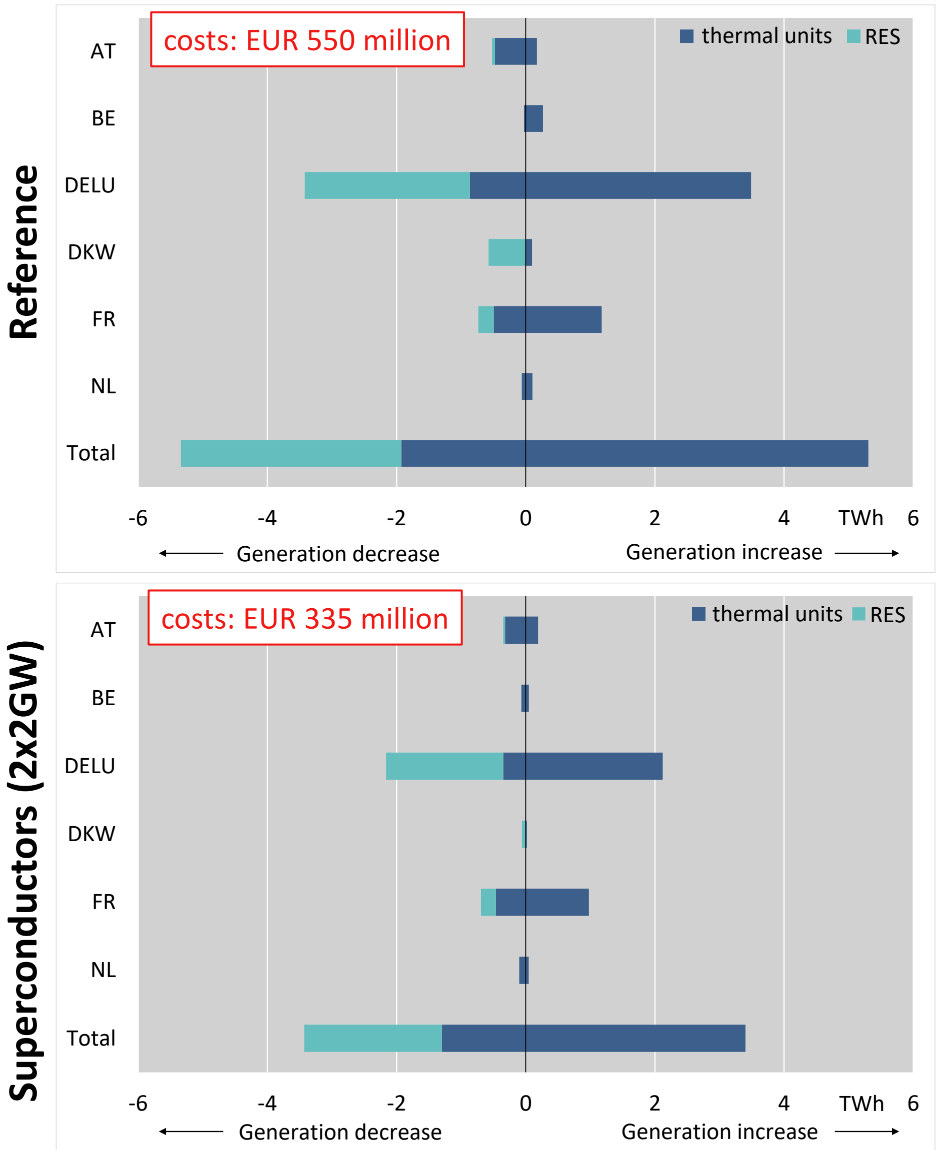


Figure 3-7: Redispatching volumes and related costs with a superconducting system instead of a HVDC system for "Suedlink"

Our second sub-scenario considers the fact that the capacity of the superconducting cable itself is effectively limitless. Hence, by increasing the capacity of converter stations, the transmission capacity of the overall system can be increased. With cost assumptions for cables and converter capacity as provided by currENT, a superconducting cable system with a capacity of 2 x 4.5 GW could be realized without significant additional costs compared to a conventional 2 x 2 GW cable system[26]. We are aware that such high capacities could bring significant challenges to system operation. Those challenges could not be investigated in detail in the present study but should be investigated before real-world application so that such value can be realized for consumers.

