Electricity Grid Expansion in the Context of Renewables Integration in the Baltic Sea Region

Prepared for BASREC by Ea Energy Analyses

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1 Summary

Wind power and other renewable energy sources will be key to reducing the CO_2 emissions from the countries surrounding the Baltic Sea Region. In this respect, the transmission grid is a crucial component as it is a pre-requisite for cost-efficient exploitation of the wind power in in the region.

Purpose of the study

The overall purpose of this study is to analyse how increasing deployment of renewable energy, in particular wind power, will affect the demand for reinforcement and expansion of the electricity transmission grid in the Baltic Sea Region. The result is a list of the most attractive investments in new interconnectors considering different scenarios for energy and climate policies in the region.

The reasons for establishing new interconnectors can be manifold: to improve the technical resilience of electricity grids, to improve the security of energy supply or to facilitate well-functioning markets.

This study is limited to addressing the value of new interconnectors to the electricity market, i.e. the benefits of connecting electricity regions (price zones) with different electricity prices. The Baltic States have a joint political goal of synchronizing their electricity systems with Western European grids. This issue has not been subject to examination within the present study and the possible impacts of a synchronization have therefore not been covered.

1.1 Methodology and key assumptions

Apart from Iceland, all countries in the Baltic Sea Regions are analysed in the study, i.e. Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Norway, Poland, Russia (North West) and Sweden. In the simulations, we also include Austria, Belgium, the Czech Republic, France, Italy, the Netherlands, Luxemburg and Switzerland, but results from these countries are not presented. The United Kingdom is not included in the simulations. This should be kept in mind when the results of the study are interpreted.

The analyses are made with the electricity market model, Balmorel, which allows for an economically optimal dispatch of power plants as well investments in new generation and transmission capacity. The study focuses on the situation in 2030. Simulations of 2014 and 2020 are included for comparison.

Four scenarios

Four scenarios with investments in new transmission capacities and four reference scenarios without investments in new transmission capacities are evaluated for 2030.

	Scenarios *with* investments in new interconnections	References *without* investments in new interconnections
1. LowCO2. Low CO_2 price (25 €/ton)	X	X
2. HighCO2. High CO_2 price (42 €/ton)	X	X
3. HighCO2_RE-sub. High CO_2 price with subsidy for wind/solar (15 €/MWh) and higher biomass price	X	X
4. HighCO2_CapMark: High CO_2 price and capacity markets in all countries	X	X

Table 1: Overview of scenarios and references for 2030.

The overall driver for the deployment of renewable energy in the two first scenarios is the price of CO_2 quotas: a low price in the first scenario and a high price in the second scenario. In the third scenario, the high CO_2-price is combined with a high price of biomass and subsidies to wind power and solar power in order to shed light on a situation where the conditions for fluctuating renewables are particularly favourable. In the fourth scenario, we analyse how the introduction of capacity markets will affect the demand for interconnectors.

Existing subsidies and taxation schemes are not considered in the study

Planned renewable energy deployment

The differences in the framework conditions across the scenarios lead to different deployment of generation capacity and generation patterns. Still, some factors are kept the same across all scenarios. Towards 2020, the development of renewable energy is made in accordance with each country's National Renewable Energy Action Plan (NREAP) or other national targets. Except for Germany, this also provides a minimum level of renewable energy deployment until 2030. In Germany, a national projection of renewable energy deployment is used for the period towards 2030. This projection takes into consideration the expected renewable deployment foreseen in the law for renewable energy (EEG). Furthermore, the study takes into consideration national policies regarding nuclear power, including for example the phase-out of nuclear power in Germany and the intentions to establish new nuclear capacity beyond 2020 in several countries in the region.

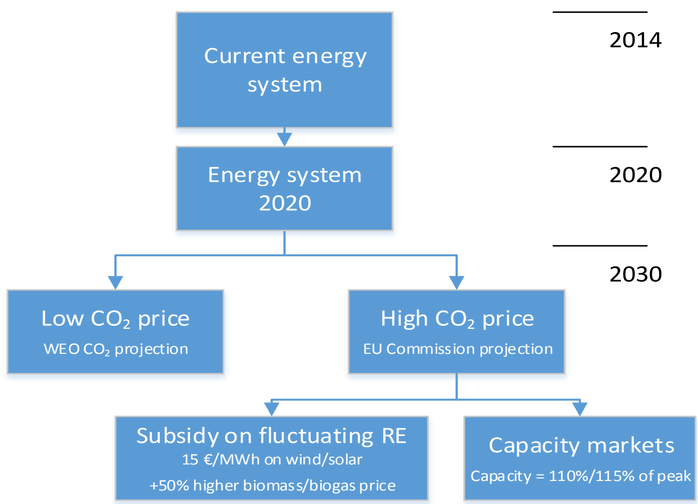


Figure 1: Scenario methodology.

Investments in new generation and transmission capacity
The Balmorel model may invest in new electricity and district heating generation capacity according to a comprehensive catalogue of technologies. Investments are undertaken in a given year if the annual revenue requirement in that year is satisfied by the market.

Similarly, the model may invest in new transmission capacity. The cost of new interconnection capacity is dependent on the specific connections' length and technology. In the study, generic cost data for substations, HVDC cables, overhead lines etc. are used to determine the costs of all relevant new interconnectors in the region. Considering possible local opposition to overhead lines we use HVDC ground cables as the default technology for connections on land. The assessed reference capacity is equal to a line with capacity of 600 MW. We do not assume any limit on investments in new transmission capacity between price zones. This is not necessarily realistic, but this approach is chosen in order to show the overall potential for expanding the transmission grid in the region.

1.2 Results and findings

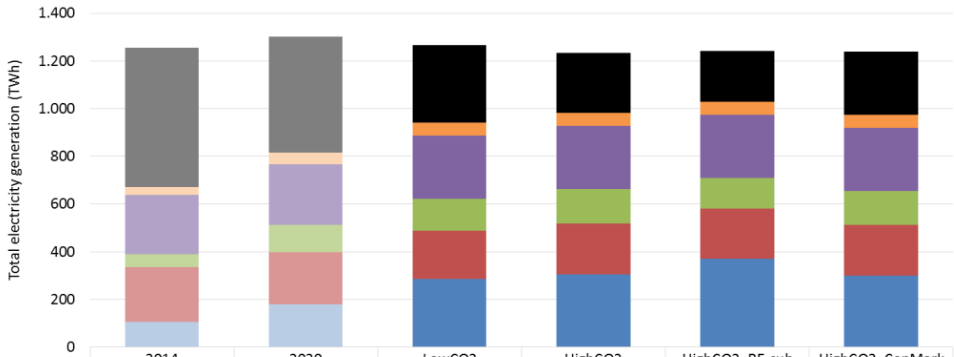
The four scenarios with and the four references without investments in new transmission capacities beyond 2020 lead to a total of eight different developments for the region.

Generation mix

Figure 2 shows the total generation mix for the BASREC countries in the four scenarios where investments in new transmission capacity are permitted. We see a clear impact of the different framework conditions in the scenarios with the highest shares of wind power obtained in *HighCO2_RE-sub* scenario, which combines a high price of CO_2 with subsidies for wind and solar and a high price on biomass. In this scenario, wind and solar power together makes up 34 % of total generation compared to 27 % in the low CO_2 price scenario and 29 % in the high CO_2 price scenario.

The carbon prices in the four scenarios are not sufficient to drive investments in carbon capture and storage technologies (CCS). However, previous analyses indicate that CCS may become an important measure to achieve CO_2 reductions in the period after 2030 (Ea Energy Analyses 2012, "Energy policy strategies of the Baltic Sea Region for the post-Kyoto period").

The introduction of capacity markets in the fourth scenario leads to a slightly lower uptake of wind power (comparing *HighCO2_CapMark* with *HighCO2*) because the capacity markets act as subsidies to thermal power plants thus increasing their competitiveness relative to wind power and solar power.



	2014	2020	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
FOSSIL	583	487	323	251	213	265
SUN and GEOTHERMAL	32	48	55	55	55	55
WATER	249	255	265	265	265	265
BIO and WASTE	54	115	135	144	130	143
NUCLEAR	231	218	202	212	208	212
WIND	105	179	287	306	372	300

Figure 2: The total generation mix for the BASREC countries in 2014 (model simulation), 2020 and the four scenarios for 2030.

CO_2 emissions

Looking at the effects on CO_2 emissions, the impact from integrating the grids in the region is most apparent in the scenario with highest renewable deployment. It follows, that the level of CO_2 emissions, is 8 % lower in the *HighCO2_RE-sub* scenario compared to the reference where we do not allow investments in additional transmission capacity. In the three other scenarios, the difference in CO_2 emission is minimal. The lowest level of CO_2 emissions, 186 Mtons for the region as a whole, is obtained in the *HighCO2_RE-sub* scenario.

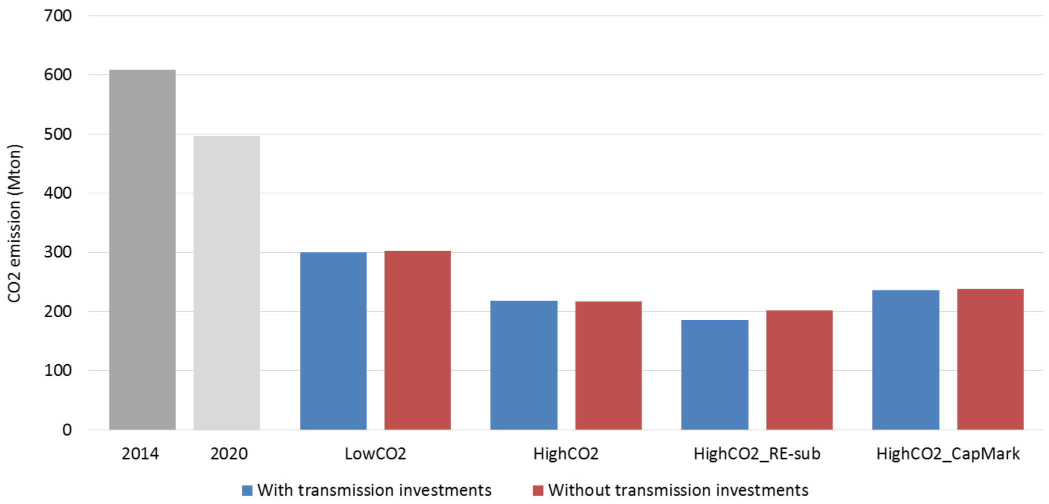


Figure 3: Total CO_2 emission of the Baltic Sea Region in 2030 for the different scenarios with and without investments in new transmission capacities.

Wind power capacity

The analyses also reveal that the investments in new wind power capacity depend on the possibility to invest in new transmission capacity (see Figure 4). On a regional level, investments in wind capacity decrease by 3 % in the *HighCO2_RE-sub* scenario when investments in new transmission capacity are not allowed. In the other scenarios, the picture is not as clear, and in the *HighCO2* scenario we do in fact see the opposite relationship. This is probably due to the fact that increasing transmission capacity also allows increasing amounts of Nordic “surplus electricity” to be transported from Norway and Sweden to Continental Europe where it may replace local investments in wind power.

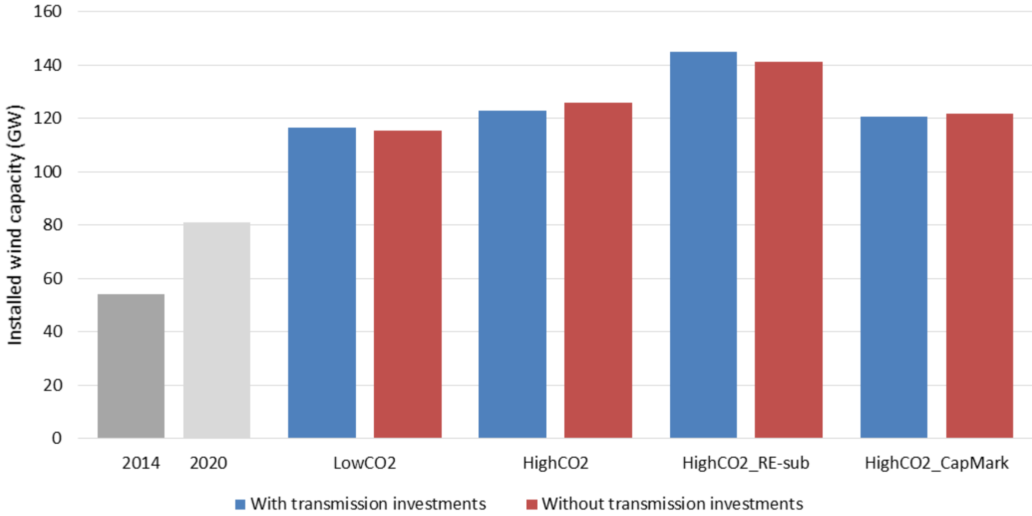
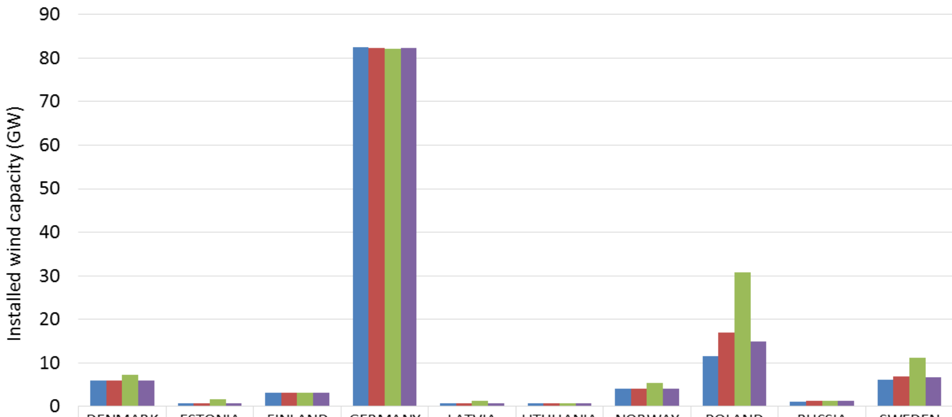


Figure 4: Installed wind capacity for the different scenarios with and without investments in new transmission capacity.



	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN
LowCO2	5,9	0,6	3,2	82,5	0,8	0,8	4,1	11,5	1,2	6,0
HighCO2	6,0	0,6	3,2	82,3	0,8	0,8	4,1	17,0	1,3	6,8
HighCO2_RE-sub	7,2	1,6	3,2	82,2	1,4	0,8	5,4	30,8	1,3	11,2
HighCO2_CapMark	5,9	0,6	3,2	82,3	0,8	0,8	4,1	14,9	1,4	6,7

Figure 5: Wind power capacity in 2030 per country for each of the four scenarios.

Investments in transmissions capacity

Significant investments are made in new interconnection capacity across the region in all scenarios. The lowest level of investments, 9,900 MW in total, is observed in the *LowCO2* scenario where the challenges related to the integration of renewable energy is also the lowest. In the *HighCO2* scenario the level increases to 12,200 MW and in *HighCO2_RE-sub* scenario, which also demonstrates the highest level of wind power, the investments in interconnection capacity reach 15,700 MW. When capacity markets are included in all countries in the region, the demand for new interconnection capacity is reduced by more than 1,500 MW compared to the same situation without capacity markets (*HighCO2 scenario*).

North-South reinforcements

All four scenarios show that it will be feasible to increase, particularly the level of interconnection from North to South in the region. Specifically, the following intersections appear attractive:

- ✓ Internal North-South reinforcements in Norway, 1,400-3,000 MW
- ✓ Internal North-South reinforcements in Germany, 900-1,800 MW
  - In addition to already planned reinforcements towards 2020
- ✓ North West Germany to Norway, 800-2,600 MW
  - In addition to the 1,400 MW NordLink connection, expected to be established by 2018.
- ✓ Western Denmark to Norway, 400-1,000 MW
  - In addition to the existing Skagerrak connections and the Skagerrak 4 connection expected to be established by the end of 2014.
- ✓ Western Denmark to Sweden, 400-2,500 MW
  - In addition to the existing Konti-Skan connection of app. 700 MW
- ✓ Sweden to Poland, 0-1,800 MW
  - In addition to the existing SwePol connection of app. 600 MW
- ✓ Sweden to Northern Germany, 800-1,800 MW
  - In addition to the existing Baltic cable with a connection of app. 600 MW.

Generally speaking, the higher level of intervals are feasible in the, *HighCO2_RE-sub* scenario whereas the lower levels apply to the *LowCO2* scenario.

A number of other connections appear attractive in some but not all scenarios. In the *Low-* and *HighCO2* price scenarios, it will be feasible to increase the capacity between Germany and Poland by up to 2000 MW, but this is not the case in the *HighCO2_RE-sub* scenario where it appears more attractive to increase the interconnection capacity between Poland and Sweden. The reason for this is probably the high amount of wind power in Poland in the *HighCO2_RE-sub* scenario, which can be balanced by Nordic hydro power through a connection to Sweden.

Moreover, all scenarios, except the Low CO2 price scenario, show increasing demand for interconnection capacity between Lithuania and Poland, but this is not driven by investments in renewable energy. Also, a number of scenarios indicate a demand for new interconnection capacity – up to 1,600 MW – in the northernmost part of the Baltic Sea Region, connecting Northern Sweden more closely to either Northern Norway or Finland.

Exchange of electricity

The exchange of electricity in the region increases very considerably in the 2030 scenarios compared to the current situation. The flow on the interconnectors mainly runs from North to South, but the interconnection from Germany to Norway is also utilized for export to Norway at times when wind power production in Germany is peaking.

Germany is a net importer of electricity in all 2030 scenarios, but in particular in the *HighCO2* (56 TWh,) and *HighCO2_RE-sub* (76 TWh) scenarios where the renewable deployment increases significantly in the other countries in the region. Imports to Poland are also significant in the *HighCO2* scenario (37 TWh) and *HighCO2_RE-sub scenario* (36 TWh). The above figures include exchange of power with third countries

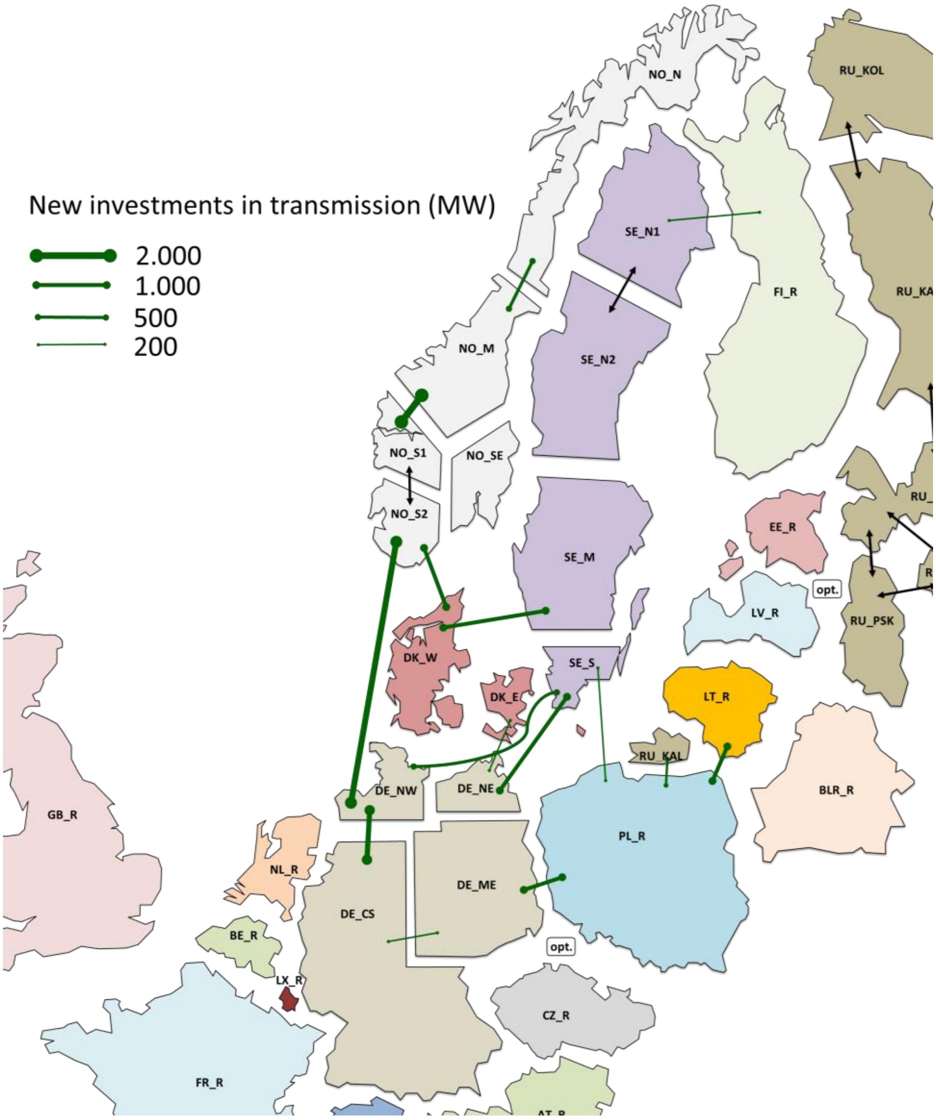


*Figure 6: Map of the model's investments in new transmission capacities for the **High CO_2 price** scenario.*

Barriers to the integration of grids in region

As part of the ENTSO-E's TYNDP from 2012, a total of 46 grid projects of "pan-European" in the Baltic Sea Region were evaluated according to a multi-criteria methodology. Reviewing the multi-criteria analyses indicate to what are the main barriers for developing the grid in the region.

The review showed that 59 percent of the projects are subject to "medium or high risk" with respect to social and environmental impact**.** In other words, the project will have (or is perceived to have) social and environmental impacts, which pose a risk to the implementation of the project or could mean delays.

The ENTSO-E report also provides an assessment of the economic consequences of the 46 projects. An assessment by Ea Energy Analyses based on the ENTSO-E data indicates that 17 percent of the projects demonstrate good socio-economy, 57 percent a balanced economy and 26 percent a negative economy.

Lastly, the ENTSO-E mentions that the large volume of projects in some countries represents a challenge in itself, as it requires increased implementation capacity both internally and in the suppliers market.

The ENTSO-E analyses does not reveal how the different projects affect stakeholder economy. However, experience shows that the benefits of infrastructure projects are often unevenly distributed between stakeholders group (consumers, electricity producers, TSO's etc.) as well as between countries. This is likely to pose a separate barrier for the financing and implementation of infrastructure projects even if they demonstrate good economy for the region as a whole.

The European Union recognizes the importance of developing electricity transmission grids in order to accommodate increasing shares of renewable energy. Under the Connecting Europe Facility (CEF) the EU has allocated substantial funding for supporting trans-European energy infrastructure, which could be important for alleviating the above-mentioned barriers.

