Statnett

Long-Term Market Analysis

The Nordic Region and Europe 2016–2040

October 2016

Analysis

Issue: Long-Term Market Analysis, the Nordic Region and Europe 2016–2040

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Document ID:

Date: 14 October 2016

Preface

In this report we present our updated analysis of the long-term market development in the Nordic region and Northern Europe until 2040. The objective of the report is to:

- Discuss important trends, uncertainties and present what we consider to be the most probable market development
- Give estimates of anticipated power prices and a range of uncertainty
- Provide a common foundation for our other analyses

As a point of departure, the analysis and our model datasets cover large parts of Europe. In the report, however, we have focused on the factors we believe to be most relevant for Statnett. For example, this means that we show more graphs and figures for the development in Norway, the Nordic region, Germany and the UK, than for the rest of Europe.

The report has been prepared by Eirik Tømte Bøhnsdalen, Karin Lövebrant Västermark, Ivar Husevåg Døskeland, Vegard Holmefjord, Jørgen Aarstad and Anders Kringstad.

All future prices and development costs in the report are real 2016 figures.

Summary

Statnett's long-term market analysis extends to 2040. The analysis reinforces our established view of the fundamental development of the European power system. The share of renewable energy continues to increase, coal power is being gradually phased out and the power sector is important in the transition to an energy system with continuously declining CO_2 emissions.

We anticipate increasing power prices towards 2030, with average annual prices at 40-50 €/MWh throughout Northwest Europe. The increase is mainly driven by higher prices for gas and CO_2, and that gas power sets the price on the Continent in an increasing number of hours. In combination with more renewable power generation, the increased price level also gradually generates more short-term price variation, both on the Continent, in the Nordic region and in the UK. At the same time, there is considerable uncertainty linked to the future market development. We therefore have a range of uncertainty for average annual power prices of 30 to 60 €/MWh from 2030.

Fundamental transition of the European power system – less emissions, more renewables
We presume that the EU countries reach the adopted energy and climate goals for 2030. Furthermore, in recent years it has become significantly more likely that the development toward lower emissions and increasingly stringent climate goals will continue towards 2040. The key question now is rather how quickly this will happen. Both the EU and many of the most prominent member states base their climate policy on an objective of 80% emission reduction by 2050. In order to achieve this, the power sector must be virtually emission-free as early as in 2040. As of today, this is hardly realistic, even though the EU countries have ratified the Paris Agreement. However, in our Base scenario, we presume there will be considerable changes for the EU10[1] countries during the period 2016 - 2040:

- A 50% cut in CO_2 emissions – entails a 62% reduction compared with 1990
- An increased renewables share to 65-70%, primarily by expansion of solar and wind power
- Substantially less thermal generation capacity and tighter capacity margins

We anticipate that the practice of using multiple policy instruments within the area of energy and climate policy will continue. In the Base scenario, we therefore presume a relatively moderate growth in the European CO_2 price to 25 €/tonne in 2040. The EU ETS is thus not a key driver for emission cuts in the first 10-15 years, although we assume it will gradually have greater significance in the 2020s.

With increasingly lower construction costs and greater efficiency, solar and wind power currently appear to be the winners of the competition to be the preferred technologies for emission-free power generation. We therefore anticipate that half of Europe's power generation will come from solar and wind power in 2040. All the European countries will contribute, but we expect the greatest expansion in countries with the most ambitious national goals.

Advancing age, various regulations and political decisions will lead to the closure of many of Europe's existing coal, gas and nuclear power plants before 2040. At the same time, thermal power plants currently have low profitability, much due to the increased share of solar and wind power. One of the most important challenges for national authorities is thus how to ensure acceptable security of supply in periods with little sun and wind. There are mainly two solutions to ensure sufficient capacity margins – introduce capacity markets[2] or establish strategic reserves outside the market. There is considerable

[1] EU10 is our own abbreviation for the countries described in detail in our market model, with the exception of the Nordic region and the Baltics. I.e. Germany, Poland, the Czech Republic, Slovakia, Austria, Switzerland, Italy, France, Benelux and the United Kingdom.
[2] A system where generation, consumption and energy storage are paid to provide capacity in the power market.

uncertainty around future market design, but we presume that Germany will stick to its decision to introduce a strategic reserve. At the same time, we assume that France and the UK will set a relatively low capacity margin through their capacity markets, and that the demand side will participate actively therein. In our Base scenario, this will yield a net reduction in thermal generation capacity of around 100 GW in EU10, until 2040. The consequence is tighter capacity margins[3] and an increased number of price peaks where e.g. brief reductions in industrial consumption will set the price. This is necessary in order to give the remaining power plants sufficient earnings and initiate new investments. We expect new thermal capacity to mainly come in the form of biopower plants and gas turbines.

We presume growth in European power consumption after 2020, mainly as a result of electrification of the transport and heating sectors. For example, we anticipate high growth in the share of electric vehicles. This increase in consumption is significantly greater than the effect of energy efficiency, and we expect it to yield an overall consumption growth of 25% until 2040. We also assume high growth in demand side flexibility and various forms of energy storage. Our analyses show that this is both profitable and necessary in order to utilise the high volumes of new solar and wind power.

Increased consumption, less nuclear power and more variable renewables in the Nordic region
In spite of a large contribution from energy efficiency, we expect an overall Nordic consumption growth of 50 TWh from today to 2040. The growth will mainly come within industry, petroleum-related activities and data storage, as well as through electrification of the transport and heating sectors. We also expect an overall reduction in generation from Nordic nuclear power and other thermal power of 30 TWh. This is offset by an increase in overall Nordic renewable generation of just under 100 TWh until 2040. The Nordic annual power surplus will remain somewhat stable around 10-15 TWh from 2020 to 2040. In Norway we expect the surplus to increase to more than 15 TWh in 2040.

We anticipate price increase until 2025-30, before it stabilizes until 2040
In our Base scenario, power prices on the Continent will rise to 45-50 €/MWh in 2025-30. The main drivers are higher gas price, higher CO_2 price and that gas power will set the price more often. In the UK, prices will remain roughly at the current level, and will thus converge with the continental level. Further on to 2040, we expect average prices to be stable as a result of unchanged gas prices and that an increased number of hours with very low prices are offset by an increased number of price peaks.

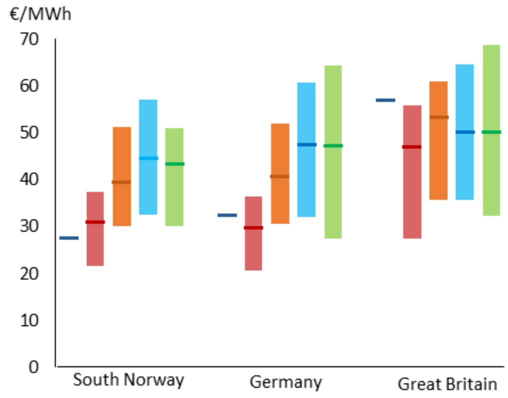

Figure 1-1: Average prices for 2017, 2025, 2030 and 2040 in low, baseline and high scenarios. 2017 is future prices as of September 2016. All prices are real 2016 figures.

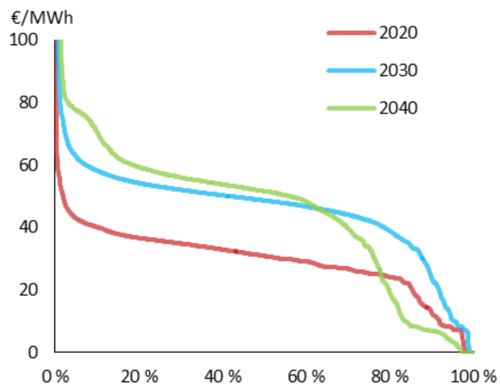

Figure 1-2: Duration curves for the German power price in the Base scenario. All prices are real 2016 figures.