Figure 3-8 shows the results of the second scenario with the capacity of the superconducting system being increased to 2 x 4.5 GW. Costs for redispatching decrease by another EUR 100 Mio. (-30%), and redispatch volumes decrease by roughly 25%. RES curtailment is reduced by another 0.5 TWh, compared to the 2 x 2 GW system. Again, this is achieved by the increased transmission capacity that relieves AC power grid elements.

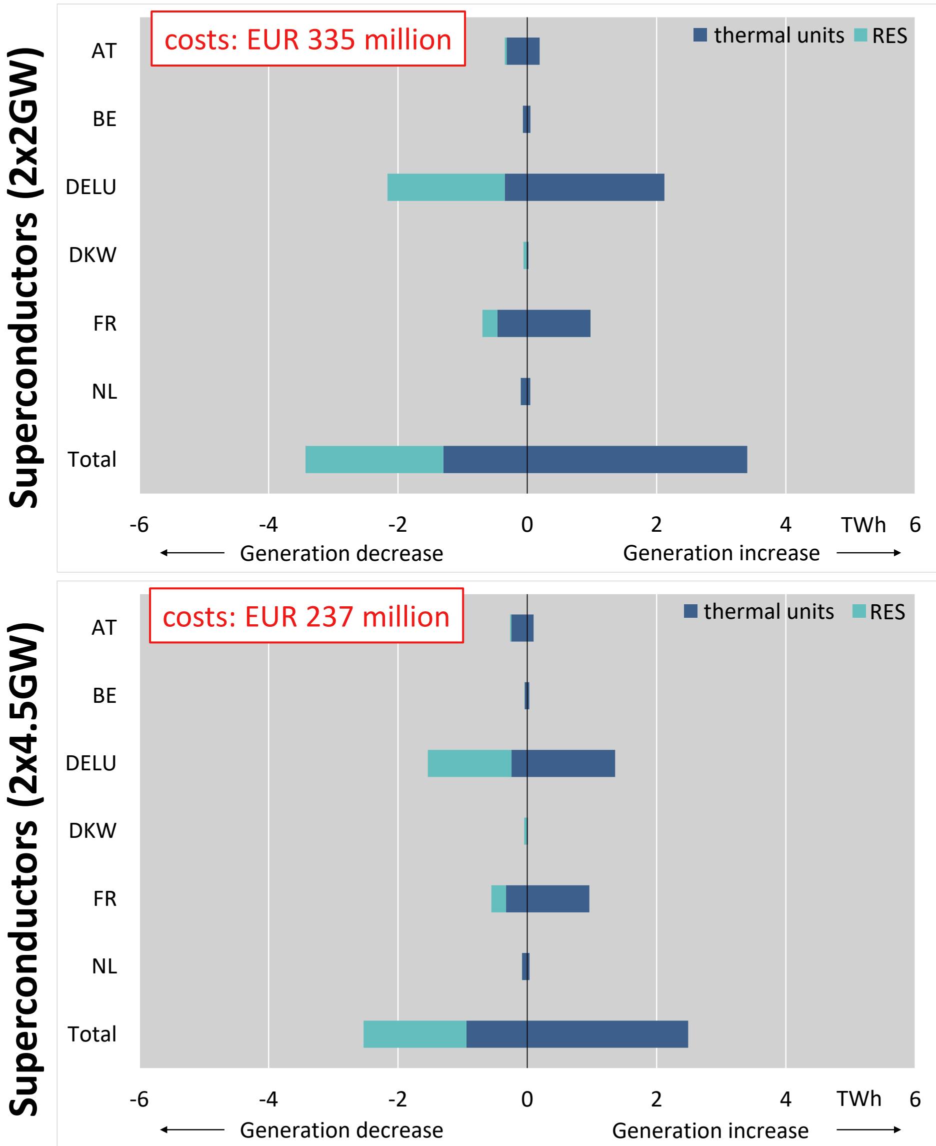


Figure 3-8: Comparison of redispatch volumes and related costs with two different superconducting systems

[26] The technical and economic parameters were provided by currENT.