Key findings

The model analyses show that the deployment of renewable energy will lead to an increasing demand for interconnection capacity in the Baltic Sea Region towards 2030. In particular capacity will be needed to allow for expanding North-Sound bound transport of power. This concerns both reinforcements of the domestic grids in Norway and Germany and links between Scandinavia and Continental Europe.

The study also demonstrates that given the same level of support to renewable energy, indirectly through the price of CO_2-quotas or directly through subsidies, efficient integration of the grids in region is likely to lead to lower CO_2-emissions in the Baltic Sea Region.

2 Introduction

This report is part of the study of the Baltic Sea Region Energy Co-operation (BASREC) project "Electricity Grid Expansion in the context of Renewables Integration in the Baltic Sea Region".

Background

At the Baltic Sea Region Energy Co-operation (BASREC) Ministerial Meeting in Berlin 14-15 May 2012 the Energy Ministers emphasized that continuation of their close co-operation is essential for efficient and sustainable growth in the Baltic Sea Region (BSR).

The ministers also confirmed the need for continued work on identification of solutions for and removal of barriers of market integration and development of energy infrastructures in the BSR, and stated that the co-operation in the period 2012-2015 should focus ,among other things on the "Analysis of options for the development and integration of energy infrastructure in the region, in particular regional electricity and gas markets, including legal frameworks", as well as on the "Increased use of renewable resources available in the region, including integration of fluctuating wind power into the electricity system".

In the EU, effective interconnection of the BSR is a high priority. It was identified as one of the six priority energy infrastructure projects in the Second Strategic Energy Review adopted by the Commission in November 2008. The Baltic Energy Market Interconnection Plan (BEMIP) was launched at in 2008 at autumn European Council and by June 2009 a final report including an action plan was presented.

2.1 Content of this study

The overall purpose of the study is to analyse the impact of increasing wind power on the BSR national connections and interconnections between countries. The main result is a list of the most attractive investments in new interconnectors considering different development of energy and climate policies in the region. The study focuses on 2030, but uses 2014 and 2020 as comparison years.

In addition, to this a short review has been made of barriers and challenges for integration of renewable energy focusing on the demand for new interconnectors in the region and the most important barriers to their establishment. The review is presented in chapter 7.

3 Starting point

The geographical scope of the study is the Baltic Sea Region comprising the countries of Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Norway, Poland and Sweden as well as the North Western part of Russia. Iceland is also member of BASREC but the country is not part of the present analyses due to the geographic distance from the other countries in the region.

The Baltic Sea Region by this definition holds a total population of around 165 million people with an aggregated gross electricity consumption of approx. 1,300 TWh. This corresponds to close to 40% of the total electricity demand in the EU.

The largest electricity load centres are located in the south of the region, in Germany and Poland – the two countries with the highest population (as the study only considers North West Russia) – but Norway, Sweden and Finland also have relatively high electricity demand, due to high consumption of electricity for heating purposes and the presence of energy intensive industries.

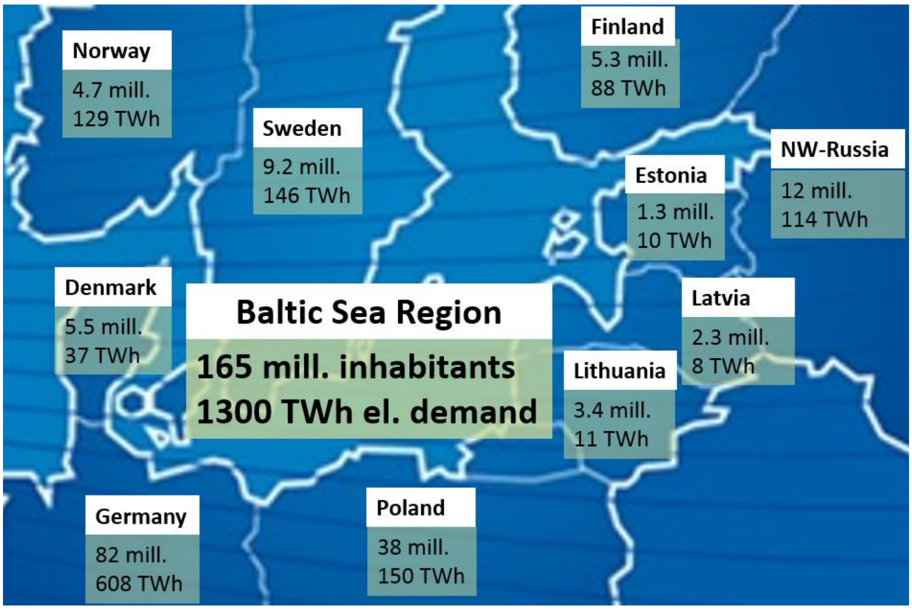


Figure 7: Inhabitants and gross electricity demand (2008) in the Baltic Sea Region.

A region which is rich in resources

The countries surrounding the Baltic Sea are rich in resources for energy production – both fossil fuels and renewables. Significant gas reserves are available in Norway and Russia; Germany and particularly Poland have substantial coal resources and Norway has large oil reserves. Several countries in region also hold significant shale gas resources and in Poland exploration activities have been significant in recent years. However, it is still unclear, what level of commercial shale gas production we will see in the region in the years to come.

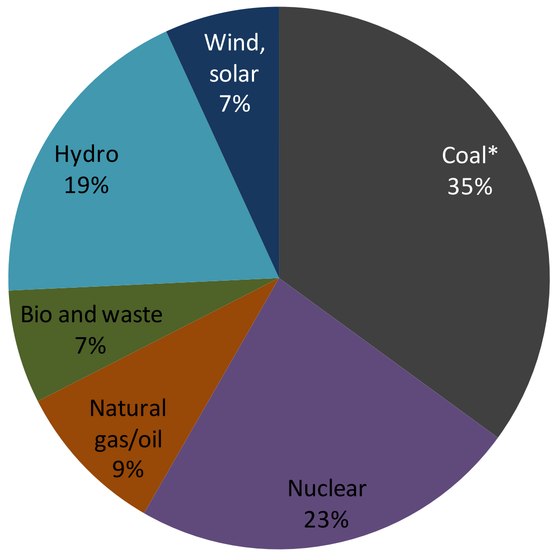


*Figure 8: Energy sources for electricity generation in the Baltic Sea Region in 2010. Simulation with the Balmorel model. *The fuel category "coal" includes lignite, oil shale and peat.*

Hydropower is an important source of electricity generation in Norway, Sweden, Finland and Latvia. Biomass resources are significant as well, deriving from both agricultural residues and from the large areas covered by forests. Wind power already contributes considerably to electricity generation, particularly in Denmark and Germany, and is likely to play a much greater role in the region in the years to come, both onshore and offshore.

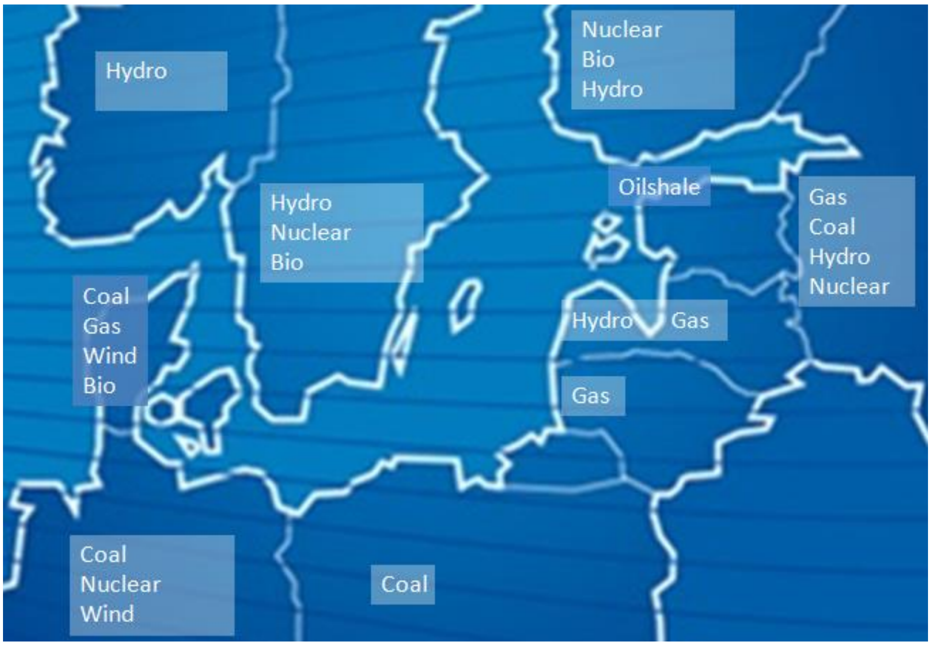


Figure 9: The most important sources of electricity generation in the region today.

In the longer term, solar power and heating and geothermal energy may also provide notable contributions to the overall energy supply.

The electricity systems are interconnected

All countries surrounding the Baltic Sea are electrically connected directly or indirectly (see Figure 10). Despite a common frequency of 50 Hz, the region comprises three different synchronous areas: the Nordic area (Norway, Sweden, Finland and Eastern Denmark), the continental European area (Germany, Poland and Western Denmark and more than 20 other European countries) and the Baltic synchronous area, which covers the three Baltic countries and is synchronous with the Russian power system UPS. Between the synchronous areas, power exchange can only take place through HVDC links.

The transmission system operators in the EU countries in the region and Norway are organised within ENTSO-E.

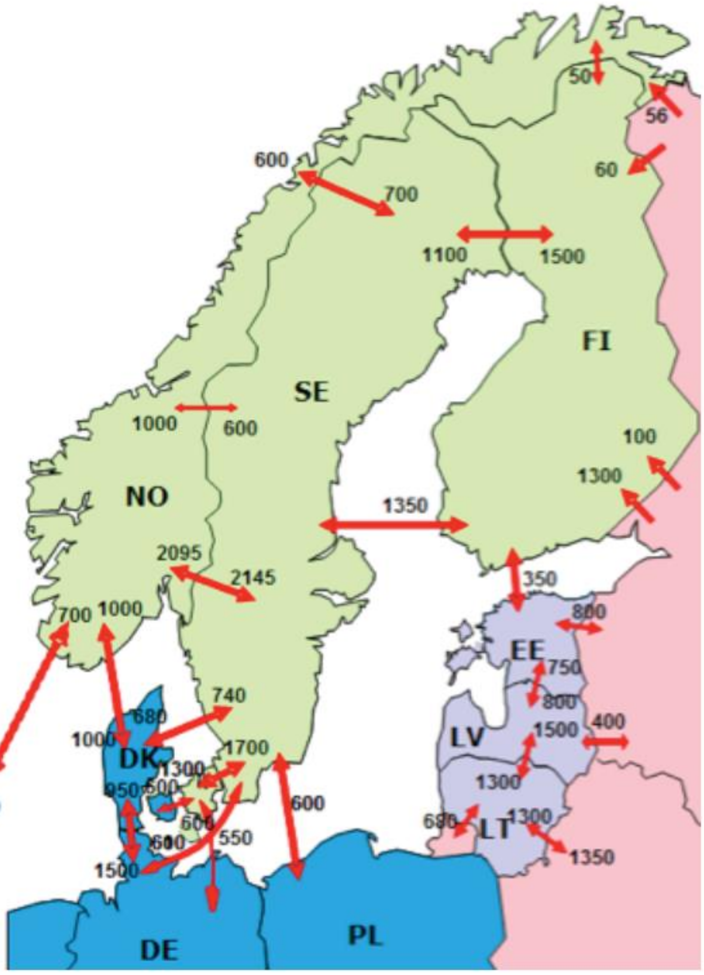


Figure 10: Power systems of the Baltic Region Source: ENTSO-E (2012). The Baltic countries are synchronous with Russia and Belarus. The 650 MW extra Estlink 2 connection has been in operation since February 2014, so the connection between Finland and Estonia is 1000 MW in total.

Whilst the Nordic countries and central Europe are presently well interconnected, the three Baltic countries are currently only able to exchange energy with the Nordic countries through two interconnectors between Estonia and Finland (EstLink 1 and 2). However, new interconnectors are being established, which will connect Lithuania with Sweden (Nordbalt, 700 MW at the end of 2015) and Poland with Lithuania (LitPol Link, 500 MW at the end of 2015 increasing to 1000 MW by 2020).

On the way to a common regional electricity market

The Nordic and Baltic countries form a common power exchange (Nord Pool) jointly owned by the transmission system operators. In Germany power is exchanged through the European Energy Exchange and in Poland through the Polish Power Exchange.

Nord Pool and the European Power Exchange are linked through so-called market coupling to ensure efficient use of existing cross-border interconnections. Since 4th February 2014, a joint auction between regions in North West Europe has been in operation. The North West Europe pan-European Market Coupling of day-ahead power market, is a joint power market between the Central Western Europe, Great Britain, the Baltic countries and the Nordic countries.[1] In addition, Sweden and Poland are coupled via the SwePol interconnection.

Reform of the Russian electricity sector

In Russia, the reformation and liberalisation of the electricity sector was completed in 2010. This included an unbundling by separation of generation capacity from transit and distribution, with transit being controlled by the state and the other two being open for competition. Russia has since 2012 been split into 27 separate trading zones.

The Russian market now consists of eight wholesale generating companies of which six are based on thermal generation and two state-owned companies: a company consisting of only hydro power plants (RusHydro) and a company consisting of all nuclear power plants (Rosenergoatom). In addition, there are 14 so-called territorial generating companies consisting of the smaller power plants and combined heat and power plants[2].

Contrary to the other countries in the region, the Russian market design also includes a separate capacity market to ensure resource adequacy in periods of peak demand. The Russian capacity market is not replicated in the scenarios apart from scenario 4 where capacity markets are assumed to be adopted by all countries.

3.1 Scenario setup

The analyses in the present study focus on identifying the needs for expanding the electricity transmission grid to balance the growing share of renewable energy wind power that is expected in the future.

The development with wind power and other renewables are very dependent on the framework conditions, most notably the level of support, which can be

[1] North-Western European Price Coupling (NWE), http://www.nordpoolspot.com/How-does-it-work/European-Integration/NWE/
[2] Roadmap of the EU-Russia Energy Cooperation until 2050 Progress report July 2011, http://ec.europa.eu/energy/international/russia/press_en.htm

direct via subsidies or tradable certificate schemes or indirect through quotas or taxes on CO_2-emissions.

Four scenarios for 2030

Four scenarios for 2030 are set up to analyse the investment in wind power and transmission capacity.

The first scenario explores a situation with a low or modest CO_2 quota price of 25 €/ton in 2030. The three other scenarios assume a higher CO_2 quota price of 42 €/ton corresponding to the price necessary to achieve an overall 40% GHG reduction according to the impact assessment underlying the EU Commission's proposal for "A policy framework for climate and energy in the period from 2020 to 2030" (EU Commission, 2014). Wind and solar power is in competition with other renewable energy technologies including electricity generation based on biomass. To shed light on a situation with more wind power, we explore a situation where wind and solar power receive a subsidy of 15 €/MWh and where the price of biomass is 50 % higher than our standard assumptions. The higher biomass prices could be a result of a strong demand for biomass or due to increasing environmentally related constraints on the biomass resource. Finally, we examine a scenario, where each of the countries in the region implement a capacity market to ensure security of supply by means of local generation technologies. In the simulations, we assume that wind power and solar power are not considered "reliable" electricity generation in these capacity markets, which therefore provide an indirect incentive to thermal power capacity.

The analysis of these different possible futures will give an indication of which transmission connection that it would be economically ideal to invest.

The years 2014 and 2020 are also modelled. This is mainly done in order to show how the system evolves over time. Investments in transmission capacity are not allowed in these years. For 2020 investments in new generation technology is allowed.

Simulations	Description
2014	Simulation based on observed data for fuel and CO_2-prices, generation and transmission capacity in 2014.
2020	Transmission capacity planned until 2020 is established based on ENTSO-E. Investments in new generation capacity is allowed. The CO_2 price followed the IEA World Energy Outlook 2013 New Policies Scenario, i.e. 10 EUR/tCO_2.
2030: Scenario 1 (LowCO2)	CO_2 quota prices projected in IEA World Energy Outlook 2013, New Policies Scenario, i.e. 25 EUR/tCO_2 in 2030. Investment in new transmission capacity and new generation capacity allowed
2030: Scenario 2 (HighCO2)	As scenario 1 but higher CO_2 quota price in 2030 as projected by the EU Commission, i.e. 42 EUR/tCO_2 in 2030[3].
2030: Scenario 3 (HighCO2_REsub)	As scenario 2, with a 15 €/MWh subsidy to wind and solar power and 50% higher biomass and biogas prices.
2030: Scenario 4 (HighCO2_CapMark)	As scenario 2, but with a capacity restriction on each country, demanding that all countries (except Norway) have a total "reliable" generation capacity of 110% of peak electricity demand for larger countries (Germany, Russia and Poland) and 115% for all other countries

Table 2: Overview of simulations. Special conditions apply to Russia.

Specific assumptions for Russia

Policies aiming at reducing CO_2-emissions and promoting renewable energy technologies are assumed to be less firm in Russia compared to the rest of the region. By 2020, we do not assume any price on CO_2-emissions in Russia. By 2030, we assume that the CO_2-price in Russia is only 50 % as high as in the rest of region, i.e. 13 €/ton CO_2 in the Low CO_2-price scenario and 21 €/ton in the High CO_2-price scenario. Similarly, the subsidies to wind and solar power in scenario 3 are assumed to be only 7.5 €/MWh. It should be emphasised that Russia does not currently plan to implement a CO_2 emissions trading scheme or to support renewable energy.

[3] 40 €/ton in €2010.

Each of the four 2030 scenarios are compared with reference case, where investments in new transmission capacity are not allowed.

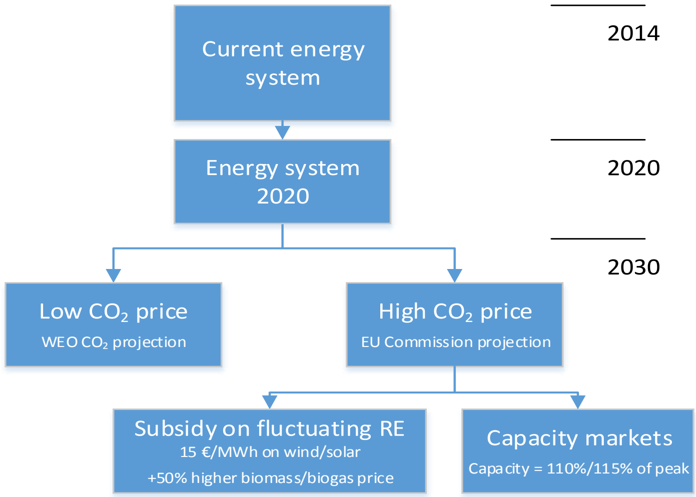


Figure 11: Overview of the scenarios. For the Current energy system scenario 2014 is analysed with historical data. For all other scenarios 2030 is analysed.

3.2 Modelling tool

The quantitative analyses are made with Balmorel, which is a least cost dispatch power system model. The model is based on a detailed technical representation of the existing power system; power and heat generation facilities, as well as the most important bottlenecks in the overall transmission grid. The main result in this case is a least cost optimisation of the production pattern of all power units. The model, which was originally developed with a focus on the countries in the Baltic region, is particularly strong in modelling combined heat and power production.

In the simulations, we also include Austria, Belgium, the Czech Republic, France, the Netherlands, Luxemburg and Switzerland. However, in this study we only focus on the assumptions and results related to the countries in the Baltic Sea Region.

In addition to simulating the dispatch of generation units, the model allows investments to be made in different new generation units (coal, gas, wind, biomass, CCS etc.) as well as in new interconnectors. A separate analysis on the cost of establishing new interconnectors in the region has been prepared, in which the cost of the individual potential new transmission line of the region have been estimated (Ea Energy Analyses 2012, Costs of transmission capacity in the Baltic Sea Region).

Section 5 accounts for assumptions regarding the connections, which the model is allowed to invest in. There is no limit on the amount of transmission capacity (MW), which the model can invest in, on the selected lines.

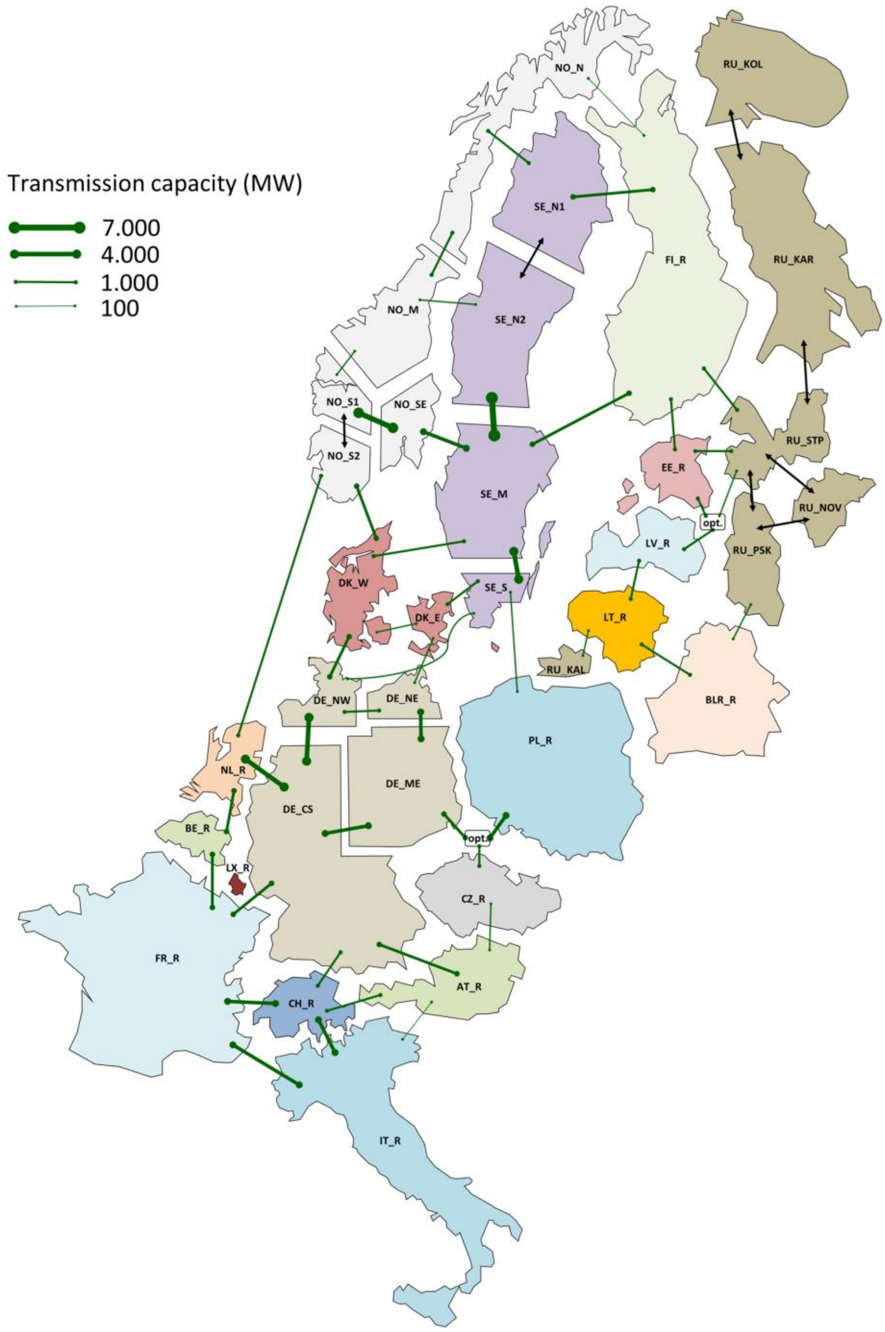


Figure 12: Map of the countries included in the model, as well as existing interconnections (2014).

