The Norwegian energy policy strategy and its outcome

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An important aspect of Norwegian Energy Policy strategy, clearly formulated by the Government in 2012, was to integrate with power markets in neighbouring countries by building interconnectors as long as they were macroeconomic viable. This strategy principle is evaluated by performing a contrafactual analysis of interconnector expansion projects approved between 2005 and 2020. The analysis tells us that this strategy has been successful so far as the interconnector capacity expansion increases the macroeconomic surplus. It also shows that the increased investments in renewable generation in the Nordic countries have made the interconnectors more valuable, and furthermore that the increase in interconnector capacity has made renewables more valuable.

Introduction

The purpose of this paper is to describe the Norwegian energy policy strategy and evaluate its outcome in terms of changes in the macroeconomic surplus over the period 2005 to 2016. We primarily address Norwegian Energy Strategy decisions aiming at integrating Norway's power market more closely with the power markets on the Continent and in the UK. Essentially, we have analysed three main questions;

- How is the Norwegian Energy policy strategy related to European power market integration defined?
- How has the social surplus based on Norwegian power resources developed between 2009 and 2016?
- How have investments in more interconnector capacity to the Continent and the UK impacted the social surplus of Norwegian power resources?

We start by defining the Norwegian strategy related to power exchange by studying important changes in legislation and how the strategy is formulated in recent policy documents. We do this by studying the Norwegian energy policy history from the beginning of the 1990s, when the new Norwegian Energy Act was adopted, and the recommendations of the Energy Commission, appointed by the Norwegian Government, in 2012 (OED, 2012), including how these recommendations have been followed up by the Norwegian Government in the following years.

The next step is to present and analyse the impacts of power market developments on the macroeconomic surplus in the Norwegian electricity sector and on the income distribution between producers and consumers from 2005/2009 to 2014/2016. This period corresponds to the period between the implementation of the EU's Third Energy Package and the presentation of the Clean Energy Package proposal.

Market developments are influenced by an array of factors, and it is difficult to specifically isolate the effects of the Norwegian strategy on the macroeconomic surplus based on empirical data. We therefore performed a partial contrafactual analysis of the effects of the expansion in interconnection capacity over the same period. In this analysis we used a sophisticated power market model framework, that enable us to isolate the impact of specific factors while keeping other factors constant. The purpose is to assess if the strategy has been successful or not, by calculating the effects of the investments on the macroeconomic surplus and how it is distributed between producers and consumers.

The core principles of the current energy strategy were established in 1990

Norway was one of the first countries to deregulate its electricity sector. The Norwegian Energy Act of 1990 made fundamental changes in electricity sector regulation. Core elements were unbundling of generation and distribution, and to establish competition in generation and supply combined with new principles for grid regulation. The main principles were thus very much in line with the later adopted EU target model. Hourly prices were set by the balance between supply and demand, and new regulatory schemes were developed to secure third party access to the grid and to stimulate more efficient grid investments and operations. The deregulation in Norway, and subsequently the Nordic market, was expected to give lower investments in generation capacity and grid infrastructure (at a time of overcapacity), lower and more similar prices for the end-users, lower grid tariffs and a higher rate of return for investors.

The other Nordic countries followed suit with similar electricity market reforms a few years after. Before the end of the century the Nordic countries had established the first regional integrated power market in Europe, based on the principles of competition in supply and demand and infrastructure regulation. During the 1990s all Nordic countries left the principle of self-sufficiency, meaning that security of supply was increasingly based upon power trade with neighbouring countries.

In 2011, twenty years after the Norwegian power market reform, the Norwegian Government appointed a commission (Energiutvalget), here called the Commission, to assess the long-term prospect for the Norwegian energy sector and to review the current energy and climate policies. The Commission was also asked to discuss possible implications of the EEA agreement on the Norwegian energy sector, including Norwegian energy policy options.

In its report (OED, 2012), the Commission commented briefly on the impacts of deregulation from 1980 to 2009. Its main observations were that:

Opening up for competition resulted in power price convergence between domestic regions, where prices previously were based on cost-plus principles, giving large price differences between consumers.

Security of supply was improved even though the principle of self-sufficiency was left. This was due to increased interconnector capacity with neighbouring countries, many of which were dominated by thermal generation capacity.

More efficient utilization of energy resources and less environmental impacts on Norwegian nature due to reduced investments, due to the overcapacity in the Nordic power system when the market was deregulated.

Regarding the future, the Commission referred to the fact the that Norway chose a market-based energy system when the energy law was adopted in 1991. It described the merits of competitive markets including the positive effects of market-based prices instead of cost-plus prices, arguing that market-based energy systems are preferential to monopolized systems.

According to the Commission, the following driving forces were expected to impact the energy sector in the next 40 years (from 2012);

- High population and economic growth would increase energy demand despite increased emphasis on energy efficiency measures;
- Climate change policy would reduce consumption of fossil fuels;
- EU's energy and climate change policies, as well as global climate change policies, would impose important framework conditions on the Norwegian energy sector;
- Electrification would increase significantly
- Increased dependence on electricity would increase the demand on security of supply and yield higher system costs
- Obligations to increase the share of renewables in the generation mix in countries currently dominated by thermal generation would give lower power prices in the Nordic countries.
- In the long run, as emission costs were expected to be internalized in energy prices, the competitive position of industries (value creation) based on Norwegian renewable energy would improve;
- Climate change policies would give significant changes in energy systems in neighbouring countries, giving increased need for flexibility both in Norway and abroad.
- The European power markets would be more integrated, due to increased cross border transmission capacity and market coupling

The considerations and recommendations, presented to the Government in 2012, can be summarized to the following:

An efficient market-based energy system is a competitive advantage for Norway. The basis for this statement is threefold;

Firstly, a belief that Nordic power prices will be lower than in the rest of Europe, as new investments in renewable production capacity were expected to be lower in the Nordic countries.

Secondly, that increasing emission costs would, through carbon pricing schemes, would be internalized in future power prices, benefitting Norwegian renewable power producers.

Thirdly, that the expected transition to a low carbon economy would increase the demand for flexibility and thereby strengthen the business case for Norwegian hydropower producers.

According to the Commission, the main challenges for the Norwegian energy policy would be to keep security of supply in the Norwegian power system at a sufficient level, increase value creation based on Norwegian energy resources, protect the environmental, adequately address the climate problem, and stimulate more efficient domestic energy use.

The Norwegian Government followed up the recommendations in an attachment to the 2013-budget (FIN, 2013). In a separate chapter on international cooperation, the Norwegian Government state that "*Cross-border power trade constitutes a foundation for Norwegian value creation by utilizing the competitive advantages of Norwegian power generation".*

The Government underlined that Norway should be aiming at "a balanced" integration with neighbouring countries, taking into account domestic demand and value creation based on Norwegian energy resources. More specifically, licencing of new interconnections would require that the interconnectors were macroeconomic viable, where a long list of preconditions should be addressed, including security of supply as the most important consideration. The Government also underlined that that the assessment of macroeconomic viability should include both consumer and producer surplus.

The Norwegian Government supported the hypothesis that the value of Norwegian renewable energy resources would increase as the decarbonization of the power system would raise the value of flexibility.

How market developments and higher grid costs have changed economic surplus

We start our investigation of the Norwegian energy policy strategy by studying important market developments from 2005 to 2016 and calculating the changes in the social surplus in the power sector. In the same period, the Norwegian power market has become physically increasingly integrated with adjacent power markets by investments in interconnector capacity. In parallel, we have seen large capacity investments in renewable power generation both in the Nordics and in the rest of Europe. So, we want to check if the market developments, the increased trading capacities, the domestic grid investments and more production capacities has turned out positive in terms of its contribution to the total macroeconomic surplus of the Norwegian economy.