3.6 All Three Technologies Combined

The last technology scenario analyzes the complementarity of the three intelligent grid tool technologies. Consequently, this scenario assumes the combination of the progressive DLR approach (see chapter 3.3), the M-SSSCs as in chapter 3.4, and the installation of a superconducting DC cable system with 2 x 4.5 GW capacity (see chapter 3.5).[27]

As a result, we conclude that combining these three technologies provides significant additional benefits compared to the deployment of a single technology alone. The overall costs for redispatch shrink by roughly 90% to EUR 50 Mio. This is almost twice the reduction that any individual technology achieves. Redispatch volumes are reduced significantly to very low volumes of less than 1 TWh of upward and downward redispatch. In line with that we conclude that RES curtailment is significantly reduced by more than 90% to 0.4 TWh.

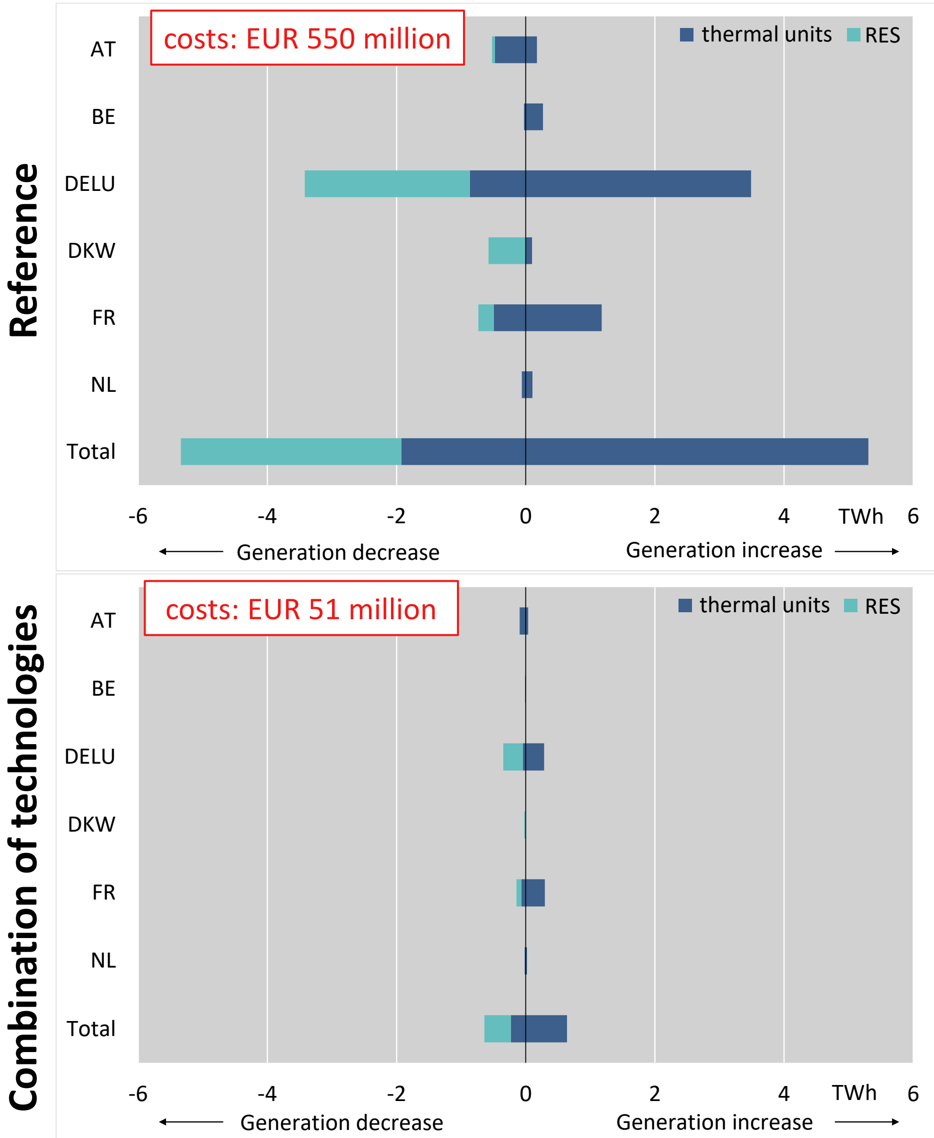


Figure 3-9: Comparison of redispatch volumes and related costs when combining the three technologies with the reference scenario

[27] Due to timing constraints of the study, we did not re-optimize the configuration of the three different technologies, but rather used the exact same configuration as applied in the individual technology scenarios.