When running the model each year is split into 48 time steps representing variations in demand and wind power generation.

4 Key assumptions

4.1 Fuel price and CO_2 quota price projection

Fossil fuel prices

The fuel prices of coal, oil and gas in this study are based on the IEA New Policies Scenario as presented in the IEA's World Energy Outlook, November 2013 (see Figure 13). The New Policies Scenario, dealing with the period 2012-2035, assumes that current G20 low carbon agreements are implemented.

The World Energy Model (WEM), the main tool used in the development of the IEA WEO scenario projections, operates under the assumptions of long-term equilibrium, i.e. a state of the economy where the general price level is fully reflecting – and adjusted to - the existing set-up of the main price drivers and market factors. In the short -to medium- term, however, it is reasonable to assume that the price projections based on the best available actual market information would be more representative. For this reason future/forward contract prices are used for price pathway projections in the short-term, whilst IEA scenario projections – in the longer-term.

The global efforts to combat climate change will reduce the demand for fossil fuels at the global level compared to a development with no or limited climate change regulation. Therefore, according to the International Energy Agency (IEA), increases in prices of coal, oil and natural gas will be relatively moderate.

All fuel prices are assumed the same in BSR, except the natural gas prices in Russia, which are assumed 20% lower due to the proximity local resources. The Russian gas prices have in recent years been around a third of the European prices. In accordance with the official policy of Russia, we expect that the Russian gas prices will gradually converge towards the European price level (minus the abovementioned 20 % discount).

Biomass prices

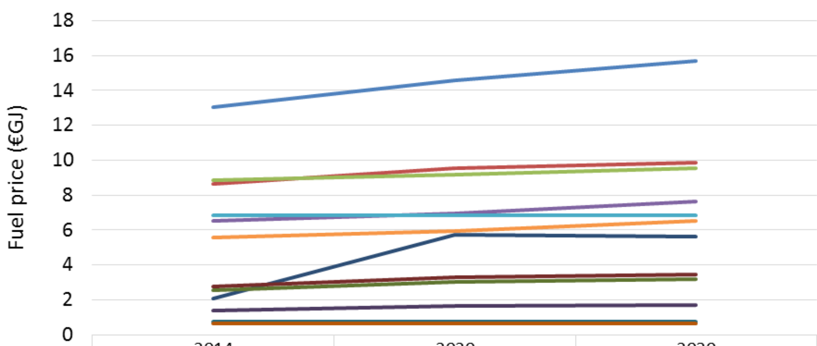
The biomass and biogas prices (also shown in Figure 13) are based on a study the Danish Energy Agency (2013). In the High biomass price scenario (scenario 3) 50% is added to the prices of biomass and biogas.

CO_2 quota prices

For the High CO_2 price scenario, the prices projected by the EU Commission in their document "A policy framework for climate and energy in the period from 2020 up to 2030" from January 2014 is used. The CO_2 quota price is here

42 EUR/ton in 2030 (in 2014 prices). The CO_2 quota prices used are shown in the table below. The prices are in 2014 prices.

For the Low CO_2 price scenario, a price projected by the WEO 2013 is used. This is, in line with the above fuel prices, based on the New Policies. In the 2014 simulation the historical price of 5 EUR/tCO_2 is used.



	2014	2020	2030
FUELOIL	13.0	14.6	15.7
NAT_GAS	8.7	9.6	9.9
WOOD PELLETS	8.8	9.1	9.5
WOOD CHIPS	6.5	7.0	7.6
BIOGAS	6.9	6.9	6.9
STRAW	5.6	6.0	6.5
OIL SHALE	2.1	5.7	5.6
COAL	2.7	3.3	3.4
PEAT	2.5	3.1	3.2
LIGNITE	1.4	1.7	1.7
NUCLEAR	0.7	0.7	0.7
WOOD WASTE	0.6	0.6	0.6

Figure 13: Fuel prices for all countries (in 2014 prices). For historical reasons the natural gas price in Russia is 70% lower in 2014 and assumed 20% lower in 2020 and 2030 than in the rest of Europe. In the High Biomass price scenario the prices of wood waste/pellets/chips and biogas are 50% higher than the prices shown in this figure.

(EUR/tCO_2)	2014	2020	2030
Low CO_2 quota price	5	10	25
High CO_2 quota price	5	10	42

Table 3: CO_2 quota prices used in the scenarios. (In 2014 prices).

In Russia we apply a CO_2-price of 0 €/ton in 2014 and 2020. By 2030 we utilize a 12.5 €/ton as the low CO_2-prices and 21 €/ton as the high CO_2-price.

4.2 Generation capacities

The data on power plants are based on the model's inventory, which is continuously updated, as decisions on the commissioning and decommission of power plants in the region are made.

Input to Balmorel

This section describes specific technical data for the power plants in the Baltic countries. Furthermore, the exogenously defined power plant capacity is described for all countries in the model for the base scenario.

In the Balmorel model, the individual power stations or types of power stations (aggregated groups) are represented by different technical and economic parameters, e.g.

- Technology type
- Type of fuel
- Capacity
- Efficiency
- C_b and C_v values for extraction and backpressure CHP plants
- Desulphurisation
- NO_x emission coefficient
- Variable production
- Fixed annual production
- Investment costs

The fuel type could for instance be oil, natural gas or biomass. It is possible to specify any type of fuel in the model.

The capacities in the model are given as net capacities for either electricity or heat. For extraction units, the capacity is given as the electrical capacity in condensing mode; while for backpressure units it is given as the electricity capacity in co-generation mode.

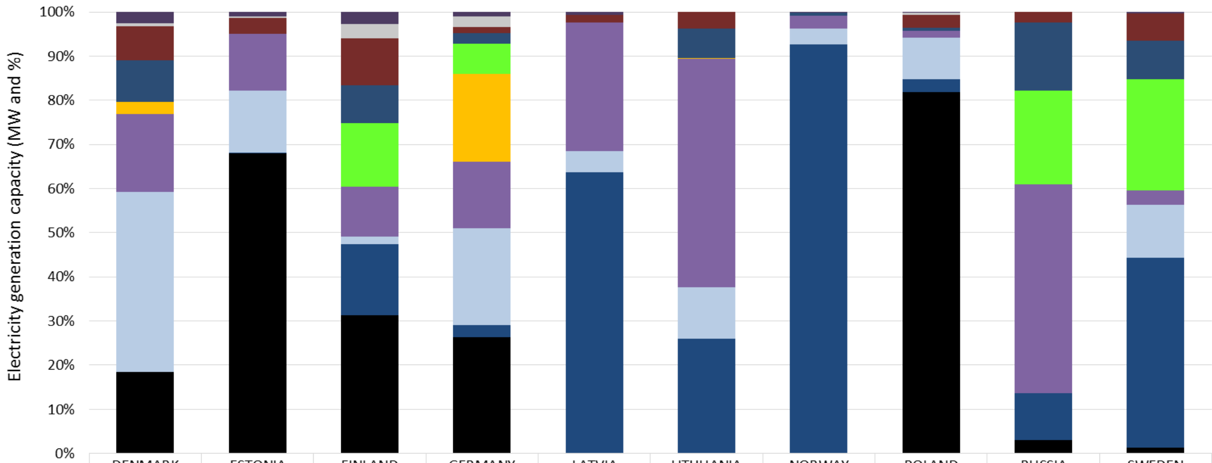
In full cogeneration mode at CHP units, the C_b-value specifies the ratio between electricity and heat. For extraction units, the C_v-value specifies the loss in electricity when producing heat for maintained fuel consumption. The fuel efficiencies in the model are for CHP units given as the fuel efficiency in condensing mode for extraction units and the total fuel efficiency in CHP mode for back pressure units. Fuel efficiencies are defined on an annual average basis.

In the model, the generation on the hydro plants is calculated using the capacity and a set of full load hours, which are given specifically for each area.

Decommissioning of power plants

The decommissioning of thermal power plants can happen both exogenous and endogenous in the model. The exogenous approach is based on data about the year of commissioning of power plants and assumptions about typical technical lifetime. Moreover, the model can decide to decommission a power plant when it is no longer economical profitable to operate (endogenous decommissioning).

Data on existing power plants is presented on an aggregated level in Figure 14 and Table 4. The data regarding heat-only boilers is not represented in this overview. The data is based upon national statistics as well as the National Renewable Energy Action Plan (NREAP) reports.



	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN
GEOTHERMAL				22						
WASTE	308	23	500	1,597	15		20	34		138
BIOGAS	63	6	625	4,286				162		
BIOMASS	914	83	1,958	2,578	45	151	30	987	646	2,403
OIL	1,121		1,608	4,072		279	188	220	4,167	3,390
NUCLEAR			2,691	12,068					5,760	9,782
SUN	315			35,099		8		1		2
NAT. GAS	2,096	286	2,107	26,372	712	2,131	900	483	12,775	1,261
WIND	4,801	313	321	38,809	116	484	1,113	3,030	4	4,692
WATER		4	2,980	4,617	1,560	1,068	28,564	970	2,862	16,733
COAL	2,185	1,521	5,847	46,445				26,576	811	490

Figure 14: Electricity generation capacity in 2014 (31st December). Wind capacities are based on Eurobserv'er "Wind energy barometer" (2014). Table below shows the capacity in MW and the plot shows the fuel mix in percentage of total capacity.

(MW)	THERMAL	WIND	WATER	GEOTHERMAL	SUN	TOTAL
DENMARK	6,687	4,801			315	11,803
ESTONIA	1,918	313	4			2,235
FINLAND	15,336	321	2,980			18,637
GERMANY	97,418	38,809	4,617	22	35,099	175,965
LATVIA	772	116	1,560			2,448
LITHUANIA	2,561	484	1,068		8	4,121
NORWAY	1,138	1,113	28,564			30,815
POLAND	28,462	3,030	970		1	32,463
RUSSIA	24,159	4	2,862			27,025
SWEDEN	17,464	4,692	16,733		2	38,891
TOTAL	**195,915**	**53,683**	**59,358**	**22**	**35,425**	**344,403**

Table 4: Electricity generation capacity (MW) in 2014.

Estonia

The Estonian electricity generation mainly takes place at large oil shale power plants in the northern part of Estonia nearby the oil shale mines. The two largest plants are Eesti PP and Balti PP, which are owned and operated by AS Narva Elektrijaamad (Narva EJ).

Iru CHP is the largest producer of thermal energy in Estonia and supplies heat to approx. 50% of the city of Tallinn. Iru CHP is located in the outskirts of Tallinn and is a natural gas fired plant.

Lithuania

Lithuania also has several thermal oil/gas plants including thermal CHP, some hydro power stations and one hydro storage plant. Lithuanian Power Plant (LPP) in Elektrenai is the largest thermal power station in Lithuania. The power station consists of eight units with a total capacity of 1,955 MW. The first unit at LPP was commissioned in 1963, and two units have been refurbished in 1992 and 1994. A new 455 MW combined cycle unit was installed and became operational in 2012 as part of the plant’s modernisation process.

The Kaunas hydro plant is run-of-river plant, meaning that the must-run requirement is default for this unit.

Latvia

The Latvian electricity production is dominated by hydro power (run of river), representing about two-thirds of the total installed power capacity. Other important generators are two CHP units located in the city of Riga.

The three major hydroelectric plants on the Daugava are Kegums Hydro Electrical Station (HES), Plavinas HES and Riga HES. Kegums HES consists of two hydroelectric plants with a total capacity of 264 MW. Plavinas HES consists of 10 hydroelectric units and has a total capacity of 868 MW. Riga HES started operation in 1974 and consists of 6 hydroelectric units with a total capacity of 402 MW.

Poland

Hard coal and lignite are the dominant fuels for electricity generation in Poland. The largest power plant is Belchatow with a net electrical capacity of 4113 MW.[4] During recent years the deployment of wind power has increased significantly and until half of 2014 reached more than 3700 MW.[5]

The Polish government sees nuclear power as part of the solution to reduce CO_2-emissisons and diversify energy sources. The Polish Energy Group (PGE) is expected later this year (2014) to choose the companies that they will be used as technical consultants on the nuclear projects. The PGE aims to have the final design and permits ready in 2018 and starts construction in 2019. The expected capacity will be 2,700 MW and be in commercial operation by 2024[6]. PGE has plans for another plant of around the same size being in operation by 2035.

Finland

Power generation in Finland takes place on a mix of different technologies: nuclear power plants, hydro power facilities, as well as thermal power plants based on coal, biomass and natural gas. Moreover, Finland imports around 4-5 TWh from Russia and 12–14 TWh from the Nordpool area.

Finland plans to further expand their nuclear capacity. The new Olkiluoto 3-reactor has been delayed a number of years, and is now assumed to be in operation by 2018. Two older units are expected to be decommissioned in 2027 and 2030 (Loviisa 1 and 2, total of 1 GW). Furthermore, two additional nuclear power plants are expected to go online between 2020 and 2030. The total nuclear power capacity is expected to be 5.7 GW by 2030.

NW Russia

The Russian electricity sector is among the largest in the world. In 2012, the electricity generation reached over 1000 TWh.

In this study, we only include the North Western part of Russia which has a electricity demand of around 100 TWh per annum. In this part of Russia, the most important sources for electricity generation are nuclear power, gas power and hydro power.

In 2013, there were 33 operating nuclear reactors in Russia with a total capacity of 24.2 GW. Almost 6,000 MW of nuclear power capacity are installed in North

[4] ARE SA. *Katalog elektrowni i elektrocieplowni zawodowych*. Warszawa: ARE SA, 2010.
[5] http://www.ure.gov.pl/uremapoze/mapa.html, updated 30.06.2014
[6] http://www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Poland/, 18 May 2014

West Russia and a number of new nuclear power stations are being proposed, including plants in Kaliningrad and St. Petersburg. On the other hand, the existing plants, among others in St. Petersburg, are scheduled to be closed or renovated within the next 15 years. In the analyses, the model is allowed to invest in one new nuclear reactor plant in Kaliningrad with a capacity of 1200 MW. Apart from that, we assume that nuclear power capacity in North West Russia remains unchanged.

Denmark

The Danish power system is characterised by both central and decentralized CHP and a relatively high proportion of wind power. The large power plants are mainly located in bigger cities, where there are district heating networks and thus the opportunity to benefit from cogeneration and heat. Denmark uses a variety of fuels for electricity generation, mainly coal and gas, but also biomass centralised and decentralised.

The Danish electricity and cogeneration system is represented in detail in the model. The large power units are shown individually, while the decentralised plants are aggregated into groups according to plant type.

Norway

Virtually all of the Norwegian electricity production is based on hydropower (95%) and in addition some wind, natural gas and biomass.

Sweden

Sweden, like Norway, has a large share of hydropower in the electricity system. In addition, Sweden has three operational nuclear power plants and cogeneration with a relatively high proportion of biomass.

The government has decided that new nuclear plants are allowed to be constructed to allow the replacement of the existing facilities. This analysis assumes nuclear capacity to be increased by 410 MW during the period 2010-20 due to renovations of existing plants.

During recent years, the increase in wind power capacity has been considerable and by the end of 2013 the total capacity exceeded 4000 MW.

Germany

Coal (and) lignite are still the most important sources of electricity generation in Germany, but the generation from renewable energy sources has increased substantially in recent years making some 24 % in 2013[7]. In accordance with

[7] DE Statis, 20 May 2024.
https://www.destatis.de/EN/FactsFigures/EconomicSectors/Energy/Production/Tables/GrossElectricityProduction.html

the German government's decision, all nuclear power plants are assumed to be decommissioned by 2022/23.

4.3 Investments in new generation capacity

The Balmorel model's investment module is used to analyse the future energy mix of the Baltic Sea region. This module allows the model to invest in new electricity and heat capacity to satisfy electricity and heat demand for the period towards 2050. Investments are made from an overall least cost optimisation of the entire energy system in the Baltic Sea region.

Investment categories by area

In the model predefined technologies, which the model allows to invest in, are categorised in different investment areas, depending on the characteristics of the area. The model is allowed to invest in various types of generation specified for this specific area depending on the characteristics of the area. The following categories exist in the model.

Area type	Technology
Central condensing area	Condensing power plants
Central CHP area	CHP only
Decentralised small CHP area	Natural gas-fired plants
Decentralised large CHP area	Natural gas-fired plants
Decentralised area without gas network	Non-natural gas technologies
Waste incineration area	Waste incineration
Offshore wind area without wave power	Offshore wind technologies only
Offshore wind area with wave power	Offshore wind and wave power
Offshore wind are far from shore	Offshore wind far from shore

Table 5: Investment areas.

Technology options

The model has a technology catalogue with a set of new power generation technologies that it can invest in according to the input data. The investment module allows the model to invest in a range of different technologies including (among others) coal power, gas power (combined cycle plants and gas engines), straw and wood based power plants and wind power (on and off-shore). Thermal power plants can be condensing unit – producing only electricity, or combined heat and power plants. The model is also able to rebuild existing thermal power plants from the existing fuel to another. The model can, at a lower cost than building a new power station, rebuild a coal fired plant to a wood pellets or wood chips, and natural gas fired plant to biogas. Wave power and solar power technologies are also included in the technology catalogue.

Basic technical and economic data for the power generation technologies, that the model may invest in are presented in Table 7. The technology assumptions develop from now to 2050, which means costs and efficiencies are assumed to develop depending on the learning curve of the specific technology. This development can be seen from the intervals presented in the table below. Generally, the technologies develop to have higher efficiencies and lower investments costs.

1. Investment costs is for electricity generation units per MW_{el}.
2. For heat only units investments costs per MW_{heat}.
3. Variable O&M for condensing and electricity-only (wind, PV, hydro etc.) units are per MWh electricity generation
4. Variable O&M for backpressure units are per MWh electricity and heat generation.
5. Variable O&M for heat-only units are per MWh_{heat}.
6. The technology is available in the year given in the last year of the "technology" name. Eg. "...10_19" means the technology is available from 2010 to 2019. If the technology name ends by e.g. "...20" the technology is available from 20 to 2050.
7. The fuel efficiency is the electricity efficiency for condensing and extraction units, as well as for electricity-only generation (wind, PV, hydro etc.). For backpressure units, it is the thermal efficiency (electricity+heat), and for heat-only units it is the thermal efficiency as well (only heat).

Capital costs of nuclear is based on the average from the IEA and the Finish Olkiluoto, unit 3 and the French Flamanville, unit 3. This gives a cost of 4.13 mill. EUR/MW. Investments in new nuclear capacity are allowed in Finland, Lithuania, Poland and Russia.

(MW)	Existing 2014	Existing and planned by 2030	Allowed extra investment in the model
Finland	2,790	3,300	3,900
Poland	0	2,780	900
Lithuania	0	0	1,600
Russia	5,760	5,760	1200
Germany	22,640	0	0
Sweden	9,780	9,780	0

Table 6: Nuclear capacity allowed for investment in 2030.

The model may also invest in heat generation capacity such as coal, biomass and gas boilers, as well as large-scale electric heat pumps, electric boilers, solar heating, electric storages and heat storage.

The opportunities to invest in the different technologies are not uniform across the region, for example because there are differences in the availability of renewable energy resources in the different countries.