[3] The difference between available generation capacity and consumption during hours of low renewables generation and high consumption.

Increased Continental and UK price volatility from 2020 – a trisection of the market
We anticipate increased short-term price variation after 2020, driven by an ever-increasing share of renewable generation, the shutdown of thermal plants and rising fuel and CO_2 prices. When we approach 2040, this leads to a clear trisection of the price duration curve. We will have an increased number of price peaks where the price is set by flexible consumption with high willingness to pay, back-up power generators and power plants with high marginal costs. At the same time, we will have an increasing number of hours where renewables, nuclear power or flexible consumption with low willingness to pay set the price low or even at zero. More accessible energy storage and flexible consumption dampens the price variation, but will most likely not prevent increased short-term price variation. The reason for this is that it is probably not profitable to develop sufficient flexibility to remove the largest price impacts of renewables, particularly during the winter when we have significant variation in wind power generation.

The price level and variation in price increases also in Norway and the Nordics
Power prices in Norway and the Nordic region are currently closely linked to the Continental and in particular German prices. Rising German average prices towards 2025-30 thus yield an increase in the Nordics as well. However, the prices in Norway and Sweden are somewhat below the level in Germany as the result of a power surplus and a lower price level in the summertime. Toward 2040, we will see a significant decline in prices in the summer, driven by more intermittent generation, and thus somewhat lower average prices. We see increased short-term price volatility in Norway, Sweden and Finland until 2030-2040. This is due to both higher and more volatile prices on the Continent, and more intermittent generation in the Nordic region.

Substantial uncertainty surrounds future power prices – scenarios for high and low power price
Multiple factors affect power prices over time. The most important uncertainty factors are the prices of fossil fuel and CO_2, the share of renewables, capacity margins and the development within energy storage and demand side flexibility. The power balance through the year and the share of intermittent generation in the Nordic region, as well as potential additional transmission capacity out of the area, are additional factors for the Norwegian and Nordic prices.

Our two alternative scenarios, High and Low, intend to provide a range of uncertainty for average power prices over the long term. The scenarios provide a range of uncertainty of 30 to 60 €/MWh for Continental prices from 2025 and beyond. High and Low provide a somewhat narrower range of uncertainty for prices in Norway of 30 to 55 €/MWh. The reason why the prices in High do not increase as much such as on the Continent is that we have accounted for a larger expansion of renewable energy on the Nordic side, and that prices in Norway fall relative to the Continent with increased price level.

Both High and Low follow the same main direction as in the Base scenario with large emission cuts and continuous growth in the share of renewable power generation. In High the transition to lower emissions is more market-driven. Higher and more volatile prices result in stronger incentives for investments in both renewables, thermal power plants and storage. A higher CO_2 price also reduces the need to use direct regulations to phase out coal power plants. In Low the market prices are to a lesser extent a driver of the development of renewables and reduced emissions of CO_2. This implies a greater need to use subsidies and various forms of regulation in order to achieve desired emission cuts.

More renewable generation results in increased cross-border power exchange
With rising market shares for intermittent renewable generation, we see that there will be more power exchange between countries and within each country. This is a key driver for the extensive grid development plans throughout Europe, and we have presumed that these will generally be followed.

As a result of continued expansion of wind power in the north and delays in grid development, we expect continued internal bottlenecks in Germany. How this will affect prices is uncertain, and depends on the size of the bottlenecks and how they are handled. If Germany is split into multiple bidding zones, our simulations indicate that we will have both lower and more volatile prices in Northern Germany. Both are primarily due to many hours with very low price in periods with a lot of wind in the winter. This, in turn, results in somewhat lower average prices in Norway and the Nordic region.

An increasingly larger share of intermittent generation in the Nordic region will result in much greater fluctuations in the hour-by-hour power balance on the Nordic side. During periods with little contribution from renewable generation in the winter, hours will occur with capacity shortages and high power import. In the summer months, non-dispatchable hydro, wind and solar power will cover the entire Nordic demand in an increasing amount of hours, and we will see more power exports. At the same time, we expect high imports during the winter when wind generation is high on the Continent and the Nordic region has the possibility to regulate down on reservoir hydropower generation.

Renewables may be profitable without subsidies in Norway and Sweden

The development towards increasingly lower costs for solar and wind power will most likely continue. Along with rising power prices, it may thus be profitable to build solar and wind power without subsidies. Nevertheless, we expect that renewables will need support until 2040. This is due to the fact that the large volume of renewable energy investments requires continuous investment activity, and that the value of solar and wind fall quickly as the market share increases.

The need for support varies in the three scenarios. In High, good solar and onshore wind projects may be profitable without subsidies as early as the 2020s. In Low, there is a need for support throughout the analysis period. As regards offshore wind, there is most likely a need for subsidies in all scenarios. However, there are significant differences between regions. Norway, Sweden and Finland have favourable conditions both due to good resources and the large market share of dispatchable hydropower. This yields a smaller decline in the achieved power price, particularly for wind power. We therefore find it likely to see projects being developed without subsidies in this region over the course of the 2020s. This dampens the price increase, but in our opinion does not provide a fixed price ceiling.

Europe's power system in 2040 differs significantly from today's – though uncertainty is high

When we move the analysis horizon to 2040, uncertainty increases in multiple factors. The analysis of 2040 nevertheless provides a useful overview of important trends and fundamental understanding we believe is valid despite of the uncertainty. We also see the contours of several unsolved challenges.

The significant variations in solar and wind power generation will be a major challenge, and it will be necessary to develop a lot of new flexibility in order to make the system balanced. In addition, it will most likely be necessary to think a bit differently and more broadly around the concept of security of supply. Differently in the sense that we must to a greater extent accept that demand is reduced as a result of high prices in shortage periods and broadly e.g. by looking at the issue beyond country borders. On the other end of the scale, it is difficult to envision that we will not have to accept that generation is curtailed when there is high solar and wind generation.

The entire energy and power sector will be in a continuous state of change over the next 25 years. In combination with rapid technology development, this results in considerable uncertainty for anyone investing in the power system. Furthermore, our simulations of 2040 indicate that we will have a relatively unstable long-term market balance, where even minor changes can have relatively large consequences for the income of various stakeholders in the market. This may yield greater imbalances and challenges than what we have seen in our market simulations. It can also lead to a discussion about whether a market where the prices are set by short term marginal costs will function satisfactorily when such a large share of generation has negligible generation costs.

It seems demanding to build an emission-free power sector based on solar and wind power alone. At the same time, there are currently few good alternatives. Technology development within storage, CCS and nuclear power will most likely be significant, but it is also a relevant question whether it would be better to focus more on emission cuts in other sectors, before eliminating the last emissions in the power sector.

On the Nordic side, a key question is what will replace Swedish nuclear power. Our analyses show that solar and wind power are not satisfactory replacements alone, and that less nuclear power affects both power prices, transmission needs and security of supply in large parts of the Nordic region. As regards Norway, there is a clear possibility that we will see greater changes than what we have presumed in our scenarios. The price level we see in 2040 could make it profitable to invest in more generation capacity, power output expansion and pumps in the hydropower system and establish new interconnectors.

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Part I
Background, Method and our Scenarios

In this section, we first explain why we prepare a separate long-term market analysis in Statnett, what this consists of and what this work is used for. We then briefly present our general method and some basic assumptions for the analysis. Finally, we will cover central drivers for power prices now and looking forward, and provide an overview of the principles behind our three main scenarios.