The finding of the study is thus that the benefits from the technologies considered are largely complementary. We underline here at once that the very low redispatch costs and redispatch volumes result not only from the intensive use of innovative grid technologies but are also based on the assumption of ambitious grid development, as built in the used TYNDP scenario data. As stated before: expanding the grid and optimizing the use of existing infrastructure is not mutually exclusive, but both necessary to meet ambitious targets. The scenarios used for this study have been replaced already by more ambitious ones[28] and congestion levels might therefore actually exceed those assumed for the purpose of this study. This does not diminish the outcome of this study, that clearly shows the proportional very high impact already of each individual technology, and even more so the high efficiency of their combination.

Therefore, even with higher levels of congestions than in our reference scenario, Consentec is still confident that a significant reduction of congestion costs was possible by the combined application of the considered technologies.

This could turn out to be especially helpful with a more rapid deployment of renewable energies in order to meet the more ambitious climate targets as enshrined in the Climate Law and in the "Fit for 55"-package. Experience shows that conventional grid expansion lags behind so that more severe congestion and curtailment occur, increase costs to society, and require the ambitious use of the toolbox of innovative grid technologies.

3.7 Overview Modelling Results

Our modelling indicates that each of the technologies could provide significant cost savings regarding costs for redispatch. Furthermore, combining the three technologies delivers additional benefits, thus, indicating that they are not cannibalizing each other's advantages. Figure 3-10 gives a brief overview of all quantitative results.

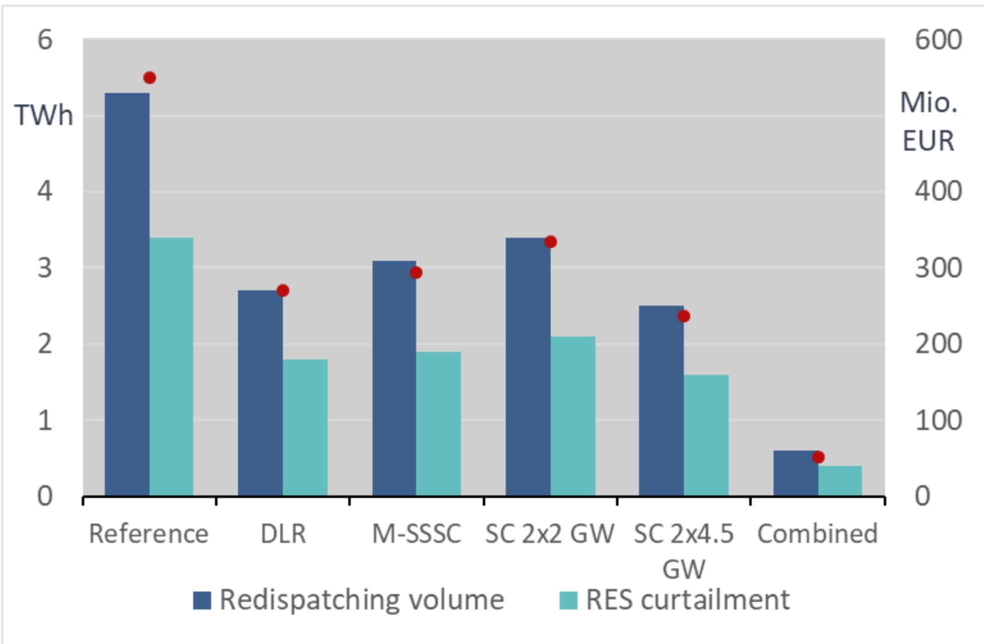


Figure 3-10: Summary of all quantitative results

[28] E.g., German Climate Change Act 2021; other EU members will also adapt to "Fit for 55%"-package by the EU, which is not reflected in the National Trends scenario of the 2020 TYNP; TYNPD Scenarios 2022 are in the making.