Technology name	Technology type	Fuel type	Investment cost (mil.€/MWel)	Fixed O&M (€1000/MWel)	Variable O&M (€/MWh)	Fuel efficiency
SteamTur-CON-CO-10_19	Condensing	Coal	2.04	57.25	2.00	0.46
SteamTur-CON-CO-20_29	Condensing	Coal	2.03	61.65	2.20	0.49
SteamTur-CON-CO-30_49	Condensing	Coal	1.99	61.65	2.20	0.52
SteamTur-CON-CO-50	Condensing	Coal	1.89	61.65	2.20	0.54
SteamTur-CON-WP-10_19	Condensing	Wood pellets	2.04	57.25	2.00	0.46
SteamTur-CON-WP-20_29	Condensing	Wood pellets	2.03	61.65	2.20	0.49
SteamTur-CON-WP-30_49	Condensing	Wood pellets	1.99	61.65	2.20	0.52
SteamTur-CON-WP-50	Condensing	Wood pellets	1.89	61.65	2.20	0.54
SteamTur-CON-NG-10_19	Condensing	Natural gas	1.40	38.03	0.82	0.47
SteamTur-CON-NG-20_50	Condensing	Natural gas	1.30	38.03	0.82	0.47
SteamTur-CON-COccs-	Condensing with CCS	Coal	3.00	79.56	18.08	0.43
SteamTur-CON-WPccs-	Condensing with CCS	Wood pellets	3.00	79.56	18.08	0.43
SteamTur-EXT-CO-10_19	Extraction CHP	Coal	2.04	57.25	2.00	0.46
SteamTur-EXT-CO-20_29	Extraction CHP	Coal	2.03	61.65	2.20	0.49
SteamTur-EXT-CO-30_49	Extraction CHP	Coal	1.99	61.65	2.20	0.52
SteamTur-EXT-CO-50	Extraction CHP	Coal	1.89	61.65	2.20	0.54
SteamTur-EXT-WP-10_19	Extraction CHP	Wood pellets	2.04	57.25	2.00	0.46
SteamTur-EXT-WP-20_29	Extraction CHP	Wood pellets	2.03	61.65	2.20	0.49
SteamTur-EXT-WP-30_49	Extraction CHP	Wood pellets	1.99	61.65	2.20	0.52
SteamTur-EXT-WP-50	Extraction CHP	Wood pellets	1.89	61.65	2.20	0.54
SteamTur-EXT-NG-10_19	Extraction CHP	Natural gas	1.40	38.03	0.82	0.47
SteamTur-EXT-NG-20_50	Extraction CHP	Natural gas	1.30	38.03	0.82	0.47
SteamTur-EXT-COccs-30_50	Extraction with CCS	Coal	3.00	79.56	18.08	0.43
SteamTur-EXT-WPccs-30_50	Extraction with CCS	Wood pellets	3.00	79.56	18.08	0.43
GasTur-CON-NG-10_19	Condensing	Natural gas	0.63	8.17	1.36	0.40
GasTur-CON-NG-20	Condensing	Natural gas	0.54	8.68	1.45	0.46
GasTurCC-CON-NG-10_19	Condensing CC	Natural gas	0.78	25.52	2.13	0.56
GasTurCC-CON-NG-20_29	Condensing CC	Natural gas	0.74	25.52	2.13	0.60
GasTurCC-CON-NG-30_49	Condensing CC	Natural gas	0.73	25.52	2.13	0.62
GasTurCC-CON-NG-50	Condensing CC	Natural gas	0.71	25.52	2.13	0.62
GasTurCC-CON-BGn-10_19	Condensing CC	Biogas net	0.78	25.52	2.13	0.57
GasTurCC-CON-BGn-20_29	Condensing CC	Biogas net	0.74	25.52	2.13	0.60
GasTurCC-CON-BGn-30_49	Condensing CC	Biogas net	0.73	25.52	2.13	0.62
GasTurCC-CON-BGn-50	Condensing CC	Biogas net	0.71	25.52	2.13	0.62
GasTurCC-CON-NGccs-	Condensing with CCS	Natural gas	1.29	35.62	7.58	0.53
GasTurCC-EXT-NG-10_19	Extraction CHP CC	Natural gas	0.87	30.02	2.50	0.57
GasTurCC-EXT-NG-20_29	Extraction CHP CC	Natural gas	0.82	30.02	2.50	0.60
GasTurCC-EXT-NG-30_49	Extraction CHP CC	Natural gas	0.81	30.02	2.50	0.62
GasTurCC-EXT-NG-50	Extraction CHP CC	Natural gas	0.79	30.02	2.50	0.62
GasTurCC-EXT-BGn-10_19	Extraction CHP CC	Biogas net	0.87	30.02	2.50	0.57
GasTurCC-EXT-BGn-20_29	Extraction CHP CC	Biogas net	0.82	30.02	2.50	0.60
GasTurCC-EXT-BGn-30_49	Extraction CHP CC	Biogas net	0.81	30.02	2.50	0.62
GasTurCC-EXT-BGn-50	Extraction CHP CC	Biogas net	0.79	30.02	2.50	0.62
GasTurCC-EXT-NGccs-30_50	Extraction with CCS CC	Natural gas	1.37	40.12	7.96	0.53
GasTurCC-BP-NG-10_19	Backpressure CC	Natural gas	1.35	30.02	1.40	0.86
GasTurCC-BP-NG-20	Backpressure CC	Natural gas	1.45	30.02	1.43	0.91
Engine-NG-10_19	Backpressure	Natural gas	1.25	27.62	4.60	0.44
Engine-NG-20_29	Backpressure	Natural gas	1.25	27.62	4.60	0.46
Engine-NG-30_49	Backpressure	Natural gas	1.25	27.62	4.60	0.49
Engine-NG-50	Backpressure	Natural gas	1.25	27.62	4.60	0.49
WasteToEnergy-BP-10_19	Backpressure	Waste	8.50	404.14	6.19	0.98
WasteToEnergy-BP-20	Backpressure	Waste	8.50	373.05	6.25	0.97

Technology name	Technology type	Fuel type	Investment cost (mil.€/MWel)	Fixed O&M (€1000/MWel)	Variable O&M (€/MWh)	Fuel efficiency
SteamTur-LARGE-CON-WO-	Condensing Large	Wood chips	2.13	61.65	2.20	0.45
SteamTur-LARGE-CON-WO-	Condensing Large	Wood chips	2.06	61.65	2.20	0.47
SteamTur-LARGE-CON-WO-	Condensing Large	Wood chips	1.98	61.65	2.20	0.49
SteamTur-LARGE-EXT-WO-	Extraction Large	Wood chips	2.13	61.65	2.20	0.45
SteamTur-LARGE-EXT-WO-	Extraction Large	Wood chips	2.06	61.65	2.20	0.47
SteamTur-LARGE-EXT-WO-	Extraction Large	Wood chips	1.98	61.65	2.20	0.49
SteamTur-LARGE-BP-WO-	Backpressure Large	Wood chips	2.64	61.65	2.20	1.03
SteamTur-LARGE-BP-WO-	Backpressure Large	Wood chips	2.50	61.65	2.20	1.03
SteamTur-LARGE-BP-WO-30	Backpressure Large	Wood chips	2.35	61.65	2.20	1.03
SteamTur-Medi-BP-WO-10	Backpressure Medium	Wood chips	2.60	68.36	2.62	1.06
SteamTur-Medi-BP-WW-10	Backpressure Medium	Wood waste	2.60	68.36	2.62	1.06
SteamTur-Medi-BP-ST-10	Backpressure Medium	Straw	4.00	68.36	2.62	1.01
Central-CHP-BG-10_19	Backpressure	Biogas	3.38	93.63	15.60	0.43
Central-CHP-BG-20_29	Backpressure	Biogas	3.20	93.63	15.60	0.46
Central-CHP-BG-30	Backpressure	Biogas	3.20	93.63	15.60	0.48
Wind-Onshore-10_19	Wind power Onshore	Wind	1.40	29.33	3.42	1.00
Wind-Onshore-20_29	Wind power Onshore	Wind	1.32	29.45	3.16	1.00
Wind-Onshore-30_49	Wind power Onshore	Wind	1.29	29.13	3.03	1.00
Wind-Onshore-50	Wind power Onshore	Wind	1.22	28.3	2.90	1.00
Wind-Onshore_LCI-20_29	Wind power LCI	Wind	1.65	32.91	3.16	1.00
Wind-Onshore_LCI-30_49	Wind power LCI	Wind	1.61	32.56	3.03	1.00
Wind-Onshore_LCI-50	Wind power LCI	Wind	1.53	31.63	2.90	1.00
Wind-Offshore-10_19	Wind power Offshore	Wind	3.10	54.14	4.74	1.00
Wind-Offshore-20_29	Wind power Offshore	Wind	2.42	53.19	4.22	1.00
Wind-Offshore-30_49	Wind power Offshore	Wind	2.32	52.25	3.96	1.00
Wind-Offshore-50	Wind power Offshore	Wind	2.11	49.86	3.68	1.00
Wind-nearOffshore-20_29	Wind power Offshore	Wind	2.06	53.19	4.22	1.00
Wind-nearOffshore-30_49	Wind power Offshore	Wind	1.97	52.25	3.96	1.00
Wind-nearOffshore-50	Wind power Offshore	Wind	1.79	49.86	3.68	1.00
Wind-farOffshore-20_29	Wind power Offshore	Wind	2.91	53.19	4.22	1.00
Wind-farOffshore-30_49	Wind power Offshore	Wind	2.78	52.25	3.96	1.00
Wind-farOffshore-50	Wind power Offshore	Wind	2.53	49.86	3.68	1.00
SolarPV-10_19	Solar volt	Sun	2.00	24.5	3.40	1.00
SolarPV-20_29	Solar volt	Sun	1.30	19.1	2.65	1.00
SolarPV-30_49	Solar volt	Sun	1.10	13.69	1.90	1.00
SolarPV-50	Solar volt	Sun	0.90	9.37	1.30	1.00
WavePower-10_19	Wave power	Water	7.80	20.02	6.68	1.00
WavePower-20_29	Wave power	Water	6.40	25.02	7.51	1.00
WavePower-30_49	Wave power	Water	3.35	23.35	5.00	1.00
WavePower-50	Wave power	Water	1.60	21.02	3.50	1.00
HeatPump-EL-10_19	Heat pump	Electric	0.68	2.75	0.46	2.80
HeatPump-EL-20_29	Heat pump	Electric	0.63	1.83	0.30	2.90
HeatPump-EL-30_49	Heat pump	Electric	0.58	1.83	0.30	3.00
HeatPump-EL-50	Heat pump	Electric	0.53	1.83	0.30	3.20
El-Boiler	Electric boiler	Electric	0.08	11.01	0.50	0.99
Boiler-WO	Heat only boilers	Wood chips	0.80	8.11	2.70	1.08
Boiler-WP	Heat only boilers	Wood pellets	0.40	4.05	1.35	0.95
Boiler-ST	Heat only boilers	Straw	0.80	6	2.00	1.03
Boiler-NG	Heat only boilers	Natural gas	0.10	1.85	0.62	1.01
Boiler-WASTE	Heat only boilers	Waste	1.13	53.04	5.41	0.98
SolarDH-10_19	Solar heat	Sun	0.00	0	0.57	1.00
SolarDH-20_29	Solar heat	Sun	0.00	0	0.57	1.00
SolarDH-30	Solar heat	Sun	0.00	0	0.57	1.00
Geo_EL_HeatPump-10_19	Heat pumps Geo	Electric	1.60	18.52	2.65	4.43
Geo_EL_HeatPump-20	Heat pumps Geo	Electric	1.60	17.01	2.43	4.43
G-HSTORE-10	Heat storage	Heat	0.00	0	0.00	0.95
G-HSTORE_S-10_29	Seasonal storage	Heat	0.00	3.55	0.00	0.88
G-HSTORE_S-30_49	Seasonal storage	Heat	0.00	3.37	0.00	0.88
G-HSTORE_S-50	Seasonal storage	Heat	0.00	3.02	0.00	0.88

Technology name	Technology type	Fuel type	Investment cost (mil.€/MWel)	Fixed O&M (€1000/MWel)	Variable O&M (€/MWh)	Fuel efficiency
PumpH_Norway	Electricity storage	Electric	0.06	0.63	0.00	0.80
PumpH_Conti	Electricity storage	Electric	0.12	1.19	0.00	0.80
Nuclear-35	Condensing Nuclear	Nuclear	4.13	36.93	4.62	0.42
GeothermalEl-10_19	Geothermal heat		5.09	23.75	3.39	1.00
GeothermalEl-20_29	Geothermal heat		5.09	23.75	3.39	1.00
GeothermalEl-30_50	Geothermal heat		5.09	23.75	3.39	1.00
SteamTur-Small-BP-WO-	Backpressure Small	Wood chips	4.25	75.06	3.03	1.03
SteamTur-Small-BP-WO-20	Backpressure Small	Wood chips	4.00	75.06	3.03	1.03
SteamTur-Small-BP-WW-	Backpressure Small	Wood waste	4.25	75.06	3.03	1.03
SteamTur-Small-BP-WW-20	Backpressure Small	Wood waste	4.00	75.06	3.03	1.03
SteamTur-Small-BP-ST-	Backpressure Small	Straw	5.15	103.08	5.63	0.90
SteamTur-Small-BP-ST-20	Backpressure Small	Straw	4.60	92.08	5.03	0.90
OilShale_EXT_10_19	Extraction CHP	Shale	2.14	57.25	2.00	0.36
OilShale_EXT_20	Extraction CHP	Shale	2.14	61.65	2.20	0.36
OilShale_CON_10_19	Condensing	Shale	2.14	57.25	2.00	0.36
OilShale_CON_20	Condensing	Shale	2.14	61.65	2.20	0.36

Table 7: Generation technologies, in which the model can invest. The intervals indicate the development in technology and costs from 2010 to 2050. The biogas on these plants is upgraded biogas, meaning it has the same quality as natural gas but with higher fuel costs. Offshore wind power is categorised in three groups with different investment costs, i.e. low, mid and deep water depth. The technology catalogue is mainly based on Energinet.dk's and the Danish Energy Agencies 'Technology Data for Energy Plants', May 2012 and own assumptions.

Investment approach

The Balmorel model is myopic in its investment approach, in the sense that it does not explicitly consider revenues beyond the year of installation. This means that investments are undertaken in a given year, if the annual revenue requirement (ARR) in that year is satisfied by the market.

A balanced risk and reward characteristic of the market is assumed, which means that the same ARR is applied to all technologies, specifically 0.08, which is equivalent to 5% internal rate for 20 years. This rate should reflect an investor's perspective.

In practice, this rate is contingent on the risks and rewards of the market, which may be different from technology to technology. For instance, unless there is a possibility to hedge the risk without too high risk premium, capital intensive investments such as wind or nuclear power investments may be more risk prone. This hedging could be achieved via, feed-in tariffs, power purchase agreements or a competitive market for forwards/futures on electricity, etc.

New coal fired power plants

New coal fired power plants without CCS are not considered to be accepted politically in Sweden, Denmark or Lithuania. In Norway, it is assumed in all scenarios that gas fired capacity is only to be accepted if CCS is applied. There are currently no applications for gas fired power plants.[8]. CCS is assumed to be in a test phase, i.e. restrictions on investment in generation capacities (4,800 MW in total in region), until and including 2030.

4.4 Countries goals and plans

In the model, the countries' future political goals, requirements, and plans of CO_2 emission reduction, renewable shares in the electricity and/or heating sectors, electricity production from wind etc. are implemented. This means that the models investments will ensure that these requirements are fulfilled.

For all countries (except Russia) is assumed the development required by the countries in their NREAP until 2020, and is thereafter assumed constant. For Russia, the study assumes a small requirement for renewable share in the electricity sector (4.5%).

For Denmark and Germany, we include additional deployment of wind power reflecting the governments' energy policies. In Denmark, we apply the capacities made by the Danish TSO Energinet.dk in their assumption for analyses, which meet the 50 % wind power target by 2020[9]. For Germany, the deployment of renewable energy is projected all the way to 2030 in accordance with the Netzentwicklungsplan (NEP) 2014. However, the NEP is adjusted to take into account that the most recent law on renewable energy (EEG) defines a goal of 15 GW off-shore capacity by 2030. This projection implies a very considerable increase in the generation of power from wind power, increasing from approx. 53 TWh in 2013 to approx. 190 TWh in 2030. This development is included in all scenarios.

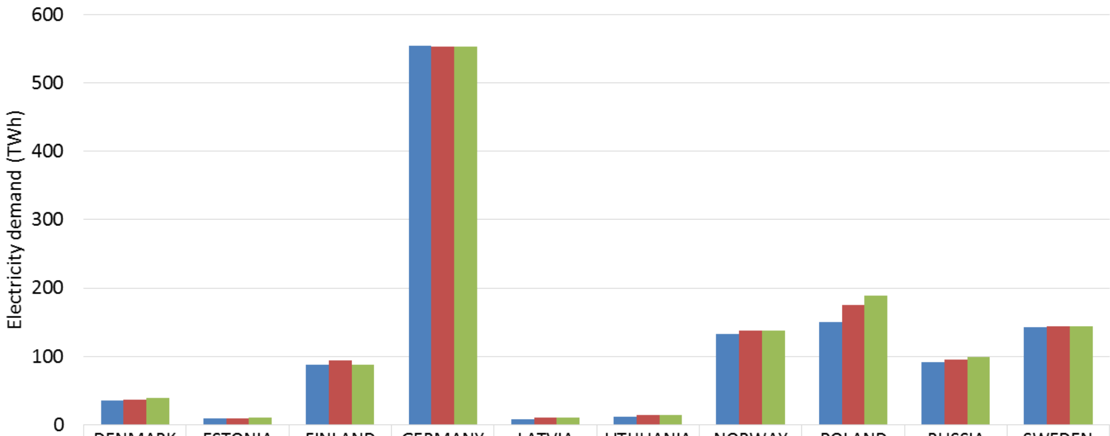
(GWh)	Biogas	Biomass	Geothermal	Wind (Offs.)	Wind (Ons.)	Solar
FINLAND	270	12,640			6,090	
GERMANY	31,718	14,927	1,821	58,962	141,074	52,153
LATVIA	584	642		391	519	4
LITHUANIA	413	810			1,250	15
NORWAY					11,000	
POLAND	4,018	10,200		1,050	14,160	3
SWEDEN	53	16,700		500	12,000	4

[8] Norway has no expressed policy on coal power, but we assume that a new coal power plant would only be accepted if equipped with CCS.
[9] Energinet.dk's analyseforudsætninger 2014-2035 (http://energinet.dk/SiteCollectionDocuments/Danske%20dokumenter/El/Energinet%20dks%20analyseforuds%C3%A6tninger%202014-2035%20maj%202014%20final.pdf)

4.5 Projections of the demand for electricity and district heating

Electricity demand

The projections from the BASREC "Energy policy strategies of the Baltic Sea Region for the post-Kyoto period”. (Ea Energianalyse, 2012). The projection for Germany has been adjusted to reflect expectations of a more constant electricity demand (as opposed to declining demand in the Post-Kyoto study) whereas the projection for Poland has been adjusted slightly downwards to represent updates of national forecasts. In Norway and Sweden we assume unchanged demand between 2020 and 2030. For Denmark, the most recent projection of the system operator Energinet.dk is applied.

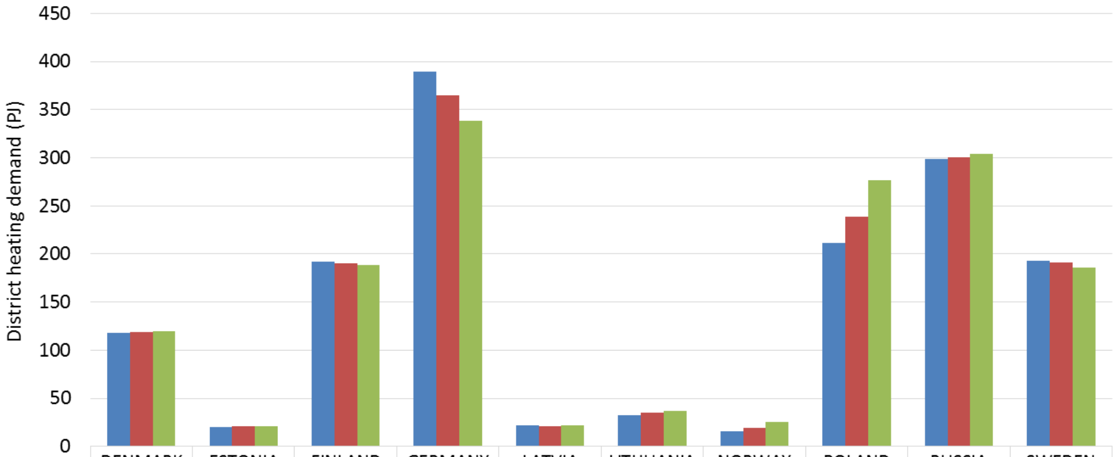


	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN
2014	35	9	88	554	8	12	132	150	92	143
2020	37	10	94	553	10	14	138	175	96	144
2030	39	10	88	553	10	15	138	189	99	144

Figure 15: Projected electricity demand for the BASREC countries (including grid losses).

District heating demand

The development in heat demand for 2014-2030 is based on the figures from the EU Commissions scenario report (2010): “Energy Trends 2030”. The net heat demand can be seen in the plot below. A network loss of 21 % in all district heating networks is assumed.



	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN
2014	118	20	192	390	22	32	16	211	299	193
2020	119	21	190	365	21	35	19	239	301	191
2030	120	21	188	339	22	36	26	277	304	186

Figure 16: Net district heating demand 2014-2030 in PJ.

4.6 Renewable energy potentials

The biomass potentials available for the power sector and district heating are restricted by national constraints. The estimation of the total biomass potential is mainly based on the EEA report “How much bioenergy can Europe produce without harming the environment?” [10] (European Environment Agency, 2006). The estimates derived from this report were originally developed for a project on Energy Policy Strategies of the Baltic Sea Region for the Post-Kyoto Period (Ea Energianalyse, 2012). To a large extent, the following description is based on this work.

Total resource

Table 8 provides an overview of possible biomass resources in 2030 in the Nordic countries, Baltic countries, Poland and Germany divided into five general categories:

- Energy crops and grass cuttings
- Forestry residues from felling and complementary felling
- Biogas (mainly from manure)
- Wood like biowaste (wood processing residues, black liquor)
- Straw like biowaste (mainly agricultural residues)

[10] Norwegian data is based on the following source,
http://www.fornybar.no/imagecache/43.OriginalImageData.20070320085549.jpg
http://www.fornybar.no/sitepageview.aspx?articleID=37
http://www.avfallnorge.no/fagomraader/energiutnyttelse/nyheter/energiutnyttelse_2008 , 22.05.2009

Municipal solid waste fractions are treated separately in the subsequent section.

PJ	Energy crops, grass cuttings	Forestry residues	Biogas	Biowaste - wood like	Biowaste - straw like	Total
Denmark	4	40	36	11	29	120
Estonia	54	8	2	35	2	101
Finland	54	75	9	215	17	370
Germany	980	201	149	133	177	1640
Latvia	63	25	3	1	4	96
Lithuania	331	17	7	40	10	405
Norway		160		9	8	177
Poland	1273	50	79	59	121	1582
Russia	109	151	18	430	33	741
Sweden	59	100	15	347	21	542
Baltic Sea	**2927**	**827**	**318**	**1280**	**422**	**5774**

Table 8: Available bioenergy resources in the Baltic Sea Region. The figures are derived from the report "How much bioenergy can Europe produce without harming the environment?" (EEA 2006)[11]. Data for Russia is lacking. For the purpose of modelling a crude assumption has been made that the biomass resources in NW Russia equal twice the resources in Finland.

The total identified bioenergy potential will not be available to the electricity and district heating sector due to biomass usage in other sectors, such as industry, households and the transport sector. The amount assumed available to the electricity and district heating sector is dependent on the scenario and described further below.

Biomass categories

For the purpose of modelling, the three biomass categories "Energy crops and grass cuttings", "Forestry residues" and "Wood like biowaste" are merged into three fuel categories termed "Wood chips+Wood pellets" and "Wood waste". "Wood waste" is a cheap local resource used at existing power plants in Poland, Sweden and Finland. For this fraction, a price close to zero is used. "Wood chips" is a more expensive biomass resource, which can be traded across the countries considered. For "Wood pellets", a higher price is applied, reasoned upon higher transportation and handling costs. Wood pellets are more expensive than wood chips, but easier to transport and handle at the power plants. This is mainly to be interpreted as a technology choice, where wood chips require higher power plant investments at a lower fuel price and vice versa for wood pellets. Therefore the resource of wood chips and wood

[11] Norwegian data is based on the following source,
http://www.fornybar.no/imagecache/43.OriginalImageData.20070320085549.jpg
http://www.fornybar.no/sitepageview.aspx?articleID=37
http://www.avfallnorge.no/fagomraader/energiutnyttelse/nyheter/energiutnyttelse_2008 , 22.05.2009

pellets is constrained by one total sum, “Wood”, while the model is free to define the share of the total sum used as wood chips or wood pellets.

The “Straw-like biowaste” resource is termed “Straw” in the model. Straw is considered to be a domestic resource, due to the higher transportations cost compared to wood chips.

Biogas is treated as two separate fractions in the model: “Biogas” and “Biogas-net”, where the first fraction refers to biogas stand-alone plants (CHP plants or boilers) and the latter to biogas, which has been upgraded for utilisation in the gas grid. “Biogas-net” may be used at conventional power plants. The total sum of biogas is constrained in the model, while the model is free to determine the share used on stand-alone plants and from the grid. See also the section on biogas in Denmark further below. Biogas is considered a domestic resource.

