CEPS SPECIAL REPORT
Thinking ahead for Europe

The Benefits of Investing in Electricity Transmission

A case study of northern Europe

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Abstract

Electricity trading can bring down the costs of the EU's transition to a competitive low-carbon economy, in particular by facilitating the integration of renewable energy from variable sources. Yet insufficient grid infrastructure and regulatory obstacles prevent the trading potential from being fully realised in northern Europe. While many interconnector projects are under development, various barriers are precluding the grid rollout from taking place on time. The European Commission's energy infrastructure package is an important step forward to overcome these barriers. But the scale and urgency of the infrastructure challenge call for significant further progress.

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Executive Summary

The EU is committed to achieving a rapid transition to a competitive low-carbon economy. As reconfirmed in the European Council Conclusions of February 2011, the EU aims at reducing greenhouse gas emissions by 80-95% by 2050 compared with 1990.[1] An interim step towards achieving this long-term goal is the 20-20-20 targets, which set, inter alia, the binding objective of raising the share of energy from renewable energy sources (RES) to 20% of overall energy consumption. Increasing the share of electricity generated from RES (RES-E) is key to reaching this objective. Indeed, the National Renewable Energy Action Plans show that significant additions to RES-E generation capacity are planned all across Europe. In northern Europe – understood in this study as including the Nordic and Baltic states, Germany, the UK, Poland, the Netherlands and Belgium – a large part of this new capacity will be variable wind energy. Beyond 2020 there is still considerable uncertainty as regards political support for renewables, but in view of the huge potential of wind energy in northern Europe and with wind being a highly competitive RES, variable sources will continue to grow. As a result, the challenge lies in integrating variable RES-E in the northern European electricity grid, while maintaining the security of electricity supply and enhancing EU competitiveness. Investing in transmission can benefit all three pillars of the energy policy triangle and foster the security, sustainability and affordability (i.e. competitiveness) of energy supplies.

The benefits of expanding transmission

Originally, the main purpose of cross-border electricity interconnections was to contribute to security of supply. Interconnectors were built to allow for mutual support in case of supply disruptions, thereby ensuring the reliability of electricity supply. More recently, their role in fostering competition and other efficiency gains potentially related to cross-border trading has received growing attention. Given the ambitious renewable-energy targets of the EU, a new motive for interconnectors is emerging: the integration of electricity from RES. Notably, the case for increased interconnections is relevant in relation to the merit order effect of wind production (and that of other variable RES-E) on wholesale electricity prices. In deregulated electricity markets this exerts downward pressure on wholesale prices.[2] As increasing wind penetration results in fewer full-load hours for fossil fuel-fired power plants, it also reduces greenhouse gas emissions. In the longer term, however, as RES-E capacity expands, prices might become highly volatile. This may create problems for non-flexible capacity, because it cannot strategically target the volatile high-price peaks. In this case, interconnectors can play an important role in distributing peak production across Europe, thus flattening out peak RES-E production with the positive effect of reducing price volatility in specific (regional) markets.

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[1] See Council of the European Union (2011).

[2] See Pöyry Management Consulting (2010). For a more holistic approach, see Philibert (2011).

There are three geographically-specific benefits associated with electricity trading between the Nordic area and other northern European countries.

- First, electricity trading can allow the use of Nordic hydro capacity to be optimised from a European perspective. Currently, this benefit is related to the fact that hydropower in the Nordic market can complement the thermal-dominated mix in other northern European countries. In the future, the flexible hydro capacity in Norway and Sweden will become more relevant with a view to integrating a significant amount of the variable renewables that are being built up in northern Europe. To some extent hydropower could replace coal and gas in balancing variable wind power. Electricity trading is also beneficial from a resource-efficiency perspective. For example, as hydropower inflows sometimes exceed reservoir capacity in Norway, exporting power during periods of high inflow may in these cases be the only alternative to spilling water.
- Second, the analysis of market developments demonstrates that developments are quite heterogeneous across northern Europe. Owing to the increasing share of low-carbon electricity with low marginal costs in the Nordic countries (mainly driven by additions in nuclear and wind capacity), which could result in excess capacity by 2020, power trading can be expected to exert downward pressure on wholesale electricity prices in other northern EU member states and may also decrease the costs of decarbonisation.[3]
- Third, analyses conducted by the OffshoreGrid consortium (2011) show that the spatial correlation of wind is generally lower in the north–south direction than east–west. For example, correlation coefficients between the Nordic countries and Germany are quite low (44% for Denmark–Germany, 6% for Finland–Germany, 30% for Sweden–Germany and 40% for Norway–Germany). By contrast, the correlation between Germany and the UK is 67%. As a consequence, north–south transmission infrastructure is particularly helpful for the integration of more wind energy in the northern European electricity grid and can contribute to reducing price volatility.

The differences in price levels that continue to exist even in scenarios that assume significant additions to transmission capacity confirm the general case for more power trading in northern Europe.

A balanced approach to RES integration includes a range of initiatives

Increasing interconnector capacity cannot stand alone when it comes to exploiting renewable energy. Trading through interconnectors should thus be combined with the implementation of measures that enhance flexibility on both the demand and the supply sides. Responses to demand, for example, can encourage consumers to reduce demand during peak hours or to shift demand to off-peak times. In addition, such flexibility in demand can contribute to an efficient use of the distribution grid. On the supply side, more flexible generation, load management and electricity storage can help to balance variations in RES-E generation and in electricity demand. But it should be noted that transmission expansion distinguishes itself from 'other options' in that it is particularly beneficial from a market integration perspective.

Potential for electricity trading

This study reveals that there is insufficient capacity in the existing infrastructure for transboundary transmission between the Nordic market and other northern European countries. But barriers to trading are not limited to countries' borders. The limited utilisation of interconnectors is also caused by internal congestion. Here, the public reaction to the division of Sweden into four price zones on 1 November 2011 may serve as anecdotal evidence demonstrating how valuable explicit price signals are to alert the public of where real congestion exists and potentially trigger public support for grid

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[3] It should be noted, however, that this could come at the expense of power companies with a concentration of their generation assets in countries that have opted out of nuclear energy. Also, consumers in the Nordic countries will face somewhat higher prices in the short term – even though analyses suggest that "the price reducing effect of renewable generation is much stronger than the price increasing effect of new interconnector capacity" (P&T, 2010).

extension.[4] It is acknowledged that transmission expansion is not the only option to increase power trading: new technologies can also be deployed to make better use of the existing grid. The analysis of new interconnector projects reveals that the debate is no longer centred on building classic point-to-point interconnectors between two countries, but more and more attention is being paid to innovative solutions that allow, for instance, for the connection of offshore wind farms and the use of spare capacity for electricity trading.

Barriers to investing in transmission

New investment in transmission is hampered by a large number of factors, as analysed by the European Commission's blueprint on energy infrastructure priorities of November 2010.[5] Using this as a starting point, the study discusses the economic, financial, political, administrative and technical barriers. The study does not deal in detail with the complex matter of financing, although the analysis of the benefits of interconnectors leads to the conclusion that financial support can be justified for projects with significant externalities. The well-known complicated and lengthy permitting procedures and the somewhat related NIMBY[6] issue represent important administrative and political obstacles. The study is somewhat optimistic about the classical political barrier to investing in transmission – the differential impact on prices. The reason is that the massive deployment of RES-E in many northern European countries and the resulting more dynamic differences in price will make it clearer that enlarged markets are a win–win situation in the long run. The effective unbundling requirements of the third energy package should further complement this situation. The study does not find any insurmountable technical barriers, but identifying the right level of standardisation with regard to HVDC[7] technology and offshore grid equipment would facilitate transmission expansion.

Key corridors for northern Europe – Projects of common interest

On 19 October 2011 the European Commission proposed a regulation on guidelines for a trans-European energy infrastructure.[8] At the heart of the proposal are so-called "projects of common interest" (PCIs), which would benefit from streamlined and faster permit-granting procedures, improved cost-allocation procedures and access to EU funding through the 'Connecting Europe' facility. While the regulation only applies to certain "energy infrastructure priority corridors and areas", with regard to electricity projects in northern Europe the definition is broad enough for almost all the relevant cross-border projects in northern Europe to be eligible in principle under the regime of "common interest". Electricity projects would be prioritised based upon a methodology for analysing the costs and benefits for the entire electricity system, to be developed by the European Network of Transmission System Operators for Electricity (ENTSO-E). As the regulation foresees that regional groups would be in charge of identifying projects within each priority corridor, some bottom-up dynamics within a competitive framework are ensured. The effectiveness of the selection procedure also depends on the openness of the process to third-party project developers. One would imagine that each regional group has an interest in clearly identifying the benefits of a certain project to ensure having as many priority projects as possible. This could lead to some healthy competition. ENTSO-E could then weigh these benefits, taking into account the European perspective (with the support of the European Commission and the Agency for the Cooperation of Energy Regulators, ACER). Some 80-

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[4] Yet a recent study commissioned by Bundesnetzagentur (Frontier Economics and Consentec, 2011) points to potentially negative consequences arising from a market splitting up, as it might, for example, increase the market power of large electricity generators.

[5] See European Commission (2010b).

[6] NIMBY refers to 'not in my backyard'.

[7] High-voltage direct current.

[8] See European Commission (2011a).

120 projects are expected to eventually receive priority status (ENTSO-E's 2010 Ten-Year Network Development Plan (TYNDP) contained roughly 500 projects).[9]

Main conclusions of the study in light of the European Commission's proposal on a trans-European energy infrastructure

1. Transparent discussion is needed about the challenges of developing a cost-benefit analysis covering the entire electricity system.

Owing to the complexity of a true, European cost-benefit analysis – which has not been done before – it is ambitious to expect ENTSO-E to submit its methodology for an energy system-wide analysis only a month after the proposed regulation enters into force. It has to be clear that the results of a cost-benefit analysis as envisaged in the European Commission's proposal of October 2011 can only be as good as the assumptions. This is further complicated by the fact that the cost-benefit analysis would need to serve two distinct purposes. First, it would be the basis for the selection of PCIs; second, the cost distribution among transmission system operators (TSOs) (or other project developers) would be decided on the basis of these calculations.

a) Only if the basis on which projects of common interest are selected and the costs allocated among TSOs is agreed upon, can stakeholder and public acceptance be fostered. In particular, it is clear that the results of such a cost-benefit analysis vary greatly depending on the value attached to the various energy policy goals. While different options for integrating variable renewables exist (e.g. storage, supply- and demand-side responses), they do not necessarily serve the internal market goal as well as building interconnectors. These political choices behind a cost-benefit analysis have to be addressed – they cannot be solved in a technical process among experts.

b) With regard to setting European strategic priorities, a long-term approach looking 20 or 30 years ahead and assessing the long-term contribution that specific projects can make to EU policy goals is certainly justified. But for such a cost-benefit analysis, a coherent, long-term EU energy policy would be crucial. Here, the energy roadmap 2050 is an important stepping stone. In the longer term, a more honest discussion about member states' energy mix can hardly be avoided. Trans-European energy infrastructure does, of course, have implications for member states' energy mix. An effective EU energy policy requires coordination of member states' energy choices.

c) For the second purpose (i.e. cost distribution among countries) shorter time horizons are more appropriate, as it is hard to imagine that national regulators will be willing to accept cost-allocation decisions that are based on a long-term cost-benefit analysis that necessarily includes a large number of 'heroic' assumptions.

2. Effective governance of regional groups must be ensured.

The involvement of regional groups as discussed in the proposed regulation is crucial. This holds true not only because of the challenges associated with a system-wide cost-benefit analysis, but also because of the need to ensure the support of all the relevant stakeholders. Only if the stakeholders are properly involved in the prioritisation process will they support the implementation of PCIs. Therefore, in the proposed regulation it would be desirable to further clarify the governance of regional groups, particularly the following aspects:

a) The process for identifying PCIs should be open to a large number of parties to present promising projects. This point stems from the sheer scale of the challenge of transmission investment that lies ahead. It implies that instead of relying entirely on TSOs, third-party project developers should be allowed to present merchant projects. To reduce administrative obstacles, it would be helpful if

[9] According to Art. 2.3 of the proposed regulation, "'project' means one or several lines", while the TYNDP works with a narrower definition of project. Nevertheless, at a CEPS workshop held on 28 November 2011, a European Commission official indicated that one would carefully assess the extent to which the project definition was circumvented to make sure prioritisation is not watered down.

merchant project developers could present the relevant exemption by the European Commission and the national regulatory authorities once their project has been identified as being of 'common interest'.

b) A specific issue that could contribute to better governance of regional groups would be the involvement of European coordinators in the identification phase. In the European Commission's proposal of October 2011, a European coordinator is only envisaged if a PCI encounters implementation difficulties (Art. 6). But what happens if a regional group cannot agree on PCIs? As a consequence, consideration could be given to amending Art. 6 and allowing European coordinators to become involved in the identification phase as well. There should be careful assessment, however, of whether this would add an unnecessary bureaucratic burden.

c) As all four of the priority electricity corridors foreseen in the proposed regulation are of relevance for electricity trading in northern Europe, it is clear that optimised transmission expansion can only succeed if the regional actors cooperate closely. It is up to the European Commission, ACER and ENTSO-E, which are all envisaged as participants in the regional group phase, to ensure that effective coordination among the groups takes place in practice.

d) The need for the close involvement of regulators already at the regional group stage as foreseen by the proposed regulation can hardly be overstated, given that regulators decide on the incentives for investment by TSOs. Regulators thus have to be convinced that the prioritisation of certain projects is indeed justified so that they are motivated to take the appropriate measures.

3. Internal grid issues should not be overlooked.

More than half of the projects outlined in ENTSO-E's TYNDP are cross-border connections and this share is expected to increase to some two-thirds by 2030. Yet in practice, internal transmission capacity within European countries represents a substantial obstacle to more electricity trading in Europe. It is therefore important that the regime of common interest proposed by the European Commission does not just focus on cross-border issues, as these investments might become stranded if internal congestion prevails. The Commission's proposal of October 2011 recognises this, but the point should be stressed further. As the proposal now enters the legislative process, it is important that this aspect is strengthened and not removed because of subsidiarity concerns.