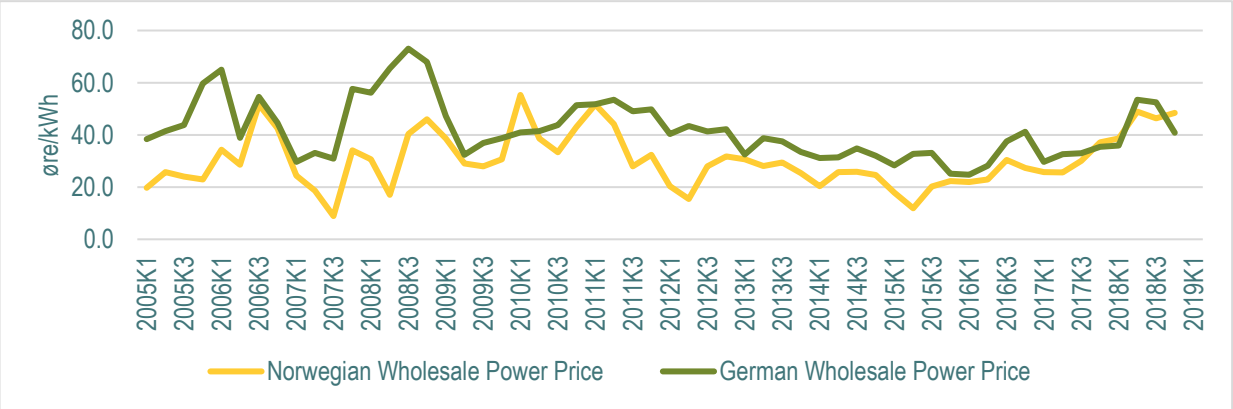
As a basis for the assessment, let us first take a look at what has actually happened in the markets.

Power market developments

Price levels have converged between Norway and the Continent

Norway, together with the rest of the Nordic market, has generally enjoyed lower prices than its continental counterparts, e.g. Germany, as can be seen in *Figure 1* below. Average price levels have converged, though. After a period with volatile prices around an average level around 30 øre/kWh between 2005 and 2012, prices stabilized between 20 and 30 øre/kWh before starting to rise again from 2017 up to almost 50 øre/kWh by the end of 2018. This sudden increase can be attributed to a weak hydrological balance due to low inflows, but also to increases in fuel prices and the price of EU CO_2 emission allowances.

Figure 1: Nominal wholesale power price development for Norway and Germany, quarterly averages Q1 2005-Q1 2019



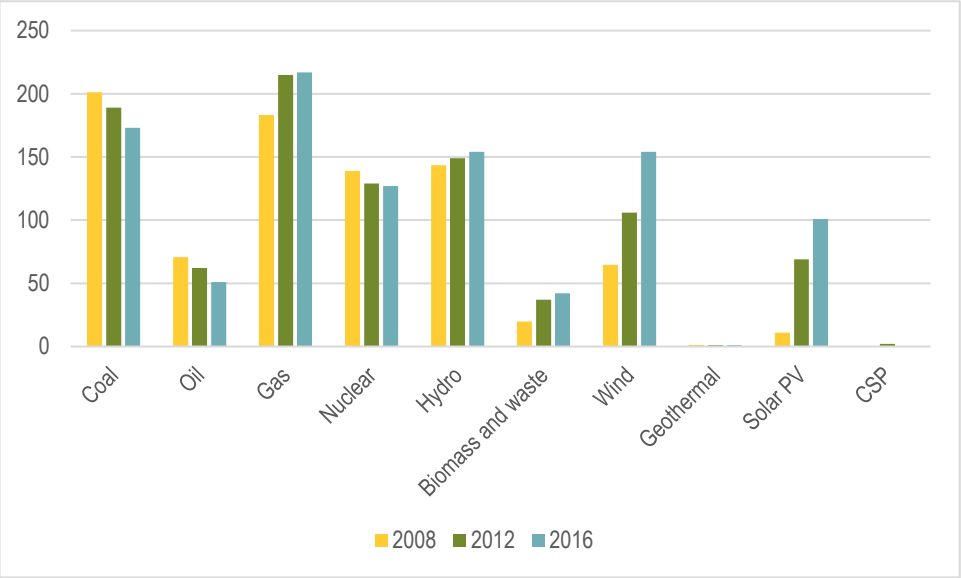
Source:

The decline in wholesale prices in Europe has been attributed to multiple factors, such as the strong expansion of renewable generation capacity in parallel with a moderate electricity demand in wake of the financial crisis, a low carbon price and a reduction in coal prices, where the coal price is the most important factor in this period (Pöyry and THEMA Consulting Group (2010))

A significant capacity surplus has built up in Continental markets

As can be seen from Figure 2, there has been a significant increase in installed capacity in the European Union between 2008 and 2016, most notably based on renewable energy sources, but in absolute terms also in coal and gas power generation.

Figure 2, Installed generation capacity in Europe Union 2008, 2012 and 2016 by technology (GW)

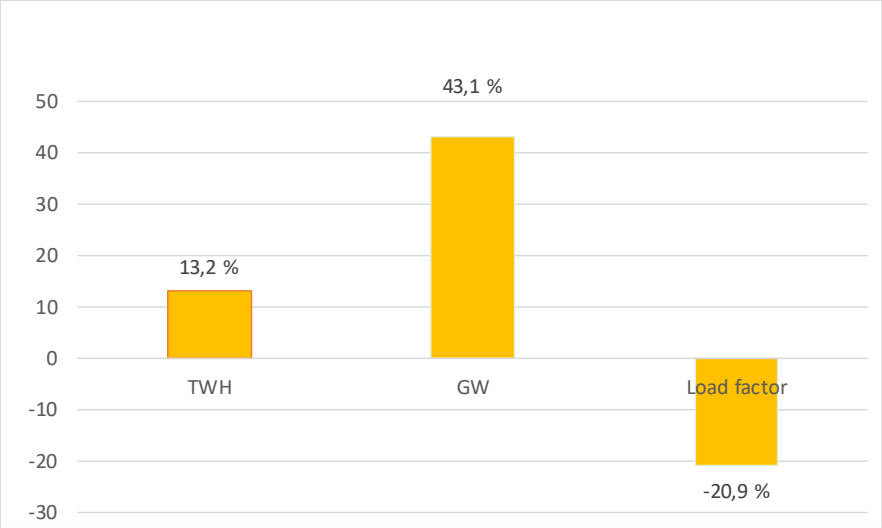


Source: IEA, World Energy Outlook 2010 and 2018

Figure 3 shows that electricity generation grew much less than the installed capacity from 2008 to 2016. As electricity generation is a good proxy for gross electricity demand on the European level, it implies that power capacity in GW has grown much more than electricity demand in TWh.

While installed capacity increased by 43 percent, electricity generation increased by only 13 percent, reducing the average load factor by 21 percent. The reduced load factor is partly due to higher shares of renewables, as wind and solar generation depend on the weather to generate, but also indicates that the market balance has become softer over the period, thereby reducing the load factor even for conventional generation capacity.

Figure 3. Changes in electricity generation, installed capacity and load factor in the OECD European power sector 2008–2016, %.



Source: IEA World Energy Outlook, 2010 and 2018

The Norwegian power balance strengthened during the period 2016 - 2018 due to wind and thermal power expansion

Figure 4 shows the Norwegian power market balance based on normalised power production and demand curves. The curves are normalised according to average water inflow to the hydropower system and temperature respectively. The curves tell us that the overcapacity gradually decreased from 1990 to 2000, the first decade after deregulation, while the market was fairly balanced in the following decade. Since 2009, however, a certain surplus, more or less corresponding to increases in wind and thermal production combined, has built up. The thermal production is mainly cogeneration used in the manufacturing industry and the petroleum industry.[1] The last ten years, the surplus has been quite steady, corresponding to a steady growth both in generation capacity and in power demand.

[1] Notably, the combined heat and power facility at Mongstad, connected to the oil and gas refinery and CCS R&D started operation in 2010. The facility has not been profitable and will be closed in spring 2020.

Figure 4: Normalised Norwegian power production and demand (TWh)