Local biomass resource

For all scenarios, it is assumed, that 90 % of the biogas resources are available for electricity and district heating and 80 % of the straw resource throughout the modelling period. Maximum 75 % of energy crops, forestry residues and wood like biowaste fractions will be used for power and district heating generation in the beginning of the period. This is reduced to 25 % in 2050 as this biomass is assumed to be increasingly used in other sectors. With these shares, 35% of the total bioenergy resource will be available to the electricity and district heating sector.

PJ	Biogas	Wood waste	Straw	Total
Denmark	3	-	21	165
Estonia	0	-	3	259
Finland	0	120	13	723
Germany	201	-	142	3791
Latvia	2	-	3	239
Lithuania	6	-	8	1030
Norway	0	-	6	450
Poland	71	15	97	3812
Russia	16	240	26	1463
Sweden	13	90	17	1213
Baltic Sea	**309**	**465**	**336**	**13,145**

Table 9: Available local and imported bioenergy resources in the Nordic countries, Baltic countries, Poland, Russia and Germany for electricity and district heating generation in 2030 scenarios. Resources are distributed on the fuel categories used in the Balmorel model. The resource for “Wood chips” and “Wood pellets” is only included in the grand total for the Baltic Sea Region (not in the country totals).

Import of biomass

Biogas, wood waste and straw are assumed a local resource, whereas wood chips and wood pellets are assumed a market commodity (i.e., it can be imported). There is therefore a restriction (limit) on the local biofuels (see Table 9), whereas there is no limit on the wood chips and pellets.

4.7 Wind power

The development and investment in wind power is important for this study. The model can invest in onshore, near-offshore and far-offshore. The investments costs of the offshore wind farms are dependent on the distance to the coast and the depth of the turbines (see investment costs in Table 7).

The model's investment module can choose to invest in wind power capacity based on the technical/economic potentials in each country. These are not the theoretical potentials for wind, but an estimate of a possible potential taking into consideration constraints related to access to sites, the economics of developing different sites and the available wind resources.

In 2009 the European Environment Agency (EEA) published the report ”Europe's onshore and offshore wind energy potential” with assessments of potentials for on- and offshore wind potentials in all EU member states. This analysis was done using a harmonised method in all countries. Based on this , an assessment of the long-term onshore wind power potential in the Baltic Sea Region has been made (Table 10). In connection with this study, the onshore potential for Germany has been revised upwards to reflect the current plans. The onshore potentials for the three Baltic countries, Finland and Sweden have been revised downwards to achieve a realistic maximum penetration level within the 2030 time horizon considering constraints related to planning, permitting and integration into grids.

For the offshore wind potential, a newer study is available - the BASREC report “Conditions for deployment of wind power in the Baltic Sea Region, Strategic Outline offshore wind promotion” - focusing specifically on the Baltic Sea Regions. This study's constrained potentials, i.e. the capacity after exclusion of protected areas etc., are used in the analysis. However, the BASREC wind study only considers offshore wind located in the Baltic Sea, so for Denmark, Norway and Germany, which have coast lines to other seas, i.e. the North Sea and the Atlantic, the potentials from the EEA are applied according to the procedure used in the study “Energy Policy Strategies of the Baltic Sea Region for the Post-Kyoto Period”. The shares between ‘Far offshore’ and ‘Near offshore’ in the BSR countries are assumed the same as in the Post-Kyoto report.

(MW)	Far Offshore	Near Offshore	Onshore	Total
GERMANY	56,000	19,100	82,400	157,500
DENMARK	97,500	35,900	4,500	137,900
ESTONIA	500	1,000	2,000	3,500
FINLAND	29,500	5,000	10,000	44,500
LITHUANIA	900	100	2,000	3,000
LATVIA	800	1,800	2,000	4,600
NORWAY	70,500	19,500	15,100	105,100
POLAND	900	1,100	33,600	35,600
RUSSIA	1170	1450	82,056	84,676
SWEDEN	26,400	16,800	17,500	60,700
TOTAL	**284,170**	**101,750**	**251,156**	**637,076**

Table 10: Wind potential is BSR.

Wind speed time series

The wind power production time series (profiles) are based on actual wind measurements in the different areas in most countries. An extensive set of data covering a large part of the Baltic Sea Region was obtained from a major Danish wind turbine manufacturer, in connection with the project "Paths to a fossil-free energy supply" (Ea Energy Analyses, 2010). The model can then optimise wind power production based on the potential, wind speed, turbine features and turbine prices.

Full load hours

The number of full load hours (FLH) is depending on the area. Offshore areas have in average a higher number of FLH than onshore. The number of FLH changes between areas within the countries.

	ONSHORE	OFFSHORE
DENMARK	1700-3200	3900-4600
ESTONIA	1900-2100	3700-4100
FINLAND	1800-2000	3600-4100
GERMANY	1700-2500	4000-4600
LATVIA	1900-2100	3700-4100
LITHAUNIA	1900-2000	3600-4000
NORWAY	2500-3200	3800-5000
POLAND	1800-2300	3900-4300
RUSSIA	2600-2900	3600-4000
SWEDEN	1900-2600	3500-4500

Table 11: Average number of full load hours for the different countries.

5 Existing and Planned Grid Infrastructure and Interconnections

In this chapter, the planned grid infrastructure and interconnections in the near and medium future in the BSR are presented.

5.1 The electricity grid infrastructure

The model of power systems includes restrictions on the power transmission capacity between different areas in the model area.
The grid infrastructure in the Baltic Sea Region comprises the Baltic grid (Estonia, Latvia and Lithuania), the North-West part of the Russian grid (including the Kaliningrad region), the Nordic grid (Denmark, Finland, Norway and Sweden), the German and the Polish grid.

The connections between the regions in 2014 and 2030 are listed in Appendix 2. The explanation of names of the regions can be seen in Figure 17.

The Nordic grid

The Nordic electricity system is tied together with strong interconnectors between the different countries. Furthermore, the Nordic countries are connected to Germany and Poland with both AC and DC interconnectors and to the Baltic and Russian grid by DC connections. The Nordic countries are one synchronous area except from Western Denmark which is synchronous with the with the Continental Synchronous Area, including Germany and Poland.

The Baltic grid

The electricity systems of Estonia, Latvia and Lithuania are closely connected. They also have strong links to Russia, and to Belarus.

Two DC interconnectors, Estlink and Estlink2, are connecting the Estonia and Finland. No other interconnectors link the Baltic States to the Nordic electricity system or with the Continental Synchronous Area today.

The Russian grid

The Baltic countries, especially Estonia and Lithuania have strong interconnectors to the Russian and Belarusian system and are also operated synchronously with these two systems. Estonia and Latvia have interconnectors to the Western part of Russia, whereas Lithuania has interconnectors to Belarus and Kaliningrad.

The transmission capacity between the Baltic countries is sometimes limited by loop flows going from Belarus up through the Baltic countries and to the Western part of Russia or vice versa.

Information about the internal transmission connections in Russia is somewhat limited. So far, NW Russia is split into the regions shown in Figure 17, and with an infinite transmission capacity between them. In reality, the RU_KOL is one price zone and the rest is combined to a single price zone.

The German grid

The German electricity system is part of the Continental European grid. There are interconnections with all surrounding countries including the Netherlands, Belgium, Luxemburg, France, Switzerland, Austria, Czech Republic and Poland. There is also a land connection to Western Denmark. Germany is connected to the Nordic system via sea cables to Eastern Denmark and Sweden.

The Polish grid

The electricity system in Poland has connections to Germany, Sweden, Czech Republic and Slovakia. In addition, Poland has connections with Belarus and Ukraine, currently only one is in operation between PL-UA. We do not consider internal bottlenecks in the Polish grid in study.

Two "artificial" nodes (dummy nodes) have been included in the model simulations to address the limitations of exchange of power between Poland, Germany, the Czech Republic and Slovakia.

5.2 Projects planned towards 2022

A number of projects which are either being undergoing construction or very likely to be implemented, are included in the simulations.

This involves among others a significant reinforcement of the internal grid between the North West and Central parts of Germany, which will take place (2,500 MW) in order to accommodate the planned expansion of wind power in the northern parts of Germany. It is assumed to be fulfilled by 2015. Moreover, we include reinforcements of the interconnections between Germany and Western Denmark and between Germany and Poland.

The LitPol link between Poland and Lithuania - 500 MW will be operational at the end of 2015 and 1000 MW will be operational in 2020. NordBalt linking Lithuania and Sweden will be commissioned at the end of 2015.

Lines between the central part of Norway and neighbouring areas in South are planned to be upgraded to strengthen the security of supply. The planned upgrade will also facilitate increased hydro power generation.

The table below depicts the complete list of new interconnectors or reinforcements, which are implemented in the analyses.

Connection	Area	Capacity (MW)	In operation
Skagerrak 4	Norway S – Denmark W	+700	2014
Sydvästlänken 1	Sweden C– Sweden S	+1400	2016
Cobra	Denmark W -Holland	700	2019
Denmark-Germany #1	Denmark W – Germany NW	+280→←+550	2013
Denmark-Germany#2	Denmark W – Germany NW	+1000→←+1550	2018
Nord.Link	Norway S – Germany NW	1400	2018
LitPol Link	Poland-Lithuania	500/+500	2015/2020
NordBalt	Sweden-Lithuania	700	2015
GerPol improvement	Germany NE-Poland	+500→←+1500	2017
Kriegers Flak	Denmark E – Germany NE	400	2021
German reinforcements	Germany NW- Germany CS	+2500	2015

Table 12: New interconnection capacity in the region included exogenously in the simulations.

The expected capacities in 2030 are listed in Appendix 2.

5.3 Study of new transmission capacity

Figure 17 shows the possible interconnections of which the Balmorel model can invest. We do not assume any limits on the invested capacities. This is not necessarily realistic, but it is done to give an indication of the potential of the expansion of transmission capacity between the regions.

Investment cost

A generic methodology,used to determine the costs of expanding the grid for the period beyond 2020 for both internal reinforcements and new interconnectors, is developed. Figure 18 illustrates a plot of investments costs and a length/capacity factor for different recent transmission project in the Baltic Sea Region.

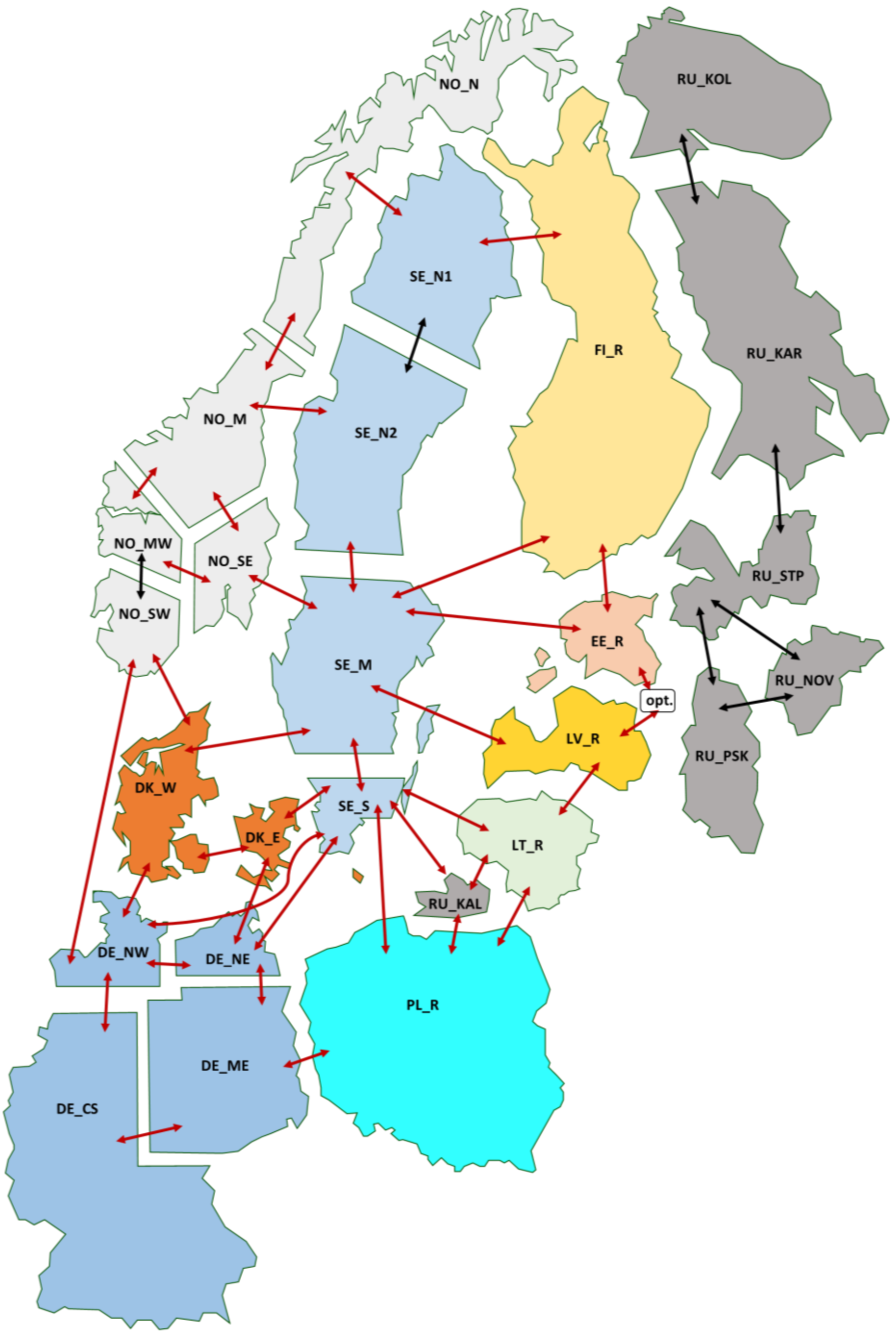


Figure 17: Possible expansion of connections (red) in the BSR to be further analysed. Black connections indicate transmission that are assumed with infinite capacity. Present and planned connections are listed in Appendix 2.

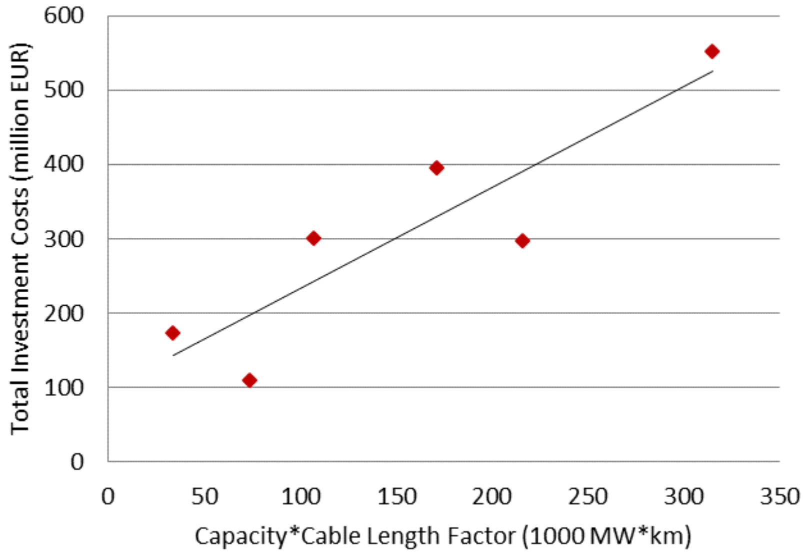


*Figure 18: Relationship between Total Investment Costs and Capacity*Cable Length factor. The red bullets represent realized costs of interconnector project implemented in the BSR.*

It can be observed from the above graph that the higher the infrastructure needs are (i.e. the higher the Capacity*Cable Length factor), the higher the required Total Investment Costs. This linear relationship between the examined sizes indicates that economy of scale is probably rather limited in the case of interconnection projects, which therefore is assumed in the model.

The costs of all new transmission lines are based on the costs of the HVDC cable technology. In many cases, overhead lines, would be able to provide a more cost-effective solution, but given the potential local opposition to additional overhead in many countries the cost estimates are based on HVDC cables.

The assumptions for the different components of an HVDC cable interconnection scheme are presented in Table 13 and Table 14.

HVDC Interconnections	
Rated Capacity (Converter)	600 MW
Voltage Level (Cables)	400-500 kV
Contingency	5% of Total Investment Cost

Table 13: Assumptions for HVDC connections in the Baltic Sea Region.

AC reinforcements are required in some of the cases when an interconnection is established or expanded. Each interconnection requires different kind of AC reinforcements depending on the local conditions, the existence of previous pole (e.g. Skagerrak 4) and the strength of the grid. These factors cannot be defined for all the assessed projects under the absence of specific data. In this context, it is very difficult to conclude in a generic AC reinforcement cost value valid for all the different projects assessed. As an alternative to defining the reinforcement cost, in this study we have chosen to consider not only the length of the interconnection itself, but the entire length between the two regions geographical centres.

However, when we consider connections between larger electricity regions on land – for example between Poland and regions in Germany – using the geographical centres would lead to a very high cost of interconnectors. On this background, we have assumed that the length of interconnectors on land are maximum 300 km.

Moreover, contingency costs are considered to be 10% of the total investment costs to account for the risk of unpredicted costs.

The reference capacity assessed is considered equal to a line with a capacity of 600 MW corresponding to cables of voltage level 400 to 500 kV.

HVDC LCC Technology		Source
Converter Substations Costs	0.20 MEUR/MW	Existinting[a], CESI (2009), CEI (2008)
HVDC Submarine Cable Cost	1.25 kEUR/(km*MW)	Existinting[b], CESI (2009)
HVDC Underground Cable Cost	1.10 kEUR/(km*MW)	Existinting[c], CEI (2008)
HVDC Overhead Line Cost	0.25 kEUR/(km*MW)	Existinting[d], CESI (2009)

Table 14: Cost Assumptions for evaluation of HVDC LCC connections in the Baltic Sea Region. [a]EstLink2 and FennoSkan2. [b] Skagerrak4, Estlink2, NordBalt and FennoSkan2.[c] Swedish South-West link. [d] Denmark, Lithuania and Sweden.

For each possible new transmission line the elements in the above table are calculated depending on e.g. length of line, if it is on on- or offshore and etc.

The price of copper has only a small influence on the total investment cost of the interconnections, whereas the length of the connection has the highest impact[12].

[12] "Electricity Transmission Costing Study - An Independent Report Endorsed by the Institution of Engineering & Technology", by Parsons Brinckerhoff (2012)

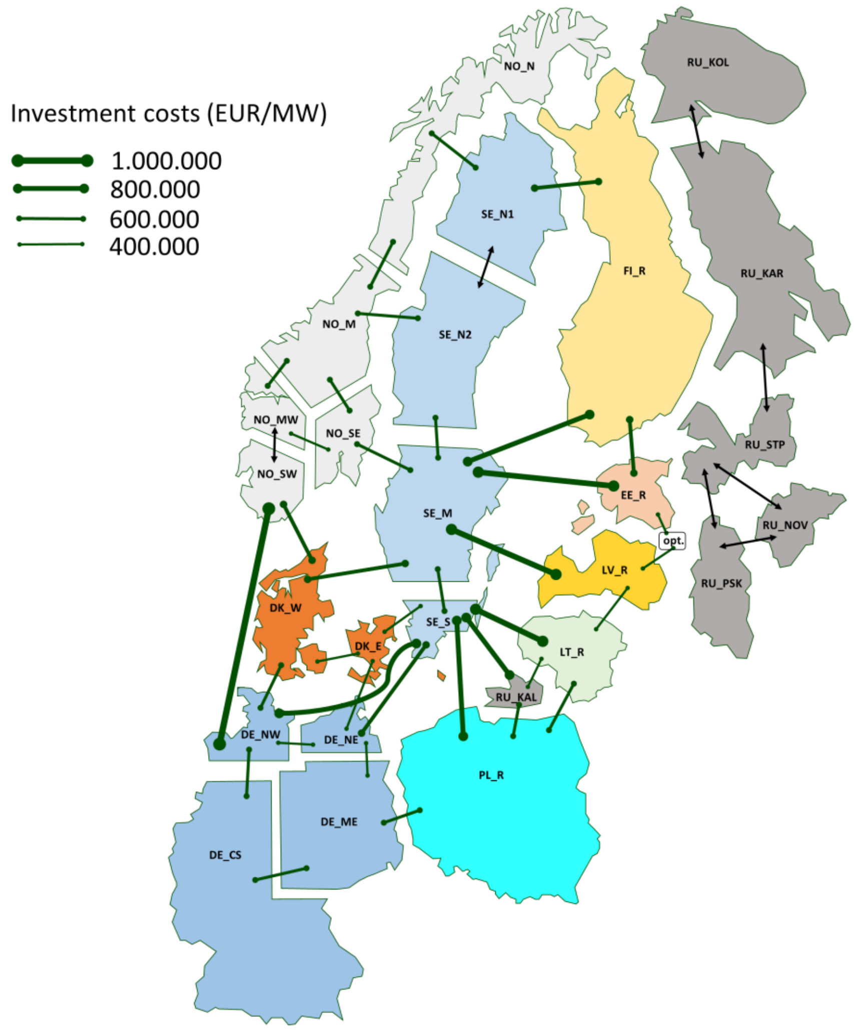


Figure 19: Investment costs for interconnections between the BSR areas (€/MW). A more detailed table of the costs are shown in appendix C.

6 Results of model analyses

This chapter accounts for the overall results of the scenario results for 2030. The following data is presented:

- Electricity generation by fuel
- Development in wind power capacity
- CO_2-emissions
- Electricity prices
- Investments in transmission capacity

More detailed country by country information, generation mix and electricity balances, are presented in appendix B.

The following scenario abbreviations are used:

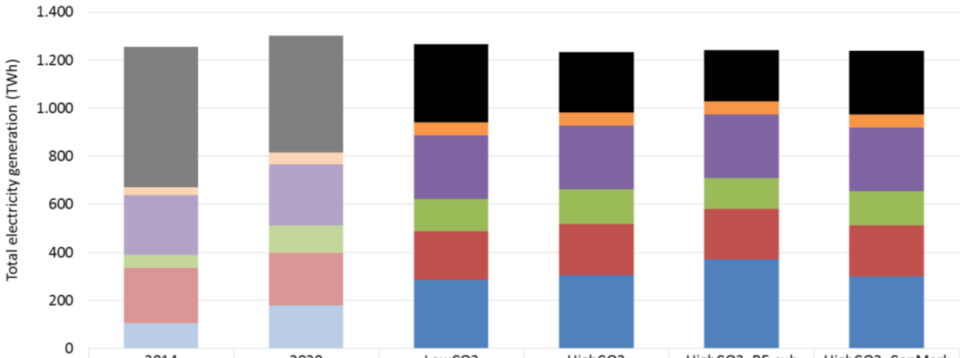
1. *LowCO2*. Low CO_2 price (25 €/ton)
2. *HighCO2*. High CO_2 price (42 €/ton)
3. *HighCO2_RE-sub*. High CO_2 price with subsidy for wind/solar (15 €/MWh) and higher biomass price
4. *HighCO2_CapMark*: High CO_2 price and capacity markets in all countries

6.1 Electricity generation by fuel

Generation mix

Figure 2 displays the total generation mix for the BASREC countries in the four scenarios where investments in new transmission capacity are included. We see a clear impact of the different framework conditions in the scenarios with the highest shares of wind power being obtained in *HighCO2_RE-sub* scenario, which combines a high price of CO_2 with subsidies for wind and solar and higher prices on biomass. In this scenario, wind and solar power together makes up 34 % of total generation compared to 27 % in the low CO_2-price scenario and 29 % in the high CO_2-price scenario.