4. The scale and urgency of the infrastructure challenge requires significant further progress in the regulatory field well beyond establishing a regime of common interest.

a) Given the scale and urgency of transmission infrastructure development, it is vital to ensure that efforts to promote infrastructure investment are not limited to PCIs. In terms of regulatory incentives for investment by TSOs, a more holistic approach is needed, going beyond discussions on rates of return. Depending on the domestic regulatory conditions, investing in transmission may carry very low risks, since consumers pay for investments. The challenge rather lies in incentivising the right kinds of investments, with solutions crucially depending on the regulatory framework within member states, which should be predictable and transparent. More specifically, the regulatory framework for congestion management should encourage the investment needed for both RES-E integration and the completion of the internal market for electricity. Merchant projects for new interconnectors should have a fair opportunity for development.

b) To make optimal use of the new transmission infrastructure, EU-wide market coupling of day-ahead and intraday markets is important and needs to be implemented by 2014 as targeted. As mentioned with regard to the first conclusion above, it cannot be neglected that this development has implications for member states' energy mix. More coordination is therefore required to make certain that the regulatory frameworks are compatible (inter alia, renewable support schemes) in order to promote fair and efficient competition in a European power market. It should also be ensured that the capacity mechanisms that a number of member states are planning to introduce do not distort the establishment of an internal market for electricity.

c) Another major regulatory challenge lies in integrating electricity balancing markets, as the traditional approach – i.e. performing balancing at the control-area level without sharing balancing resources – is not ideal in terms of either variable RES-E integration or the efficient use of available generation capacities. This will hopefully be achieved through the development of an EU code for balancing.

d) With regard to the development of an offshore grid, new models for cooperation among governments, TSOs and regulators are needed. Progress has to be made in terms of ensuring compatible support schemes for RES-E, among other things. The North Seas Countries' Offshore Grid Initiative is an important means for making further advances on these issues.

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1. Introduction

The EU is committed to achieving a rapid transition to a competitive low-carbon economy. As reconfirmed in the European Council Conclusions of February 2011, the EU aims at reducing greenhouse gas emissions by 80-95% by 2050 compared with 1990 (Council of the European Union, 2011). An interim step towards achieving this long-term goal is the 20-20-20 targets, which set, inter alia, the binding objective of raising the share of energy from renewable energy sources (RES) to 20% of overall energy consumption.

Increasing the share of electricity generated from RES (RES-E) is key to reaching this objective. Indeed, the National Renewable Energy Action Plans (NREAPs) show that significant additions to RES-E generation capacity are planned all across Europe. In northern Europe, a large part of this new capacity will be variable wind energy. Beyond 2020 there is still considerable uncertainty as regards political support for renewables, but in view of the huge potential of wind energy in northern Europe and with wind being a highly competitive RES, variable sources will continue to grow. As a result, the challenge lies in integrating variable RES-E in the northern European electricity grid, while maintaining the security of electricity supply and enhancing EU competitiveness. Investment in transmission can benefit all three pillars of the energy policy triangle and foster the security, sustainability and affordability (i.e. competitiveness) of energy supplies.

This study seeks to outline the benefits associated with new transmission projects, focusing on northern Europe. To achieve this goal, the study first reflects upon the conceptual basis and discusses criteria that can guide a European cost-benefit analysis in section 2. Then, the projected demand and capacity developments in northern Europe are analysed in section 3. Special emphasis is given to the question of the extent to which the Nordic countries can contribute to integrating variable RES-E generation in the northern European electricity grid. Based on this analysis, section 4 assesses the trading potential in northern Europe. Subsequently, section 5 looks at the economic, financial, political, administrative and technical barriers to investing in transmission. Section 6 reviews the latest, relevant EU proposals, namely the European Commission's infrastructure package of 19 October 2011 and the energy roadmap 2050 of 15 December 2011. Lastly, policy conclusions are formulated with a view to providing input to the discussion following the release of the related legislative proposals.

The study does not compare the situation in northern Europe with other regions and does not seek to single out specific projects. Rather the objective is to shed light on the potential benefits associated with transmission projects and to identify the politically pertinent issues connected with transmission expansion. Northern Europe is understood as including the Nordic and Baltic states, Germany, the UK Poland, the Netherlands and Belgium. The time horizon of the study includes both 2020 and 2030. The study does not engage in any modelling exercise but is based upon a literature review (including studies that incorporate modelling). The review has been complemented by a stakeholder consultation, conducted bilaterally as well as through two workshops held at CEPS. Unless otherwise indicated, the study follows the definitions provided in the relevant EU legislation.[10]

2. Conceptualising the benefits of an expansion in transmission

Originally, the main purpose of cross-border electricity interconnections was to contribute to the security of supply. Interconnectors were built to allow for mutual support in case of supply disruptions, thereby ensuring the reliability of electricity supply. More recently, their role in fostering competition and other efficiency gains potentially linked to cross-border trading has received increasing attention. Given the ambitious renewable-energy targets of the EU, a new motive for interconnectors is emerging: the integration of electricity from RES. This is also reflected in technological changes. The debate is no longer centred on classic point-to-point interconnectors between two countries, but more and more attention is being paid to innovative solutions that allow, for instance, the connection of offshore wind farms and the use of spare capacity for electricity trading.[11]

This section assesses what transmission expansion can, in principle, contribute to EU policy goals, yet it also explores what effects this may have on other relevant actors. Lastly, possible alternatives are discussed, i.e. measures that may have an impact on the need for transmission lines and which should be taken into account when doing a cost-benefit analysis.

2.1 Contribution to the EU's policy goals

The RealiseGrid project, co-funded by the European Commission under its FP7 programme, has developed a methodology that enables the benefits of transmission expansion to be evaluated along the three dimensions of the energy policy triangle, namely competitiveness, security of energy supply and environmental sustainability (see Figure 1). While it is impossible in practice to clearly distinguish the impact a given project has on the different dimensions, the operationalisation is nevertheless helpful to identify the key challenges that arise from the development of a transnational infrastructure.

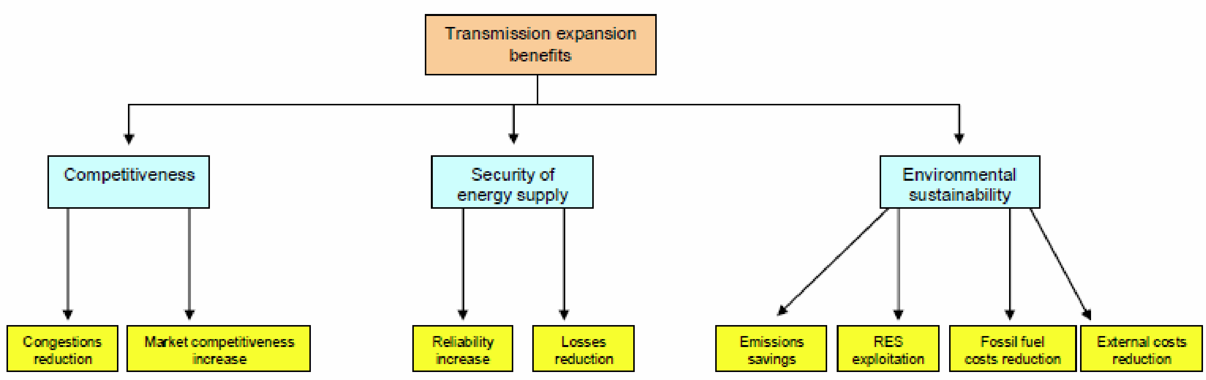
The benefits in relation to the first dimension (i.e. *competitiveness*) materialise through congestion reduction, which facilitates more electricity trading. As network constraints are alleviated, more efficient generators can replace less efficient ones.[12] Apart from this substitution effect, RealiseGrid also identifies a related strategic effect, i.e. market competitiveness increases as opportunities for the abuse of market power decrease. These effects, resulting from the greater potential for electricity trading, can increase social welfare.

[10] Transmission means the "transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors" (Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity, OJ L 211/55, 14.8.2009). Interconnector refers to "a transmission line which crosses or spans a border between Member States and which connects the national transmission systems of the Member States" (Regulation (EC) No. 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity, OJ L 211/15, 14.8.2009). Congestion is understood as "a situation in which an interconnection linking national transmission systems cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and/or the transmission systems concerned" (ibid.).

[11] These new 'interconnector options' are discussed in section 4.3.

[12] It should be noted that the substitution effect is limited by the need to provide reactive power locally.

Figure 1. Main benefits of transmission expansion grouped according to the dimension of EU energy policy



Source: L'Abbate et al. (2011).

In terms of the *security of energy supply*, RealiseGrid points to two key benefits: increases in reliability and reduction of losses. While the reliability of the European grid remains quite high, increased interconnection capacity still reinforces security of supply as it increases the possibilities for backup in case of breakdowns. To fully reap the benefits of new infrastructure, however, grid expansion needs to be combined with regulatory progress (see also section 4.6). In this regard, pooling capacity through EU-wide market coupling of day-ahead and intraday markets will assist in achieving the goal of affordability and will support RES-E integration. In addition, effective cross-border balancing schemes will reduce the cost of balancing, although transmission system operators (TSOs) have to contract for adequate system reserves within their control areas.[13] The impact of new transmission infrastructure on grid losses is twofold. On the one hand, relatively speaking, new corridors usually reduce losses at constant levels of transit as a result of technological improvements. But since the very reason for building interconnectors is to allow for greater transit, losses in absolute terms will most likely grow. Cost-benefit analyses of transmission expansion thus have to monetise losses at market prices (Migliavacca, 2011).

A key element of *environmental sustainability* is emissions reductions. Here, as noted with regard to the first dimension, new corridors benefit cost-effective supply sources, and not necessarily green energy.[14] Generally speaking, the impact might therefore be negative, for example if German coal replaced Italian gas (ibid.). But even if the emissions savings effect was positive, for instance if French nuclear energy replaced German coal, the lack of a European consensus on nuclear energy poses some challenges for a European-wide cost-benefit analysis that tries to take the emissions savings aspect into account (see also section 5.1).

Increased transmission capacity can assist RES-E exploitation as destination markets for variable RES are enlarged.[15] This is related to the merit order effect of wind production (and that of other variable RES-E) on wholesale electricity prices. In deregulated electricity markets this exerts downward

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[13] In Germany, there is a common reserve system for the four TSOs, as there are no permanent, structural bottlenecks of the grid within Germany.

[14] As the power sector is covered by the Emissions Trading Scheme (ETS), an effective ETS would increase the competitiveness of low-carbon power and make assessments of the impact new corridors have on emission reductions somewhat more straightforward.

[15] Integrating regions reduces volatility, as different geographical areas have different demand curves (ECF, 2010a). Greater geographical spread means that the weather might equal out – an effect that potentially facilitates variable RES-E integration. A more integrated electricity market would allow the "balanc[ing of] the location of wind power over a larger region with respect to wind availability, thereby reducing the risk of having high or low wind situations simultaneously" (NEP, 2010). Along these lines, the European Wind Integration Study (EWIS, 2010), initiated by TSOs to ensure the successful grid integration of wind, concludes that the pan-European electricity system needs to be strengthened to ensure improved utilisation of variable RES-E.

pressure on electricity prices.[16] As increasing wind penetration results in fewer full-load hours for fossil fuel-fired power plants, it also reduces greenhouse gas emissions. Yet in the longer term, as RES-E capacity expands, prices might become highly volatile. This may create problems for non-flexible capacity because it cannot strategically target the volatile high-price peaks. In this case, interconnectors can play an important role in distributing peak production across Europe, thus flattening out peak RES-E production with the positive effect of reducing price volatility in specific (regional) markets.

Importantly, RES-E integration has positive implications for the other two dimensions as well. More to the point, greater RES-E penetration can reduce import dependence on fossil fuels, thereby benefitting security of supply. In addition, such a development might reduce the market power of fuel monopolists and in that way contribute to the competitiveness goal.

When evaluating individual projects, RealiseGrid stresses that a utility function should translate these aspects into monetary terms and eventually create a mono-dimensional ranking that enables the best solution to be identified. Nevertheless, as this section has already shown, "benefit evaluation is a...demanding exercise since for example some technical improvements (for Security of Supply) or pursuing policy objectives (integration of renewable sources) are difficult to quantify" (ENTSO-E, 2010). Also, there is no clear hierarchy among different policy objectives. Furthermore, as noted earlier, there is no consensus on a 'European energy mix', which is most evident with regard to the nuclear question.

2.2 Effects on relevant stakeholders

Transmission expansion has important effects on many stakeholders. If expansion plans are to be successful in practice, it does not suffice that the plans are in line with EU policy goals; multiple perspectives have to be taken into account. As emphasised by the California ISO Transmission Economic Assessment Methodology, a thorough cost-benefit analysis has to dwell on the implications of investment projects for consumers, generators and transmission operators as well as society in general (Awad et al.).[17]

Assessing the benefits and costs for these different players is challenging, as it depends on future demand- and supply-side developments.[18] It is important to note that increases in social welfare and the distributional effects associated with new interconnectors should not be calculated based upon *historical* price differences among countries. While such an approach can draw from a rich set of reliable data, the future distribution of benefits and costs will most likely look considerably different. In particular, it can be expected that owing to the deployment of variable renewables with low marginal costs, price differences will be more dynamic in the future. This should help mitigate the winner–loser conundrum that sometimes hinders the development of interconnectors (see Box 1).

A comprehensive analysis of the costs and benefits of investing in transmission implies looking not only at the effect on wholesale prices and investment cost recovery through network tariffs. Transmission expansion may also have an impact on the costs associated with the provision of ancillary services, which are likewise recovered through network tariffs. This is of special interest to consumers, given that network tariffs constitute a large share of retail electricity prices.

A further aspect that complicates cost-benefit analyses is the fact that the choice of different time horizons influences the results. For an effective cross-border allocation of costs, relatively short-term cost-benefit analyses are needed, as stakeholders cannot be expected to evaluate transmission benefits that may only materialise in the distant future. At the same time, the goals of EU energy policies are more long term, as evidenced by the 2050 energy roadmap. As a consequence, a one-size-fits-all cost-benefit analysis is not feasible.

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[16] See Pöyry Management Consulting (2010) and for a more holistic approach, Philibert (2011).

[17] See also section 5.

[18] It should be noted that supply-side developments are, in turn, also influenced by the transmission investment decisions taken today.

Box 1. Distributional effects of interconnectors

The classical approach to assessing the welfare gains resulting from investment in interconnections is looking at price arbitrage. Assuming stable price differences, the logic is straightforward. Increased interconnection capacity will allow producers in the low-price zone to sell electricity in the high-price zone. Social welfare is increased as long as the increase in producer surplus, consumer surplus and congestion rent exceeds the investment costs in transmission infrastructure. While this is beneficial for both countries in the long run, as the importing country can allocate resources away from power generation to more competitive sectors, and the exporting country can allocate its resources vice-versa, in the short run the distributional effects may create problems. Simply speaking, consumers in the high-price zone gain as prices fall, while consumers in the low-price zone will face higher prices. Conversely, producers in the low-price zone gain as prices go up, whereas producers in the high-price zone would have to cope with lower prices. Those who think they will be negatively affected by the price effects may oppose the respective interconnection project. More dynamic price differences resulting from variable renewable or otherwise complementary energy mixes may render this logic more and more obsolete, as net trade between two countries may well be balanced while the value of the interconnector arises from gross trade.