1 Why Conduct a Long-Term Market Analysis?

Long-term market development and the prices of energy and power are vital to Statnett's activities. It is important to have a sufficient understanding of market developments in order to identify future operational challenges and make investment decisions. However, more transmission capacity out of the Nordic region, and the restructuring of the European power system, make this a wide-ranging task.

- The development on the Continent and in the UK is becoming more relevant, which means that we must take more factors into account than in our earlier analyses.
- The restructuring from fossil to renewable power generation gives rise to more uncertainty and an increased need to analyse potential development paths and their consequences.

Based on this, we have in recent years significantly increased our efforts to analyse the European market development. A part of this process involves preparing a comprehensive long-term market analysis every two years prior to the central planning process in Statnett[4]. Our analysis extends to 2040, and consists of several equal elements:

- Discuss key trends and central uncertainties associated with the development within generation, consumption, transmission capacity and prices of coal, gas and CO_2
- Establish/adjust assumptions for what we consider to be the most probable development
- Make model datasets for 2015, 2020, 2025, 2030 and 2040
- Provide a power price prognosis and scenarios that outline a relevant range of uncertainty
- Take a more in-depth look at selected topics – investigate, explain and outline

The analysis focuses on power prices in the day-ahead market. We focus on average prices, attained prices for different types of generation, price volatility and price differences between countries. At the same time, we find it important to investigate the fundamentals behind the price formation.

The end result is this report, and specific datasets that can be used in our market models for various stages until 2040. This will in turn be used as a basis in investment analyses for ongoing projects and analyses of the long-term transmission demand. The report also forms an important baseline for the central planning process in Statnett and for various strategic assessments. While, in some cases, the power price prognosis is used directly as an input factor in our investment analyses, the report and the model datasets are the primary results and assets of this work.

We do not focus on the profitability of new international interconnectors, where internal bottlenecks in Norway may occur, or which operational challenges we may experience over the next 20 years. This will be addressed in the central planning documents, upcoming concept and feasibility studies and new investment analyses. Preparing a separate market analysis report also reduces the need to write long chapters concerning market development in these reports. This saves us time and makes it easier to gain insight into our assumptions and the reasoning that lies behind them.

We will implement more simplified updates to this analysis in the event of significant changes during the period between each official update. Major changes in fuel price prognoses or the decision to phase out Swedish reactors ahead of time are examples of changes that will typically require updates.

[4] The central planning processes consists of several different publications. The Nettutviklingsplan is Statnett's grid development plan and is publicly published every 2 years. Kraftsystemutredningen is a foundation report for Nettutviklingsplanen. It is required by and published for the Norwegian regulator (Norwegian Water Resources and Energy Directorate, NVE) every 2 years. The System- og markedsutviklingsplan is Statnett's System Operation and Market Development Plan, and is also published every 2 years in parallel with Nettutviklingsplan/Kraftsystemutredningen.

2 General Method and Basic Assumptions

2.1 Fundamental analysis and model simulations form the basis for our studies

Statnett's overall analysis activity related to grid development and the system as a whole is largely based on fundamental analyses. This is necessary in order to:

- Quantify future power flow in the grid, identify bottlenecks, estimate price differences and calculate the benefits of different grid reinforcements.
- Analyse the effects of various alternatives for grid development.
- Achieve a better understanding of challenges we may encounter in operation of the system in the long term, and to better see what measures will counteract these challenges.

For this purpose we use models that, insofar as possible, reproduce the fundamental physical and economical correlations in the power system. We use our two primary models Samlast/Samnett and BID to simulate the market and power system sequentially, hour by hour over a full year, given our assumptions regarding generation, consumption and transmission capacity at various stages in the future. In order to replicate the effect of varying inflow, temperature, wind and sunlight, we normally simulate up to 50 historical weather years every time. Altogether, this provides us with a good insight of how changes in generation and consumption affect power prices, the power flow and bottlenecks.

- BID is a pure market model with hourly resolution, realistic description of the properties of thermal plants and a relatively good description of the hydropower system. The majority of the European power market is fundamentally modelled in our datasets for BID[5].
- The datasets for the Samlast and Samnett model[6] cover the Nordic region. The strength of these models is a much more detailed modelling of the Nordic hydropower system, in addition to a detailed model of the Nordic grid. The models have hourly resolution and use simulated price series from BID as representation of the markets on the Continent and in the UK.

Both our two main models undergo continuous development. The objective is for the models to always provide us with a realistic representation of the power systems in the Nordic region and otherwise in Europe with a horizon of 20 years. We also focus on understanding model weaknesses and evaluating the results against theory, historical observations and external analyses.

2.2 Analytical method

We use the current power system as a basis when establishing our assumptions for the future development of the power system. The first item on the agenda is therefore to establish the most up-to-date data description of the current system as possible. The next step is to gain an overview of and add what we can call certain prognoses for physical changes, for example when investment decisions have been made to develop generation, grids or major consumption units. This also includes more short-term political objectives that are very likely to be achieved, or arrangements such as the Norwegian-Swedish certificate scheme for renewable generation. Altogether, this gives a reasonably certain prognosis for the physical development of the power system five to ten years ahead.

Moving further ahead, the uncertainty increases, and we are to a larger extent relying on forecasts, uncertain development plans and other forms of more or less fixed facts. Examples include:

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[5] Detailed modelling of the Nordic region, the Baltics, Germany, Poland, the Czech Republic, Slovakia, Austria, Switzerland, Italy, France, Benelux and the United Kingdom.

[6] Samlast use the current method for handling bottlenecks between price zones. Samnett uses flow-based market algorithm.

- Political goals and political policy instruments
- Long-term development plans for grid and generation
- Self-produced and external analyses and forecasts
- Basic assumptions concerning financial correlations, physical laws and similar
- Model simulations

Energy and climate policy goals have a major impact on development and are therefore a central basis for our assumptions. At the same time, we cannot simply use adopted and planned goals and policy measures as a basis without assessing consistency and the likelihood of execution. First, they may partially contradict each other. Second, they are often unspecific and, in many cases, not binding. We therefore use political goals and policy instruments primarily as a foundation for our assumptions regarding the general direction of the development. Furthermore, we place varying degrees of emphasis on the different goals, based on an evaluation of realism and the willingness to execute.

We use separate prognoses for the development of existing thermal generation capacity, development of renewables, consumption, fuel prices and CO_2 prices when we build our datasets. These come from several different sources and we have built up a credible portfolio of such prognoses.

- Coal and gas prices: IHS, Bloomberg New Energy Finance, IEA, EIA, Nena, MK ++
- Phase-out of existing thermal generation capacity: Database from Pöyry
- Prognosis for general consumption in Norway and Sweden: Model developed by Optimeering
- Forecast for industrial consumption in the Nordic region: INSA
- Consumption prognosis for the Continent and UK: ENTSO-E, IHS and various long-term analysis reports
- EU ETS (CO_2): Thomson Reuters Point Carbon
- Development of renewables: Political goals in the EU and nationally, external analysis reports
- Cost development forecasts within renewables and storage: Bloomberg New Energy Finance, IHS, IRENA, IEA ++

In order to further improve the foundation for our assumptions and increase our understanding of key uncertainties, we have also conducted several targeted and exploratory sub-analyses within selected topics. Examples of this include our study of a European energy-only market in 2030 (Statnett 2015) and an analysis of the consequences of continued large-scale development of renewables after 2030[7].

Although we have many forecasts and analyses to build upon, many choices still need to be made to complete the picture and ensure we achieve an effective and credible whole. We rely e.g. on a selection of more fundamental assumptions in this connection.