The introduction of capacity markets leads to a slightly lower uptake of wind power (comparing *HighCO2_CapMark* with *HighCO2*), because the capacity markets act as a subsidy to thermal power plants thus increasing their competitiveness relative to wind power and solar power.



	2014	2020	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
FOSSIL	583	487	323	251	213	265
SUN and GEOTHERMAL	32	48	55	55	55	55
WATER	249	255	265	265	265	265
BIO and WASTE	54	115	135	144	130	143
NUCLEAR	231	218	202	212	208	212
WIND	105	179	287	306	372	300

Figure 20: The total generation mix for the BASREC countries.

6.2 Deployment of wind power

The results indicate that the investments in new wind power capacity are to some extent dependent on the possibility to invest in new transmission capacity. On a regional level, investments in wind power capacity decrease by 3% in the *HighCO2_RE-sub* scenario when investments in new transmission capacity are not allowed (see Figure 21).

In the other scenarios the picture is not as clear and in the *HighCO2* scenario we do in fact see the opposite relationship. This is probably due to the fact that increasing transmission capacity also allows increasing amounts of Nordic “surplus electricity” to be transported from Norway and Sweden to Continental Europe where it may replace local investments in wind power.

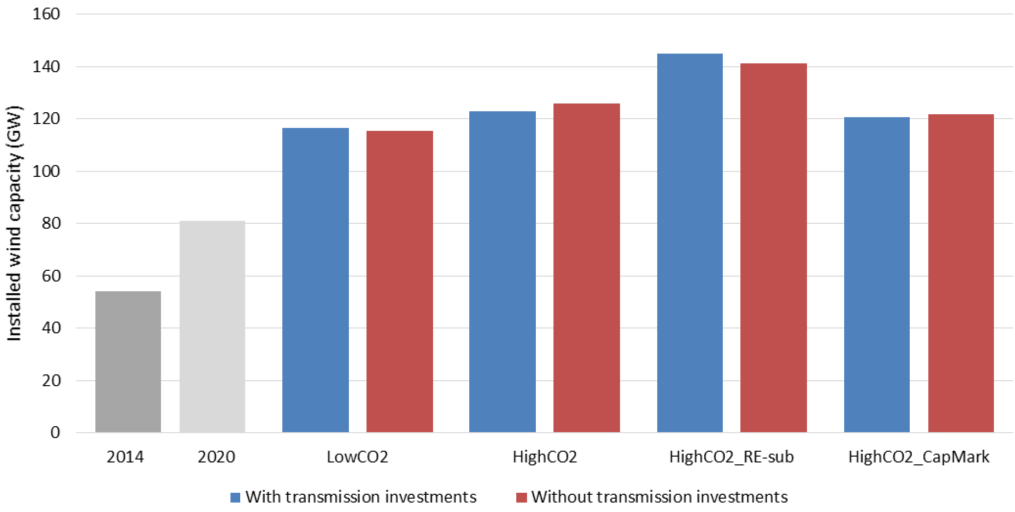


Figure 21: Installed wind capacity in the BSR with and without allowing expansion of transmission capacity in 2030.

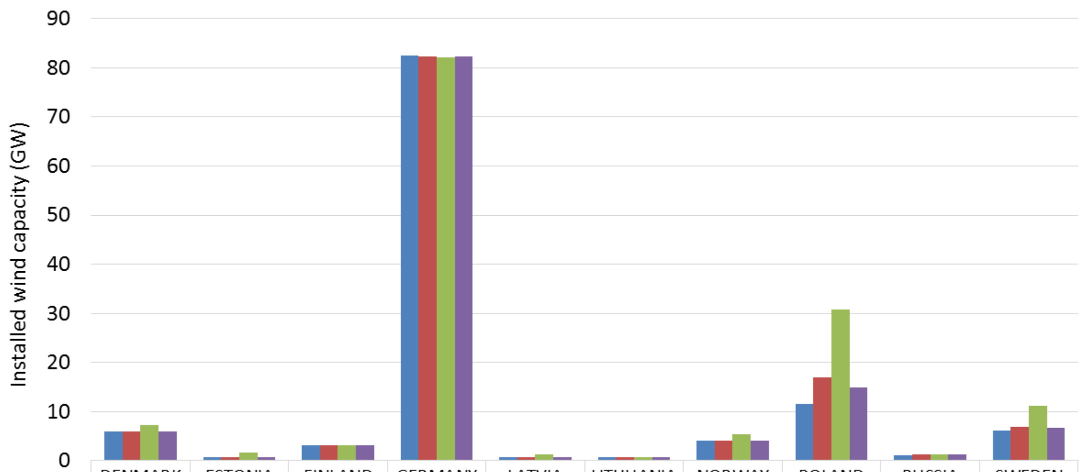
The wind power deployment in Germany remains at the same level - the level which is projected in accordance with the German renewable energy law - in all four scenarios. This shows that the incentives provided in the scenarios – even in the *HighCO2_RE*-sub scenario - are not sufficient to facilitate additional wind power capacity in Germany (i.e. stronger incentives are required to comply with the national target of Germany). In the other countries, where the exogenous implementation of wind power is moderate, the deployment of new wind power capacity is more sensitive to the incentives in the scenarios. In particular, we see a strong deployment of wind power in Poland when the incentives are improved.

Finland, Lithuania and Russia are the only countries, where the generation from wind power, does not increase. In the case of Finland and Lithuania it is more economical to invest in new nuclear capacity and in the case of Russia, the policy incentives are not as strong as in the rest of region.

A large proportion, 5 GW out of 11 GW, of the wind power capacity in Sweden is offshore wind power in the *HighCO2_RE-sub* scenario. In Poland, 6 GW out of 31 GW, is offshore capacity in the *HighCO2_RE-sub* scenario.

In Denmark, the wind power deployment remains at the national target for 2020 in all scenarios except in the *HighCO2_RE-sub* scenario, where it reaches 7,200 MW, which is actually slightly lower than the level expected by the system operator Energinet.dk.

The wind power development in Russia is concentrated in the Kaliningrad region, which in the model's data has favourable wind power conditions. However, it may be that the model's data wind for Kaliningrad is too optimistic and this result should therefore be interpreted with caution.



	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN
LowCO2	5,9	0,6	3,2	82,5	0,8	0,8	4,1	11,5	1,2	6,0
HighCO2	6,0	0,6	3,2	82,3	0,8	0,8	4,1	17,0	1,3	6,8
HighCO2_RE-sub	7,2	1,6	3,2	82,2	1,4	0,8	5,4	30,8	1,3	11,2
HighCO2_CapMark	5,9	0,6	3,2	82,3	0,8	0,8	4,1	14,9	1,4	6,7

Figure 22: Total wind capacity in 2030.

6.3 CO_2-emissions

A clear relationship is observed between the incentives for low carbon technologies and the level of CO_2-emissions in the scenarios. We observe the highest level of CO_2-emisisons, 301 Mt for the region as a whole, in the *LowCO2 price scenario* and the lowest level of CO_2-emissions, 186 Mtons, is obtained in *HighCO2_RE-sub* scenario. The introduction of capacity markets lead to higher CO_2-emissions in the order of 18 Mt because the capacity markets work as a subsidy to dispatchable generation capacity.

The value of integrating the grids in the region is apparent from the level of CO_2-emissions, which are 9 % higher in the *HighCO2_RE-sub* reference scenario, where we do not allow investments in additional transmission capacity. In the other scenarios the difference in CO_2-emission is minimal.

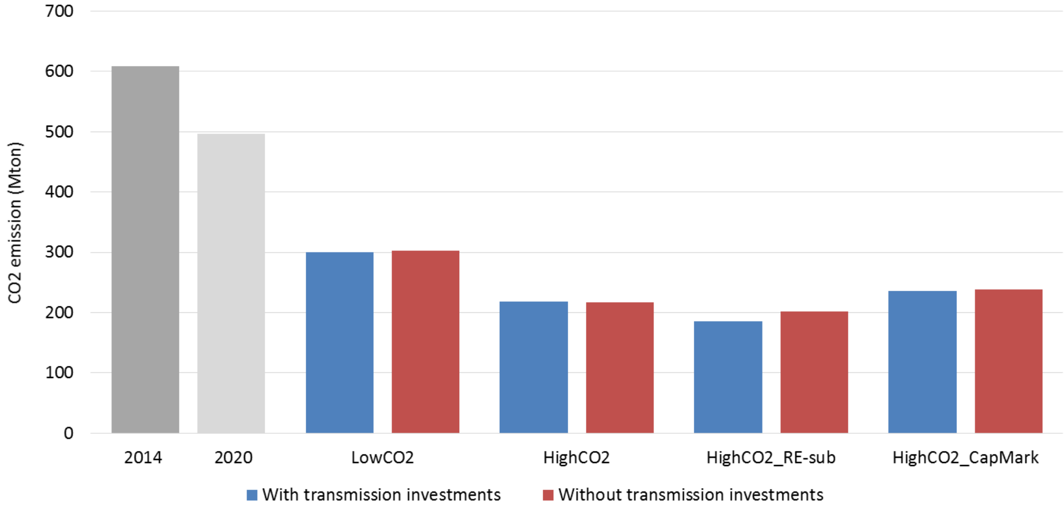


Figure 23: Total CO_2 emission of the BSR in 2030 for the different scenarios with and without investments in new transmission capacities.

6.4 Electricity prices

Generally speaking, the lowest electricity market prices are observed in Norway and Sweden whereas continental Europe, in particular Poland, demonstrate the highest price levels.

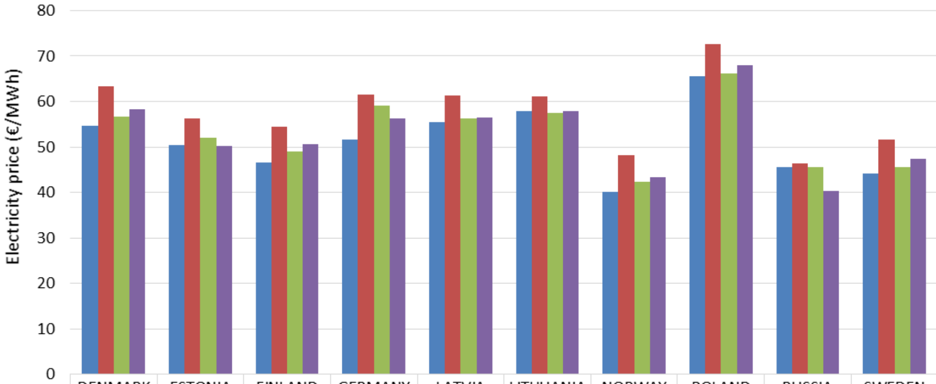
Russia also demonstrates relatively low power prices, which should be seen in the light of lower price of natural gas (20 % discount compared the rest of the region) and lower CO_2-prices.

It is important to mention that the electricity prices, represent spot market prices. In addition to this should be added the cost of financing renewable energy subsidies or capacity market schemes. These costs would have to be recovered from consumers or tax payers.

The reason that we do not see as high electricity market prices in Germany as in Poland is due to the planned large-scale deployment of renewable energy in Germany, which has a downward impact on electricity market prices.

Higher CO_2-price causes electricity market prices to increase as the CO_2-price affects the marginal cost of fossil-based power generation. Renewable energy subsidies have the opposite impact on electricity market prices, since they lead to an increasing deployment of wind power and solar, which have low marginal generation costs, and the same time reduces the bidding price of these technologies in the spot market.

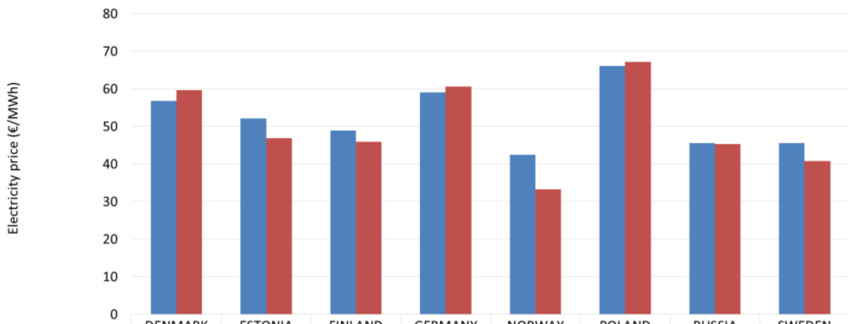
Capacity markets also have a downward impact on spot prices, since the schemes work as a subsidy to dispatchable power generation. As is the case for renewable energy subsidies, the cost of the capacity schemes would have to be recovered from consumers (or tax payers).



	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN
LowCO2	55	50	47	52	55	58	40	65	46	44
HighCO2	63	56	55	61	61	61	48	73	46	52
HighCO2_RE-sub	57	52	49	59	56	58	42	66	46	46
HighCO2_CapMark	58	50	51	56	56	58	43	68	40	47

Figure 24: Annual electricity prices (time average) by country for each scenario in 2030.

Allowing investments in transmission capacity lead to a smoothening of electricity prices in the region. This relationship is illustrated in Figure 25, which compares electricity market prices of the HighCO2_RE-sub scenario with the similar reference case where investments in transmission capacity are not allowed.

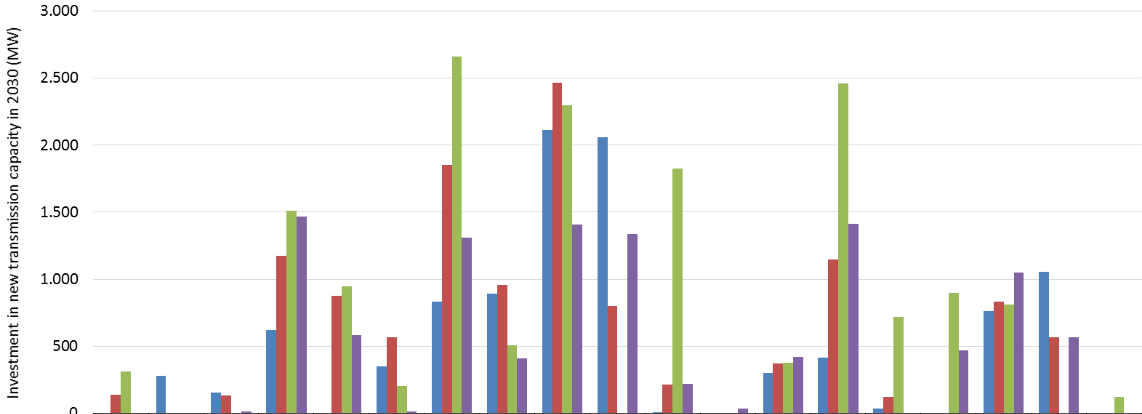


	DENMARK	ESTONIA	FINLAND	GERMANY	NORWAY	POLAND	RUSSIA	SWEDEN
HighCO2_RE-sub	57	52	49	59	42	66	46	46
HighCO2_RE-sub_noInv	60	47	46	61	33	67	45	41

Figure 25: Annual electricity prices (time average) by country in the HighCO2_RE-sub scenario *with and without investments in transmission capacity.*

6.5 Investments in interconnections

Significant investments are made in new interconnection capacity across the region in all scenarios. The lowest level of investments, 9,900 MW in total, is observed in the *LowCO2* scenario where the challenges related to the integration of renewable energy is also the lowest. In the *HighCO2* scenario the level increases to 12,200 MW and in *HighCO2_RE-sub* scenario, which also demonstrates the highest level of wind power, even higher to 15,700 MW. When capacity markets are included in all countries in the region the demand for new interconnection capacity is reduced by more than 1,500 MW compared to the similar situation without capacity markets (*HighCO2 scenario*).



	DE_CS	DE_ME	DK_E	DE_CS	PL_R	NO_N	DE_NW	DK_W	NO_M	DE_ME	SE_S	LT_R	PL_R	DK_W	FI_R	NO_N	DE_NE	DE_NW	DK_E
	DE_ME	DE_NE		DE_NW	LT_R	NO_M	NO_S			PL_R		RU_KAL		SE_M	SE_N		SE_S		
LowCO2		277	155	621		352	830	890	2.113	2.059	2		298	415	32		760	1.055	
HighCO2	139		131	1.173	875	564	1.852	958	2.466	798	213		369	1.147	120		832	565	
HighCO2_RE-sub	313			1.509	949	202	2.660	506	2.300		1.828		377	2.461	720	898	812		124
HighCO2_CapMark			14	1.466	584	11	1.311	408	1.407	1.338	217	32	422	1.413		468	1.048	566	

Figure 26: The investments in new connections additional to the exogenous connection listed in Appendix A.

All four scenarios show that it will be feasible to increase particularly, the level of interconnection from North to South in the region. Specifically, the following intersections appear attractive:

- ✓ Internal North-South reinforcements in Norway, 1400 - 3000 MW
- ✓ Internal North-South reinforcements in Germany, 900 - 1800 MW
    - In addition to already planned reinforcements towards 2020
- ✓ North West Germany to Norway, 800 - 2600 MW
    - In addition to the 1400 MW NordLink connection, expected to be established by 2018.
- ✓ Western Denmark to Norway, 400-1000 MW

    - In addition to the existing Skagerrak connections and the Skagerrak 4 connection expected to be established by the end of 2014.
- ✓ Western Denmark to Sweden, 400 - 2500 MW
    - In addition to the existing Konti-Skan connection of app. 700 MW
- ✓ Sweden to Poland, 0 – 1800 MW
    - In addition to the existing Swe-Pol connection of app. 600 MW
- ✓ Sweden to Northern Germany, 800 - 1800 MW
    - In addition to the existing Baltic cable with a connection of app. 600 MW

Generally speaking, the higher level of the intervals, are feasible in the, *HighCO2_RE-sub* scenario whereas the lower levels apply to the *LowCO2* scenario.

A number of other connections appear attractive in some but not all scenarios. In the *Low*- and *HighCO2*-price scenarios it will be feasible to increase the capacity between Germany and Poland by up to 2000 MW, but this is not the case in the *HighCO2_RE-sub* scenario where it appears more attractive to increase the interconnection capacity between Poland and Sweden. The reason for this is probably the high amounts of wind power in Poland in the *HighCO2_RE-sub* scenario, which can be balanced by Nordic hydro power through a connection to Sweden.

Moreover, all scenarios except the Low CO2-price scenario show increasing demand for interconnection capacity between Lithuania and Poland, but this is not driven by investments in renewable energy. Likewise, the model results indicate that there may be a need for increasing the interconnection capacity between Kaliningrad and Poland. However, this result builds on the assumption that there will be a strong expansion with wind power (approx. 1200 MW) in Kaliningrad, which – based on discussions with the BASREC GSEO – does not seem realistic.

Moreover, a number of scenarios indicate a demand for new interconnection capacity – up to 1600 MW – in the northernmost part of the Baltic Sea Region, linking Northern Sweden more closely with either Northern Norway or Finland.

Figure 27 depicts the invested transmission connection (above 100 MW) for the high CO_2 price scenario (HighCO2).

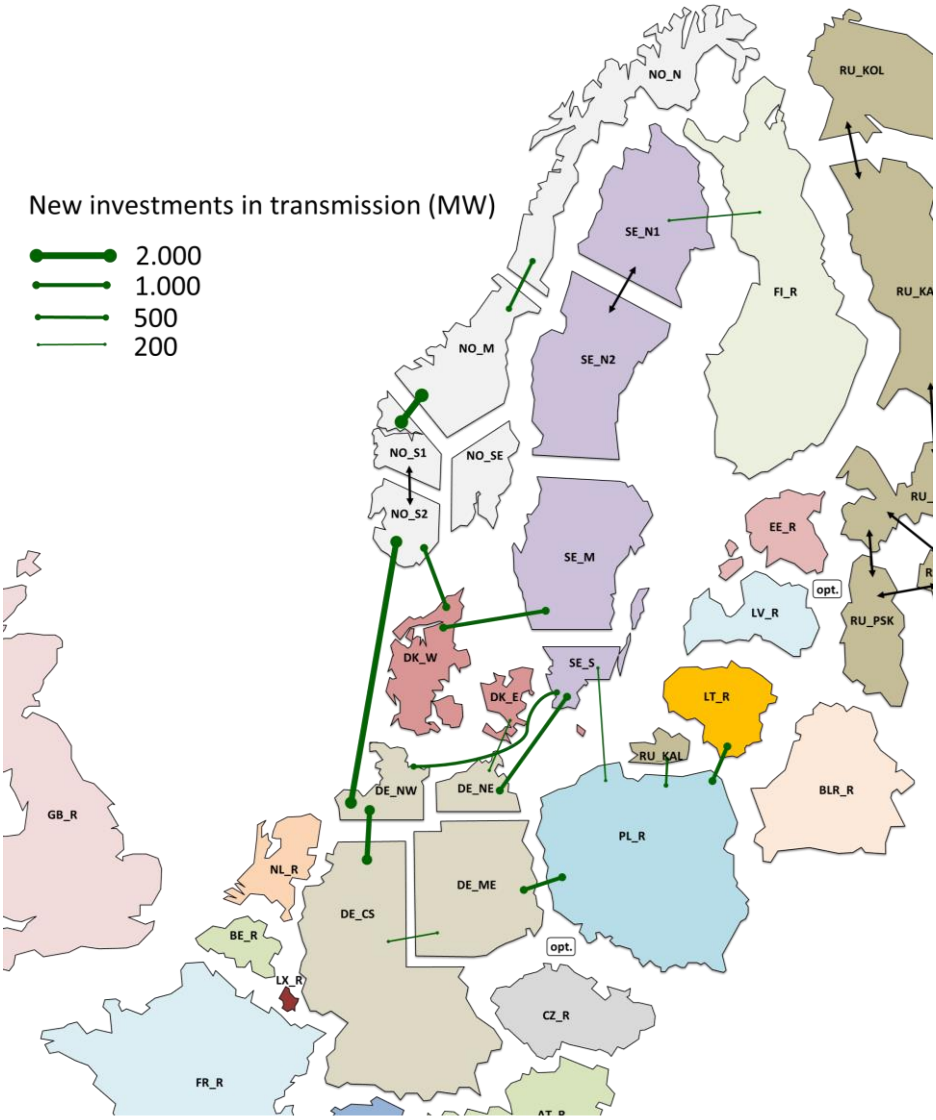


*Figure 27: Map showing the investments in new connections additional to the exogenous connection in appendix 6 for the high CO2 price scenario (**HighCO2**).*

Exchange of electricity

The exchange of electricity in the region increases very considerably in the 2030 scenarios compared to the current situation. The flow on the interconnectors, mainly run from North to South (as depicted in Figure 28 and Figure 29), but the interconnection from Germany to Norway is also used for export to Norway at times when wind power production in Germany is peaking.