2.3 Alternatives to transmission expansion[19]

A cost-benefit analysis of grid extension needs to weigh the options compared with other possible measures that may have an impact on the extent of transmission expansion that is need. For example, interconnectors are not the only option to deal with the variability of renewable energy sources. Enhancing flexibility on both the demand and the supply sides contributes to RES-E integration as well. Responses to demand, to begin with, can encourage consumers to reduce demand during peak hours or to shift demand to off-peak times. On the supply side, more flexible generation, load management and electricity storage can help to balance variations in RES-E generation and in electricity demand. Also, transmission expansion does not necessarily imply the need to build new lines; it may be possible to upgrade existing lines with new technology. In short, assessing the benefits of investing in transmission in practice is a demanding task, because a vast array of different options needs to be considered.

More generally, future technological developments may, of course, also have an impact on the competitive edge of investment in transmission vis-à-vis other options to integrate variable RES-E, notably storage, demand-side and supply-side measures. An analysis by the European Climate Foundation (ECF) suggests that storage is currently a very expensive alternative and it is thus “hard to see how seasonal variations will be handled without grid investment or substantially bigger investments in back-up plus fuel supply” (ECF, 2011). If RES-E integration was the only guiding principle underlying decisions to invest in transmission, such demand-side measures as demand response or an improvement in energy efficiency (or both) would reduce the need for transmission infrastructure (ibid.). But it should be noted that transmission expansion distinguishes itself from ‘other options’ in that it is particularly beneficial from a market integration perspective.

3. Demand- and supply-side developments in northern Europe

After a quick overview of the importance of electricity in the EU, this section analyses projected demand- and supply-side developments in the Nordic countries. Then market developments in other northern European countries are discussed. Special attention is paid to the extent to which countries are exposed to the challenge of integrating variable of RES-E into the network.

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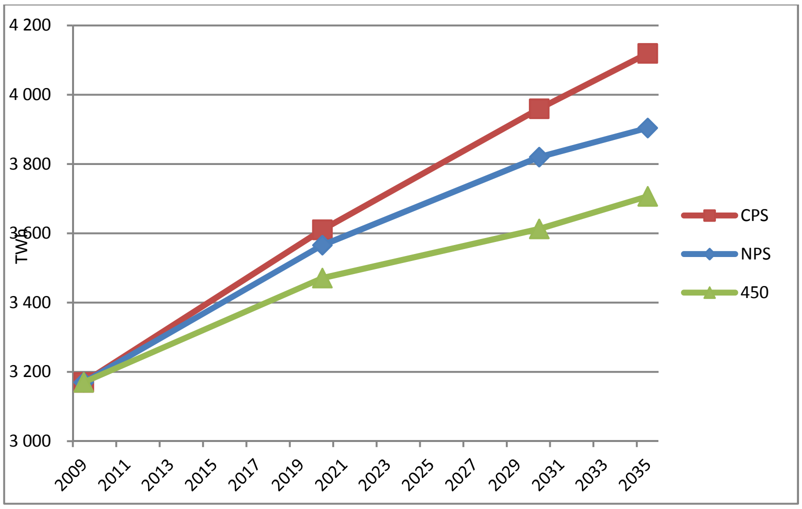
[19] See also LBST et al. (2012).

3.1 Context

The importance of electricity will rise in the future. In the EU, electricity generation and consumption are expected to grow moderately in the coming years. In the three scenarios of the IEA's World Energy Outlook (see Figure 2), electricity generation is expected to increase by a yearly average of 0.6%-1% between 2009 and 2035.

The PRIMES reference scenario (European Commission, 2010a) estimates an annual increase of electricity consumption of 1.2% from 2010 to 2020 and 1% p.a. for 2020 to 2030. Consumption forecasts by the European Network of Transmission System Operators for Electricity (ENTSO-E, 2011a) assume an annual rate of increase for the period 2011–20 of 0.6-0.7% (scenario 2020) and 1.3% (scenarios A and B). Between 2020 and 2025, the expected annual increase amounts to approximately 0.8% (ibid.).

Figure 2. EU electricity generation by IEA scenario

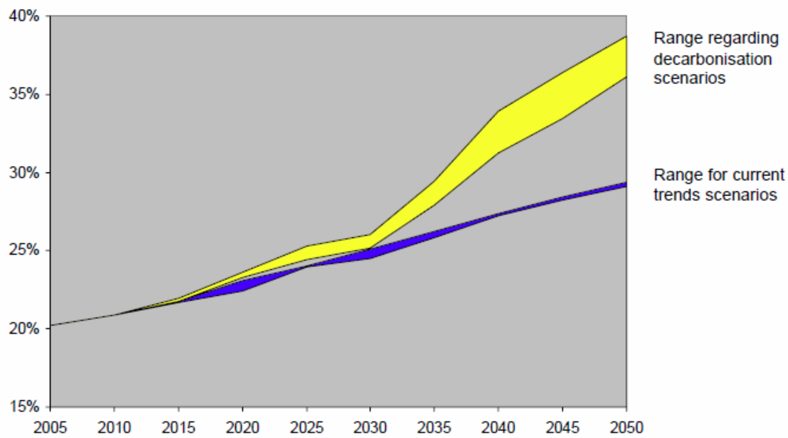


Note: CPS = current policies scenario; NPS = new policies scenario; 450 = 450 scenario

Source: IEA (2011).

The growing importance of electricity becomes even clearer when looking at the share of electricity in final energy demand. In the decarbonisation scenarios of the European Commission's energy roadmap 2050, the share almost doubles to 36-39% in 2050 (see Figure 3).

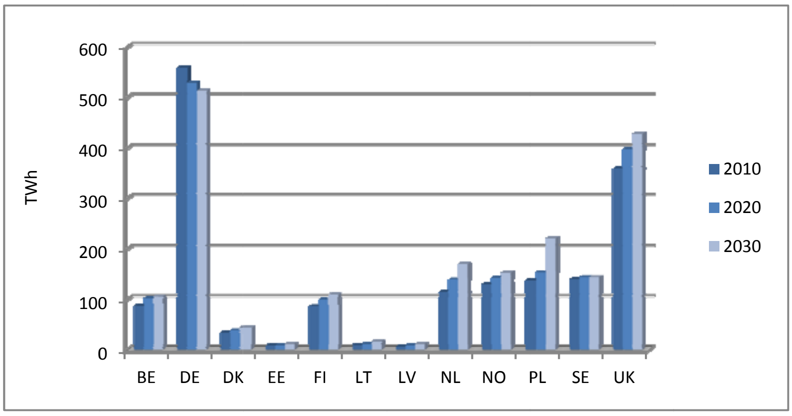
Figure 3. Share of electricity in total energy demand in the EU (%)



Source: European Commission (2011c).

Moving to the country-level of analysis, figures from Eurelectric (2010) confirm this upward trend for the 12 countries of their study (see Figure 4). With the exception of Germany, in all northern European countries electricity demand in 2030 is expected to exceed 2010 levels.

Figure 4. Total yearly electricity demand in northern Europe (TWh)



Source: Eurelectric (2010).

3.2 The Nordic electricity market

The Nordic electricity market is the result of the deregulation of the domestic power markets in Denmark, Finland, Sweden and Norway. Wholesale market integration is very advanced. Electricity is traded at a multinational power exchange, Nord Pool Spot, which was established in 1996 as a joint Norwegian–Swedish exchange for electrical energy. The financial trading in power was separated in 2010 and moved to Nasdaq OMX Commodities Europe. In 2010, 307 TWh were traded at Nord Pool Spot. In the same year, 74% of the consumption of electricity in Denmark, Sweden, Finland and Norway was traded through the Nord Pool Spot electricity exchange (Nord Pool Spot, 2011). There are plans to implement a common market for Nordic end-users that would be open for all customers by 2015 (NordREG, 2010). Already today the Nordic power market is considered the most integrated of all regional electricity markets (LBST et al., 2010).

3.3 Growth of Nordic electricity demand

As noted earlier, electricity demand is generally expected to grow in the Nordic countries. Eurelectric (2010) expects an annual growth rate for the Nordic countries of 0.8% for the period 2010–20 and 0.6% p.a. for 2020–30. Table 1 compares Eurelectric's estimates with the assumptions made by Pöyry and Thema (P&T, 2010) when estimating the Nordic countries' export potential (see section 3.7).[20] If one calculates the average of P&T's assumption, the growth rate is almost identical to that given by Eurelectric (for 2010–20, 0.8% p.a.; for 2020–30, 0.7% p.a.). The assumed growth rate differs significantly across scenarios, however. It ranges from the stagnation scenario with very moderate growth rates (0.3% p.a. for 2010–20; 0.2% p.a. for 2020–30) to the green (high-) growth scenario (1.2% p.a. for 2010–20, 1.1% p.a. for 2020–30). This raises the question of why the demand forecasts differ so much across the scenarios.

The reason is that demand forecasts depend on a number of assumptions about uncertain macroeconomic, technological and political developments. From a macroeconomic perspective, for example, a decline in power-intensive industry might lead to lower electricity demand even in times of general economic growth. While this is largely irrelevant in Denmark, it would significantly affect the demand projections for Finland, as the latter is home to a large pulp and paper industry. Power-intensive industry plays an important role in Sweden and Norway as well.

[20] The other two studies discussed in section 3.7 are not included in Table 1 as they did not provide detailed, input assumption data that would have been comparable.

Table 1. Comparison of forecasts for electricity demand (TWh)

	Denmark			Finland			Sweden			Norway			Nordic		
Year	**2010**	**’20**	**’30**	**’10**	**’20**	**’30**	**’10**	**’20**	**’30**	**’10**	**’20**	**’30**	**’10**	**’20**	**’30**
Eurelectric	34	38	44	86	99	109	140	144	144	130	143	153	390	424	449
P&T avg.	35	38	41	85	93	103	135	150	159	121	127	137	376	408	439
Politics work	35	37	39	85	92	107	135	146	154	121	126	140	376	401	440
Green growth	35	40	47	85	98	111	135	155	167	121	132	147	376	425	472
Stagnation	35	36	38	85	86	90	135	145	149	121	120	119	376	387	396
Supply worries	35	38	40	85	97	105	135	154	164	121	131	140	376	420	449

Sources: Eurelectric (2010) and P&T (2010).

Technological innovation can either lead to an increase in electricity demand (if electric vehicles become commercially viable) or have the opposite effect (if new energy-efficient technologies are developed that decrease electricity demand). In the case of heat pump technology, it is not even clear what effect a specific innovation will have on electricity demand as “new heat pump technology is not only making electric heating much more efficient but also more competitive” (NEP, 2010: 112). It could therefore either decrease electricity demand – if existing installations are simply replaced by more efficient ones – or increase power demand if more competitive electric heating gains a greater market share. As 98% of Norwegian households already dispose of electric heating, the former development (i.e. decreased electricity demand due to efficiency gains) should materialise in this country. By contrast, Denmark’s electric heating share is largely irrelevant (5%). If anything, electricity demand stimulated by electric heating could increase there.[21] The effect that more competitive electric-heating technology would have on net electricity consumption is less clear in Sweden (with a current share of 33%) and Finland (22%).[22] Technological developments also affect the nature of electricity demand; they might, for example, enable electricity demand to become smarter and adapt to the supply situation. More flexible demand would facilitate the integration of variable RES-E.

Political choices affect all of the above given that the regulatory framework has, for instance, an impact on economic and technological developments. In particular, electricity demand might increase to a lesser extent because the Nordic countries are especially committed to achieving improvements in energy efficiency. For instance, in its recently published energy strategy, which aims at making Denmark independent of fossil fuels by 2050, the Danish government (2011a) set itself the interim target of being among the OECD’s three most energy-efficient countries by 2020. Even so, electricity demand might actually rise as a result of an energy-efficiency agenda, since electricity could replace other energy sources, as illustrated by the example of electric heating in Denmark. In addition, without a global agreement on climate change the competitive pressure on electricity-intensive industry could be expected to be quite high and potentially lead to lower electricity demand, as trade-exposed enterprises might gradually shift their production outside the EU. Such a shift might occur irrespective of climate change policy taking into account more cost-effective factors of production (e.g. labour) in emerging economies.

3.4 Current Nordic supply situation

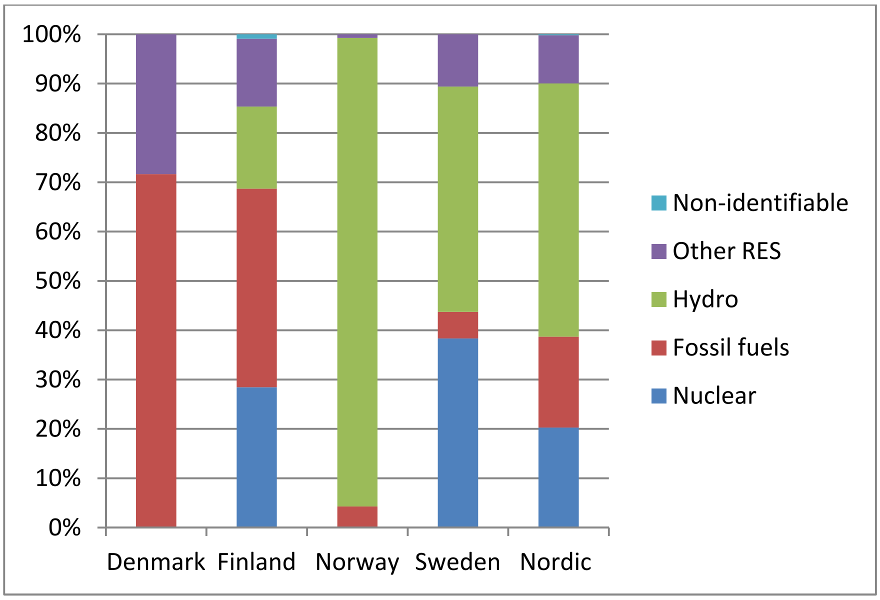
Figure 5 shows that the share of low-carbon electricity is fairly high in the Nordic countries. In 2010 only 25% of the installed capacity was associated with fossil fuel-fired power plants (see appendix 1), and a large share of this was combined heat and power with a high level of energy efficiency and often using biomass fuels. Because of the relatively high marginal costs of thermal condensing power generation, the share of fossil fuels in the actual electricity generation was low (18%), as the

[21] As district heating is very popular in Denmark, an interesting option might be to use electricity in district heating at times of electricity surplus.