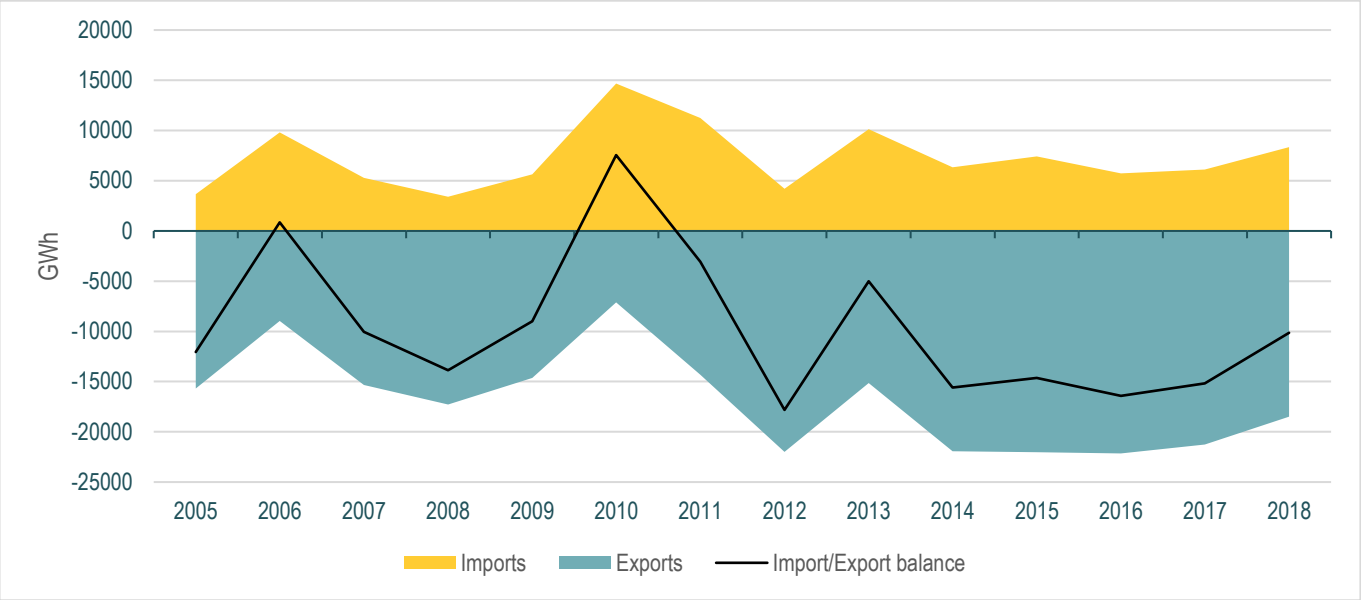
Source: Energifakta Norge (2018)

Figure 5 shows Norway's annual electricity trade balance for the period 2005 to 2018 based on actual production and consumption. Variations in hydrology is usually the main driving force behind short term changes in Norway's power trade balance. With 2010 being a dry year and 2012 a very wet year, the balance shifted heavily in the positive and respectively in the negative direction with Norway importing more than 7.5 TWh in 2010 and exporting almost 18 TWh in 2012. From 2014 onwards, the net export volume has been stable at around 15 TWh, slightly falling in 2018 due to another comparatively weak hydrological year.

Thus, developments support the expectation that the Norwegian power balance would get stronger after 2012. Some of the increase is however based on increased thermal generation, but both wind and hydro generation have increased as well. It should be noted, however, that the increase in normal year hydro power generation is partly due to an increase in expected inflow to existing hydro power plants, and that the increase in wind generation due to the Elcertificate support scheme was rather moderate through 2016.[2] However, it should also be noted that Norwegian prices are also heavily influenced by the power balance in Sweden where the increase in generation capacity from renewable sources has been much stronger since 2012. As an example of this, renewable generation from wind power in Sweden more than doubled from 2012 to 2018, with 16.6 TWh of wind power generation in 2018.

[2] Wind capacities have grown more rapidly since 2018 and approximately 4 GW of additional capacity is expected to be set in operation from 2018 until 2021.

Figure 5: Norway's electricity trade balance (positive: Imports, negative: Exports)



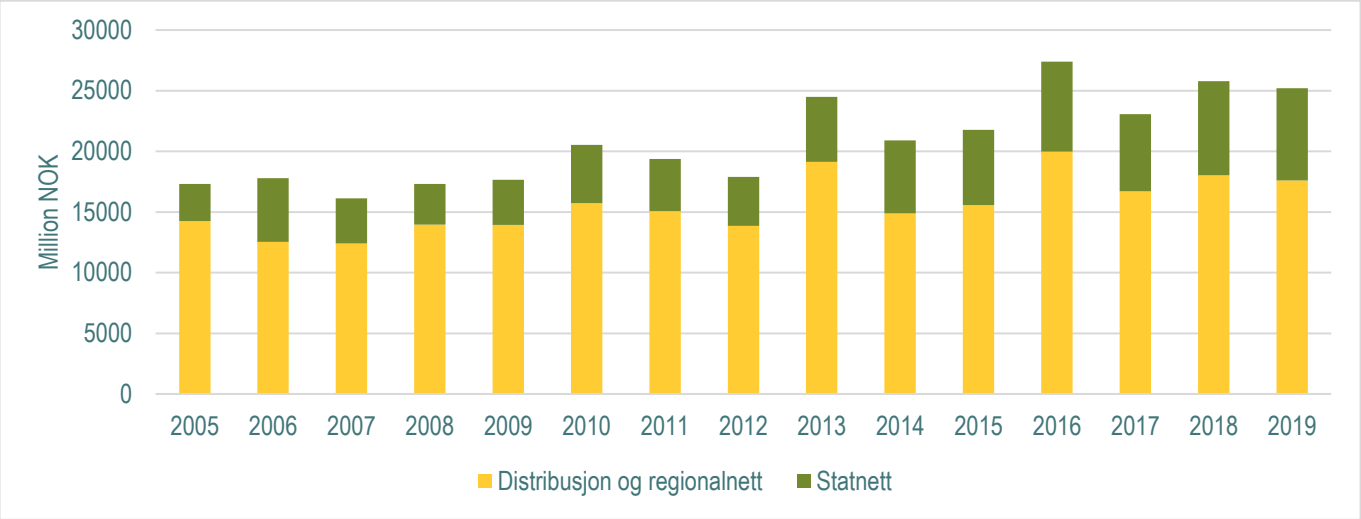
Source: SSB

Domestic grid costs in Norway have increased

Increases in interconnector capacity, with corresponding increases in trade flows and changed flows in the internal grid, affect congestions and investments in the domestic grid. Thus, domestic grid costs should be taken into account in the assessment of the social cost of the trade-based energy policy strategy.

Grid companies are regulated through revenue caps. The revenue caps reflect the underlying grid costs. The aggregated development in revenue caps for grid companies is shown in *Figure 6*. Apart from two outliers in 2013 and 2016 with higher caps than in the preceding and subsequent years, the aggregated income cap grew steadily from around NOK 17 bn. in 2005 to over NOK 25 bn. in 2019. Howeven, just a small part of the increase in revenue caps is related to changes in trade flows. A major part of the increase is related to rehabilitation needs and capacity expansion due to changes in demand and supply, including increased renewable generation. A rough estimate indicates that 20 percent of Statnett's income cap increase is related to changes in trade flows, which correspondates with approximately 10 percent of the aggregated income cap increase across all grid levels.

Figure 6: Development in aggregated revenue caps for Norwegian DSOs and the TSO Statnett



Source: The Norwegian Water Resources and Energy Directorate

In summary, market developments have diverged from expectation

To sum up, the power market development between 2005 and 2016 confirms that Norwegian power prices have been lower than European prices except in periods with low water influx to Norwegian hydro power reservoirs. Contrary to expectations, however, the differences have been reduced over time.

On the one hand, the Norwegian overcapacity has been reduced, and corresponded, at the end of 2016, to the sum of wind and thermal power generation. On the other hand, prices on the Continent have not increased as expected. The main reason is probably that investments in renewable generation has been heavily subsidized and total costs not reflected in market prices.

The evidence seems to suggest that, in line with the expectations in 2012, the Continental market has been characterized by a rapid expansion in renewable capacity, but contrary to expectations in 2012, a capacity surplus has emerged and depressed continental power prices. The culprit is likely to be the aftermath of the financial crisis in autumn 2008 which not only reduced power demand from industry, but also depressed global fuel prices, in particular for coal, which directly affect European power prices. This effect of low coal prices could have been dampened by increasing CO_2 prices in the EU ETS, but lower electricity demand and reduced industry activity also reduced demand for allowances.

On the other hand, the price developments also show the strong relationship between Nordic and Continental prices. The CO_2 price has affected power prices both in Norway and on the Continent, but the prices of allowances have been lower than expected due to the weak economic growth.

In the same period, we have seen a strong increase in the aggregated income caps of Norwegian TSO and DSOs, due to a combination of rehabilitation needs and capacity expansion. Thus, grid costs have increased as the Energy Commission anticipated.

Impact on social surplus in Norway

The social surplus in the power sector is reduced after 2012

Market developments from 2009 to 2016, and further to 2019, show fluctuating quarterly wholesale power prices between 40/50 and 20/30 øre/kWh. In the same period, grid costs have increased due to investments caused by a combination of rehabilitation needs and capacity expansion.

The development impacts the macroeconomic surplus related to the power sector and how it is distributed between consumers and producers. We have compared the average economic surplus for the period 2005–2009 with the period 2014 – 2016. The result is presented in *Table 1* below. The average numbers for the period 2005 – 2009 represent the market situation before the Third Energy Package was approved and implemented, while the period 2014 – 2016 represent the situation after. We use average numbers to reduce the random impact of inflow variations to the Norwegian hydro power reservoirs.