Germany is a net importer of electricity in all 2030 scenarios, but in particular in the *HighCO2* (56 TWh, including from third countries) and *HighCO2_RE-sub* (76 TWh) scenarios where the renewable deployment increases significantly in the other countries in the region.

Imports to Poland are also significant in the *HighCO2* (37 TWh, including from third countries) and *HighCO2_RE-sub* (36 TWh) scenarios.

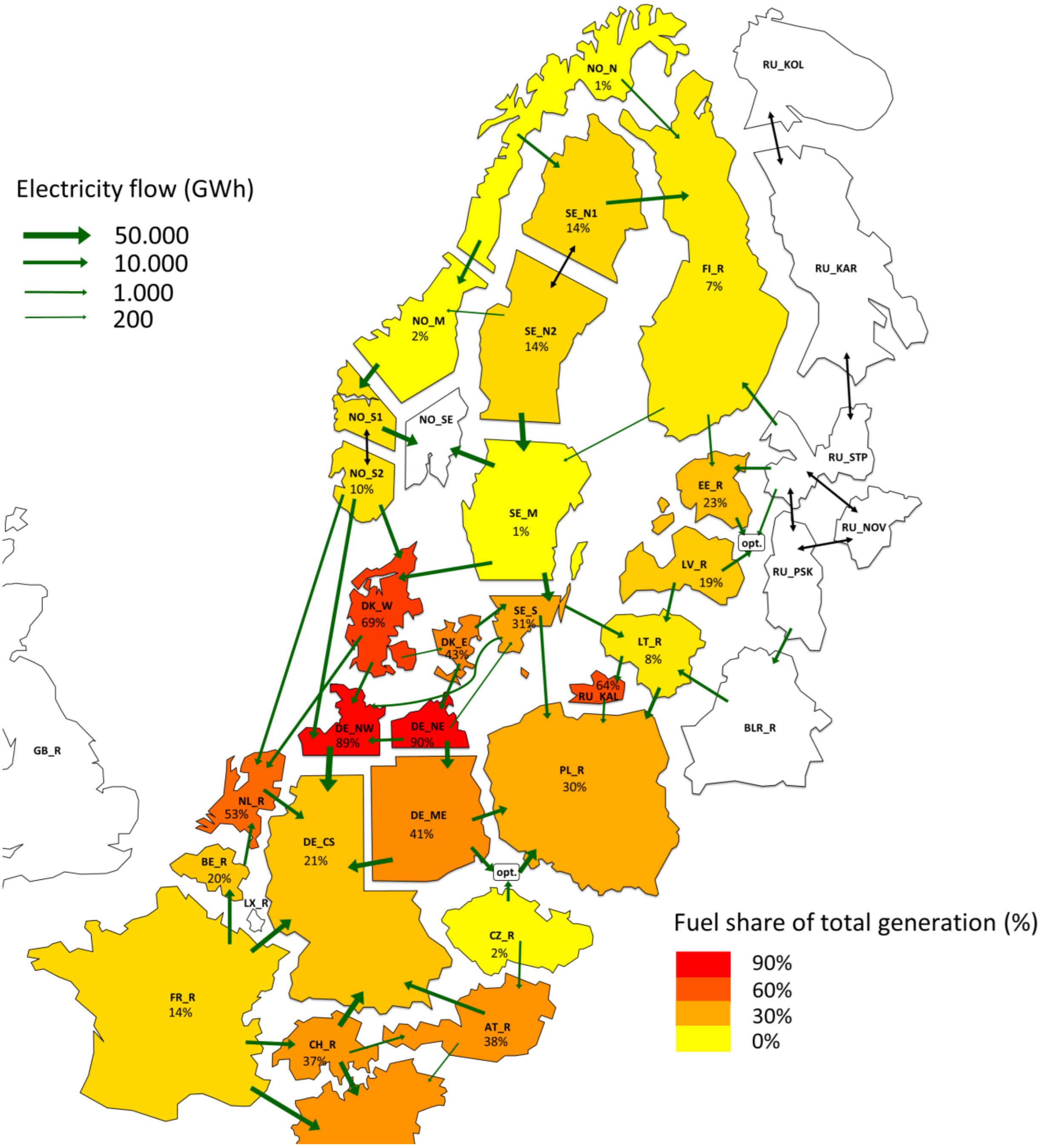


*Figure 28: Map showing the wind share of total generation in each region and the yearly net electricity transmission between the regions in TWh in 2030 in the high CO2 price scenario (**HighCO2**). White indicate 0% (or negligible) wind share of generation.*

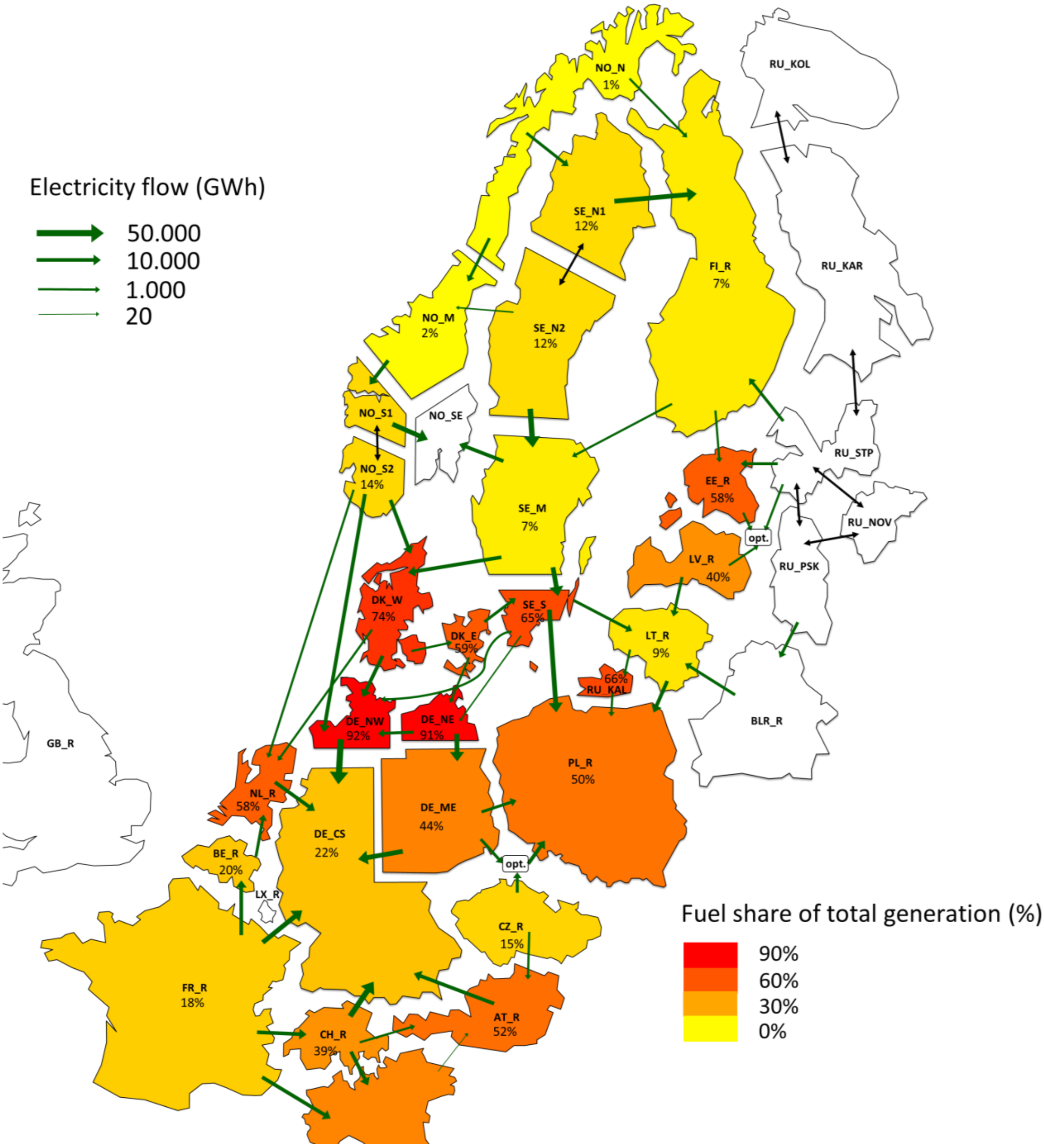


*Figure 29: Map showing the wind share of total generation in each region and the yearly net electricity transmission between the regions in TWh in 2030 in the high CO2 price scenario (**HighCO2_RE-sub**). White indicate 0% (or negligible) wind share of generation.*

7 Barriers and challenges for further grid development

This chapter examines barriers and challenges for the implementation of new infrastructure projects in the region.

The examination largely relies on the project assessments made by ENTSO-E as these provide valuable information into the different project in pipeline and the barriers to their realisation. The review is based on the Ten-Year Network Development Plan, TYNDP 2012. Since the review was made the ENTSO has published its TYNDP 2014 exploring the demand for new infrastructure in the longer-run through to 2030. The TYNDP 2014 also includes a numerical quantification of every projects economy according to a specified cost benefit analyses methodology – a feature, which we lacked, when we reviewed the 2012 plan.

7.1 ENTSO-E project assessment methodology

Within the ENTSO-E TYNDP 2012 ten common criteria (or parameters) are applied for assessing new infrastructure projects:

1. **Grid Transfer Capability**, shows in MW the order of magnitude or a range for the additional grid transfer capability brought by the project (strictly speaking this is a technical parameter not a criterion).
2. **Social and economic welfare indicator**, characterized by the ability of a power system to reduce congestions. The reduction of congestions is an indicator of social and economic welfare.
3. **Renewable energy indicator,** defined as the ability of the system to allow the connection of new RES plants and unlock existing “green” generation, while minimizing curtailments.
4. **Security of supply**. The ability of a power system to provide an adequate and secure supply of electricity in normal conditions
5. **Losses variation.** The impact on thermal losses in the power system. It is an indicator of energy efficiency.
6. **CO_2 indicator**. Impact on CO_2 emissions in the power system. It is a result of unlock of generation with lower carbon content (RES criterion) and changes in losses (losses variation criterion)
7. **Technical resilience**. The ability of the system to withstand increasingly extreme system conditions (rare contingencies).

8. **Flexibility,** is the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios, including trading of balancing services.
9. **Social and environmental indicator**, characterizes the project impact as perceived by the local population, and as such, gives a measure of probability that the project will be built at the planned commissioning date. [13]
10. **Project costs,** Total project expenditures are based on km of lines, land costs, costs of obtaining, permissions, damages etc.

The assessments of the project are based on the market and grid analysis i.e. on a number of scenarios and sensitivities with technical models and electricity market models. Table 15 shows an example of two concrete projects evaluated with in the Baltic Sea Regional Investment Plan. Colour codes are used to illustrate the impacts. Dark green shows favourable outcome whereas red colours indicate negative impacts.

Project identification					Project assessment									
Project number	Investment number	Substation 1	Substation 2	Brief technical description	Grid transfer capacity increase	Socio-economic welfare	RES integration	Improved security of supply	Losses variation	CO_2 mitigation	Technical resilience	Flexibility	Social and environ-mental impact	Project costs
70	70.405	Kristiansand (NO)	Rød (NO)	Voltage upgrading of an existing single circuit 300 kV OHL and a new section of OHL between Rød and Bamle. Total length: 175 km	700 MW									
	70.426	Kristiansand (NO)	Tjele (DK)	Skagerak 4: 4th HVDC connection between southern Norway and western Denmark, built in parallel with the existing 3 HVDC cables, new 700 MW including 230 km 500 kV DC subsea cable.										
71	71.427	Endrup (DK)	Eemshaven (NL)	COBRA: New single circuit HVDC connection between Jutland and the Netherlands via 350 km subsea cable. The DC voltage will be up to 320 kV and the capacity 600 – 700 MW.	700 MW									

Table 15: Example of evaluation of two concrete projects. Source: ENTSO-E 2012 (Regional Investment Plan Baltic Sea).

7.2 Comments to the criteria of ENTSO-E

Socio-economic welfare

Among the ten different criteria the economic criteria would often have a special status because it is able to embrace several of the other criteria. For example introducing renewable energy technologies has an impact on electricity prices, which is reflected in the cost-benefit of an interconnector.

[13] The Norwegian government considers the following impact on the environment: Visual effects on landscape, cultural monuments/areas, residential areas and recreational facilities, areas of importance to the tourist industry, etc. , Risk of bird collisions, general disturbance for wildlife, consequences for the natural environment , Inconveniences for agriculture, forestry, fisheries and other businesses Land use , Electromagnetic fields and noise. Source: http://www.nordicenergyregulators.org/wp-content/uploads/2013/02/Grid_investments_in_a_Nordic_perspective.pdf (jan 2014)

The same is the case of the CO_2-mitigation criterion as the cost of CO_2 emissions are (at least to some extent) internalized through the EU Emissions Trading System. A project's contribution to improving the security of supply and the technical resilience of a project may also be monetized by assessing the benefits related to the provision of regulating power, reserve capacity and other ancillary services to the power system.

Cost-benefit vs. multi criteria analyses

The ENTSO-E discusses if pure cost-benefit should be favoured over the multi-criteria analyses but concludes that a "single criterion provides less information (and is less transparent) then a multi-criteria balance sheet. Moreover, it is not well adapted in the case of a multi-actor governance [….] where the actors will need information on each of the criteria in order to take common decisions. And moreover that "A « pure « CBA cannot cover all criteria […], since some of the benefits are difficult to monetize"[14].

In the ENTSO-E methodology benefits and cost are accounted for as a separate criteria ("socio-economic welfare" and "project cost"). No actual cost-benefit analysis is presented, which complicates the economic interpretation of the results.

Cost-benefit analysis

To get an impression of the economics we have compared economic benefits and costs according to the categories/colour codes in the Regional Investment Plan. Projects with high benefits and low costs are considered "very good", projects with high benefits and medium cost are "good" etc. this leads to the cost-benefit analyse exhibited in Figure 30. It shows the only 17 % of projects demonstrate very good or good economy whereas 57 % are considered neutral and 26 % have negative or very negative economy.

[14] ENTSO-E 2013; "ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects"

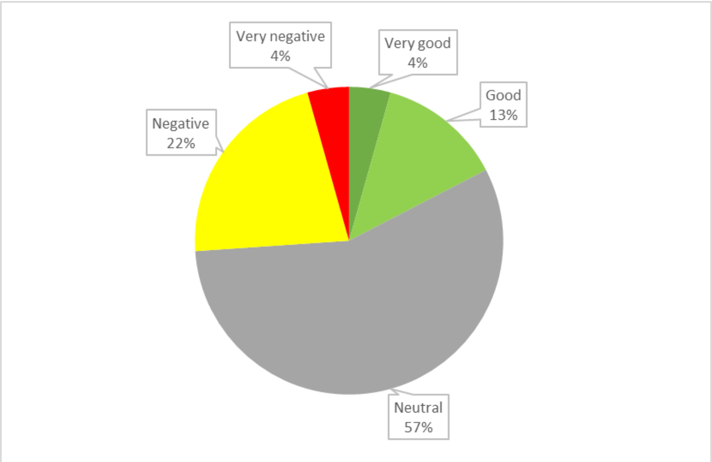


Figure 30: Approximated cost-benefit analysis of the 46 project in the ENTSO-E Regional Investment Plan of the Baltic Sea.

Social and environmental impacts

We also looked into the distribution of "social and environmental impact" of the projects. This shows that 7 % of the projects are exposed to high risks, 52 % to medium risk whereas only 41 % is subject to low risk. Based on this we would see "social and environmental impacts" among the important barriers to the further grid development in the region.

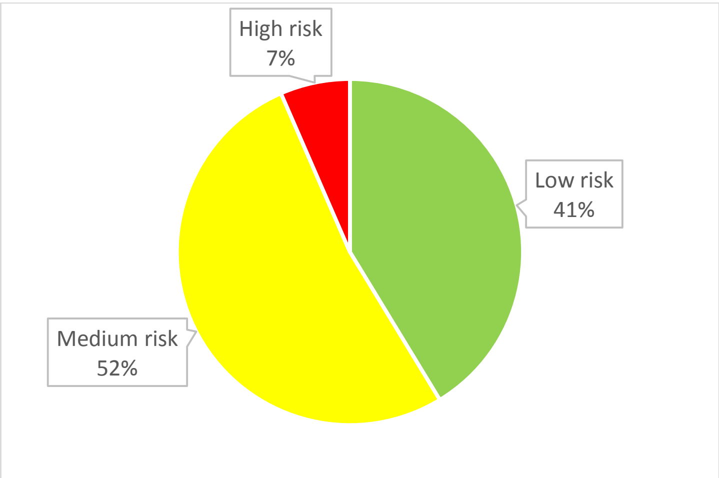


Figure 31: exposure to social and environmental risks of the 46 projects in the ENTSO-E Regional Investment Plan of the Baltic Sea..

Impact on stakeholder economy

The purpose of a welfare economic analysis is to measure the net impact of a project on economic welfare on the whole of society. Essentially, the socioeconomic value is comprised of the sum of the economy of all stakeholders taking part in, or being affected by, the project. Externalities – i.e. costs or benefits that spill over from the project towards other parties without monetary compensation (for example air pollution or noise) – should to the extent possible, also be taken into account monetarily.

When breaking down the economic consequences of a transmissions infrastructure project on relevant groups of stakeholders it is obvious that some stakeholders will benefit whereas others will lose. Relevant stakeholder groups would include for example electricity consumers, electricity producers, transmission system operators (collecting congestion rents on bottlenecks) and governments (collecting taxes and giving subsidies) in the countries (bidding areas) affected by the transmission project.

In general terms a project that increases the transmission capacity between two countries - or more precisely bidding areas since some countries include more bidding areas - allows generators in the lower-priced area to export power to the higher-priced (import) area. Thereby the total cost of electricity supply is reduced thus increasing the socio-economic welfare. In a cost-benefit analysis the benefits of access to cheaper electricity supply should be compared with the costs of the interconnection, that is investments costs and operation and maintenance costs.

Electricity producers in the high price area normally lose from the connection because prices will drop whereas consumers will benefit – and vice versa in the low price areas. Often the picture will be more complex however, because an interconnector between two countries could often have significant impacts on third countries because it changes the flow of power in the whole region. Results may also show that one country will benefit as a whole (i.e. sum of the benefits of producers, consumers, TSO etc.) where another country will see its total welfare reduced.

Example: Common grid interconnection of Krieger's Flak

Table 16 illustrates the economics for different stakeholders of concrete infrastructure project. The case explored here is the benefits of a common grid interconnection at Kriegers Flak in Baltic, as opposed to individual connections to Denmark, Sweden and Germany. The analyses shows that the total welfare economic benefit for the region is approx. 17 mill. €, but for the individual countries the benefits or losses can be much greater. For example, Germany – the sum of all stakeholder groups - sees a benefit of 110 mill. € whereas Russia loses just above 50 mill. €.

Mill. €, NPV	DENMARK	ESTONIA	FINLAND	GERMANY	LATVIA	LITHUANIA	NORWAY	POLAND	RUSSIA	SWEDEN	Total:
Generator profits:	-33	-0	40	-65	0	7	-59	74	22	1	-12
Consumer surplus:	15	-2	-29	-92	-8	-12	59	-92	-70	115	-117
TSO profit:	56	-3	8	-1	-0	2	-10	10	1	47	109
Public profit:	-26	-0	-14	268	1	1	0	-16	-5	-172	37
Socio economic benefit:	**13**	**-6**	**5**	**110**	**-7**	**-2**	**-10**	**-24**	**-52**	**-10**	**17**

Table 16: Socio-economic consequences of a common interconnection at Kriegers Flak compared to individual interconnections. Min. €, Net Present Value.

The abovementioned analysis was made within the project “Energy Perspectives for the Baltic Sea Region”, which Ea Energy Analyses prepared in 2009 for the Baltic Development Forum and the Nordic Council of Ministers[15].

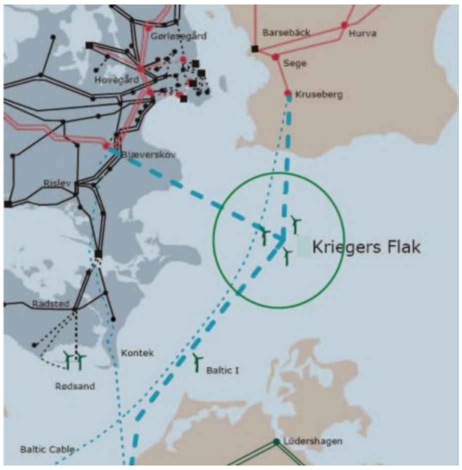


Figure 32: Location and sketched connection of Kriegers Flak.

The fact that the benefits of an infrastructure project are unevenly distributed between stakeholders group and countries often poses a barrier for the implement of such projects.

This issue is dealt with in the report “Grid investments in a Nordic perspective” by NordReg, the Nordic Energy Regulators (2010). As pointed out in the report “A possible barrier related to the national evaluation criteria may arise if an investment is profitable for the Nordic region as a whole, but not for one particular country. There is then a risk that the investment will be denied a licence in this country, thus stopping the entire investment. If this is the case the financing model should in principle be designed to balance costs and benefits at the national level. As long as the parties agree that the investment as a whole is beneficial the financing model should provide

[15] Report available at http://ea-energianalyse.dk/reports/806_sustainable_energy_scenarios_energy_perspectives_for_BSR.pdf

possibilities for countries with higher costs than benefits to be compensated by countries with higher benefits than costs."

On this background the abovementioned report evaluated alternative ways for the financing of common network infrastructure projects with regard to three parameters: 1) incentives to invest, 2) market consequences and 3) their legitimacy – and concludes the following

"The alternatives that were regarded as viable were tariffs complemented with congestion rents. Since the benefits of investments may be unequally distributed, investment contributions between TSOs could be a feasible way to distribute costs in a better way among the TSOs. Alternatives that were not considered feasible were a Nordic trading fee meaning a fee per kWh traded in some predefined manner, e.g. based on trading in the financial or physical market, or be applied to all balance-responsible entities in the Nordic market. The Nordic fee was considered likely to be against EU legislation."

It is without the scope of this study to further investigate different models for financing infrastructure projects where benefits are unevenly distributed but we recognize that fact that benefits are not distributed evenly is likely to provide an important barrier for infrastructure developments in many contexts.