[22] Electric heating share estimates as reported in Pakkanen et al. (2008).

condensing capacity is mostly used in peak periods when electricity prices are high. Hydropower constituted 51% of both installed capacity and total power-station generation in 2010.[23] As a result, the Nordic generation mix is relatively well suited to integrate variable RES-E in the future electricity system since, in principle, both thermal and hydropower represent flexible forms of supply.

Figure 5. Nordic net generation in 2010 (TWh)



Source: ENTSO-E (2011b).

Hydropower production is subject to major annual variations, however, depending on precipitation levels. In addition, the flexibility of hydropower generation crucially hinges upon the type of plant; the figures presented above include reservoir-based, pumped storage and run-of-the-river power plants. According to Statnett, 60-70% of Norwegian hydropower comes from mountain reservoirs, meaning that it is relatively flexible and can be generated quickly on demand – as long as precipitation levels are high enough. Even though reservoir capacity for the Norwegian hydropower system amounts to some 84.3 TWh (NVE, 2011), in periods of very high hydro inflow, water sometimes has to be spilt, because owing to grid limitations the generated power cannot be transported to consumers. While the technical potential of pumped storage (especially in Norway) is huge, for environmental reasons little may materialise in practice. Run-of-the-river plants, by contrast, have no or very limited storage capacity for water and thus represent a non-flexible form of supply.

3.5 RES-E deployment in the Nordic countries

While it is usually quite difficult to predict future capacity developments (see section 3.6), binding targets for renewable energy give a good idea about the RES-E capacity additions in the three Nordic EU member states up to 2020. An analysis of the NREAPs presented in Table 2 reveals that the total installed RES-E capacity of Denmark, Sweden and Finland combined would increase by 8,587 MW between 2010 and 2020. This is projected to lead to an increase in annual gross RES-E generation of almost 30 TWh. In addition, Norway has agreed to finance half of the 26.4 TWh of RES-E in the framework of the common market for green electricity certificates between Norway and Sweden that is expected to run from 2012 and to 2020.

[23] The year 2010 was relatively dry in the Nordic countries; thus the average hydropower generation is higher.

Table 2. Nordic NREAP analysis

	Year	Denmark	Finland	Sweden
Sectoral RES target for electricity (% of gross final electricity consumption)	2005	27	27	51
	2010	34	26	55
	2020	52	33	63
Installed RES-E capacity (MW)	2005	3,919	5,260	19,453
	2010	4,614	5,010	20,912
	2020	6,754	8,540	23,829
Hydro	2005	10	3,040	16,345
	2010	10	3,050	16,350
	2020	10	3,100	16,360
Wind	2005	3,129	80	536
	2010	3,584	170	1,873
	2020	3,960	2,500	4,547
Biomass	2005	777	2,140	2,568
	2010	1,017	1,790	2,683
	2020	2,779	2,920	2,914
Gross RES-E generation (GWh)	2005	9,881	23,730	81,384
	2010	12,412	22,660	86,675
	2020	20,595	33,420	97,258
Hydro	2005	23	13,910	72,874
	2010	31	14,210	71,249
	2020	31	14,410	68,000
Wind	2005	6,614	150	939
	2010	8,606	360	4,793
	2020	11,713	6,000	12,500
Biomass	2005	3,243	9,660	7,506
	2010	3,772	8,090	10,567
	2020	8,846	12,910	16,689

Source: National Renewable Energy Action Plans.

A closer look at the NREAPs reveals that the challenges the Nordic countries face in terms of RES-E integration differ considerably.[24] In 2020, most Danish RES-E generation (12 TWh) is expected to come from wind power – which is difficult to integrate due to its variable character. While the former Danish government (2011a) had already announced initiatives seeking to increase the RES-E share even further – to more than 60% of overall electricity consumption in 2020 (as opposed to the 52% target of the NREAP) – the new centre-left government has raised the level of ambition even higher. Denmark aims at phasing out all use of fossil fuels by 2050, without relying on nuclear power or carbon capture and storage (The Danish Government, 2011b).

In Finland and Sweden, by contrast, RES-E generation is mainly based on non-variable sources, namely hydro (mostly conventional reservoir-based plants) and biomass. In addition, Finnish RES-E generation is planned to grow only moderately to 33% of gross, final electricity consumption in 2020 (from 26% in 2010). The situation in Norway is not problematic because of the dominance of hydropower. In short, while there may still be regional (e.g. northern Norway) and local problems with grid capacity, integrating RES-E in what is already a fairly well interconnected Nordic market should not pose major problems.

[24] The RES-E targets of other northern EU member states are discussed in appendix 3.

3.6 The future Nordic generation mix

Unlike in the exceptional case of renewable energy– where binding political targets allow for fairly precise forecasts – assessing future capacity developments is challenging for the following reason:

> [T]he overall capacity of the generation fleet in the coming years, and thus the mix and generation adequacy, is uncertain: no body or market mechanism – beyond TSOs' generation adequacy reports and warnings which enhance market transparency – ensures an appropriate generation capacity to cover demand harmoniously. Decommissioning is a particular concern, as a power plant can be closed with no prior notice to the TSO. (ENTSO-E, 2010)

Changes in the electricity generation mix can be caused by diverse factors. In the simplest case, old power plants are decommissioned because they have reached the end of their lifecycle and have to be replaced by new power plants. The Danish government (2011a), for example, estimates that a significant number of Danish plants will "wear out before 2020". Similarly, the Finnish Energy Market Authority (2010) anticipates that 1,700 MW of condensing power capacity will be decommissioned between 2016 and 2023, as the plants reach an age close to 45 years.

But even generation capacity that could still run for a couple of years might be phased out if it is no longer profitable. For example, high CO_2 prices render carbon-intensive generation capacity uncompetitive and therefore drive it out of the market. Thus, the development in carbon prices is one important factor that has to be taken into account when assessing the future energy mix. As the carbon price is low at the moment (around €7 per allowance in December 2011) – and is not expected to recover any time soon – it puts only limited competitive pressure on carbon-intensive generation capacity.

Another element of the EU's climate strategy is therefore more relevant at the moment: RES-E deployment. Also, in light of the preference given to renewables, old conventional power plants that were intended to be operated as base-load plants are now to an increasing extent run as peak-load capacity. While many of the existing plants have already recovered their capital costs, their operating and maintenance costs might still be too high to be profitable at low load factors. In addition, coal plants in particular were not designed for this kind of flexible operation.[25] In some cases it might be possible to add renewable biomass to their fuel sources.

Compared with fossil fuel power plants, hydropower capacity is usually more stable, because the plants have a life span of up to 100 years and their profitability does not suffer from high fuel or carbon prices; by contrast, this would only increase their comparative advantage vis-à-vis fossil fuel-fired plants. While hydropower resources are largely tapped, capacity might still increase moderately as old plants are refurbished with new technologies.

Nuclear energy constitutes an important part of both Sweden and Finland's future energy mix. While there are no phase-down/out plans in these countries at the moment, another nuclear catastrophe might put this issue back on the table. The current legislative framework in Sweden allows for the replacement of the existing ten reactors (whereby capacity could be increased) (Government Offices of Sweden, 2009). Finland is expanding its nuclear capacity, with a fifth reactor providing a total electricity generation capacity of about 1,600 MW expected to go on-line in 2014 and there are plans to build new nuclear power plants that would be operational in the 2020s (Finnish Energy Market Authority, 2010). While the plans are still uncertain, both projects have received a positive 'decision in principle' by the Finnish Parliament.

3.7 Estimates of Nordic excess capacity

The Nordic countries are not traditional exporters of electricity to other regions. In fact, the energy balance of the Nordic countries was negative in 2009, with 7,880 GWh having to be imported

[25] Mitigating effects, such as an increased rate of wear, decreased thermal efficiency and increased fuel costs due to more frequent unit starts, pose some technical challenges (Hesler, 2011).

(ERGEG & CEER, 2011).[26] The deficit for 2010 was even greater, amounting to 19,541 GWh (ENTSO-E, 2011b).[27] Nonetheless, three studies (NEP, 2010; P&T, 2010; BALTSO et al., 2009) suggest that there is – under certain circumstances – substantial potential for net exports, mainly as a result of the RES capacity additions discussed in section 3.5.

An analysis of these studies (see appendix 2) reveals that a significant Nordic surplus crucially depends on the large-scale deployment of renewable energy in the Nordic countries (which is likely). It should be noted that Nordic countries would generally benefit from the introduction of European-wide green certificate trading, as their renewables are highly competitive. Obviously, the magnitude of the net trade balance does hinge upon uncertain developments in demand. While most sources predict moderate growth in demand in the coming years, this could change because of macroeconomic, technological or political developments. Non-renewable capacity developments also matter. Here in particular the phase-out of old thermal generation capacity in Denmark, Sweden and Finland, and the future of nuclear energy in Finland and Sweden, have to be mentioned. Taking these uncertainties into account, the estimates for the trade balance in Nordic electricity in 2020 range from -7 TWh to +46 TWh. With regard to 2030, estimates range from -7 TWh to 22 TWh. The maximum export potential would correspond to more than 10% of projected Nordic electricity consumption in 2020 and 5% in 2030. The Nordic countries would only be net electricity importers in a scenario where Sweden decides to phase down its nuclear capacity.

3.8 Market developments in other northern European countries

This section sums up market developments in other northern European countries, namely Germany, the Netherlands, Belgium, Poland, the Baltic countries and the UK. A more in-depth discussion is provided in appendix 3.

The challenge of variable RES-E integration differs considerably among these other northern European countries. While variable RES-E capacity is expected to represent more than 50% of projected peak demand in Germany, the Netherlands and the UK, it is of only minor relevance in the Baltic countries and Poland (see appendix, Table 7).

General developments in the electricity market are similarly heterogeneous. An analysis of various national sources reveals that there are concerns that Germany, the UK and Belgium will be short of electricity unless significant additional investment in local, flexible forms of generation capacity takes place. Owing to the large share of variable RES-E foreseen for these countries, investment in generation capacity might be hard to attract. These countries are currently debating the introduction of capacity mechanisms.

The Netherlands, by contrast, is building up significant conventional capacity and the Dutch TSO expects the Netherlands to export electricity in the future, identifying post-nuclear phase-out Germany as a major destination market. With regard to Poland and the Baltic countries, variable RES-E will not play such an important role. Poland's future electricity balance hinges on the carbon price and the commercial viability of carbon capture and storage technology, since Poland's electricity generation is almost exclusively based on coal, even though it is planning to build a nuclear power plant that might be operational by 2020. The extent to which the Baltic countries could turn into competitive producers of electricity crucially depends upon the future of nuclear energy in Lithuania.[28]

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[26] According to Nordic regulators, the principal reason for the net imports of Nordic countries was the low level of availability within Swedish nuclear power generation.

[27] As noted earlier, 2010 was a dry year in the Nordic countries.

[28] While Ignalina (with a capacity of 3,000 MW), the country's only nuclear power plant, was shut down on 31 December 2009**,** the new Visaginas nuclear power plant (with a capacity of 1,300 MW) could be in operation by the end of 2020. The supply situation in the Baltic countries will also be affected by the development of nuclear projects in Kaliningrad and Belarus.

4. Potential for electricity trading in northern Europe

This section first reflects upon geographically-specific benefits that could be associated with electricity trading in northern Europe, complementing the conceptual approach of section 2 and drawing from the analysis of section 3. Then, the limitations in current interconnection capacity between the Nordic and other northern European countries are discussed and interconnector projects that would allow for more electricity trading are presented. Internal grid issues that pertain to cross-border trading and technological developments to keep in mind are discussed, as well as regulatory challenges that deserve the attention of policy-makers.

4.1 Geographically-specific benefits

There are three geographically-specific benefits associated with electricity trading between the Nordic area and other northern European countries.

First, electricity trading can enable the use of Nordic hydro capacity to be optimised from a European perspective. Currently, this benefit is related to the fact that hydropower in the Nordic market can complement the thermal-dominated mix in other northern European countries.[29] In the future, the flexible hydro capacity in Norway and Sweden will become more relevant, with a view to integrating a significant amount of the variable renewables that are being built up in northern Europe. To some extent hydropower could replace coal and gas in balancing variable wind power. While such substitution effects would not lead to lower carbon emissions, as the power sector is covered by the Emissions Trading Scheme (ETS), it could decrease the costs of pursuing decarbonisation objectives in general and of reaching the 2020 targets in particular. Electricity trading is also beneficial from a resource-efficiency perspective. For example, as hydropower inflows sometimes exceed reservoir capacity in Norway, exporting power during periods of high inflow may in these cases be the only alternative to spilling water.

Second, the analysis of market developments provided in section 3 demonstrates that developments are quite heterogeneous across northern Europe. Owing to the increasing share of low-carbon electricity with low marginal costs in the Nordic countries (mainly driven by nuclear and wind capacity additions), which could result in excess capacity by 2020, power trading can be expected to exert downward pressure on wholesale electricity prices in other northern EU member states. It may also decrease the costs of decarbonisation (see the first benefit discussed above). It should be noted, however, that this could come at the expense of power companies with a concentration of their generation assets in countries that have opted out of nuclear power.[30] Also, consumers in the Nordic countries will face somewhat higher prices in the short term, even though analyses by P&T (2010) suggest that "the price-reducing effect of renewable generation is much stronger than the price increasing effect of new interconnector capacity".[31]

Third, analyses by the OffshoreGrid consortium (2011) show that the spatial correlation of wind is generally lower in the north–south direction than east–west (see appendix 4). For example, correlation coefficients between the Nordic countries and Germany are quite low (44% for Denmark–Germany, 6% for Finland–Germany, 30% for Sweden–Germany and 40% for Norway–Germany). By contrast,

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[29] Thermal-based systems (e.g. in Germany, the Netherlands and Poland) see large price differences between day and night, but are not so volatile across seasons. Hydro-based systems (e.g. in Norway and Sweden), by contrast, have more stable prices during the day and night, but seasonal and annual prices hinge upon precipitation levels. In this regard, the empirics of the NorNed cable are noteworthy. Depending on precipitation levels, the main direction of the commercial flow changes. According to the detailed statistics on electricity exchange by ENTSO-E, the Netherlands was a net importer from Norway in both 2008 (2.8 TWh) and 2009 (1.6 TWh). In 2010, however, a dry year in the Nordic countries, the Netherlands became a net exporter to Norway (1 TWh). Put simply, in dry years Norwegian consumers benefit and in wet years the Dutch consumers do. Taking a multiannual perspective, both countries' consumers benefit as they have lower average prices and less price fluctuation.

[30] See also section 5.2.

[31] This is due to the merit order effect of wind (Pöyry, 2010).

the correlation between Germany and the UK is 67%. As a consequence, north–south transmission infrastructure is particularly helpful for the integration of more wind energy in the northern European electricity grid and can contribute to reducing price volatility.