Table 1. Changes in producers' and consumers' surplus, 2014-2016 vs 2005-2009. Million NOK per year.

Reduced producers' surplus initial volume	-10 090
Reduced producers' surplus capacity expansion	- 1 617
Total reduced producers' surplus before increased grid costs	- 11 708
Increased consumers' surplus initial volume	9 418
Increased consumers' surplus increased volume	3 323
Total increased consumers' surplus before increased grid costs	12 741
Net economic surplus before changes in grid costs	1 033
Increased income caps	-6 468
Increased power trade surplus	347
Total change in socioeconomic surplus	-5 087

The calculations are based on the following observations:

- The average power price fell from 30 to 23 øre/kWh, down 30 percent, reducing producers' surplus related to initial volumes by 10 bn. NOK, while increasing consumers' surplus by 9,4 bn NOK annually.
- Assuming that the willingness-to-pay (WtP) for new consumption is 100 øre/kWh (see appendix A.1), increased consumption adds 3,3 bn NOK to the consumers' surplus annually.
- Average yearly power production increased from 132 to 143 TWh, a total growth of 8 percent. Based on cost data from NVE, the levelized cost of electricity for new capacity is higher than the power price during the period, giving a loss in producers' surplus of approximately 1,6 bn NOK annually. Note that some of the capacity investments has been supported by green certificates. The loss has therefore not entirely been covered by generators. Furthermore, the producer surplus might increase in the future along with increasing power prices.
- Net exports went up from 9 TWh to 16 TWh annually. The associated annual trade gain increased by 347 million NOK.

- We have used aggregated income caps for grid companies as a proxy for grid cost. We have added the net trade gain since it is subtracted from the Statnett's income cap. The grid cost increase is 6121 million NOK, of which over 90 percent is paid by consumers.

Taking all elements into consideration, the annual social surplus fell by approximately 5 bn NOK, when comparing average numbers for the period 2005–2009 with 2014–2016.

However, only a minor part of the income cap increase is related to grid investments needs spurred by increased external power trade. How much is unfortunately hard to tell. If we assume that 100 percent of the income cap increase on the distribution and regional level and 20 percent of Statnett's transmission investments are related to domestic developments, only 10 percent would be associated with more power exchange with neighbouring countries.

Grid costs are decisive for the income distribution effects, but consumers' come out as winners

So far, we observe that when we consider market prices alone and compare the periods 2005–2009 and 2014–2016, producers' surplus is reduced and consumers' surplus increased. These changes are mainly attributed to lower wholesale power prices. The price reduction is partly related to external factors such as lower coal prices, Norwegian policy decisions also matter. One important factor is investments in interconnectors and incentive schemes to spur new renewable generation investments. We explore the impacts of interconnectors and renewables in the next section.

Increases in grid costs are mainly borne by consumers. Although generators connected to the Norwegian grid also have to pay tariffs, EU regulations cap maximum G-tariffs. Thus, if all of the grid costs, as reflected by the aggregated grid revenue caps, are related to changes in grid flows due to interconnector expansion and increased trade, consumers' surplus is halved. It should, however, also be noted that grid tariffs vary considerably among consumers, most notably between industry and households. Thus, there are also substantial differences in the distribution of costs within the consumer group. In the next section we provide a contrafactual analysis of Norwegian investments in interconnectors and how investments in renewables impact the results.

Model based contrafactual analysis – Effects of less trading capacity

The purpose of the analysis in this paper is to study the effect of increased interconnector capacity on total welfare and how it is distributed between Norwegian consumers and producers. Has the expansion of interconnector capacity since 2009 been beneficial for Norway in welfare economic terms? Above, we have presented an overview of market developments and we have estimated the value of Norwegian electricity generation before and after 2009 based on market data. A large variety of changes has however affected the results in the last decade or so, and not all can be attributed to the Norwegian strategy. In order to isolate the effect of interconnectors, we would ideally perform a contrafactual analysis.

Here we present a stylized contrafactual analysis where we only vary the interconnector capacity and the generation mix. As explained above, the trade-based policy was partly based on the expectation of expansion of renewable capacity in Europe and the Nordics.

The study is performed by comparing the power market results in 2020 with situations where we assume 1) unchanged interconnector capacity since 2009, and 2) unchanged generation capacity since 2009. The market simulations are carried out using THEMA's European power market model.[3]

Methodology

In the period since 2009, the market fundamentals have changes dramatically, in particular the power generation mix. In contrafactual terms, we look at the results of the interconnector investments – seeing interconnector expansion as a core element in the Norwegian energy policy strategy – and how the results are affected by the energy transition that has taken place in the period. More specifically, we use the expansion of renewable capacity as an indicator of the energy transition.

To simplify and isolate the effects, we base the analysis on the expected[4] market situation in 2020, where the demand level is kept at 2020 levels. The demand levels are kept constant due to a modest growth between 2009 and 2020, and to better isolate the consequences of increasing the interconnector capacity as well as replacing fossil generation capacity with renewable generation capacity.

Interconnector capacities

The variables we change are interconnector build-out and the share of renewable energy in the generation mix. Contrafactually, we assume that three cables, listed below, are not built, reducing the assumed interconnector capacity between Norway and other countries (Germany, UK, and Denmark) by 3500 MW.

- NordLink (Norway Germany) 1400 MW capacity
- North Sea Link (Norway – UK) 1400 MW capacity
- Skagerrak 4 (Norway – Denmark) 700 MW capacity

Generation capacity

Regarding the generation capacity in the analysis, the current European generation capacity was compared to the generation capacity in 2009. In other words, since the demand is expected to be equal to the 2020 demand in all scenarios, the plants in the 2009 scenario are expected to be prolonged until 2020. However, no new capacity is being built, and therefore no costs are allocated to this other than the operating costs of the facilities. The Norwegian generation capacities for the different scenarios are shown in *Figure 7* as an example. Due to a generation mix dominated by renewable generation also in 2009, the change is not that evident in the Norwegian market, other than the total capacity. However, the same methodology is applied to the entire European power sector, with larger differences on the Continent.

[3] THEMAs power market model has been developed and expanded over a period of 10 years. It is widely used in market analysis in various projects for public and private stakeholders, and the basis for price prognosis used by power market participants and investors (see Appendix and www.thema.no for more information).
[4] Expectation according to THEMAs best guess scenario for the Nordic and European markets as of October 2019, used on price forecasts for Nordic and European power prices. The scenario is based on <main sources>.

However, the energy commission expected an increase in renewable capacity in the period. We therefore also investigate the impacts of interconnectors with the actual generation mix in 2020 as compared to the 2009 generation mix.

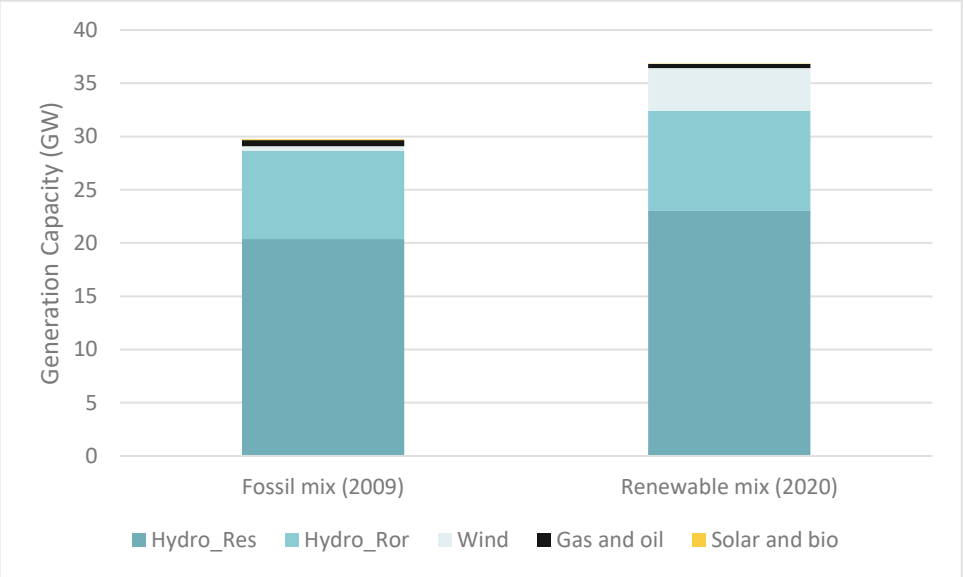
The energy consumption is assumed to be equal for all scenarios and is in other words not scaled to the growing consumption. The reason for this choice is that it is not obvious how the capacity should be correctly scaled, and a number of assumptions would have had to be made. The alternative would imply that we assume phase-out of capacity according to historical numbers, to replace that capacity with something else than renewable generation and take demand growth into account. However, a number of issues arise if we were to apply such a method, such as:

- Should we use the growth in energy consumption as the basis for the increase in capacity? Or the growth in peak demand?
- What should we assume in terms of efficiency as old thermal capacity is replaced by new, more efficient capacity?
- How should we distribute the capacity across Europe?