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9 Appendix A – Existing and planned transmission capacities between regions in 2014 and 2030

The operational transmission capacities in 2014, and the planned (exogenous) transmission capacities in 2030 is shown in the tables below. The location of the regions can be seen in Figure 17.

Investment cost in interconnections between regions (EUR/MW)										2014											
	DK_E	DK_W	DK_KF	DE_CS	DE_ME	DE_NE	DE_NW	DE_KF	FI_R	NO_N	NO_M	NO_S	NO_O	SE_N	SE_M	SE_S	PL_R	EE_R	LV_R	LT_R	RU_KAL
DK_E		600				600										1.700					
DK_W	600						1.780					1.700			740						
DK_KF																					
DE_CS					3.000		3.330														
DE_ME				3.000		3.060											3.000				
DE_NE	600				3.060		1.200														
DE_NW		1.500		3.330		1.200										600					
DE_KF																					
FI_R										100				1.200	1.350			1.000			
NO_N									100		900			700							
NO_M										900		600		750							
NO_S		1.700									600		5.200								
NO_O												2.500			2.300						
SE_N									1.600	700	600				7.000						
SE_M		740							1.350				2.400	7.000		4.000					
SE_S	1.300						600								4.000		600				
PL_R					3.000											600					
EE_R									1.000												
LV_R																				1.300	
LT_R																			1.300		600
RU_KAL																				600	

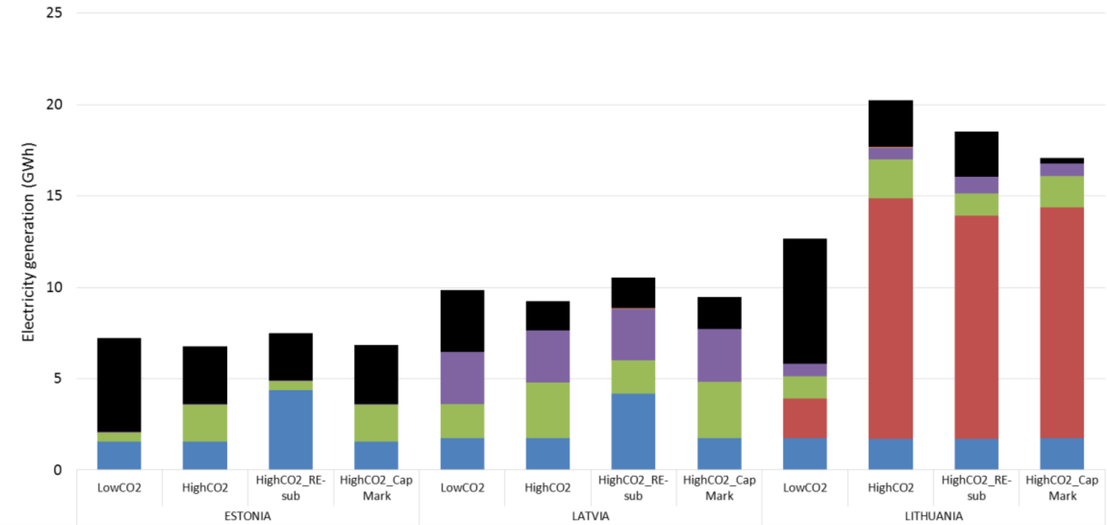
Table 17: Interconnections included in the model exogenous in 2014.

Investment cost in interconnections between regions (EUR/MW)										2030											
	DK_E	DK_W	DK_KF	DE_CS	DE_ME	DE_NE	DE_NW	DE_KF	FI_R	NO_N	NO_M	NO_S	NO_O	SE_N	SE_M	SE_S	PL_R	EE_R	LV_R	LT_R	RU_KAL
DK_E		600	600			600										1.700					
DK_W	600						3.000					1.700			740						
DK_KF	600							600													
DE_CS					3.000		9.330														
DE_ME				3.000		3.060											3.000				
DE_NE	600				3.060		1.200	400													
DE_NW		3.000		9.330		1.200						1.400				600					
DE_KF			600			400															
FI_R										100				1.200	1.350			1.000			
NO_N									100		900			700							
NO_M										900		600		750							
NO_S		1.700					1.400				600		5.200								
NO_O												2.500			2.300						
SE_N									1.600	700	600				7.000						
SE_M		740							1.350				2.400	7.000		5.200					
SE_S	1.300						600								5.200		600			700	
PL_R					3.000											600				1.000	
EE_R									1.000												
LV_R																				1.300	
LT_R																700	1.000		1.300		600
RU_KAL																				600	

Table 18: Interconnections included in the model exogenous in 2030.

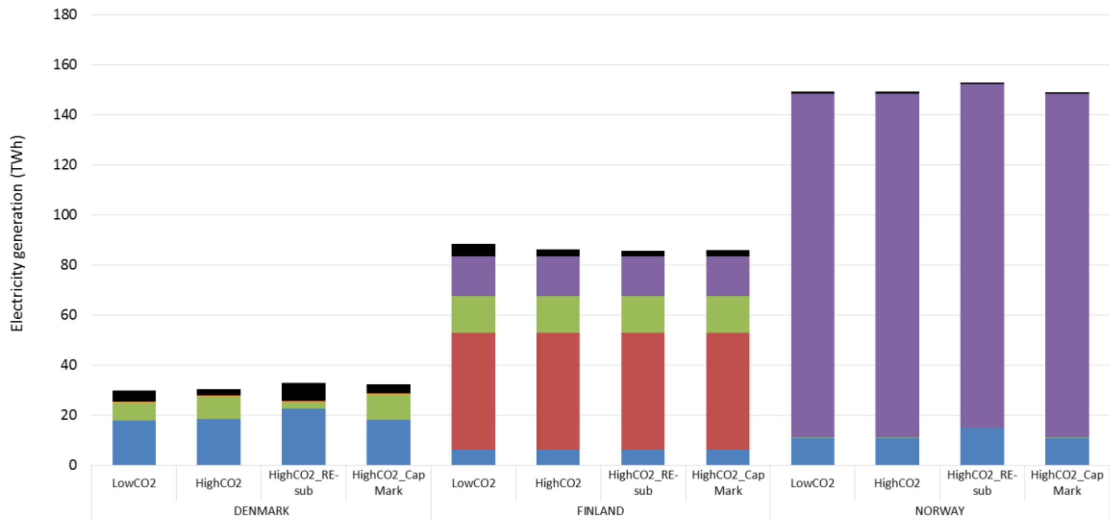
10 Appendix B – Generation mix in 2030 for each country

The figures below shows the electricity generation distributed by fuel for the four scenarios.



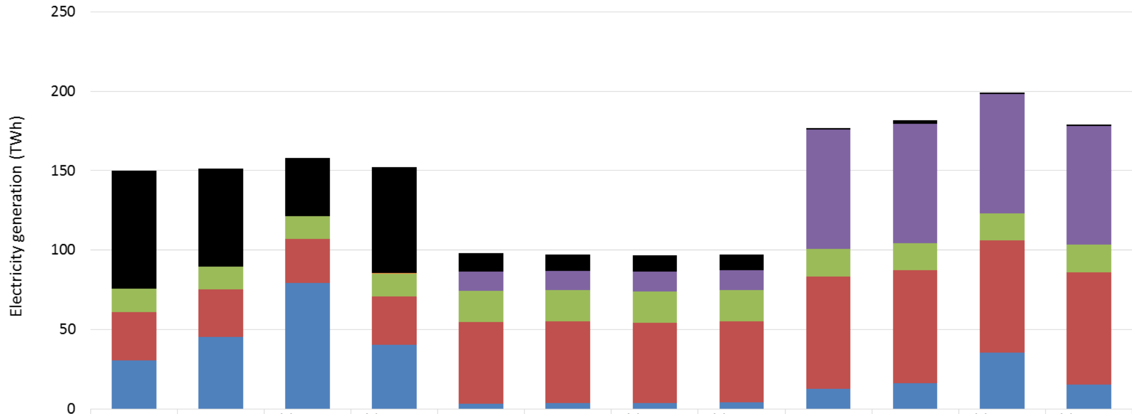
	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_Cap Mark	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_Cap Mark	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_Cap Mark
	ESTONIA				LATVIA				LITHUANIA			
FOSSIL	5	3	3	3	3	2	2	2	7	3	2	0
SUN and GEOTHERMAL					0	0	0	0	0	0	0	0
WATER	0	0	0	0	3	3	3	3	1	1	1	1
BIO and WASTE	1	2	0	2	2	3	2	3	1	2	1	2
NUCLEAR									2	13	12	13
WIND	2	2	4	2	2	2	4	2	2	2	2	2

Figure 33: Generation mix for Estonia, Latvia and Lithuania.



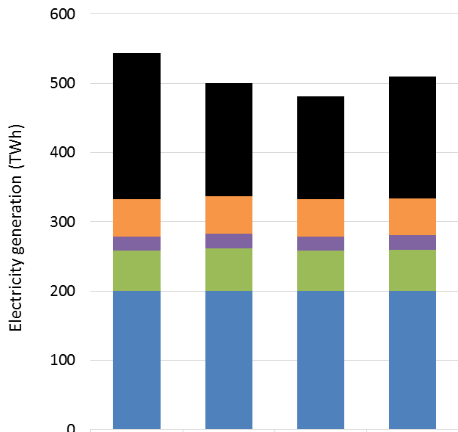
	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_Cap Mark	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_Cap Mark	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_Cap Mark
	DENMARK				FINLAND				NORWAY			
FOSSIL	5	3	7	4	5	3	2	2	1	1	1	1
SUN and GEOTHERMAL	1	1	1	1								
WATER					16	16	16	16	137	137	137	137
BIO and WASTE	7	9	2	10	15	15	15	15	0	0	0	0
NUCLEAR					47	47	47	47				
WIND	18	18	23	18	6	6	6	6	11	11	15	11

Figure 34: Generation mix for Denmark, Finland and Norway.



	POLAND LowCO2	POLAND HighCO2	POLAND HighCO2_RE-sub	POLAND HighCO2_Cap Mark	RUSSIA LowCO2	RUSSIA HighCO2	RUSSIA HighCO2_RE-sub	RUSSIA HighCO2_Cap Mark	SWEDEN LowCO2	SWEDEN HighCO2	SWEDEN HighCO2_RE-sub	SWEDEN HighCO2_Cap Mark
FOSSIL	74	62	37	67	11	10	10	10	1	2	1	1
SUN and GEOTHERMAL	0	0	0	0					0	0	0	0
WATER					12	12	12	12	75	75	75	75
BIO and WASTE	14	14	14	14	20	20	20	20	17	17	17	17
NUCLEAR	30	30	28	30	51	51	51	51	71	71	71	71
WIND	31	45	79	40	3	4	4	4	13	16	35	15

Figure 35: Generation mix for Poland, Russia and Sweden.



	GERMANY LowCO2	GERMANY HighCO2	GERMANY HighCO2_RE-sub	GERMANY HighCO2_CapMark
FOSSIL	211	164	148	175
SUN and GEOTHERMAL	54	54	54	54
WATER	20	20	20	20
BIO and WASTE	58	62	58	60
NUCLEAR				
WIND	200	200	200	200

Figure : Generation mix for Germany.

11 Appendix C – Investment costs in new transmissions

Investment cost in interconnections between regions (EUR/MW)																		
	DK_E	DK_W	DE_CS	DE_ME	DE_NE	DE_NW	FI_R	NO_N	NO_M	NO_S	NO_O	SE_N	SE_M	SE_S	PL_R	EE_R	LV_R	LT_R
DK_E																		
DK_W	500.939																	
DE_CS																		
DE_ME			551.034															
DE_NE	460.864			480.902														
DE_NW		561.051	621.165		440.827													
FI_R																		
NO_N																		
NO_M								561.051										
NO_S		681.277				1.162.179			561.051									
NO_O		851.597							561.051	500.939								
SE_N							561.051	530.995	561.051									
SE_M		761.427					821.541				561.051	561.051						
SE_S	410.770				711.334	831.558							561.051					
PL_R				561.051										851.597				
EE_R							661.240						971.822					
LV_R													981.842					
LT_R													981.842	971.822	561.051		440.827	
RU_KAL														811.522	530.995			380.714

12 Appendix D – Energy balance in 2030

DENMARK

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	29.874	30.463	32.751	32.280
FOSSIL	*4.516*	*2.501*	*7.202*	*3.603*
SUN and GEO	*536*	*536*	*536*	*536*
WATER	-	-	-	-
BIO and WASTE	*6.845*	*9.019*	*2.319*	*9.984*
NUCLEAR	-	-	-	-
WIND	*17.977*	*18.408*	*22.694*	*18.158*
EXPORT	16.973	20.207	21.626	19.705
IMPORT	29.995	32.290	34.654	29.782
BALANCE	**42.896**	**42.547**	**45.778**	**42.357**

ESTONIA

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	7.222	6.787	7.497	6.846
FOSSIL	*5.130*	*3.170*	*2.602*	*3.239*
SUN and GEO	-	-	-	-
WATER	*30*	*30*	*30*	*30*
BIO and WASTE	*518*	*2.043*	*486*	*2.033*
NUCLEAR	-	-	-	-
WIND	*1.544*	*1.544*	*4.379*	*1.544*
EXPORT	2.837	3.224	3.174	3.160
IMPORT	6.168	6.556	6.506	6.492
BALANCE	**10.553**	**10.119**	**10.829**	**10.178**

FINLAND

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	88.423	86.261	85.762	85.799
FOSSIL	*4.919*	*2.757*	*2.258*	*2.295*
SUN and GEO	-	-	-	-
WATER	*15.991*	*15.991*	*15.991*	*15.991*
BIO and WASTE	*14.586*	*14.586*	*14.586*	*14.586*
NUCLEAR	*46.838*	*46.838*	*46.838*	*46.838*
WIND	*6.090*	*6.090*	*6.090*	*6.090*
EXPORT	4.719	4.574	6.307	3.932
IMPORT	14.097	17.273	20.946	18.026
BALANCE	**97.802**	**98.960**	**100.400**	**99.893**

GERMANY

(GWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	543.838	500.688	481.172	509.532
FOSSIL	*211.074*	*164.038*	*148.366*	*175.275*
SUN and GEO	*53.974*	*53.974*	*53.974*	*53.974*
WATER	*20.475*	*20.462*	*20.440*	*20.475*
BIO and WASTE	*58.278*	*62.177*	*58.355*	*59.771*
NUCLEAR	-	-	-	-
WIND	*200.037*	*200.037*	*200.037*	*200.037*
EXPORT	62.589	49.689	40.139	51.745
IMPORT	76.841	106.036	116.419	100.112
BALANCE	**558.090**	**557.034**	**557.452**	**557.899**

LATVIA

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	9.850	9.235	10.535	9.481
FOSSIL	*3.384*	*1.581*	*1.692*	*1.774*
SUN and GEO	*4*	*4*	*4*	*4*
WATER	*2.867*	*2.867*	*2.824*	*2.867*
BIO and WASTE	*1.833*	*3.047*	*1.819*	*3.074*
NUCLEAR	-	-	-	-
WIND	*1.762*	*1.736*	*4.197*	*1.762*
EXPORT	3.691	3.206	3.875	3.371
IMPORT	3.958	3.987	3.448	3.905
BALANCE	**10.117**	**10.015**	**10.109**	**10.015**

LITHUANIA

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	12.656	20.216	18.517	17.084
FOSSIL	*6.820*	*2.544*	*2.468*	*294*
SUN and GEO	*15*	*15*	*15*	*15*
WATER	*682*	*675*	*894*	*682*
BIO and WASTE	*1.223*	*2.110*	*1.223*	*1.737*
NUCLEAR	*2.183*	*13.170*	*12.214*	*12.624*
WIND	*1.732*	*1.703*	*1.703*	*1.732*
EXPORT	7.185	13.239	11.439	10.798
IMPORT	6.670	5.736	6.963	6.000
BALANCE	**12.140**	**12.713**	**14.041**	**12.287**

NORWAY

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	149.205	149.377	152.923	149.045
FOSSIL	*781*	*921*	*759*	*621*
SUN and GEO	-	-	-	-
WATER	*137.351*	*137.351*	*137.351*	*137.351*
BIO and WASTE	*73*	*105*	*73*	*73*
NUCLEAR	-	-	-	-
WIND	*11.000*	*11.000*	*14.739*	*11.000*
EXPORT	30.212	33.458	38.182	31.976
IMPORT	20.257	23.273	24.519	22.223
BALANCE	**139.250**	**139.192**	**139.260**	**139.291**

POLAND

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	149.759	151.436	158.003	152.035
FOSSIL	*74.222*	*61.678*	*36.523*	*66.747*
SUN and GEO	*3*	*3*	*3*	*3*
WATER	-	-	-	-
BIO and WASTE	*14.498*	*14.498*	*14.488*	*14.498*
NUCLEAR	*30.447*	*30.075*	*27.935*	*30.447*
WIND	*30.589*	*45.183*	*79.055*	*40.340*
EXPORT	2.913	4.043	6.998	4.287
IMPORT	42.248	41.888	43.246	41.422
BALANCE	**189.094**	**189.282**	**194.251**	**189.170**

RUSSIA

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	110.528	113.229	110.159	115.335
FOSSIL	*23.942*	*26.221*	*23.955*	*28.156*
SUN and GEO	-	-	-	-
WATER	*12.307*	*12.307*	*12.307*	*12.307*
BIO and WASTE	*19.639*	*19.639*	*19.639*	*19.639*
NUCLEAR	*51.316*	*51.493*	*50.647*	*51.383*
WIND	*3.325*	*3.570*	*3.611*	*3.850*
EXPORT	9.507	11.648	9.145	13.300
IMPORT	2.857	2.560	3.139	2.477
BALANCE	**103.878**	**104.141**	**104.152**	**104.512**

SWEDEN

(MWh)	LowCO2	HighCO2	HighCO2_RE-sub	HighCO2_CapMark
TOTAL GENERATION	176.910	181.758	199.046	179.046
FOSSIL	*1.184*	*2.228*	*851*	*681*
SUN and GEO	*4*	*4*	*4*	*4*
WATER	*75.021*	*75.021*	*75.020*	*75.021*
BIO and WASTE	*17.233*	*17.257*	*17.233*	*17.233*
NUCLEAR	*70.913*	*70.913*	*70.683*	*70.913*
WIND	*12.556*	*16.336*	*35.254*	*15.195*
EXPORT	44.084	49.251	67.872	49.317
IMPORT	15.629	15.532	18.603	18.808
BALANCE	**148.454**	**148.040**	**149.777**	**148.536**

13 Appendix E – Comparison with ENTSO-E Ten Year Network Development Plan 2014

Figure 36 compares the interconnectors suggested by the model in the High CO2-price scenario with the interconnectors included in the ENTSO-E Ten Year Network Development Plan (TYNDP) 2014. Both studies consider investments in the period 2020 to 2030.

It is apparent, that there are many similarities between the two studies. However, compared to the TYNDP 2014 this study see a stronger need for South-North bound capacity within Norway and between Norway and Germany, whereas the TYNDP 2014 identifies a demand for East-West bound connections, for example between Sweden and Lithuania/Latvia and between Eastern and Western Denmark.

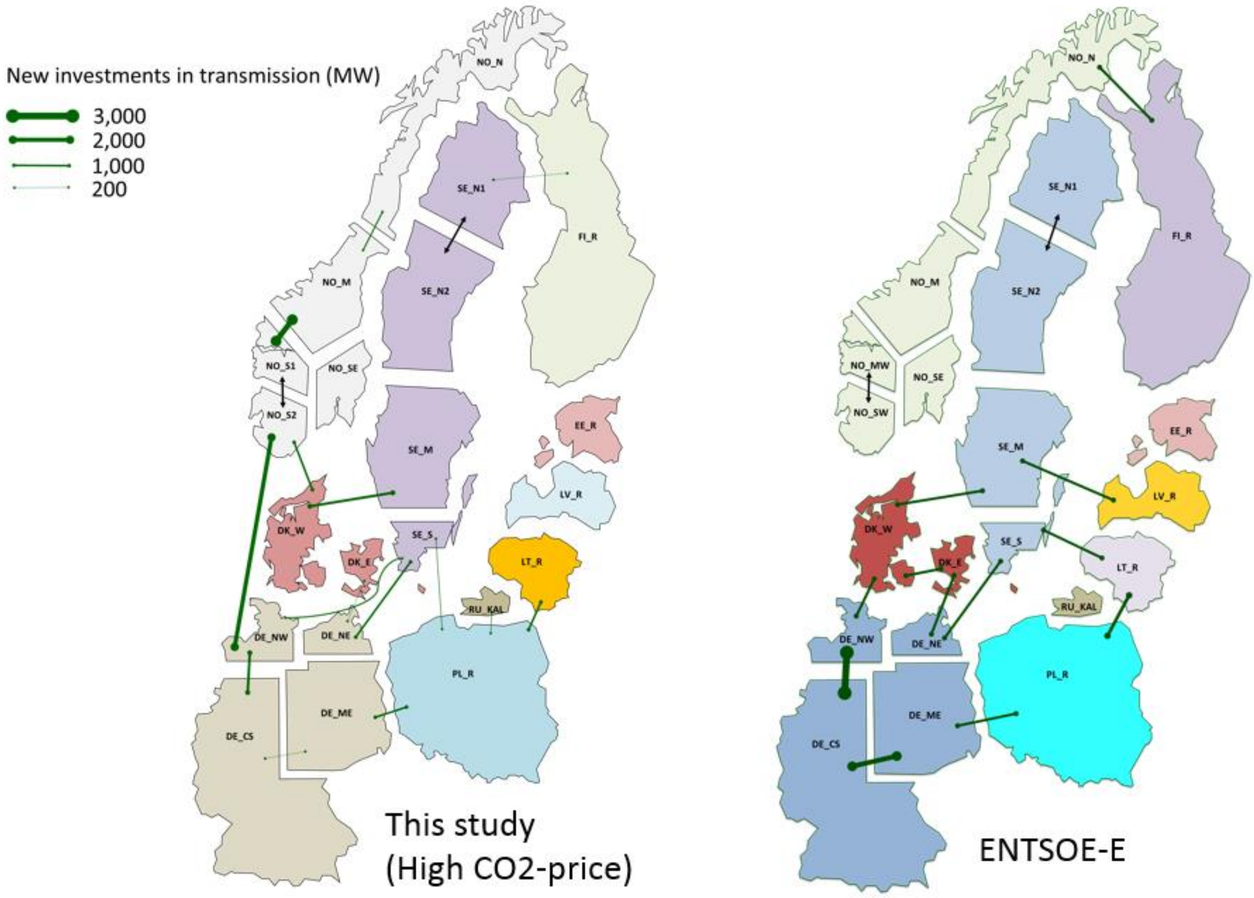


Figure 36: Comparison of interconnectors suggested by the model in the High CO2-price scenario with the interconnectors included in the ENTSO-E Ten Year Network Development Plan 2014. Both studies consider investments in the period 2020 to 2030.