The price differentials that continue to exist even in scenarios that assume significant additions to transmission capacity confirm the general case for more power trading in northern Europe (see appendix 5).

4.2 Limitations in the current interconnection capacity

While a great many interconnectors and internal transmission lines have an impact on power flows in northern Europe (see e.g. appendix 6), this study focuses solely on connections between the Nordic and other northern EU member states. This reduction of complexity seems necessary to allow for a meaningful discussion, and the isolation of the problem also makes sense given the idiosyncratic characteristics of the Nordic electricity market outlined in section 3.

Obviously, in the case of a Nordic power surplus, as discussed in section 3.7, electricity could only be exported if sufficient interconnection capacity was available. Table 3 shows the existing capacity between the Nordic countries and other markets. Denmark disposes of 2,250 MW export capacity to Germany. Finland is linked to the Baltic countries through the Estlink connection (350 MW). While Norway has a direct link to the Dutch market, the capacity is currently limited to 700 MW. Sweden has direct access to the German market (a capacity of 600 MW) as well as to Poland (600 MW). In short, in total 4,500 MW of export capacity to other EU member states is available. This means that a maximum of 39 TWh could be exported in the hypothetical case that the entire capacity was used for exports 24 hours a day, all year long. While this is obviously not feasible given that demand varies throughout the day and across seasons, cables may be out of order and so forth, even such a rough calculation shows that export estimates of up to 46 TWh require significant investment in transmission infrastructure.

Table 3. Existing interconnectors (Nordic countries to other markets)

Countries From	**To**	**Stations**	**Name**	**Voltage (kV)**	**Capacity (MW) Export**	**Import**
Denmark	Germany	Kassø – Audorf		2 x 400~	1,500	950
		Kassø – Flensburg		220~	–	–
		Ernsted – Flensburg		220~	–	–
		Ernsted – Flensburg		150~	150	150
		Bjæverskov + Rostock	Kontek	400=	600	600
	Subtotal				**2,250**	**1,700**
Finland	Russia	Imatra – GES 10		110~	0	100
		Yllikkälä – Viborg		2 x 400~	0	1,400
		Kymi – Viborg		400~	–	–
		Nellimö – Kaitakoski		110~	0	60
	Estonia	Espoo – Harku	Estlink	150=	350	350
	Subtotal				**350**	**1,910**
Norway	Russia	Kirkenes – Boris Gleb		154~	50	50
	Netherlands		NorNed	450=	700	700
	Subtotal				**750**	**750**
Sweden	Germany	Västra Kärrstop – Herrenwyk	Baltic Cable	450=	600	600
	Poland	Starnö – Slupsk	SwePol Link	450=	600	600
	Subtotal				**1,200**	**1,200**
Nordic	**Total**				**4,550**	**5,560**

Source: P&T (2010: 11) (based on Nordel).

Importantly, price levels will not always be higher in the Nordic countries. For example, when the wind is blowing strongly in northern Germany but lightly in the Nordic countries, power flows may well go the other way around. Thus, interconnection capacity will not only be needed for exports from the Nordic countries to other markets, but also to reap the benefits associated with power trading outlined in section 4.1. Owing to the large-scale, variable electricity-generation capacity that is currently built up in the EU – especially in Germany, the Netherlands and the UK – investment in transmission infrastructure is also necessary to ensure the cost-effective integration of variable RES-E in the northern European electricity grid. This applies to interconnection projects as well as to internal grid reinforcements (see also section 4.3).

Limitations in the current transmission infrastructure likewise become evident if one looks at congestion rents. Supponen (2011) reports congestion rents for 28 European countries.[32] In 2008 and 2009, the congestion rents for the 12 northern European countries under study amounted to €843 mn and €472 mn, respectively. For the Nordic countries alone, congestion rents were €351.3 mn (2008) and €137 mn (2009). The 2009 figures are lower, stemming from a general decrease in electricity demand leading to less congestion at price zone borders.

4.3 Interconnector developments

Apart from the NorNed2 cable, which was postponed, all of the projects presented in Table 4 could in principle be operational before 2020. This means that by 2020, 8,750 MW of additional transmission capacity could be available between the Nordic countries and the northern EU member states. Transmission capacity could thus easily more than triple between now and 2020, allowing a significant increase in power trading. At the same time, the table shows that many of the projects are still uncertain, because of the various barriers to investing in transmission, as later discussed in section 5.

While most of the interconnectors presented in the table are classic point-to-point interconnectors, the characteristics of interconnectors will change in the future. Innovative, combined grid solutions to connect offshore wind farms could be built with an integrated interconnector. Spare capacity could then be used for trade. Kriegers Flak, expected to be operational sometime between 2018 and 2020, is an example of a hub-to-hub solution that could affect the cross-border capacity, while the main driver would be the integration of wind power. Up to 900 MW of interconnector capacity could be available between Germany and Denmark for trade in situations where it is not used by a wind farm. Sweden might join at a later stage (50Hertz et al., 2010).

The OffshoreGrid (2011) project assessed several innovative options concerning how to better integrate wind energy into the northern European electricity grid.[33] While a detailed discussion of these options would go beyond the scope of this paper, it is important to note that efforts should be made to ensure that integrating offshore wind and fostering more electricity trading go hand in hand.

[32] Only one aggregate figure per country is reported, even if more than one TSO operates in the respective country.

[33] These are wind farm hubs (i.e. “the joint connection of various wind farms in close proximity to each other, thus forming only one transmission line to shore”), tee-in connections (i.e. “the connection of a wind farm or a wind farm hub to a pre-existing or planned transmission line or interconnector between countries, rather than directly to shore”) and hub-to-hub connections (“the interconnection of several wind farm hubs, creating, thus, transmission corridors between various countries”). All definitions are from OffshoreGrid (2011).

Table 4. Selected, planned interconnector projects between Nordic and other northern European countries

Countries From	To	Name	Capacity (MW)	Year (est.)	Cost est. (€ mn)	Owner/operator	Additional information
DK	DE	Reinforcements I	500	2012	NA	Energinet.dk and TenneT	Cost estimate only available for the Danish share of reinforcements (€8 mn); an aggregate figure is estimated
DK	DE	Reinforcements II	500	2017	NA	Energinet.dk and TenneT	Own cost estimate
DK	DE	Krieger's Flak	900	2018–20	1,200	50Hertz Transmission (Elia), Energinet.dk	600 MW HVDC, 300 MW AC; capacity only available for trade if not used by wind farms; Sweden might join at a later stage; own cost estimate based on a feasibility study
DK	NL	COBRAcable	700	2016	456	TenneT, Energinet.dk	Subsea HVDC
FI	EE	Estlink2	650	2014	320	Fingrid and Elering	Subsea HVDC
NO	DE	Nord.Link	1,000	2018–21	1,544	Statnett and TenneT	Subsea HVDC; regulated investment
NO	DE	NorGer	1,400	2016?	1,400	Statnett	Subsea HVDC cable; the Commission did not grant an exemption as a merchant line; the future is uncertain
NO	NL	NorNed2	700	>2021	683	Statnett and TenneT	Subsea HVDC, postponed as Statnett prioritises projects with Germany and the UK
NO	UK	NSN	1,000	2018–21	1,740	National Grid and Statnett	Subsea HVDC, possibly a wind farm connection mid-way (Dogger Bank)
NO	UK	NorthConnect	1,400	<2020	1,740	Agder Energi, E-CO, Lyse, SSE (Scottish and Southern Energy), Vattenfall AB	Subsea HVDC; capacity might be extended to up to 2,000 MW; merchant; own cost estimate based on an NSN project
SE	LT	NordBalt	700	2015–16	553	Svenska kraftnät, LITGRID Turtas AB	Subsea HVDC
		Total	**9,450**				

Note: For investment cost estimates in currencies other than €, the following exchange rates were applied: DKK 1 = €0.13, NOK 1 = €0.13, SEK 1 = €0.11; in cases of contradictory estimates, the most recent one is reported.

Sources: ENTSO-E (2010, 2011a), P&T (2010), the reports of national regulators and press releases of project developers.

4.4 Internal congestion

Notably, cross-border interconnections are not the only challenge for grid planners. As stated in the European Commission's Communication on energy infrastructure priorities for 2020 and beyond, "offshore development will strongly influence the need for reinforcements and expansion of onshore networks" (European Commission, 2010b). In the German case, for example, wind power capacity and new conventional power plants are mainly located in the north, while demand rises mostly in the south. Thus, huge north–south transit capacity is needed, as stressed by the dena grid studies (2005, 2011). Similarly, hydro reservoirs are concentrated in the north of Sweden, while centres for consumption are in the south. This leads to significant price differences among different bidding areas in Sweden.

In cases where there is an absence of multiple bidding areas within countries (in the case of Germany and Austria two countries form a single price zone), internal bottlenecks are not transparent. To create a constituency for an internal grid extension, it may be helpful to create more bidding zones in countries where structural bottlenecks exist. From the perspective of network operation, it makes most sense to form bidding zones "so that the congested parts of the network are at their outer borders and that inside the zones transmission from any generator to any load can be guaranteed with reasonable certainty" (Supponen, 2011). In addition, public reaction to the division of Sweden into four price zones on 1 November 2011 may serve as anecdotal evidence demonstrating how valuable explicit price signals are to alert the public of where real congestion exists and to potentially trigger public support for grid extension. Still, a recent study commissioned by Bundesnetzagentur (Frontier Economics and Consentec, 2011) points to possible negative consequences arising from market splitting, as it might, for example, lead to reduced market liquidity, the increased market power of large electricity generators and reduced retail competition.

Internal congestion can be one reason for the limited utilisation of interconnectors. OffshoreGrid (2011) reports an average utilisation of 64% for selected interconnectors between 2008 and 2010. Accordingly, a recommendation by the OffshoreGrid project is that the development of an offshore grid has to be complemented by adequate reinforcements of the onshore grid. On a general note it is safe to conclude that when it comes to establishing the internal market for electricity, both the domestic and European dimensions are inherently intertwined.

4.5 Technological improvement to existing lines

Transmission expansion is not the only option to increase power flows:

> Novel and unconventional technologies can make better use of existing assets by increasing the capacity of the existing grid. FACTs devices (flexible AC transmission) and PSTs (phase shifting transformers) reallocate power flow away from heavily loaded routes to more lightly loaded ones and so make a more optimal use of the transmission assets. The capacity of overhead lines can be increased by reconductoring with high temperature low sag (HTLS) conductors, and/or by implementing flexible line management (FLM), also known as dynamic line rating, which adjusts the line rating depending upon the actual environmental conditions and the physical state of the conductors. (Timpe et al., 2010)

Another possibility discussed at a CEPS stakeholder workshop, as a promising solution to make more out of existing lines, was AC to DC line conversion. Here, the EU could get involved by providing financial assistance to pilot projects.

4.6 Regulatory challenges[34]

To make optimal use of new transmission infrastructure, successful completion of the internal market for electricity is essential. More precisely, market coupling with implicit auctioning is needed. Only if interconnection capacity is traded day-ahead and intraday, can the benefits of interconnectors be fully reaped. Yet this also requires that the technical features (including technical losses) of HVDC

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[34] See also LBST et al. (2012).

interconnectors are properly modelled in the allocation process. Gate closure time as close to real time as possible would be desirable from the viewpoint of variable RES-E integration. Moreover, an optimised design of market regions could improve the investment signals for interconnectors. In particular, offshore areas should be included as noted by the OffshoreGrid project.

Another major regulatory challenge lies in the integration of electricity balancing markets, as the traditional approach – i.e. performing balancing at the control-area level without sharing balancing resources – is not ideal in terms of either variable RES-E integration or the efficient use of available generation capacities. Nevertheless, given the highly complex nature of the subject (the practices of TSOs differ widely across Europe) this process will take time. The Agency for the Cooperation of Energy Regulators (ACER) is currently drafting framework guidelines for an EU code on balancing. Such a code should result in harmonised and integrated balancing markets throughout the EU.

As discussed in section 3.8, in several member states there are doubts about whether sufficient investment in conventional generation capacity will take place. Zachmann (2011) notes that “Member States’ discussions show that those mechanisms risk being non-market based and incompatible across the Union”. Radical proposals go as far as suggesting that the market is replaced by a central purchaser model.[35] Apart from the direct threat such proposals may constitute for the internal market, the uncertainty surrounding the establishment of capacity mechanisms or market-wide interventions might induce potential investors to delay investment decisions, potentially resulting in a vicious circle.

5. Barriers to investment in transmission

This section gives an overview of the major barriers that are relevant to transmission expansion in northern Europe. The recent European Commission proposal for a regulation on guidelines for a trans-European energy infrastructure of 19 October 2011 (European Commission, 2011a), which addresses a number of these barriers, is discussed in the next section.

5.1 Economic and financial barriers

Investment in transmission infrastructure is challenging. Even though ENTSO-E’s first TYNDP does not “take full account of needed infrastructure investment triggered by important new offshore wind generation capacities in the Northern Seas” (European Commission, 2010c), it estimates that projects of European significance require investments of €50-70 bn between 2010 and 2025. KEMA calculations cited in the European Commission’s impact assessment accompanying the infrastructure blueprint suggest that “these projects would need to be operational in 2020 to reach the 20-20-20 targets” (European Commission, 2010c). The impact assessment comes to the conclusion that the overall investment needs for electricity networks (including offshore and smart grids) amount to €142 bn by 2020. Importantly, according to the European Commission, in a business-as-usual scenario only €45 bn of electricity infrastructure investment would materialise, although €90 bn is deemed possible under current market and regulatory conditions (ibid.). The European Commission’s estimates suggest that – even if authorisation issues are resolved (see section 5.1) – an investment gap of €60 bn remains by 2020, mainly as a result of “the non-commercial positive externalities of projects with a regional or European interest and the risks inherent to new technologies” (European Commission, 2010b).

A Roland Berger study (2011a) on financing[36] identifies several key challenges, inter alia:

- delayed approval of transmission projects (up to ten years), which may cause additional costs that are hard to foresee *ex ante* (see next section);
- insufficient stability of the regulatory regime and remuneration of grid investments, also in light of the increased complexity of projects (e.g. offshore grid); and

[35] In a central purchaser model, “the regulator determines system requirements for new generation in lieu of the competitive price-based investments of market players” (Hood, 2011).

[36] A quick overview on financing is included in appendix 7.

- the lack of competence and experience among some (especially smaller) TSOs in raising capital, as they have only recently emerged as separate companies owing to the unbundling requirements.