Either way, we would have to make a number of assumptions that would not be accurate and would affect the results. The assumption that the capacity would not change at all from 2009 is of course not realistic either, but on the other hand, it is a well-defined scenario and enables us to isolate the market effect of interconnectors.

Now, alternatively, we could have kept consumption at 2009 levels and scaled down the 2020 capacity to 2009, but that would not have solved the issues related to up-scaling discussed above.

Figure 7: Norwegian generation capacity mix used in the analysis.



Overview of cases

Through the comparison of four cases, detailed below, we can answer the questions:

- Would the interconnectors be profitable without the energy transition?
- How has the energy transition affected the profitability of interconnectors?
- How has the interconnectors affected the buildout of renewable generation?

The simulation year is 2020 and we compare the results of 4 different combinations of assumptions. The resulting scenarios are shown in *Table 2*.

Table 2: Overview of scenarios for interconnector build-out and capacity development.

	No Energy transition	Energy transition
Interconnector build-out	A New interconnectors built, no investments in renewables after 2009	D Interconnectors built, actual investments in renewables by 2020
No interconnector build-out	B No interconnector built, no investments in renewables after 2009	C No interconnector built, actual investments in renewables by 2020

Scenario B is a base-case scenario where we assume that the three interconnectors are not built, and there are no new investments in renewable or any other generation capacity. The only change from 2009 to 2020 is an increase in consumption levels. (The growth in normalized electricity consumption in Norway is 11 TWh, or about 9 percent in the period.) In the other scenarios we change the interconnector capacity, the renewables build-out, or both.

In scenarios A and B, i.e. without the energy transition, Norway has a negative power balance, and thus imports 18 TWh annually. In the scenarios with the energy transition, C and D, Norway has a positive power balance, and thus exports 9 TWh annually.

Case 1. By comparing A with B, we estimate the impact of interconnector investments, given that investments in renewables are not implemented after 2009.

Case 2. By comparing D with C, we estimate the impact of interconnector investment, given actual investments in renewables by 2020.

Case 3. By comparing B with C, we estimate the impact of investments in renewables without interconnector investment¨

Case 4. By comparing D with B, we estimate the combined impact of interconnector and actual investments in renewables by 2020.

The results are summarised in figures *Figure 8*–*Figure 11* below.

Case 1: The value of interconnectors without the energy transition

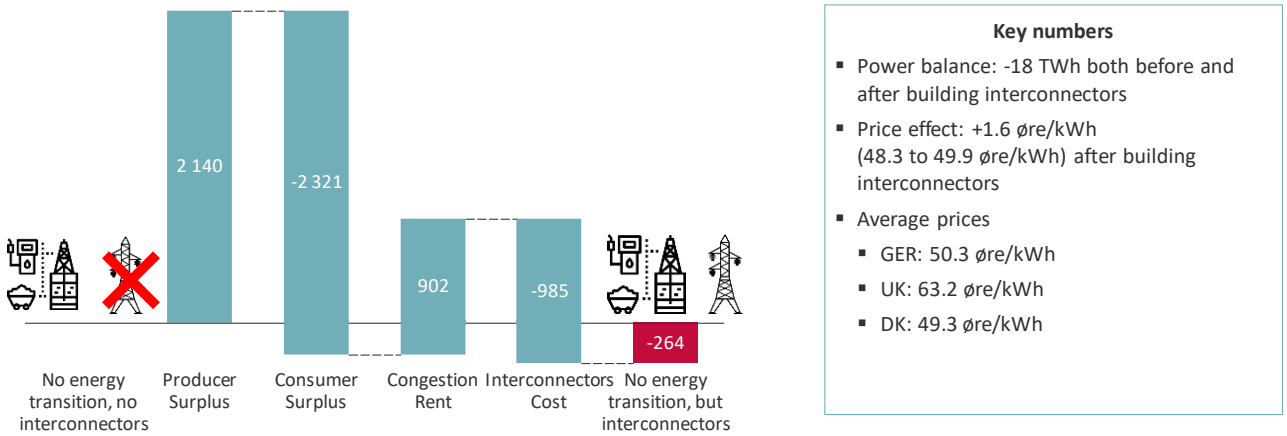
In Case 1, the Norway imports 18 TWh in a normal year. The impact of the expansion of interconnectors is an increase in average power prices by 1,6 øre/kWh. Due to the price increase, the annual producers' surplus increases by 2.14 bn NOK, while the consumer surplus is reduced by 2.32 bn NOK due to higher interconnector capacity. The normal year increase in congestion rents is slightly lower than the annualized investment cost of the new interconnectors. The net result on socioeconomic surplus ends up negative at 264 million NOK. The key results are summarized in *Figure 8*.

Thus, the result shows that taken together, the interconnector investments after 2009, would not have been profitable without the energy transition and the expansion of renewable generation. The build-up of a significant negative power balance is the main explanation for this. When prices increase, the generators' gain and the consumers lose. Mainly due to the difference in volume, with generation being 18 TWh lower than consumption, the generators' gain does not

outweigh the consumers' losses. There is also a slight difference in the average price paid by consumers and the average price received by generators since generation patterns differ from consumption patterns, but with prices in the Norwegian market area being rather flat, this difference is small.

The significance of the power balance is also seen in the average prices, as referred in the box in the figure. In both scenarios, i.e. with and without interconnectors, the average price in Norway is on about the same level as prices in Germany and Denmark. Market prices in other countries are less affected by the interconnector expansion, with the exception of Sweden.

Figure 8. Case 1: Impact of interconnector investments on Norwegian social surplus without energy transition, million NOK (annualized 2020)



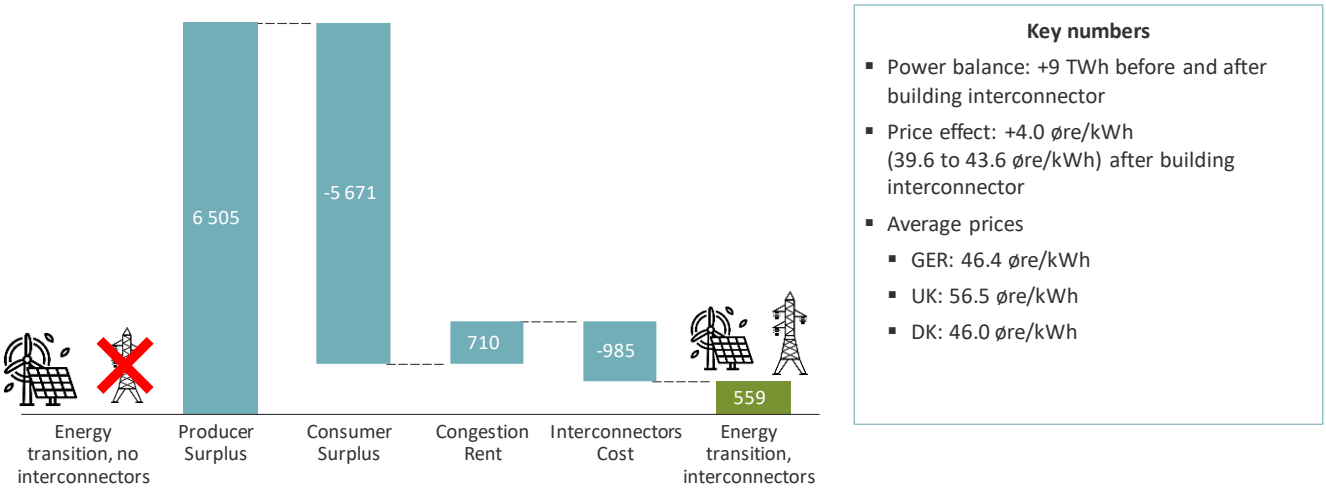
Case 2: The value of interconnectors with the energy transition

In Case 2, when we assume that the energy transition, and the increase in renewable capacity takes place, the impact of interconnector expansions increases the Norwegian social surplus by 559 million NOK. Thus, compared to the result of Case 1, the factual investments in renewables make the interconnector investment socioeconomically viable, which they were not in Case 1. The interconnectors become socioeconomic beneficial because we build up an energy surplus. Increased trading capacity increases the value of generation, and since the generation volume is much higher in this case, the interconnectors are beneficial for Norway overall.