- Both the energy and power markets tend towards financial balance over time. There can obviously be significant imbalances at times, but over time we expect movement towards long-term balance. For example, there may be significant surplus capacity and prices lower than the total generation costs for coal and gas during a temporary period, but in the long-term, the price must be high enough to carry necessary investments.
- The power market has free competition and rational stakeholders. This means that no player can expect extraordinary high profits over time, and it is also not possible to expect comprehensive investments without necessary earnings, either through the market or via subsidies.

[7] Not a separate report, but part of this main report – mainly presented in Chapter 16.

- The energy and climate policy is mostly financially reasonable over time. Obviously irrational choices and plans may occur, but are limited in scale and timeframe.

A significant part of the work involves evaluating and ensuring an adequate degree of internal consistency and comprehensive correlation in individual datasets and between these, and this has a decisive impact on the end-result. Model simulations are an important tool in this work, and there are many iterations between simulations and adjustments of different assumptions in the process for arriving at complete datasets. Examples of what we examine in this process include the profitability of power plants we have added, whether simulated emissions are in line with the assumptions concerning emission cuts and whether we have enough grid and storage capacity in light of simulated price differences and price volatility.

In order to ensure that we have solid assumptions, simulation results and conclusions, we also compare our assumptions, simulation results and conclusions with a selection of external long-term market analyses[8]. Furthermore, we want to provide the most nuanced picture possible of the future development, and therefore place considerable emphasis on discussing both assumptions and simulation results. It is vital for us to highlight the uncertainties and logic behind our assumptions to achieve a greater degree of transparency in our decisions regarding both grid development and operating issues. The objective is for our reasoning to be clear and easy to understand. This also involves a desire to facilitate feedback and potential criticism.

2.3 LMA provides a common basis for assessing project feasibility and grid investments

Statnett's portfolio consists of a large number of early phase projects where different factors affect demand and profitability. In order to ensure consistency and equal treatment, the assessment of each project must be based on a common understanding of the future market development. We use the report and baseline scenario from the long-term market analysis for this purpose.[9]

At the same time, there is a great deal of uncertainty associated with the market development, the future need for transmission capacity in the Norwegian grid and the socioeconomic benefit of new reinforcement measures. Much of the work in concept and feasibility studies and investment analyses is therefore about preparing a good picture of relevant uncertainty. However, in our case there are such vast differences between what affects the uncertainty in the various projects that it is not possible to cover this with just a few common scenarios. The scenarios we present in this report for high and low power prices can therefore only cover parts of the uncertainty and potential outcomes for the socioeconomic benefit of new reinforcement measures in the grid. We therefore supplement these with sensitivity analyses and scenarios adapted to the relevant issues in the individual concept and feasibility studies and investment analyses.

[8] SKM, Nena, IHS, MK, Bloomberg New Energy Finance ++

[9] The relevance of the power price and long-term market development for the various projects varies considerably. In some instances it is essential, whereas in others it is virtually irrelevant for the investment decision.

3 Central Drivers for the Power Price Towards 2040

3.1 Coal, gas and CO_2 prices currently hold a dominant position

Currently, power prices on the Continent, in the UK and in the Nordic region are largely determined by the short-term operating costs for coal and gas power. This means that the prices of coal, gas and CO_2 become key factors for the power prices. Figure 3-1 shows how the average German power price follows the marginal costs for coal and gas power, which in turn follow the fuel and CO_2 prices. We also see that German prices are closer to the marginal cost for coal than gas power, due to a relatively significant share of coal power. This is in contrast to countries such as the Netherlands and the UK, which both have more gas power.

Solar and wind power are having an increasing impact on prices as the volume grows. Seen in isolation, this results in lower prices due to several hours where the price drops down to zero or the marginal cost for lignite and nuclear power, and simultaneously fewer hours where there is a need to run the most expensive thermal power plants. More solar and wind power also results in greater price variation between periods with high and low levels of generation from renewables.

Other examples of factors that affect the prices in the current system are demand volume and profile, grid restrictions, composition of the thermal plants and technical properties of the individual power plants - flexibility, start/stop costs and efficiency.

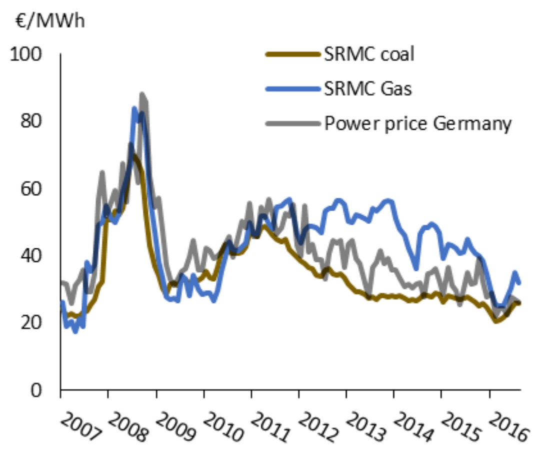

Figure 3-1: Historical marginal costs in typical coal and gas-fired power plants and historical German power price since 2007. Average per month.

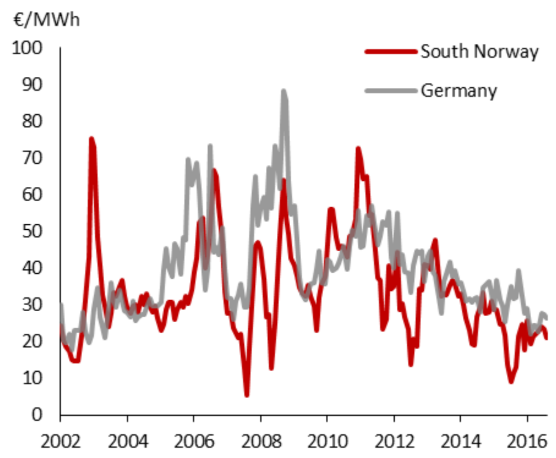

Figure 3-2: Historical power prices in NO2 and Germany since 2002. Average per month.

The prices in Norway and the Nordic region are largely linked to the Continental prices. This is shown in Figure 3-2 where we see how the prices in Southern Norway follow the level of German prices. This makes the prices of coal, gas and CO_2 key drivers for Norwegian power prices as well, even though 95% of generation in Norway comes from hydropower. At the same time, the hydrological situation is an important additional factor on the Norwegian and Nordic side. As the figure shows, this results in relatively extensive fluctuations in the Norwegian and Nordic price around the relevant price level in Germany. In recent years, a growing surplus on the power balance through the year and more intermittent generation have resulted in an increased likelihood of summer prices that are significantly below the level on the Continent.

3.2 Lower coal, gas and CO_2 prices explains declining power prices in recent years

In recent years, power prices in Norway and the rest of Europe have fallen year-by-year. In 2015, the price in Southern Norway averaged just 20 €/MWh, compared with 45 €/MWh in 2011. The corresponding figures for Germany were 32 and 50 €/MWh, respectively. The decline continued into 2016, but has picked up somewhat in the last few months.

Lower prices for coal, gas and CO_2 make up the most important reason why we now have significantly lower power prices compared to five years ago. In 2011, European coal, gas and CO_2 prices averaged 110 $/tonne, 21 €/MWh, and 14 €/tonne, respectively. In 2015, the equivalent prices were 55 $/tonne, 20 €/MWh and 7 €/tonne[10]. This has resulted in a significant reduction in marginal costs for coal and gas-fired power plants, and thus also lower power prices both on the Continent and in the Nordic region. At the same time, the development of intermittent renewable power generation, both on the Continent and in the Nordic region, also contributed downward pressure on the power prices. However, the development of renewables has had a far lesser impact than the decline in prices for fuel and CO_2.