The time lag of infrastructure investments and transmission capacity poses some problems as well. Grids need to be reinforced before new interconnectors and generators can be connected. This might increase network tariffs (and consequently electricity prices) in the short run because congestion rents – which could be used to lower tariffs – would materialise only at a later stage. According to RealiseGrid, the current regulatory approach does not balance short-term and long-term interests well (Urbani et al., 2011).

There is also a lack of clarity about future capacity developments, as in many cases it is unclear how the EU's transition to a competitive low-carbon economy will unfold in practice. This further complicates cross-border cost allocation, given that the distribution of costs and benefits among countries also depends on future developments.

Generally, it is important to stress that improving the incentives for investing in transmission should not be reduced to a discussion on rates of return. A reliable and stable regulatory regime might well be able to attract sufficient capital at relatively mediocre rates of return owing to its low risk for investors. For example, stranded investments are borne by consumers.

5.2 Political and administrative barriers

To build a new regulated interconnector between two countries, both sides must be willing to proceed with the project. Investment in transmission suffers from a lack of coordination among member states and other relevant actors (ministries, regulators, TSOs, project promoters, etc.). Importantly, "the current policy does not address permitting issues, market or regulatory failures, the mismatch between national and European priorities and the need for strong political support" (European Commission, 2010c).

With regard to permitting procedures, a study by Roland Berger (2011b) commissioned by DG Energy identifies a number of challenges:

- the lack of a single institution that would be 'responsible' for the permitting procedures;
- a permit process that is not transparent enough;
- the lack of an effective monitoring and reporting system, as well as clearly defined measures to speed up delayed procedures;
- the involvement of stakeholders too late in the process; and
- authorities lacking sufficient capabilities.

In view of the integration of offshore wind energy, one current barrier consists of the often-incompatible schemes for the support of renewables. Within the current regulatory framework, connecting an offshore wind farm to two or more countries could in many cases create problems in terms of obtaining financial support (OffshoreGrid, 2011).

The well-known NIMBY issue represents a serious caveat with a view to political support, as opposing infrastructure projects may be an attractive option for vote-maximising politicians. Along those lines, ENTSO-E (2010) identifies the "lack of social acceptance by affected local communities and their representatives, or environmental organizations" as threatening "the timely completion of infrastructure projects and the achievement of European policy targets". Delay is not the only problem that may result from public opposition – infrastructure costs might also increase if more expensive solutions (such as underground cables in lieu of overhead power lines) are needed to ensure public support. This should be incorporated into the analysis on costing.

Interconnector projects could face strong opposition in some countries with a strong anti-nuclear movement, such as Germany, if they allow for the large-scale import of nuclear energy. Nuclear plays an important role in Sweden and Finland's power mix (see section 3). German producers might oppose interconnection projects with the Nordic countries because of the likely downward pressure on domestic electricity prices. If the UK eventually decides to build new power plants, interconnection capacity could also be used to export nuclear energy from the UK to the continent.

The classical barrier to investment in transmission – and arguably one of the many reasons why no interconnector has yet been built between Norway and Germany – is that it has a differential impact on prices. In other words, interconnector projects might well increase overall welfare but still not be in the interest of consumers in low-price zones. As a consequence, regulators or other relevant actors on this ‘losing’ side of the interconnector might oppose such an investment (Urbani et al., 2011). But the massive deployment of RES-E in many northern European countries and the resulting more dynamic differences in price will make it clearer that enlarged markets are a win–win situation in the long run. The effective unbundling requirements of the third energy package should further complement this. As of 30 September 2011, however, the Commission has opened infringement procedures for non-communication of national transposition measures against 17 member states. Only the Czech Republic, Germany, Denmark, Greece, Hungary, Italy, Latvia, Malta, Poland and Portugal have communicated about their transposition so far.

Merchant projects for investment in interconnectors face specific legal barriers. Even though they represent a special category of grid users, they are normally not mentioned as a separate category in national laws and regulations. In Sweden, pure merchant projects are not possible, as the dominant participation of the Swedish TSO is required by national law.

5.3 Technical barriers

There are no insurmountable technological obstacles to transmission expansion. Yet the integration of offshore wind into the electricity grid poses some technical challenges. An integrated solution, such as a meshed offshore grid that could integrate offshore wind more cost-effectively, requires technological developments in the field of direct current breakers and multi-terminal control systems (European Commission, 2010c; see also OffshoreGrid, 2011). Generally, a lack of standardisation of HVDC grid technology is slowing down progress.

Technical barriers are more relevant when seen from a financing angle. Projects making use of new and innovative technologies come along with first-mover risks. As investment in transmission is usually borne by consumers, regulators are understandably concerned about taking these risks. In practice, however, this may imply that suboptimal standard solutions are preferred to innovative technological options (European Commission, 2011b).

6. Overcoming the barriers

This section focuses on the European Commission’s proposal for a regulation on guidelines for a trans-European energy infrastructure of 19 October 2011 (European Commission, 2011a). It also briefly discusses the energy roadmap 2050 of 15 December 2011.

6.1 Key corridors for northern Europe – Projects of common interest

On 19 October 2011, the European Commission proposed a regulation on guidelines for a trans-European energy infrastructure (European Commission, 2011a). The proposal contains measures to reduce risks and accelerate network deployment. While the regulation only applies to certain “energy infrastructure priority corridors and areas”, with regard to electricity projects in northern Europe the definition is broad enough for almost all the relevant cross-border projects in northern Europe to be eligible in principle under the regime of ‘common interest’.

At the heart of the proposal are the PCIs, which would benefit from i) streamlined and faster permit-granting procedures, ii) improved cost-allocation procedures leading to longer-term incentives, and iii) access to EU funding through the ‘Connecting Europe’ facility.

a) Accelerated permit granting means that the projects would receive priority status at the national level. Early and better consultation of the public is also part of the proposal and should help address the NIMBY problem.[37] The introduction of a national one-stop shop and the inclusion of an ambitious three-year time limit should speed up the process considerably.

b) Establishing standards for cost-benefit analysis should facilitate cost allocation and the investment decisions of regulatory authorities for projects with cross-border impacts and provide incentives for a grid extension that follow long-term objectives. It remains to be seen, however, if member states will be able to agree on cost allocations based on such disputable criteria as the generation of regional or EU-wide positive externalities (Art. 13.5c). As discussed in section 2, there is considerable room for interpretation as to what constitutes a positive externality.

c) PCIs could also benefit from access to EU support through the Connecting Europe facility – more than half of the €9.1 bn the facility dedicates to energy infrastructure is expected to be available for electricity projects. While this funding opportunity can make a contribution to some particularly convoluted projects and also help to incentivise innovative technological solutions, the scale of the investment challenge identified in the preceding section makes it clear that a large chunk of investment needs to come from other sources.

Electricity projects would be prioritised based upon a methodology for analysing the costs and benefits for the entire electricity system, to be developed by ENTSO-E. While there would be significant regulatory oversight and both ACER and the European Commission would be involved in the process, it would still be a challenging task. This holds especially true as demand- and supply-side developments beyond 2020 are still very uncertain. Cost-benefit analyses can only be as good as the input assumptions – and the considerable political, economic and technical uncertainty associated with the EU's transition to a competitive low-carbon economy cannot be 'calculated away'.

As the regulation foresees that regional groups would be in charge of identifying projects within each priority corridor, some bottom-up dynamics within a competitive framework are ensured. The effectiveness of the selection procedure also depends on the openness of the process to third-party project developers.[38] One would imagine that each regional group has an interest in clearly identifying the benefits of a certain project to ensure having as many priority projects as possible. This could lead to some healthy competition. ENTSO-E could then weigh these benefits, taking into account the European perspective (with the support of the European Commission and ACER). Some 80-120 projects are expected to eventually receive priority status (ENTSO-E's 2010 TYNDP contained roughly 500 projects).[39]

With regard to the electricity corridor that is priority no. 1, the 'Northern Seas Offshore Grid', it seems important to note that there is a certain risk that too much coordination will slow down progress. While coordination is certainly important and will help drive down costs, as concluded by OffshoreGrid (2011), it is at least equally important that investors who want to take risk can go ahead.

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[37] A noteworthy initiative that inter alia aims at going 'beyond public opposition' and brings together both TSOs and NGOs is the Renewables Grid Initiative. On 10 November 2011, ten European NGOs, nine TSOs and five supporters signed the European Grid Declaration on Electricity Network Development and Nature Conservation in Europe.

[38] When it comes to establishing a truly integrated, European electricity market, the role of merchant lines can only be seen as a temporary solution, because congestion needs to be preserved in order to guarantee an adequate rent extraction and make merchant lines profitable (Urbani et al., 2011). In cases where the alternative is either the construction of a merchant interconnector of limited capacity and no interconnector at all, the former option is still interesting. A mixed solution that is discussed with regard to the Nemo interconnector is a cap and floor regime. In this regime, consumers would benefit from a cap, as all revenues above a certain threshold would have to be socialised. Project developers would be reassured by a floor, which would guarantee a minimum return on investment (Ofgem and CREG, 2011).

[39] According to Art. 2.3 of the proposed regulation, "'project' means one or several lines", while the TYNDP works with a narrower definition of project. Nevertheless, at a CEPS workshop held on 28 November 2011 a European Commission official indicated that one would carefully assess the extent to which the project definition was circumvented to make sure prioritisation is not watered down.

6.2 Towards a coordinated policy on European energy?

On 15 December 2011, the European Commission (2011c) adopted the energy roadmap 2050, which argues in favour of greater coordination on energy issues "to ensure that national decisions are mutually supportive and avoid negative spillovers". The debate following the release of this roadmap should seek to make it explicit that the completion of the internal electricity market has to be accompanied by a coordination of national energy policies.

The roadmap recognises the added value that is provided by the work of the North Seas Countries' Offshore Grid Initiative.[40] But it does not yet provide clarity on the 2030 horizon. The discussion of five 'decarbonisation scenarios' demonstrates how difficult a robust cost-benefit analysis of grid extension is. Greater clarity with a view to the 2030 targets as well as in terms of the decarbonisation pathway would be helpful for optimising planning for transmission expansion.

7. Policy conclusions

This section presents the main conclusions of the study in light of the European Commission's proposal on a trans-European energy infrastructure.

1. Transparent discussion is needed about the challenges of developing a cost-benefit analysis covering the entire electricity system.

Owing to the complexity of a true, European cost-benefit analysis – which has not been done before – it is ambitious to expect ENTSO-E to submit its methodology for an energy system-wide analysis only a month after the proposed regulation enters into force. It has to be clear that the results of a cost-benefit analysis as envisaged in the European Commission's proposal of October 2011 can only be as good as the assumptions. This is further complicated by the fact that the cost-benefit analysis would need to serve two distinct purposes. First, it would be the basis for the selection of PCIs; second, the cost distribution among TSOs (or other project developers) would be decided on the basis of these calculations.

a) Generally, the assumptions underlying cost-benefit analyses should be as transparent as possible. Only if the basis on which projects of common interest are selected and the costs allocated among TSOs is agreed upon, can stakeholder and public acceptance be fostered. In particular, it is clear that the results of such a cost-benefit analysis vary greatly depending on the value attached to the various energy policy goals. While different options for integrating variable renewables exist (e.g. storage, supply- and demand-side responses), they do not necessarily serve the internal market goal as well as building interconnectors. These political choices behind a cost-benefit analysis have to be addressed – they cannot be solved in a technical process among experts.

b) With regard to setting European strategic priorities, a long-term approach looking 20 or 30 years ahead and assessing the long-term contribution that specific projects can make to EU policy goals is certainly justified. But for such a cost-benefit analysis, a coherent long-term EU energy policy would be crucial. Here, the energy roadmap 2050 is an important stepping stone. In the longer term, a more honest discussion about member states' energy mix can hardly be avoided. Trans-European energy infrastructure does, of course, have implications for member states' energy mix. An effective EU energy policy requires coordination of member states' energy choices.

[40] In northern Europe, high-level political support for significant grid extension exists, as evidenced by the North Seas Countries' Offshore Grid Initiative (NSCOGI). The signatories, namely the governments of Benelux countries, Denmark, France, Germany, Ireland, Sweden, the UK and Norway, as well as the Commissioner for Energy, all declare that they "will identify and tackle barriers to grid development at both national, regional and EU-level, in particular regulatory, legal, market, planning, authorisation and technical issues" (NSCOGI, 2010). The initiative is supported by ACER, the relevant, national regulatory authorities and ENTSO-E.

c) For the second purpose (i.e. cost distribution among countries) shorter time horizons are more appropriate, as it is hard to imagine that national regulators will be willing to accept cost-allocation decisions that are based on a long-term cost-benefit analysis that necessarily includes a large number of 'heroic' assumptions.

2. Effective governance of regional groups must be ensured.

The involvement of regional groups as discussed in the proposed regulation is crucial. This holds true not only because of the challenges associated with a system-wide cost-benefit analysis, but also because of the need to ensure the support of all the relevant stakeholders. Only if the stakeholders are properly involved in the prioritisation process will they support the implementation of PCIs. Therefore, in the proposed regulation it would be desirable to further clarify the governance of regional groups, particularly the following aspects:

a) The process for identifying PCIs should be open to a large number of parties to present promising projects. This point stems from the sheer scale of the challenge of transmission investment that lies ahead. It implies that instead of relying entirely on TSOs, third-party project developers should be allowed to present merchant projects. To reduce administrative obstacles, it would be helpful if merchant project developers could present the relevant exemption by the European Commission and the national regulatory authorities once their project has been identified as being of 'common interest'.

b) A specific issue that could contribute to better governance of regional groups would be the involvement of European coordinators in the identification phase. In the European Commission's proposal of October 2011, a European coordinator is only envisaged if a PCI encounters implementation difficulties (Art. 6). But what happens if a regional group cannot agree on PCIs? As a consequence, consideration could be given to amending Art. 6 and allowing European coordinators to become involved in the identification phase as well. There should be careful assessment, however, of whether this would add an unnecessary bureaucratic burden.

c) As all four of the priority electricity corridors foreseen in the proposed regulation are of relevance for electricity trading in northern Europe, it is clear that optimised transmission expansion can only succeed if the regional actors cooperate closely. It is up to the Commission, ACER and ENTSO-E, which are all envisaged as participants in the regional group phase, to ensure that effective coordination among the groups takes place in practice.

d) The need for the close involvement of regulators already at the regional group stage as foreseen by the proposed regulation can hardly be overstated, given that regulators decide on the incentives for investment by TSOs. Regulators thus have to be convinced that the prioritisation of certain projects is indeed justified so that they are motivated to take the appropriate measures.