In the scenarios where the energy transition is carried through, the power balance is positive, and the result reflects that the producers' surplus increases more than the reduction in the consumers' surplus. The price impact of the interconnector expansion is an increase of 4,0 øre/kWh. We note that in this case, price levels are generally lower due to the increase in generation capacity. Without the interconnector expansion, the annual price in Norway is significantly lower than in the interconnected markets. Price levels converge with the increase in interconnector capacity, but the average Norwegian price is still well below prices in the other market areas.

Congestion rents do however not increase sufficiently to cover the cost of the interconnectors. In this case, the deficit of almost 300 mill. NOK/year must be covered through grid tariffs. Given the cap on G-tariffs, the burden will mostly be carried by consumers, thus reducing the consumers' surplus further.

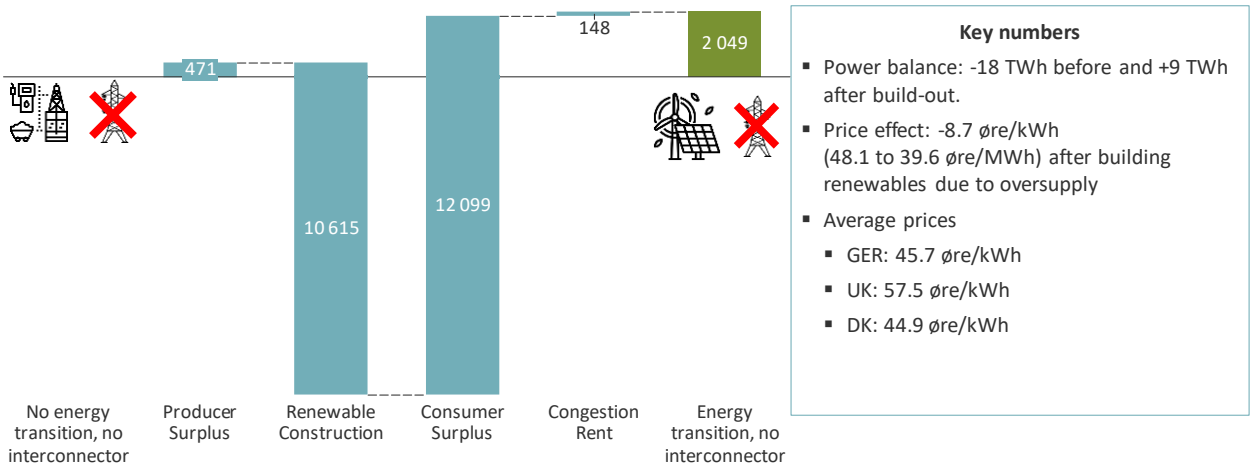
Figure 9. Case 2: Impact of interconnector on Norwegian social surplus with energy transition, million NOK (annualized 2020)



Case 3: The value of renewables investments without expansion of interconnector capacity

Comparison of Case 1 and Case 2 indicates that the value of interconnectors is highly dependent on the power balance, which in the period 2009–2020, is highly correlated with the increase in renewable generation. However, the value of renewable generation is not independent of interconnector capacity. As we have seen, expansion of interconnector capacity has a price effect which increases the value of (all) generation capacity. In Case 3, we investigate how the value of the renewable generation is affected if we did not expand the interconnector capacity in the same period.

Figure 10. Case 3: Impact of the energy transition on the Norwegian social surplus without interconnector investments, million NOK (annualized 2020).



The results show that the power price would have been 8.7 øre/kWh lower if the expansion of renewable generation had been realized without the increase in interconnector capacity. The power balance turns from a negative 18 TWh to a positive 9 TWh. Naturally, the lower price level reduces the value of existing generation, but due to the increase in total generation, the market value of all generation increases by 471 million NOK. The price reduction is due both to the increase in the Norwegian power balance and to the increase in renewable generation generally. In this case, prices in all the other market areas fall as well, with the largest drop in Norway and Sweden. The price levels shown in the table in the figure are the levels when we assume the energy transition is carried out.

There are important distributional effects among generators embedded in these numbers. For existing generation, the market value is almost 20 percent lower without the expansion of interconnectors. New renewable generation receives revenues both from the electricity market (which is the effects that are captured by our analysis) and from the sales of elcertificates and should in theory get their costs covered by the sum of the electricity wholesale price and the elcertificate price.[5]

The annualized investment costs of the renewable capacity, summing up to a total of 10.6 bn NOK, must also be taken into account. Because the consumers' surplus increases by more than 12 bn NOK in 2020, the total social surplus increases by 2.05 bn NOK.

The estimated consumers' surplus does not include the consumers' payment for elcertificates which, according to the market dynamics, will be higher the lower the electricity price is. Consumers are however only obliged to buy elcertificates corresponding to a share of their electricity consumption, so the gain due to the lower electricity price should by far outweigh the extra cost of the elcertificate obligation. There are also important distributional effects in the payment of elcertificates, as the power intensive industry is exempt from the elcertificate obligation.Since the introduction in 2012, the elcertificate price has shown high volatility, with a price peak in the fall of 2018. Following the 2018 peak exceeding 250 SEK/MWh was a sharp decline in prices, before falling below 20 SEK/MWh in 2020.

There is also a small increase in the congestion rent on existing interconnectors, which is due to increased price differences between Norway and other markets.

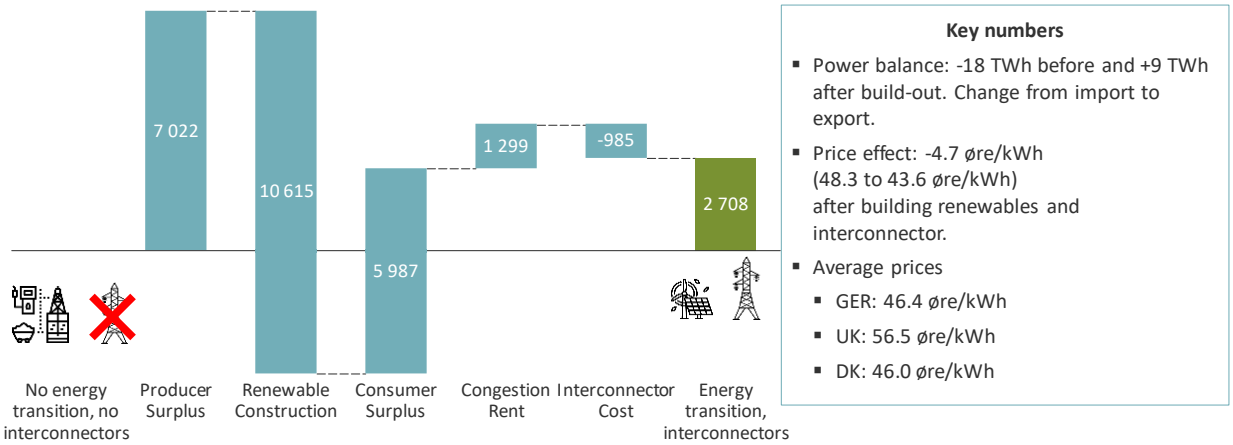
Case 4: The combined value of RES expansion and interconnector build-out

Obviously, the expansion of interconnectors and the RES build-out has not happened independently of each other, as also mentioned above and as was also part of the premises for the Norwegian strategy. Case 3 shows that the build-out of renewable generation would have yielded a positive social surplus for Norwegian society even without the expansion of interconnector capacity. Does that mean that the interconnectors should not have been built?

We investigate this question by first, calculating the change in social surplus going from scenario B, without any investments in interconnectors or new generation capacity, with scenario D, where interconnectors and renewable capacity are built out in parallel. The results are summarized in *Figure 11*.

[5] In equilibrium, the elcertificate price should reflect the difference between the LCOE of the marginal RES generation facility necessary to fulfill the elcertificate target.

Figure 11. Case 4: Combined effect of interconnector investments and the energy transition on Norwegian social surplus, million NOK (annualized 2020)



The overall result show that the combined effect of investments in renewables and interconnectors yields the highest social surplus of the four cases and outperforms the result in Case 3 by 650 million NOK. In other words, the build-out of new generation capacity, against the background of the European energy transition, has been profitable for Norway, and the parallel investments in interconnectors has increased the benefits. Put differently, the interconnectors have increased the market value of the new renewable generation capacity.