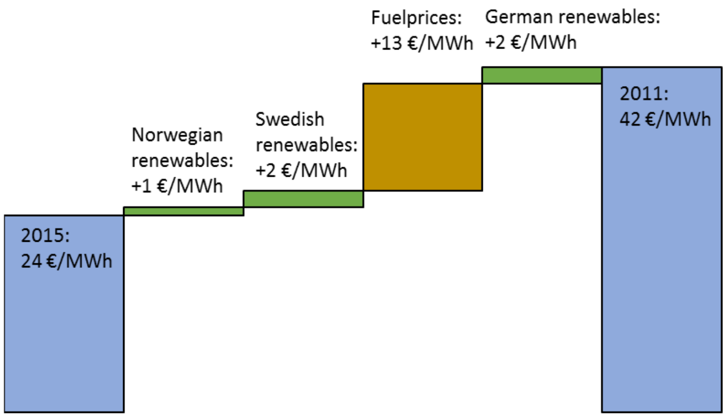

Figure 3-3: The blue bars show the simulated normal annual price in NO1 in 2015 and 2011. The green show the effect of the development of renewables in Norway, Sweden and Germany, respectively, on the Norwegian price. The brown bar shows the effect of fuel and CO_2 prices.

Figure 3-3 summarises an exercise where, using model simulations, we have investigated what has had the greatest impact on the decline in Norwegian power prices from 2011 to 2015. Here we have post-simulated the market price under the prevailing circumstances in 2015 and 2011, respectively, with different intermediate steps in order to show the effect of the different changes in generation fleet and fuel prices on the changes in power prices. In order to remove the effect of hydrological fluctuations[11], we have simulated more than 50 historical inflow years and show the average. The model simulations confirm that reduced prices for coal, gas and CO_2 constitute the main reason for lower power prices in Norway and other European countries.

3.3 A nuanced picture of factors affecting future power prices

There is considerable uncertainty associated with development of the physical power system and the market until 2030 and 2040. Based on our own analyses, external reports and current energy and

[10] Gas has declined further after this. The coal price was down below $ 40 per tonne, but has rallied in the last few months and is now around $ 60 per tonne.

[11] 2011 was a year with less inflow than normal, and thus higher prices, relatively speaking, due to hydrology. In 2015, we had the opposite situation with more inflow than normal, which resulted in extra low prices.

climate policy, however, we can say with a greater degree of certainty which factors will have the greatest impact.

If we start with the more basic and underlying drivers, the climate challenge and climate policy are clearly the most important. The UN Climate Panel has established that human emissions of greenhouse gases affect the climate and that the consequences of further emission growth could be catastrophic. This is by far the most important reason for the ongoing transition of the European power system towards more renewable power generation and lower emissions. And in light of the bleak prognosis from the world's climate scientists, we can say with a significant degree of certainty that climate will be a key driver of change throughout our analysis period. Policy instruments to promote emission cuts also play a key role. The extremities are, respectively, more direct regulation and subsidies on the one hand, and more market-based solutions and use of EU ETS as the key instrument on the other. Other important drivers in this category are economic growth and technological development. The latter has great significance for both the prices of fuel, the cost development within renewables, electrification of the transport sector and what can best capture the fluctuations in generation from solar and wind power.

As regards the more direct influencing factors, our simulations show that the prices of coal, gas and CO_2 will continue to have a dominant effect for power prices, all the way to 2040. However, with an increasingly larger share of renewable power generation we see that solar and wind power will gradually take on greater significance. The following other key factors will have a substantial and direct impact:

- Capacity margin in the market – the ratio between available generation capacity and demand during low solar and wind power generation
- Demand development and the degree of electrification within transport and the heating sector
- Volume of available flexibility from generation, demand and storage, and associated prices/costs

Looking at factors within the Nordic region, beyond the factors we have already mentioned, the development within nuclear power in Sweden and Finland is a key topic. The same applies for the development of the power balance through the year and in the summer months.

4 Scenario Outline

4.1 Baseline – our baseline scenario for the development until 2040

Our Base scenario represents what we consider to be the most probable development from now to 2040. We will present detailed assumptions and simulation results from this scenario in the coming chapters, but will, for the sake of an overview, provide a brief summary here. Compared with the current situation, the scenario is mainly based on the following development trends and changes:

- Halving the current emissions from today to 2040, entails a 62% reduction compared with 1990
- Moderate rise in the prices of gas and CO_2 to 2025-2030, coal prices at the current level
- Significantly more renewables, mainly solar and wind power
- Less thermal generation capacity and tighter capacity margins
- Increased demand, mainly driven by electrification of the transport and heating sector
- Rising price level and greater price volatility, both on the Continent and in the Nordic region

Even though we see a clear trend towards more renewables and lower emissions, there is considerable uncertainty associated with multiple sides of the long-term market development. And the uncertainty is naturally greater the further into the future we get. Our concrete assumptions for 2040 can therefore not be interpreted in the same way as our anticipation for the upcoming decade.

4.2 Alternative scenarios for higher and lower average power price

We have put together two alternative scenarios in order to quantify the uncertainty in future power prices. They illustrate development trajectories that result in lasting higher and lower average power prices, compared to what we have in the Base scenario. These are targeted scenarios, where we depart from the baseline scenario and deliberately adjust several factors that all move the power price up and down, respectively. We have focused on factors that both have considerable uncertainty and which we know are of great significance for the power price. At the same time, we presume that both alternative scenarios follow the same main direction with major emission cuts and continuous growth in the share of renewable power generation. The reason for this is that we believe the development in fuel prices and how the emission cuts are achieved amount to a greater uncertainty for power prices than the actual transition to lower emissions and more renewables.

Figure 4-1 outlines the key differences in the scenarios for high and low power price. All three scenarios represent continuous development trajectories from now to 2040. We have put together data sets for 2016, 2020, 2025, 2030 and 2040 for each scenario. These data sets are a detailed elucidation of our assumptions on the more overarching development trends. Simultaneously, we want to emphasise that the specific quantities we have presumed must be viewed in the context of the associated discussion, and should not be interpreted too literally.

It is possible to create additional alternative scenarios for high and low power price. They can provide both a wider and narrower range of uncertainty for the development of the power price than what we outline in our analysis. At the same time, the more extreme scenarios we create, the lower the probability of them occurring. While we cannot quantify the probability of our alternative scenarios, in our opinion they provide a relevant range of uncertainty for what we can envision as regards a continuous low and high power price. Simultaneously, we want to point out that there will be brief fluctuations that have a greater impact than what we see in our scenarios.

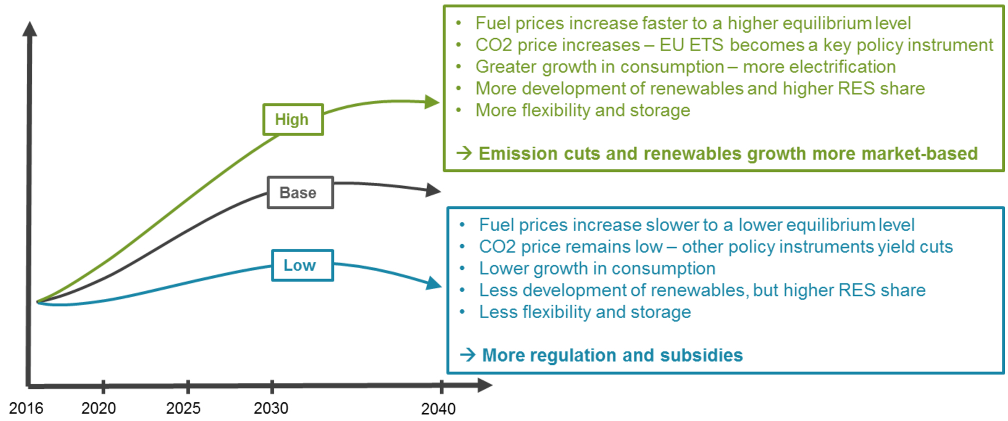

Figure 4-1: Scenario outline for the alternative scenarios for power price.