4 Outlook

This study has shown that the application of intelligent power grid solutions like DLR, M-SSSCs and Superconducting DC cable systems can achieve significant potentials for an optimized and cost-reducing power grid. It should be noted that this study has focused on the technical potentials of these technologies for mitigating grid congestion. Hence, we have not carried out a full cost-benefit analysis which would also be heavily dependent on the definition of counterfactual scenarios.

Furthermore, with an increasing dynamic in the energy sector towards carbon neutrality, and agreed by all 27 EU Member States, the future energy system is likely to incorporate even more electricity from renewable sources as considered in the underlying scenario of our study and RES targets for 2030 could well increase above the parameters considered here. Such higher ambitions could, in turn, increase the required transmission and the future distribution grid capacity in the European power system without much change to significantly increase grid expansion measures on short notice. In such scenario, the technologies considered in this study could be used to deliver additional flexibility in transmission system operation and expand actually usable capacities or options for bulk power transfer in the transmission grid that can be provided by the considered technologies. This is all the more true for the time frame beyond 2030, which was not considered in detail in this study.

Apart from that, the three technologies can facilitate an optimized grid operation in the short term. Here, we observe delays in projects to reinforce the transmission grid more frequently due to public concerns, leading to overloading in the power grid and forcing TSOs to utilize cost intensive remedial actions. Future studies could investigate how DLR and M-SSSCs applications can help dealing with this issue in the short term as the TSOs can deployed them very flexible and fast.

Other than that, it should be considered in detail, whether the significantly lower land use of Superconducting technology compared to high voltage technology can ease public opposition towards new transmission grid corridors. This is an important benefit for future grid systems. The future energy system will require ongoing grid expansion in both the onshore and offshore environment. The Suedlink project used in the comparison above is a prime example of this. Originally, this was a project that was going to use overhead lines but due to public opposition, the project was redesigned to become an underground cable project. Public opposition of overhead lines is an issue faced by each TSO in Europe and it is not a problem that is expected to disappear over time.

A Flow-based Market Coupling

One important part of electricity-market modelling is the simulation of the capacity calculation which in reality is done before the European market coupling takes place. The capacity calculation's objective is to restrict trade patterns to prevent overloading of critical network elements (CNEs). Hereby, two main challenges have to be addressed: First, commercial flows differ from physical flows due to the physics of the power grid. Thus, various commercial flows create physical flows on the same interconnectors, or CNEs in general, e.g., commercial exchanges between Germany and France as well as between Belgium and the Netherlands cause physical flows on the interconnectors from Germany to the Netherlands. Second, an incremental flow due to one exchange can increase or decrease the loading of a CNE. This depends on the "preloading" caused by other exchanges (cross-border and domestic), which are called base flows. In addition, the location of generation and load within the bidding-zone impact the incremental flow.

There are two approaches that are typically applied in Europe to perform capacity calculation. The first one limits maximum bilateral exchanges by ex-ante calculated net transfer capacities (NTC). An NTC is calculated by using forecasts of all exchanges, except the one being calculated to account for divergence of commercial and physical flows. The accuracy is limited though, because of the forecasting approach, which poses a risk to efficiency and security.