The price impact of the substantial strengthening of the power balance, as in Case 3, is almost halved in this case. Prices fall by 4.7 øre/kWh. In this case, the price reduction in Norway and Sweden due to the energy transition is on level with the price reduction in the other market areas (prices with IC and energy transition shown in the table in the figure). The cost of renewable generation is the same as in Case 3. Consumers' surplus increases by close to 6 bn NOK.

The increase in congestion rents is healthy, at more than 300 mill. NOK above the annualized investment costs for the new interconnectors.

Summary of results

Table 3 summarizes the results of our contrafactual analyses. Case 1 gives a negative aggregated impact on macroeconomic surplus of 264 million NOK, which indicates that the cable investments would not have been socioeconomic viable without the energy transition taking place between 2009 and 2016.

However, given the actual investments in renewables, i.e. the energy transition, since 2009 (Case 2) the interconnector investments turn out to be socioeconomically viable, as the total effect on macroeconomic surplus is 559 million NOK.

On the other hand, the isolated result of investments in renewables increases the total surplus increases by 2049 million NOK (Case 3), while the combined effects of investments and interconnectors (Case 4) increase the socioeconomic surplus by 2708 million NOK in 2020.

Table 3. Summary of impacts of case 1–4, million NOK. 2020

	Producers' surplus	Renewable costs	Consumers' surplus	Congestion rent	Interconnector costs	Total
Case 1	+2140		-2321	+902	-985	-264
Case 2	+6505		-5671	+710	-985	+559
Case 3	+471	-10615	12099	+148		+2049
Case 4	+7022	-10615	5987	+1299	-985	+2708

Concluding remarks

In this paper we have discussed the following three questions:

- How is the Norwegian Energy policy strategy related to European power market integration defined?
- How has the macroeconomic surplus based on Norwegian power resources developed between 2009 and 2016?
- How have investments in more interconnector capacity to the Continent and the UK impacted the macroeconomic surplus of Norwegian power resources?

By studying recent energy policy documents, we observe that a vital part of Norwegian energy policy strategy has been to integrate with surrounding markets by expanding interconnector capacities as long as the investments are macroeconomic viable. During the period 2005 to 2016 investment decisions to expand interconnector capacity by 3500 MW were made. The purpose of this paper has been to study if this strategy has been a successful strategy so far.

The first step was to study market developments between 2005/2009 and 2014/2016. On some important aspects the developments have not been as expected when the strategy was formulated. The most notable deviation has been the significant power price reduction between 2012 and 2016. This development was first of all due to increased power surplus in the Nordic market, lower CO2-prices and falling coal prices. By comparing the actual macroeconomic surplus associated with Norwegian electricity resources before and after 2009, we find that the macroeconomic surplus is reduced. However, significant changes have taken place in the market since 2012, so we cannot base on market data conclude that this implies that the strategy has been unsuccessful.

Instead, we have, as step two, tried to answer the question by performing a contrafactual analysis of the three interconnector projects behind the 3500 MW expansion. The analysis confirms that this interconnector capacity expansion increases the social surplus in 2020 compared to a situation in which these investments were not carried out. Furthermore, it is clear that the viability of the projects is highly dependent on the development in the market balance and the investments in new renewable generation capacity.

The energy transition was expected in 2012, and the strategy based on increased market integration and cross-border trade have been successful, even though the energy transition has so far not played out exactly as expected. This is what the analysis tells us: The increased investments in renewable generation has made the interconnectors more valuable, and the increase in interconnector capacity has made renewables more valuable.

We cannot, however, conclude that more renewable capacity has been built due to the interconnectors so far. The investments in renewable capacity have to a large extent been driven by the elcertificate scheme. As we enter the

2020'ies, the elcertificate prices are very low, and despite Sweden's extension of the scheme, further investments in renewable generation is expected based on expected future electricity market prices alone. Thus, in future, the utilization of renewable energy sources in Norway is likely to be affected by the interconnector capacity.

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Appendix

A.1 Assumptions for willingness-to-pay

The robustness of the assumption of setting willingness-to-pay equal to 100 øre/kWh can be elaborated on. Energy demand is highly dependent on individual consumption flexibility (concerning i.e. composition of demand; electricity-specific versus heating-specific purposes, dependency on grid connection etc.). High flexibility consumers, with good alternatives to electricity consumption and/or self-production possibilities, will not be as dependent on grid connection as consumers with no other alternatives. Consequently, willingness-to-pay for additional consumption is a function of flexibility, where there is a reverse relationship between willingness-to-pay and flexibility. We can decompose the analysis of willingness-to-pay in three different parts, namely the willingness-to-pay for:

- Consumption in the (power-intensive) industry
- Electricity-specific household consumption
- Heating-specific household consumption

The (power-intensive) industry operates in a competitive international market, and its profitability is highly dependent on power prices. Assuming this industry is utility maximizing, it will adjust its consumption so that its marginal benefit equals the price of the good. The willingness to increase consumption of a good with a known price must be equivalent to what the consumer is willing to pay as least the price of the good. Hence, as long as the marginal benefit (which ultimately equals the marginal willingness-to-pay) of increasing consumption by one unit exceeds the price of the good, the consumer will do so. Following this rationale, the willingness-to-pay for increased consumption will in an optimum situation be equal to the price of the good. We therefore assume that the power-intensive industry's willingness-to-pay is maximized at the market price of electricity

The willingness-to-pay for new consumption for the average household has a more complex composition and can be assessed in a two-way manner; the willingness-to-pay for new electricity-specific consumption and the willingness-to-pay for new heating-specific consumption.

The electricity-specific consumption in an average household has very little flexibility, and the demand for such consumption will likely increase in the upcoming years. In consequence, there is a higher willingness-to-pay for such consumption. In a tentative scenario, one can set it equal to the alternative of increasing consumption from the grid, for example by installing own production facilities. Based on 2019 cost data, we have calculated the (average) cost of electricity per kWh for different solar PV facilities (including panels, inverter, batteries, installation costs and maintenance costs). The result is an annualized (average) cost of electricity equal to 156 øre/kWh. In addition, there are some non-priced benefits and costs related to self-production. While some individuals will have a greater willingness-to-pay because of special interests, others will have a lower willingness-to-pay due to any disadvantages such as maintenance and general inconvenience. For the reason of simplicity, we will not take this into consideration and consequently assume that the willingness-to-pay for new electricity-specific consumption is equal to 156 øre/kWh.

The heating-specific consumption in an average household is more flexible than the electricity-specific consumption due to possibilities of alternative heating technologies (i.e. heat pump, wood, heating oil and so on). This ultimately results in a lower willingness-to-pay for heating-specific consumption. As a proxy, we have calculated the average price of electricity per kWh of installing a heat pump. Based on 2019 cost data for various kinds of heat pumps, this corresponds to an annualized cost of electricity equal to 0,47 øre/kWh.

To be able to say something about the average household willingness-to-pay for new consumption, one must assess the household consumption composition. NVE (2018) finds that 40 percent of the annual consumption is electricity-specific, while the remaining 60 percent is heating-specific. This results in a weighted average household willingness-to-pay equal to 91 øre/kWh. Note that household consumption increased by 9,95 percent (from 36,9 TWh to 40,6 TWh) during the two periods, effectively being accountable for most of the increased demand for electricity. However, during the same time frame, the population increased with 8,64 percent, meaning that population growth is accountable for most of the rise in household consumption.

Under consideration of the points mentioned above, the assumption of a WtP of 100 øre/kWh can be seen as a fair value, lying somewhere in between a higher WtP for households that have no easily feasible alternatives to electricity consumption from the grid and a lower WtP from the industry and household heating consumption.

NVE (2108) *Strømforbruk i Norge mot 2035*. Tilgjengelig fra:
<http://publikasjoner.nve.no/rapport/2018/rapport2018_43.pdf>

A2 TheMa power market model

The TheMA power market model is an advanced, fundamental power market model for the European power markets. The model is developed by THEMA Consulting Group and has been applied in a wide range of projects, ranging from price forecasts, to scenario analysis, to due diligence projects and investment analyses. The model is also licensed to a wide range of model users in Europe, including utilities, trading companies, and authorities. The model is constantly updated, maintained, and improved, in close collaboration with the model licensees.

Model principles and implementation

The model is a so-called fundamental power market model. This means essentially that the model finds the intersection of demand and supply, and the price is defined as the marginal cost of the marginal plant (or demand component). It should hence be distinguished from models that for example model strategic bidding behaviour, market power, or imperfect competition.

In order to find the intersection, the model uses linear programming (short LP) techniques, as the matching of demand and supply can be formulated as a mathematical cost minimisation problem under a set of constraints. Equivalently, fundamental models can also be described as a welfare maximisation problem under a set of constraints.