4.3 High scenario – policy driven emission cuts and market-driven growth in renewables

In the High scenario, the prices of coal and gas rise earlier to a long-term equilibrium. The price, unlike the current situation, represents the full costs of bringing coal and gas to the European market. The equilibrium prices are also higher than in the Baseline scenario. At the same time, the CO_2 price will increase more than in Baseline, either as a result of the EU countries agreeing on a tougher regime for the quota market for CO_2, or as a consequence of national price floors being introduced in a sufficient number of countries. In addition, we presume greater demand growth driven by electrification and that the energy sector will contribute more to emission cuts in other sectors, particularly within transport and heating. This is offset by a more extensive development of solar and wind power. Overall, this yields a substantially higher average power price level on the Continent and thus also higher prices on the Nordic side. The scenario illustrates a development where the transition towards lower greenhouse gas emissions to a greater extent runs on autopilot, driven by fortuitous market conditions and a conscious policy around the quota market and alternative policy instruments.

4.4 Low scenario – more regulation and subsidies

In Low, the situation is opposite. The coal price is reduced and the gas price remains at a low level. The same applies to the CO_2 price as other policy instruments for emission cuts are successful and make EU ETS less relevant. Consumption increasess to a much lesser extent than in High and Baseline. The development of renewables is also lower, but due to lower consumption growth, the share of renewables is somewhat higher than in the Baseline. In sum, this leads to lower average power prices and less price volatility. The latter makes it less profitable to bring new flexibility to the market and we will thus have more hours with prices close to zero. In this scenario, more regulation and subsidies is needed in order to drive the transition towards lower emissions and a higher renewable energy share.

4.5 The Nordic response moderates the range of uncertainty

In the High and Low scenarios we have mainly changed the assumptions that affect the power price on the Continent and in the UK, in addition to remaining coal and gas-fired power plants in the Nordic region. This, in turn, affects the Nordic development. We have therefore chosen to include a somewhat moderating response on the Nordic side in our scenarios for high and low power price. In High, the development of renewables is greater, which results in a greater power surplus and somewhat lower prices, in isolation. However, we have also presumed more transmission capacity out of the Nordic region, represented by an additional interconnector to the UK in 2030. This curbs the effect of an increased surplus. In the Low scenario, we have presumed a moderate response in the opposite direction.

Part II
Development Trends and Assumptions

The development of the energy sector in Europe and the Nordic region towards 2040 is influenced by a number of different factors which are associated with significant uncertainty. In this part, we will first present the most important global development trends, and the coal and gas prices we assume. These are important for the power prices in Europe and thus also the Nordic region and Norway. Then we take a closer look at the EU's energy and climate policy while we also present our key assumptions for power systems on the Continent and in the UK. We conclude the chapter by presenting our Norwegian and Nordic assumptions. We present our assumptions in the scenarios for high and low power price where they deviate from the baseline scenario.

5 Global Trends

The global energy system influences the European power market primarily through the fuel markets. The price of oil, coal and gas is determined by the major trends within consumption and generation of energy. Key drivers for these are, in turn, economic growth, climate and environmental policy and technology development. A new element now is that the development within renewables, storage and consumption (electric vehicles) is increasingly determined outside Europe. For example, last year, China installed more renewables than the US and Europe put together, but is also focusing on electric vehicles and various forms of energy storage. Major commercial players all over the world are devoting increasing resources to become leading within these industries. Here we will discuss the big picture until 2040 on the basis of the beliefs of major analysis firms and stakeholders in global energy markets. Our main sources are IHS, IEA, EIA, BP, Statoil and Bloomberg.

5.1 Growth in world energy consumption - while standstill in Europe

Southeast Asia drives the growth, but prognoses are downgraded
A basic assumption in most analyses is that world energy consumption will continue to grow towards 2040. In its prognosis (World Energy Outlook 2015), the International Energy Agency (IEA) projects a growth of just over 30% towards 2040 in their baseline scenario[12]. This amounts to about 1.4% annual growth. Other large stakeholders, such as British Petroleum and IHS, have forecasts that are close to this in their key scenarios. The EIA, the US Energy Information Administration, has an increase of as much as 50% to 2040.

At the same time, most stakeholders have downgraded their forecasts in recent years, and BP has e.g. downgraded the total energy consumption in 2035 by 1% from last year to this year. The growth will be significantly lower than what we have observed over the last 25 years. The primary causes of the trend are

- Weaker connection between economic growth and energy consumption due to improved energy efficiency and more growth in industries that use less energy
- Lower forecasts for economic growth

There is also greater emphasis than before on scenarios with lower growth in energy consumption. BP shows that if the annual global economic growth in their primary scenario is reduced from 1.4% to 1%, the increase in energy consumption will fall from approx. 33% to 23% towards 2035. In energy, this corresponds to 1,200 Mtoe/14,000 TWh, or approximately the current European energy consumption.

It will be essential to limit growth in global energy consumption in order to be anywhere near the Paris goals. The IEA is the agency that places the greatest emphasis on this. In their scenario where we reach the two-degree target, the 450 scenario, world energy consumption will increase by just 12% towards 2040, compared with more than 30% in most baseline scenarios. In their scenarios where climate is emphasised more, yet not enough to reach the two-degree target, both IHS and BP have predicted growth of around 20%.

There is broad agreement that the growth in energy consumption will come in emerging economies, especially in Asia. This is a continuation of the trend we have seen over the last 25 years. China's development is in a unique position here. Between 1990 and 2012, Chinese energy consumption[13]

[12] New Policies Scenario (NPS) is the IEA's baseline scenario.
[13] Here, energy consumption means primary energy, which means the energy content in the overall consumption of coal, gas, oil, etc.

increased by more than 300%, and in 2010, China overtook the US in the role of the world's largest energy consumer. However, more sluggish economic growth after 2014 has also slowed this trend. Regardless of whether the economy normalises, the further growth will be lower and significantly less energy-intensive than during the 1990-2012 period. For example, BP presumes that the annual increase in energy consumption will fall to below 2% over the next 20 years, compared with around 10% in the previous 20 years. India, Southeast Asia, Africa, South America and the Middle East will most likely offset this somewhat, but not fully. In the established OECD countries, the IEA, EIA and BP all expect slight growth (the US) or a standstill/decline (Europe) towards 2030–2035. However, consumption in the power sector in the OECD is expected to increase in many scenarios, e.g. as a result of electricity increasing its share of end-user energy consumption.

5.2 Although climate policy tightens, we are unlikely to reach two-degree target

Emissions are growing, but peaks before 2030

Global emissions have increased by approx. 50% from 1990 to today. This is because world energy consumption has risen by 60% during the same period, and that fossil fuels account for 80% of the growth. Coal, which releases the most CO_2, has also grown the most. Further growth in energy consumption like the prognoses mentioned above, although they have been adjusted downwards, will make it difficult to achieve the ambitious climate goals that were set in Paris[14].