The other approach solves this issue by integrating the capacity allocation into the market-coupling. It is therefore called flow-based market coupling (FBMC). FBMC allows for accurately considering the consequences of commercial trade for physical flows and allocates capacities to their most valuable uses. This is done by determining all trade balances, so-called net positions (NP), of all bidding zones within a capacity calculation region (CCR) in such a way that social welfare is maximized. In practice, this process is a mathematical optimization that is subject to network constraints, having the form $PTDF\ x\ NP \leq RAM$. In this formula, $PTDF$ is a matrix describing the change in power flows over certain network elements as a consequence of changing net positions of the CCR's bidding zones. PTDFs are calculated by approximating how a change in a bidding zone's net position would increase or decrease its generators infeed (GSK, generation shift key). For a given GSK one can distribute a change of 100 MW in a bidding zone's net position to the grid nodes where generators are connected. Performing a load-flow calculation with and without these additional 100 MW then gives the load flows impact for each CNEs. The PTDF (per bidding zone and per CNE) then is defined as the ratio between load-flow impact and change in net position. The RAM defines the maximum allowable power flow in MW over network elements as a consequence of trade within the CCR. To meet the N-1 criterion, the PTDF matrix must contain rows for each combination of CNE and contingency (CNEC). Consequently, also the RAM vector contains one RAM per CNEC. In addition to net position changes, the flow on CNECs is also influenced by network elements that can control load flows, i.e., phase-shifting transformers (PST) and high-voltage direct current lines (HVDC). Each PST has a certain range of tap positions which can be used to control load flows. The change of load flow on CNECs due to a change in a PST's tap position (TAP) is called phase-shifting distribution factor (PSDF). The effect of a HVDC line's power transmission (PT) on a CNECs load flows is called HVDC-PTDF. PST tap settings and HVDC power transmission also impact flows on AC lines, thus leading to an extended, more general formulation for the network constraints $PTDF\ x\ NP + PSDF\ x\ TAP + PT\ x\ PTDF_{HVDC} \leq RAM$. Within market coupling, tap settings and power transmissions, in addition to the variations in net position by cross-border exchange, are degrees of freedom which can be used to maximize social welfare in the CCR.

To model the market coupling in line with the CEP regulation, capacity calculation is required to fulfil some additional requirements

- The first one is the so-called CNEC selection. Here, a subset of all possible CNECs is defined being later considered in the market coupling. Each of these network elements is permitted to restrict power exchanges within the market-coupling by their individual RAM, which is based on its maximum capacity. The CEP states that a CNEC is permitted to restrict the market coupling if it is sensitive to cross border trade. In the CWE region, this requirement is assumed to be fulfilled with the maximum difference in the CNECs PTDFs exceeding 5%. However, ACER has demanded[29] quite recently to consider whether this threshold should be increased in the future. Therefore, we have assumed that the PTDF threshold is 10% in our reference scenario.
- The second one is the application of a minimum remaining margin (MinRAM) which is a mandatory lower bound for the RAM values resulting from capacity calculation and offered to the market. In the past, the RAM was calculated as the difference between a CNEC's maximum allowable flow and expected base flows, which would be the result of exchanges not controllable by the market coupling, namely inner-zonal trade (i.e., loop flows and internal flows). Load flows from inner-zonal trade are not controllable by the market coupling algorithm as they do not change the net position of a bidding zone. This practice is deemed to be discriminatory and disadvantageous for cross-border trader and no longer allowed. Instead, a minimum share of each CNEC's capacity will have to be available for flows resulting from cross-border trade. Latest 2026, this MinRAM will have to reach 70%. From a physical perspective, with MinRAM applications virtual capacity (i.e., capacity that is already occupied by baseflows) is made available to the market. Consequently, this systematically leads to congestion and flows violating security limits after market-coupling. To ensure system security, such violations must be resolved. After day-ahead (DA) market clearing, this is brought about by redispatch measures or countertrading.

[29] See Core capacity calculation methodology

B Abbreviations

AAR	Ambient Adjusted Ratings
AC	Alternating Current
CEP	Clean Energy Package
CNEC	Critical Network Element and Contingency
CWE	Central West Europe
DC	Direct Current
DLR	Dynamic Line Rating
DSO	Distribution System Operator
EMF	Electro-magnetic Field
FACT	Flexible Altering Current Transmission System
FMBC	Flow-based Market Coupling
GSK	Generation Shift Key
HVDC	High-Voltage Direct Current
LCC	Line-commuted Converter
(min)RAM	(minimum) Remaining Available Margin
M-SSSCs	Modular Static Synchronous Series Compensator
NP	Net Position
NTC	Net Transfer Capacity
PSDF	Phase-Shifter Distribution Factor
PTDF	Power Transfer Distribution Factor
RCC	Regional Coordination Center
SC	Superconductor
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
VSC	Voltage Source Converter

C See also

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