The constraints include static constraints (for example plant availabilities) and inter-temporal constraints (e.g. start-up optimisation constraints). It is in particular the latter constraints that require the model to use an advanced LP solver.

The model itself is implemented in GAMS (General Algebraic Modelling System) and is typically run with a commercial solver like CPLEX or GUROBI. Data inputs and outputs are handled via Excel. Alternatively, the model can be linked to databases, or import csv-files directly. In order to handle the large volume of output data (e.g. hourly generation values for a range of years and scenarios for all plants modelled), we have also developed an R-based output tool.

Model features

The model has full hourly sequential time resolution. While the actual principle of matching demand and supply under constraints is fairly straight forward, the constraints are very detailed and make the problem computationally non-trivial. Constraints that are taken into account include:

- *Balance constraints*: In each hour, demand has to equal the generation corrected for imports and exports and losses. The shadow value on this constraint is the price in that zone in that hour.
- *Detailed representation on thermal units*: Thermal generation modelling includes start-up costs, part-load efficiencies, ramping and minimum stable load. Plants can be modelled on a unit-by-unit basis, or by grouping them into blocks of equivalent plants. The approach for modelling start-up costs and part-load efficiencies is based on Weber, C. (2004): "Uncertainties in the electric power industry: methods and models for decision support", Springer, 2004. It is an approach to capture start-up costs, part-load efficiencies and minimum stable load restrictions by a linear approximation. All plants can be run with individual availability profiles.
- *Detailed hydro restrictions*: Reservoir, capacity and inflow restrictions can be accounted for on a plant by plant basis. In addition, the model optimises pumped-storage plants (both seasonal and diurnal pumping).
- *Accounting for volatility of wind, PV, and other intermittent generation*: The current generation mix in Europe is already characterised by large shares of renewable generation like wind and photo voltaic (PV), and these shares are likely to increase even further in the future. These types of generation have in common that they are volatile. In the model, these sources of generation are modelled with observed volatility. Like thermal and hydro plants, large wind parks or PV installations can be modelled individually with their own generation profiles and characteristics.
- *Demand*: Stepwise linear demand functions can be modelled, and the demand can be broken down into different demand components for each country with individual demand profiles.
- *Batteries*: Batteries are modelled with losses, storage, charging, and discharging constraints.
- *Modelling of trade*: Power markets are highly integrated and interconnected. Flows on interconnectors between price zones can be optimised (based on price differences, so-called *implicit auction*), or can be defined by the user (e.g. to model contracted trade). Availabilities on interconnectors can be controlled on an hourly basis.

There are, in addition, several variants of the model, including a model that simulates balancing markets, a grid model version, a version with flow-based market coupling, and a version with endogenous investments and carbon prices.

Model variants

Based on the TheMA model, we have developed a range of model extensions/modules. These include:

- *Reserve market model*: In addition to modelling the spot market, the model simulates reserve market constraints. It hence delivers both capacity reservation prices as well as activation prices. It takes account of the bid-block structure in the different markets.
- *Grid model*: The grid model is based on the TheMA framework and models dispatch and flows in a meshed grid, taking physical flows into account. It can also be used to estimate Power Transfer Distribution Factors (PTDFs) to be used in the version of the TheMA model that uses the flow-based market coupling algorithm (see below).

- *Flow Based Market Coupling (FBMC)*: The standard TheMA model uses a Net Transfer Capacity (NTC) approach to model cross border exchange. In addition, we have developed a version of the model that mimics the current FBMC system (currently applied in CWE).
- *Investment module*: Whereas capacity extension in the standard version of the model is exogenous (i.e. an assumption given by the user), in the investment module, capacity expansion and decommissioning is calculated by the model based on costs assumptions for different technologies.
- *Carbon market module*: The carbon market module is an extension of the investment module in which we define a carbon emissions cap (together with non-power sector emissions) in order to obtain an estimate for the EU-ETS price.

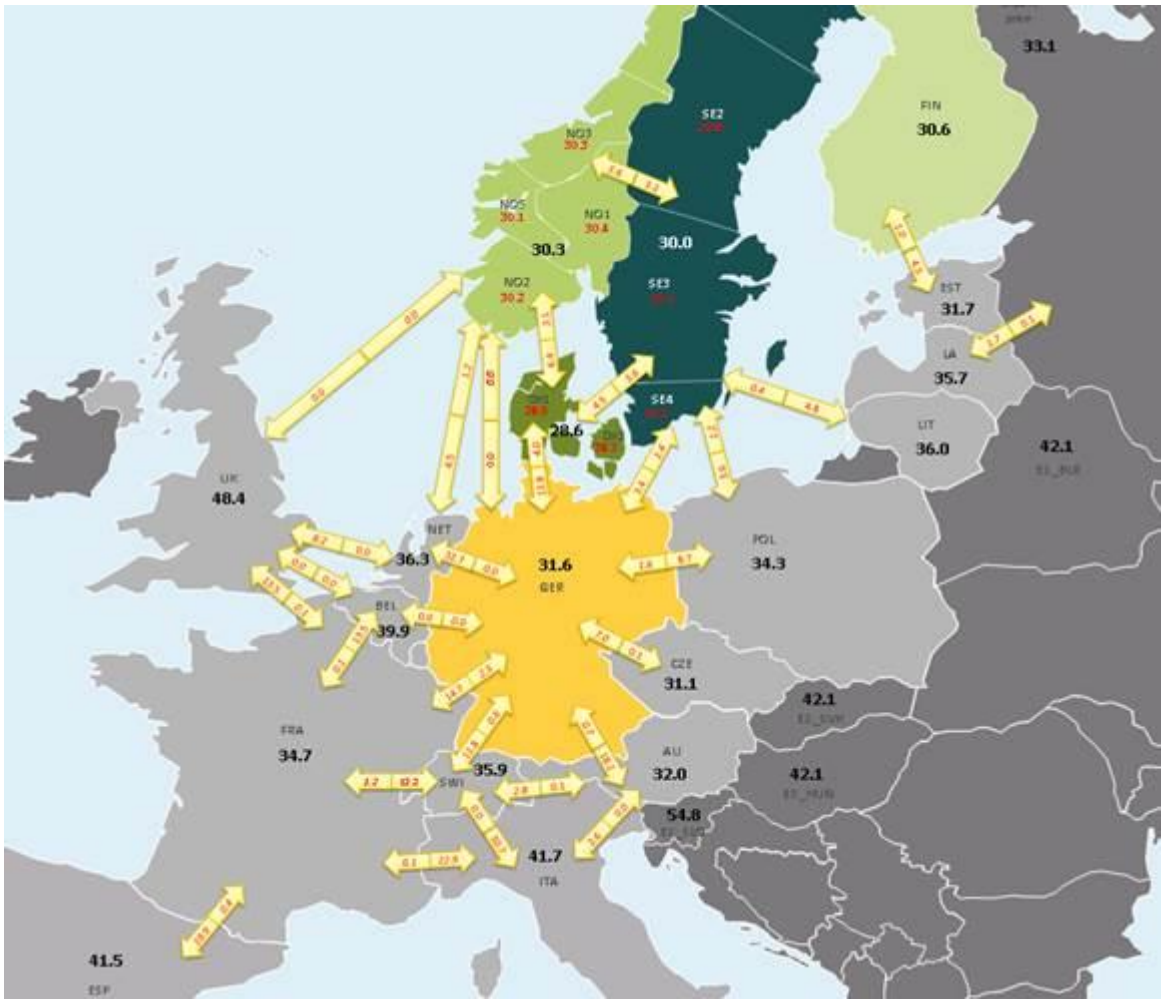
Model applications and references

The model has been applied in a wide range of projects, including price forecasting, investment analysis, due diligence, and welfare economic assessments.

The model is also used by a wide range of European companies and stakeholders that hold a TheMA license to run the model themselves. As part of this license, all model users meet once a year in a model forum to discuss and decide further model development. Model users include large utilities, trading companies, regulators, and ministries.

In its standard setup, the model includes power markets in Europe (see *Figure 12* below). The model has also been used to model specific markets, such as the power markets in Peru, Turkey, and Macedonia.

Figure 12: The current scope of the TheMA model



The model has been back-tested in several validation exercises. In addition, since the model is constantly applied in price forecasts, it is also constantly benchmarked against observed market forward prices. As part of the model development, the model is constantly improved and adjusted to changes in the market and regulatory environment.

Model architecture

The figure below illustrates the overall model architecture and how inputs and outputs are handled. The model is easily adjusted to user-specific needs and requirements.