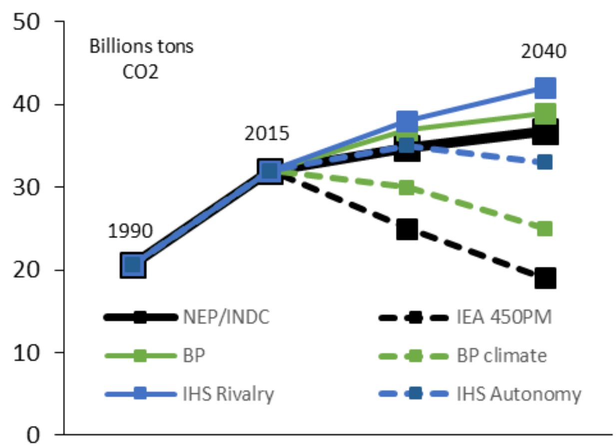

Figure 5-1: Historical emissions from 1990 and up to the present, as well as emissions towards 2040 from a few selected scenarios from the IEA, IHS and BP.

Figure 5-1 shows historical emissions from 1990 and up to the present, as well as emissions towards 2040 from a few selected scenarios. The emissions in the baseline scenarios are higher in 2040 than today, but the increase will be significantly lower than during the 1990-2015 period. This reflects both lower economic growth, more energy efficient growth and that the increase in consumption is covered by renewables to a greater extent.

The IEA's New policy scenario (NPS) presumes that the different countries fulfil the obligations (Intended Nationally Determined Contributions, INDC) they have committed to for 2030. The emissions then increase from 32 to about 35 Gt (billion tonnes of CO_2). Compared to previous editions of World Energy Outlook (WEO), this is a decrease of approx. 5%. This is due to the anticipation of a more

[14] The meeting in Paris resulted in a more ambitious climate agreement that encompassed more countries than before, but which is less binding. The background for the agreement was a new approach where individual countries report their plans instead of large global treaties, where China, India and the US are "forced" to cut. Paris is just the beginning – the hard choices that politicians must make to produce concrete emission cuts will only materialise toward 2020.

stringent climate policy, and that an abrupt stop in the growth of China's energy consumption in the two last years has led to an unexpected slowdown in emission growth since 2014.

Nevertheless, there are several signs indicating that the emissions can be cut more than indicated by the national plans. The Paris Agreement also assumes that the countries will agree on significant cuts soon. BP and others are examining the impact of a considerably tougher climate policy when they assess the uncertainty of the development of the global energy system looking forward, not less climate policy.

Several studies show that climate is also about to become people's greatest concern in large developing countries such as China and India. In combination with massive local pollution problems, this will result in an entirely different climate and environmental policy than before. The development in Chinese coal consumption in NPS and other reference scenarios is therefore most likely too high. Moreover, technology development has made it cheaper to cut emissions, and this is a trend that will continue. Several scenarios in external analyses and forecasts therefore presume that emissions will peak before 2030, and then decline.

The 2 (1.5) degree target requires an imminent energy revolution

The INDCs that form the basis for the Paris Agreement do not yield large enough emission cuts to limit the temperature increase to 2 or 1.5 degrees. The emissions in the NPS scenario in 2030 are approx. 30% higher than in the 450 ppm scenario that shows a hypothetical two-degree path, and the distance only grows up to 2040. The scenarios with the lowest emissions from BP and IHS in figure 5-1 presume that measures that are not adopted will be introduced soon. However, the emissions in these scenarios are also considerably higher than the two-degree path. This illustrates the difficulties involved in making sufficient emission cuts.

Looking at overall expected development within energy consumption, technology development and energy policy, it thus seems unlikely that the world will be able to achieve the two-degree target. However, the expected consequences of climate change are of such a scale that just giving up is not an option. The climate challenge will therefore be a key driver for changes made to energy and power markets throughout the period we are covering here, and after.

5.3 Renewables and innovative technology increasingly impacts energy markets

Enormous progress has been made in recent years within technology development for renewable energy, but also within the production of oil and gas. The shale revolution in the US has led to a major increase in the volume of oil and gas that can be produced at competitive prices[15]. Energy efficiency measures have also contributed to reducing consumption growth. This trend is more difficult to spot than the changes within renewables and shale oil, but it is important and will also become stronger going forward.

From 2000 to 2015, installed capacity in solar power increased from nearly zero to more than 240 GW. Corresponding figures for wind power are from approx. 20 GW in 2000 to 440 GW in 2015. This has resulted in a considerable decline in costs. The cost reduction has been particularly strong after 2010, which is when most of the development took place. Solar power saw the largest overall reduction in costs, with a 50% reduction between 2010 and 2016, whereas wind power costs declined by about 25% in the same period. Both the reduced costs and development in installed capacity were greater than what the IEA and several others anticipated.

[15] We will address this further in the next chapter.

Up to just a few years ago this development was largely driven by Europe, and especially Germany. Now, renewables have become a major global industry, where China is leading the way. In 2015, the country installed 29 GW of onshore wind, which is almost 50% of overall global growth. China now has approx. 40% of total installed wind power capacity. The US is number 2 on the list. China installed 15 GW within solar power, which amounted to 25% globally.

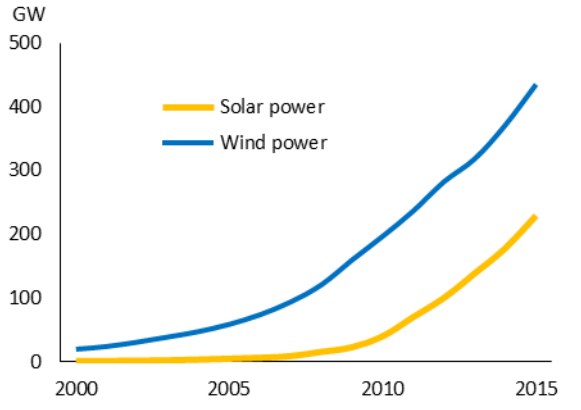

Figure 5-2: Global development in installed capacity for solar and wind power from 2000 to 2015.

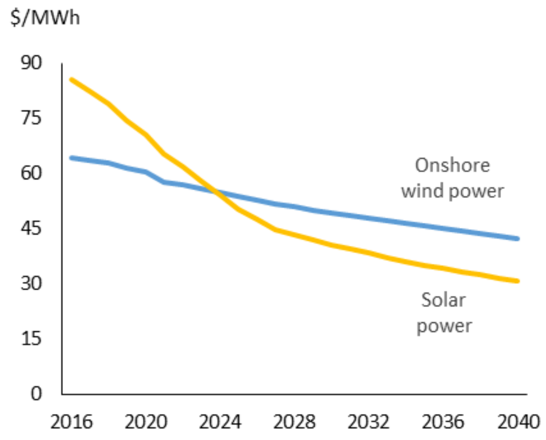

Figure 5-3: Forecast from Bloomberg New Energy Finance concerning LCOE for onshore wind and solar power in the US for 2016-2040.

At the same time, electric vehicles and storage are on their way to become commercial alternatives in the transport and energy sectors. Naturally, the development within both these fields is closely correlated. Storage and transition to electricity within heating and transportation is vital to the integration of more renewables and reduction of emissions. Bloomberg predicts a 50% growth within global power consumption for 2040, which is equivalent to nearly 13,000 TWh. From this, almost 3,000 TWh will come from electric vehicles. Technology development and cost reductions are naturally associated with uncertainty, but as we will discuss later, the question is how much the cost will fall, not whether it will fall. The fact that large companies, for example within the automotive industry, are competing for market shares, as well as China's major investments, adds a completely different element than before.

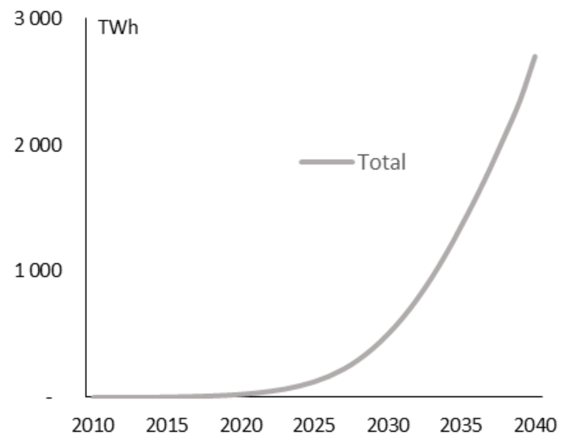

Figure 5-4: Global power consumption from electric cars up to 2040. Forecast from Bloomberg, February 2016.