3. Internal grid issues should not be overlooked.

More than half of the projects outlined in ENTSO-E's TYNDP are cross-border connections and this share is expected to increase to some two-thirds by 2030. Yet in practice, internal transmission capacity within European countries represents a substantial obstacle to more electricity trading in Europe. It is therefore important that the regime of common interest proposed by the European Commission does not just focus on cross-border issues, as these investments might become stranded if internal congestion prevails. The Commission's proposal of October 2011 recognises this, but the point should be stressed further. As the proposal now enters the legislative process, it is important that this aspect is strengthened and not removed because of subsidiarity concerns.

4. The scale and urgency of the infrastructure challenge requires significant further progress in the regulatory field well beyond establishing a regime of common interest.

a) Given the scale and urgency of transmission infrastructure development, it is vital to ensure that efforts to promote infrastructure investment are not limited to PCIs. In terms of regulatory incentives for investment by TSOs, a more holistic approach is needed, going beyond discussions on rates of return. Depending on the domestic regulatory conditions, investment in transmission may carry very low risks, since consumers pay for investments. The challenge rather lies in incentivising the right kinds of investments, with solutions crucially depending on the regulatory framework within member states, which should be predictable and transparent. More specifically, the regulatory framework for congestion management should encourage the investment needed for both RES-E integration and the completion of the internal market for electricity. Merchant projects for new interconnectors should have a fair opportunity for development.

b) To make optimal use of the new transmission infrastructure, EU-wide market coupling of day-ahead and intraday markets is important and needs to be implemented by 2014 as targeted. As mentioned with regard to the first conclusion above, it cannot be neglected that this development has implications for member states' energy mix. More coordination is therefore required to make certain that the regulatory frameworks are compatible (inter alia, renewable support schemes) in order to promote fair and efficient competition in a European power market. It should also be ensured that the capacity mechanisms that a number of member states are planning to introduce do not distort the establishment of an internal market for electricity.

c) Another major regulatory challenge lies in integrating electricity balancing markets, as the traditional approach – i.e. performing balancing at the control-area level without sharing balancing resources – is not ideal in terms of either variable RES-E integration or the efficient use of available generation capacities. This will hopefully be achieved through the development of an EU code for balancing.

d) With regard to the development of an offshore grid, new models for cooperation among governments, TSOs and regulators are needed. Progress has to be made in terms of ensuring compatible support schemes for RES-E, among other things. The North Seas Countries' Offshore Grid Initiative is an important means for making further advances on these issues.

List of abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
CEER	Council of European Energy Regulators
ECF	European Climate Foundation
ENTSO-E	European Network of Transmission System Operators for Electricity
ERGEG	European Regulators' Group for Electricity and Gas
ETS	Emissions Trading System
GFMET	German Federal Ministry of Economics and Technology
IEA	International Energy Agency
LBST	Ludwig-Bölkow-Systemtechnik
MFF	Multiannual Financial Framework
NEP	Nordic Energy Perspectives
NIMBY	Not in my backyard
NREAP	National Renewable Energy Action Plan
NSCOGI	North Seas Countries' Offshore Grid Initiative
OECD	Organisation for Economic Cooperation and Development
P&T	Pöyry Management Consulting and Thema Consulting Group
PCIs	Projects of common interest
RES	Renewable energy sources
RES-E	Electricity from renewable energy sources
TEN-E	Trans-European energy networks
TGC	Trade in green certificates
TSOs	Transmission system operators
TYNDP	Ten-Year Network Development Plan

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Appendices

Appendix 1. Capacity and generation in the Nordic countries

Table 5. Installed capacity of electricity generation plants and power station generation in the Nordic countries (2010)

	Denmark	Finland	Norway	Sweden	Nordic
Net generating capacity as of 31 December 2010 (MW)	**13,375**	**17,081**	**31,780**	**35,701**	**97,937**
Nuclear	0	2,646	0	9,151	11,797
Fossil fuels	8,867	9,004	1,166	5,035	24,072
Hydropower	9	3,133	30,164	16,200	49,506
Other RES	3,802	2,254	450	5,315	11,821
Other sources	697	44	0	0	741
Net generation in 2010 (TWh)	**36.7**	**77**	**123.5**	**145**	**382**
Nuclear	0	21.9	0	55.6	78
Fossil fuels	26.3	31	5.3	7.8	70
Hydro	0	12.8	117.3	66.2	196
Other RES	10.4	10.6	0.9	15.4	37
Non-identifiable	0	0.7	0	0	1

Source: ENTSO-E (2011b) (provisional values as of 30 April 2011).

Appendix 2. Estimates of Nordic electricity exports

The second phase of the NEP project, which was financed by more than 20 organisations, inter alia Statkraft and DONG Energy, concludes that there are "huge opportunities for Nordic electricity export in a widened European electricity market". While Denmark would become a net electricity importer, Norway and Sweden are anticipated to become large exporters to continental Europe in 2020; Finland would be a net exporter to the Nordic market. More precisely, if the renewable energy targets were fulfilled and new interconnectors built, results based on the European Econ Classic model indicate that net exports to Germany, Poland and the Netherlands would amount to around 30 TWh in 2020. The surplus is even greater if trade in European green certificates is assumed; however, doubts exist about whether this might become a reality.[41] Importantly, the Econ Classic model does not take into account that "the utilization of cables varies significantly between seasons and years" (NEP, 2010: 130). It should also be noted that the Econ Classic model makes the assumption that the electricity demand of the Nordic area would amount to 400 TWh in 2020 (NEP, 2010: 114). Thus, in the case of stronger demand (see Table 6), the estimated electricity surplus could decrease).

In the report introduced in section 3.3, Pöyry Management Consulting and Thema Consulting Group (P&T, 2010) conclude that even if electricity demand in the Nordic countries grew considerably, there would be an electricity surplus, as long as investments in RES-E generation were not delayed substantively.[42] The highest electricity surplus, namely 46 TWh in 2020, is identified for the politics work scenario. In this scenario, Denmark would be a net importer in 2020 and the other Nordic countries net exporters. There are important assumptions for this model specification:

- 5,350 MW of new transmission capacity from the Nordic to non-Nordic countries is installed by 2020;
- the Nordic electricity demand amounts to 401 TWh by 2020;
- most EU member states participate in the market for green certificates from 2015 onwards; and
- the CO_2 price remains fairly low up to 2020 (€18/ton of CO_2).

Thus, the order of magnitude of the results seems to depend on the (unlikely) successful implementation of a European scheme for green certificate trading. Yet the assumed capacity additions until 2020 more or less correspond to the figures presented in section 3.5. The second scenario that generates a significant surplus is the green growth scenario (23 TWh). Here, the assumed RES-E capacity additions are somewhat optimistic, given that Sweden, for example, is expected to dispose of 7 GW of wind capacity but the NREAP only envisages 4.5 GW. The last surplus scenario (+ 28 TWh in 2020) is called "stagnation". Here, the surplus is partly due to the relatively low Nordic demand (387 TWh in 2020) resulting from a period of low economic growth. Nevertheless, in light of fairly pessimistic assumptions (renewable targets would not be reached; only 3,250 MW of new transmission capacity would be available), the surplus is noteworthy. The only scenario for which P&T report a Nordic electricity deficit (-7 TWh) is the supply worries scenario. This worst-case scenario foresees a nuclear phase-down in Sweden (to 75% of current capacity) coupled with strong growth in demand.

A study conducted by TSOs from the Baltic Sea region (BALTSO et al., 2009), namely NORDEL, PSE Operator S.A. and BALTSO, estimates that there is an export potential of roughly 14 TWh for the

[41] Furthermore, the study reports high export potential (up to 50 TWh) for different specifications of the MARKAL–NORDIC model, but since all reported estimates are based on the assumption that an EU-wide green certificate trade is set in place, they are omitted here.

[42] The study was supported financially by a large number of major Nordic energy producers and consumers, among others Statkraft.

Nordic countries in 2025 in their climate & integration scenario. This specification entails the following key assumptions:

- the 20% emissions reduction target is reached by 2020;
- there is an increased share of electricity from RES;
- energy-efficiency measures are in place (lowering demand growth); and
- CO_2 prices are €75/ton in 2025.

With regard to this model specification, it should be noted that a CO_2 allowance price of €75 is unlikely. Moreover, the surplus would amount to only 12 TWh if prices are low for electricity generated from RES, for example due to government subsidies. A nuclear phase-down would, by contrast, result in a Nordic power deficit. In addition, the other two scenarios – business as usual and national focus – report small electricity deficits for the Nordic area.

Table 6. Estimates of the Nordic export potential

Source	**Scenario**	**Key assumptions**	**Energy model**	**Excess capacity estimates**	**Assessment**
NEP (2010)	Base scenario	RES generation developed according to national policies; no certificate trading, RES target not fulfilled; new interconnectors are utilised; Nordic demand is ~400 TWh (2020)	The European Econ Classic model (developed by ECON Pöyry) and the Eureno model (a model for long-term European RES generation potential and costs)	2020: +27 TWh	The highest export potential would only materialise if a trading system for European green certificates were to be established.
	No TGC (trade in green certificates) scenario	EU RES target fulfilled without certificate trading; new interconnectors are utilised; Nordic demand is ~400 TWh (2020)		2020: +30 TWh	
	TGC scenario	EU RES target fulfilled with full certificate trade; new interconnectors are utilised; Nordic demand is ~400 TWh (2020)		2020: +35 TWh	
P&T (2010)	Politics work	Global climate agreement in 2018; most EU member states participate in a market for green certificates from 2015 onwards; new transmission capacity from the Nordics to outside Nordics (MW) is 5,350 (2020) and 6,450 (2030); Nordic electricity demand (TWh) is 401 (2020) and 440 (2030); CO_2 prices (€/t) are 18 (2020) and 30 (2030); oil prices ($/barrel) are 86 (2020) and 87 (2030)	Econ Pöyry BID model: a partial equilibrium model, with fuel prices, carbon prices, etc., given as input assumptions	2020: +46 TWh 2030: +22 TWh	It is unlikely that a European green-certificate market is going to be established by 2015.

Table 6. cont'd

P&T (2010)	Green growth	Global climate agreement in 2012; EU 2020 emissions reduction target of 30%; new transmission capacity from the Nordics to outside Nordics (MW) is 5,350 (2020) and 7,050 (2030); Nordic electricity demand (TWh) is 425 (2020) and 472 (2030); CO_2 prices (€/t) are 30 (2020) and 45 (2030); oil prices ($/barrel) are 120 (2020) and 134 (2030)		2020: +23 TWh 2030: +22 TWh	A global climate change agreement is uncertain and a move to a 30% target in 2020 is unlikely.
	Stagnation	No global climate change agreement, demand stagnating, little investment in RES; new transmission capacity from the Nordics to outside Nordics (MW) is 3,250 (2020) and 4,450 (2030); Nordic electricity demand (TWh) is 387 (2020) and 396 (2030); CO_2 prices (€/t) are 15 (2020) and 25 (2030); oil prices ($/barrel) are 52 (2020) and 48 (2030)		2020: +28 TWh 2030: +19 TWh	This scenario is interesting in light of the current economic situation, with higher investment in RES likely.
	Supply worries	Nuclear phase-down in Sweden, strong demand growth, tight CO_2 caps; new transmission capacity from the Nordics to outside Nordics (MW) is 2,550 (2020) and 6,450 (2030); Nordic electricity demand (TWh) is 420 (2020) and 449 (2030); CO_2 prices (€/t) are 30 (2020) and 45 (2030); oil prices ($/barrel) are 120 (2020) and 134 (2030)		2020: -7 TWh 2030: -7 TWh	This is an important scenario as it shows that excess capacity hinges on the existence of nuclear capacity.
BALTSO et al. (2009)	Business as usual	Enhanced market liberalisation; strong EU energy integration and coordination; market coupling; prices in 2025 are $70/barrel for oil and €25/ton of CO_2	EMPS model: input data consist of consumption data (fixed and price elastic), generation data (including marginal costs) and transmission capacity data	2025: -1 TWh	No excess capacity exists.

Table 6. cont'd

BALTSO et al. (2009)	Climate & integration	20% emissions reduction target reached by 2020; an increased share of electricity from RES; energy-efficiency measures in place (lowering demand growth); strong EU integration; prices in 2025 are $140/barrel for oil and €75/ton for CO_2		2025: +14 TWh	Sensitivity analyses reveal that the Nordic countries are net importers in the case of a nuclear phase-down.
	National focus	Weak EU integration; a national focus when solving problems of security of supply; prices for 2025 are $95/barrel for oil and €50/ton for CO_2		2025: -2 TWh	No excess capacity exists.

Sources: NEP (2010), P&T (2010) and BALTSO et al. (2009).

Appendix 3. Market developments in other northern European countries

Table 7 gives a quick overview of the extent to which member states have to integrate variable renewables. A more detailed discussion follows of the market developments introduced in section 3.8.

Table 7. Variable RES-E capacity and projected peak demand in 2020 (MW)

	Variable capacity			Peak demand
	Wind	Solar	Total	
Belgium	4,320	1,340	5,660	16,221
Estonia	650	0	650	2,287
Germany	45,750	51,753	97,503	74,000
Latvia	416	2	418	1,700
Lithuania	10	500	510	2,120
Netherlands	11,178	0	11,178	21,750
Poland	6,650	3	6,653	28,898
UK	49,040	2,680	53,020	68,510
Total	118,014	56,278	175,592	215,486

Notes: Total variable values for the UK also include 1,300 MW of tide/wave/ocean capacity. The peak demand figure for the UK is for Great Britain alone. Hydro and biomass capacity is considered non-variable and thus is not included.

Sources: NREAPs; Eurelectric (2010).

In light of the nuclear phase-out, Germany currently plans to build new fossil-fuel generation capacity. More precisely, according to the German Federal Ministry of Economics and Technology (GFMET 2011), the idea is to construct 10 GW by 2020 on top of the capacity additions that are already under construction. At the same time, Germany is also committed to increasing its RES electricity generation capacity from 54 GW (2010) to 111 GW in 2020, in order to reach its sectoral RES electricity target of 38.6%. This is expected to lead to an increase in RES electricity generation from 105 TWh (2010) to 217 TWh in 2020 (ibid.). A large part is estimated to come from variable sources (41 TWh from solar and 104 TWh from wind).

While new, conventional thermal generation is deemed to be needed to deal with variable RES-E, this might not be profitable without subsidies due to its low load factor, as preference is given to electricity coming from RES. A quick analysis of energy scenarios prepared on behalf of GFMET underlines this concern (EWI et al., 2010).[43] Gas-fired plants are projected to continue to play an important role in the electricity-generation capacity mix (20-42 GW in 2050, representing 12-23% of overall installed capacity), but their load factor will be quite low, as they are expected to serve mainly as a backup for variable wind energy. More to the point, full load hours of gas-fired plants are estimated to decrease from 3,183 (2008) to 1,614-1,849 h in 2020 and 0-1,666 h in 2050. Indeed, it might be difficult to attract private sector investment in the necessary infrastructure.

Various studies predict that Germany will be a net electricity importer in the future. According to the energy scenarios by EWI et al. (2010), Germany will be a net importer as of 2030, since other countries are estimated to have a comparative advantage with regard to energy generation – either because of cost-effective nuclear capacity or greater RES potential. As a consequence, the study estimates net imports to range from 37 to 44 TWh in 2030 and 34-76 TWh in 2040 to 64-102 TWh in

[43] Only those scenarios that assume a nuclear phase-out in the 2020s are discussed here (reference, I A, I B).

2050.[44] P&T (2010) estimate that Germany will import significant amounts of energy from the Nordic countries in both 2020 and 2030 in three out of four scenarios (up to 25 TWh). Similarly, Germany and the Netherlands are net importers by 2025 in all of the scenarios by BALTSO et al. (2009), with net imports ranging from 15 (in the national focus scenario) to 24 TWh (in the climate & integration scenario).

P&T also estimates that the Netherlands alone is expected to be a net importer from both Norway and Sweden. Nevertheless, a recent TenneT report (2011) argues that the Netherlands have significant export potential, identifying post-nuclear phase-out Germany as a major destination market. This is based on the expectation that 14 GW of new generation capacity will become operational between 2011 and 2018. Notably, in order to reach their RES-E 2020 target of 37% (2005: 6%), the Netherlands face the challenge of having to integrate additional RES capacity of more than 10 GW by 2020 (with 2010 being the reference year), mostly consisting of variable wind energy. Thus, irrespective of the actual direction of trade flows, increased interconnection capacity would probably allow for a more cost-effective integration of RES-E in the Dutch grid.

A press release by the Belgian regulator for electricity and gas, CREG, states that Belgian generation capacity will not be sufficient to meet domestic demand – in particular between 2012 and 2015. In the face of such a potential shortage, CREG recommends prolonging the life of those nuclear and fossil fuel power plants that are currently envisaged to be phased out in 2015. Belgium could meet its own needs again by 2020, but only if all planned projects are completed on time (CREG, 2011). Belgium also faces the challenge of RES-E integration, as its RES-E 2020 target is 21% (2010: 5%). This means that in 2020, 10.5 TWh of power generation will come from wind, with 11 TWh of generation expected to be based on biomass. The contribution of other RES to Belgian power generation will be negligible.

Poland's future electricity balance hinges on the carbon price and the commercial viability of carbon capture and storage technology, as Poland's electricity generation is almost exclusively based on coal (Eurostat, 2011), even though it is planning to build a nuclear power plant that might be operational by 2020. Not surprisingly, Poland is expected to be a net importer by 2025 (9 TWh) in the climate & integration scenario by BALTSO et al. (2009: 24), because that scenario assumes a carbon price of €75 per ton of CO_2. Yet in scenarios with a lower carbon price, Poland's trade balance is roughly even and no significant net trade takes place between Poland and the Nordic countries (BALTSO et al., 2009; P&T, 2010). Poland's RES-E 2020 target amounts to 19%. More than half of RES electricity generation in 2020 is projected to come from non-variable sources, namely biomass (14 TWh) and hydro (3 TWh).

The extent to which the Baltic countries would be net importers of electricity crucially depends upon the future of nuclear energy in Lithuania. While Ignalina (with a capacity of 3,000 MW), the country's only nuclear power plant, was shut down on 31 December 2009, the new Visaginas nuclear power plant (with a capacity of 1,300 MW) could be in operation by the end of 2020. Unless the nuclear plans fail, BALTSO et al. (2009) estimate that Lithuania and the Baltic countries in general will have a positive regional balance of electric energy by 2025, with the expected surplus ranging from 1 to 9 TWh. Nevertheless, three out of four P&T scenarios suggest that Lithuania and Estonia will import around 8 TWh from the Nordic countries in 2020. RES-E integration is not a major issue from the Baltic countries' perspective, since RES-E targets are either quite low (Estonia and Lithuania) or expected to be achieved by mainly making use of non-variable RES-E (Latvia).[45]

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[44] Again, only those scenarios that assume a nuclear phase-out in the 2020s are discussed. Yet all scenarios (even those that assume some nuclear capacity to remain in place until 2050) predict a rising share of net imports for Germany (12-31% of gross energy demand in 2050; see EWI et al., 2010: 114).

[45] Lithuania's RES-E target is 21% (2010: 10%). RES-E is estimated to total 3 TWh in 2020, to which wind and biomass contribute 1.3 and 1.2 TWh, respectively (NREAP for Lithuania). Latvia is committed to raising its RES-E share from 45% (2010) to 60% (2020). But the largest part of the total RES-E power generation of 5 TWh would come from hydro (3.1 TWh) and biomass (1.2 TWh) (NREAP for Latvia). Estonia's RES-E share will remain below 5% even in 2020 (NREAP for Estonia). The supply situation in the Baltic countries will also be affected by the development of nuclear projects in Kaliningrad and Belarus.

With regard to the UK, P&T's scenarios do not indicate a clear trend in net trade; only in half of the scenarios is the UK expected to import moderately from Norway (up to 5 TWh in the 2020 scenario of politics work). But in a recently published White Paper, the UK's Department of Energy & Climate Change warns that security of supply is in danger, as around 20 GW (~25%) of electricity generation capacity will be phased out over the next decade. The White Paper concludes that "up to £110 billion [~€127 billion] investment in electricity generation and transmission is likely to be required by 2020, more than double the current rate of investment" (UK Department of Energy & Climate Change, 2011: 27).

In addition, a quick analysis of the UK's NREAP reveals that in order to reach the 31% RES-E 2020 target (2010: 9%), the UK is planning to rely almost entirely on variable wind generation. By 2020, 38 GW of RES-E capacity is projected to be installed, of which 15 and 13 GW would be onshore and offshore wind, respectively. This means that in 2020, 88 TWh of the total RES-E generation of 117 TWh would come from wind.

Several joint ventures have been formed that seek to operate new nuclear power stations as early as 2020 (EDF-Centrica, E.ON and RWE, and Iberdrola-SSE-GdF-Suez). Still, even if these consortia are able to overcome such likely obstacles as financing problems and public opposition,[46] new (inflexible) nuclear power plants would probably not be able to solve the challenge of integrating the UK's significant additions in (variable) wind capacity.

[46] In addition, the Scottish government strongly opposes the construction of nuclear plants in Scotland.

Appendix 4. Wind power correlation in northern Europe

Table 8. Correlation coefficients between countries using simulated wind-power time series for the OffshoreGrid 2030 wind-power scenario (includes both on- and offshore wind)

	BE	DK	ET	FI	FR	DE	UK	IR	LA	LT	NL	NO	PL	RU	SE
BE	100%	45%	12%	2%	59%	67%	66%	37%	20%	21%	79%	12%	28%	20%	22%
DK	45%	100%	32%	17%	32%	76%	49%	20%	44%	48%	77%	44%	78%	48%	73%
ET	12%	32%	100%	51%	10%	18%	16%	12%	66%	66%	22%	13%	36%	45%	69%
FI	2%	17%	51%	100%	2%	6%	7%	4%	30%	34%	10%	23%	16%	19%	49%
FR	59%	32%	10%	2%	100%	37%	49%	43%	16%	18%	46%	5%	23%	17%	20%
DE	67%	76%	18%	6%	37%	100%	67%	26%	28%	30%	87%	40%	53%	32%	43%
UK	66%	49%	16%	7%	49%	67%	100%	62%	20%	21%	74%	37%	29%	21%	27%
IR	37%	20%	12%	4%	43%	26%	62%	100%	13%	14%	33%	14%	15%	13%	13%
LA	20%	44%	66%	30%	16%	28%	20%	13%	100%	89%	32%	15%	55%	74%	69%
LT	21%	48%	66%	34%	18%	30%	21%	14%	89%	100%	34%	17%	61%	88%	72%
NL	79%	77%	22%	10%	46%	87%	74%	33%	32%	34%	100%	36%	50%	34%	49%
NO	12%	44%	13%	23%	5%	40%	37%	14%	15%	17%	36%	100%	24%	16%	30%
PL	28%	78%	36%	16%	23%	53%	29%	15%	55%	61%	50%	24%	100%	65%	73%
RU	20%	48%	45%	19%	17%	32%	21%	13%	74%	88%	34%	16%	65%	100%	59%
SE	22%	73%	69%	49%	20%	43%	27%	13%	69%	72%	49%	30%	73%	59%	100%

Source: OffshoreGrid (2011).

Appendix 5. Estimates of future price differentials

Table 9. Power prices in different P&T scenarios and countries (€ per MW)

	2020				2030			
	Politics Work	*Green Growth*	*Stagnation*	*Supply Worries*	Politics Work	Green Growth	Stagnation	Supply Worries
Norway	39	50	29	76	60	71	40	89
Sweden	39	51	29	77	61	72	41	90
Finland	39	51	28	77	61	71	40	87
Denmark	43	59	32	80	70	79	48	94
Germany	56	62	40	77	70	80	48	91
Netherlands	56	62	39	75	69	81	47	90
UK	57	62	41	76	69	81	47	91

Source: P&T (2010).

Table 10. Range of price differentials in 2030 after different design realisations (base case, direct, hub-to-hub and meshed) of the direct design approach

	BE		DE		DK		EE		FI		LT		LV		NL		NO		PL		SE		UK	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
BE	-	-	4	4.6	6.3	9.7	6.4	8.4	11	24	6.9	7.2	6.4	8.1	3.3	7	16	18	6	6.3	11	26	4.6	9.4
SE	11	26	10	24	5.5	17	2	7.3	4	21	4.9	21	4	21	8.9	21	5.6	8.8	7.1	22	-	-	9.3	21
FI	11	24	11	22	7	16	4	19	-	-	6.1	19	0	1	7.3	8.1	9	13	3.7	5.6	4	21	10	20
NO	16	18	15	16	10	10	5.7	9.9	9	13	10	13	9.2	13	13	15	-	-	13	15	5.6	8.8	13	15
DK	6.3	9.7	5.8	7.5	-	-	4.6	6.2	7	16	3	5.8	4	6.2	4.2	6.3	10	10	3.3	6.9	5.5	17	6.3	8.9
UK	4.6	9.4	7.3	8.8	6.3	8.9	8.2	10	10	20	7.4	9.9	7.9	10	4.1	6.5	13	15	7.4	10	9.3	21	-	-
EE	6.4	8.4	5.4	7.8	4.6	6.2	-	-	4	19	1.2	2.7	0	1	10	21	5.7	9.9	8.4	21	2	7.3	8.2	10
LV	6.4	8.1	5.4	7.3	4	6.2	0	1	0	1	1.2	1.8	-	-	6.8	8.1	9.2	13	3.7	4.7	4	21	7.9	10
LT	6.9	7.2	5.4	6.3	3	5.8	1.2	2.7	6.1	19	-	-	1.2	1.8	5.9	7.8	10	13	2.6	3	4.9	21	7.4	9.9
NL	3.3	7	4.5	5.3	4.2	6.3	10	21	7.3	8.1	5.9	7.8	6.8	8.1	-	-	13	15	5.4	7.2	8.9	21	4.1	6.5
PL	6	6.3	4.4	5	3.3	6.9	8.4	21	3.7	5.6	2.6	3	3.7	4.7	5.4	7.2	13	15	-	-	7.1	22	7.4	10
DE	4	4.6	-	-	5.8	7.5	5.4	7.8	11	22	5.4	6.3	5.4	7.3	4.5	5.3	15	16	4.4	5	10	24	7.3	8.8

Note: The table presents differences in price levels and not absolute price levels.
Source: OffshoreGrid (2011).

Appendix 6. Selected interconnector projects in northern Europe

Table 11. Selected interconnector projects in northern Europe

Countries		**Name**	**Capacity**	**Year**	**Cost**	**Owner/operator**	**Additional information**
From	**To**		**(MW)**	**(est.)**	**(€ mn)**		
GB	NL	BritNed	1,000	2011	600	National Grid and TenneT	260 km submarine cable, HVDC; merchant; operating since April 2011, with more cables planned by 2020
SE	FI	Fenno Skan 2	800	2011	300	Fingrid and Svenska Kraftnät,	HVDC subsea
DK	NO	SK4	600	2014	443	Statnett and Energinet.dk	450/500 kV DC, regulated
PL	LT	LitPol	1,000	2015-20	237	PSE Operator S.A. and Lietuvos Energija AB	HVDC, overhead, to be completed in two steps
SE	NO	Southwest Link	1,200	2016-17	-	Statnett and Svenska Kraftnät	Combination of HVAC and HVDC
BE	GB	NEMO	1,000	2016-18	-	National Grid International Limited (NGIL) and Elia	Planned as cap and floor

Sources: Same as Table 3.

Appendix 7. Financing the transmission infrastructure

In principle, TSOs are responsible for investment in electricity infrastructure. Depending on the transmission infrastructure project, the share of TSO own resources ranges between 20% and 100% of the total investment (European Commission, 2010c). The remaining investment needed is usually covered by loans; additional capital may be provided by means of partnerships with power companies (ibid.). Cross-border electricity projects are often project-financed, meaning that a special purpose company is set up for an individual project (ibid.). While member states are usually not directly involved in financing (ibid.), most TSOs are controlled by member state governments (LBST and Hinicio, 2011).

Electricity- and gas-transmission infrastructure projects of European interest (trans-European energy networks, TEN-E) are supported financially by the EU. Under the current legislative framework the following instruments are available (European Commission, 2010c):

- the TEN-E budget (€155 mn in 2007–13), with a maximum co-financing rate of up to 50% for studies and 10% of eligible costs for works (however, this usually just amounts to 0.01-1% of a project’s total investment needs);
- the European Investment Bank, through which €3.407 bn of senior loans were provided to electricity projects between 2007 and 2009;
- structural funds, with a total available sum of €1.33 bn (2007–13), of which, however, only a marginal part is allocated to electricity-related projects; and
- other EU sources, namely the European Energy Programme for Recovery (which expired on 31 December 2010, with its remaining funds having been allocated to a new European Energy Efficiency Facility), instruments for pre-accession, the European Neighbourhood Policy and the Framework Programme for Research and Technological Development.

The recent Commission proposal for the new multiannual financial framework (MFF) 2014–20 foresees a significant increase in the funds available for projects related to electricity infrastructure. Especially the proposed Connecting Europe facility (€40 bn in total, of which €9.1 bn is for the energy sector) would improve EU funding capabilities. Similarly, a European Parliament Resolution of 8 June 2011 underlines that “energy’s share in the next MFF should increase” (European Parliament, 2011).

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