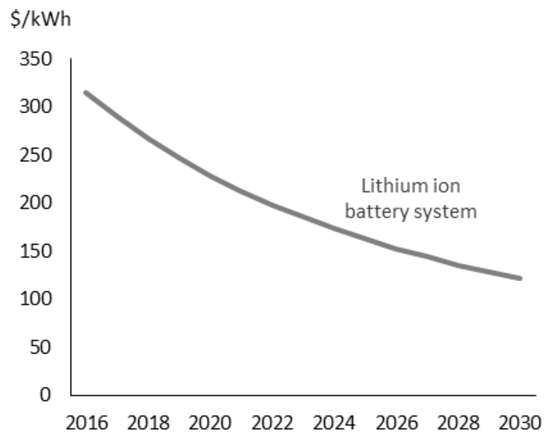

Figure 5-5: Forecast from Bloomberg New Energy Finance for production cost for a lithium-ion battery system in the US for 2016-2030.

Overall, this creates a development where different energy sources and energy carriers are competing much more than before. In their reference scenario, IHS refers to competition and technological changes as the main drivers behind the development in the global energy markets up to 2040. One example can be drawn from oil and gas. Traditionally, these sectors have largely been shielded from outside competition, and the price of gas has been directly linked to oil. Many now predict that cheap gas will compete with oil in the transportation sector, and that both fuels will compete with renewables in the transportation and energy sectors. This entails that the fossil fuel share in global energy consumption will gradually start to decline.

6 Coal, Gas and Oil Prices Rise towards 2040

The prices of coal, gas and CO_2 are the most important factors for power prices in Europe, including the Nordic region, as they determine the short-run marginal costs in thermal power plants. Our analyses show that these will probably set the price for most hours over the next 20-25 years, even in a scenario where wind, solar and other renewable energy sources account for most of the generation. The price of oil has little direct impact on the power price as most oil-fired power plants have been shut down. Nevertheless, the oil price is still important as it affects the prices of coal and gas. Fuel prices also influence climate and energy policy.

We base our fuel price assumptions on analyses from companies that specialise in the fuel markets, for example IHS, IEA, NENA and EIA. The forecasts change over time, which is why we update fuel price estimates more frequently than other assumptions. In recent years we have seen a decline first within coal, followed by the oil and then gas prices in Europe. External forecasts have followed this, particularly for the years around 2020, but also in a longer perspective.

The fuel prices in our analyses are key uncertainties, as they are both important and are associated with significant uncertainty as regards future prices. We therefore cover a considerable range of uncertainty where this is relevant. Changes in fuel prices are vital in our scenarios for high and low power prices.

6.1 Fuel prices have dropped significantly since 2011

The below figures show the price development for oil, coal and gas delivered to Europe, and US gas prices since 2000. Prices increased steadily from approx. 2000 to 2011, if we disregard the brief peak in 2008, and the subsequent drop in the aftermath of the financial crisis. The exception was US gas prices, which continued to drop. The price of coal started declining in 2011, whereas the prices of oil and gas in the rest of the world started falling dramatically in 2014.

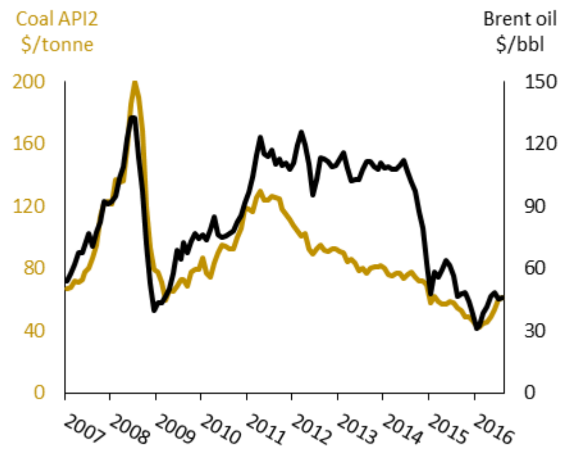

Figure 6-1: Historical price trends for oil and coal delivered in Europe.

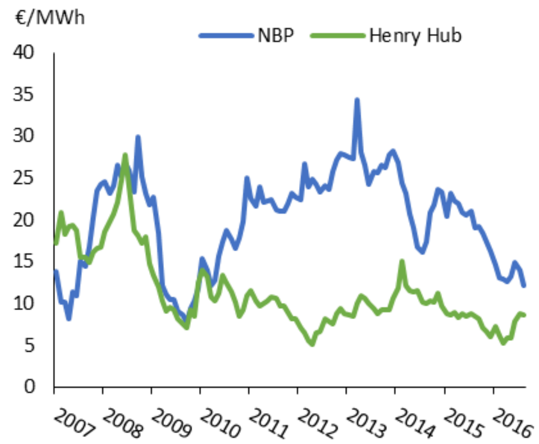

Figure 6-2: Historical price trends for gas prices in Europe and the US.

The two most important fundamental reasons for the price development since 2008 are:

- The shale revolution in the US has turned the country from the world's largest importer of oil and gas into being self-sufficient. The country is now in the process of becoming a major gas exporter.

- China's financial growth and thus seemingly insatiable demand for raw materials and energy has suffered a substantial blow from around the end of 2014. This has led to decreases in most commodity prices, especially coal.

This development led to the following situation which has had significant consequences for the global energy markets, including the European power market.

- Gas from the US was much cheaper than European gas, and the prices in Asia were even higher due to the Japanese import demand after the Fukushima accident, among other things.
- The price of coal in Europe was substantially lower than the gas price[16]. In combination with low CO_2 prices, it became significantly cheaper to produce power based on coal rather than gas.

Many argued that this situation would generally continue for the next 10-15 years, despite the fact that the US would eventually become an LNG exporter. This would nevertheless not be enough to equalise the differences on a large scale, at least not permanently (see Figure 6-3).

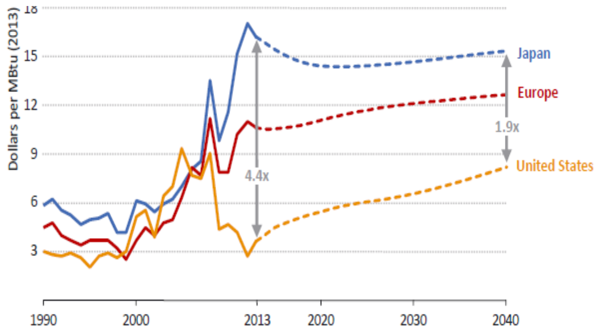

Figure 6-3: Forecast for historical and potential future development in regional gas prices from WEO2014 (IEA 2014).

However, the prices of coal and gas have become much more similar over the last year, also outside the US, both as a result of lower gas prices and higher coal prices (see Figure 6-2). The primary reason for the decline in gas prices in Europe and Asia is the decrease in the oil price. Much of the gas that is purchased and sold globally is indexed to oil prices. Examples of this include LNG contracts in Asia and Russian gas going to Europe. The price of indexed gas has dropped from approx. € 28/MWh in 2013 to about € 15/MWh at the end of September 2016. Despite most of the gas being sold at the exchanges in Western Europe no longer being associated with oil-indexed contracts, a massive supply of cheap oil-indexed gas has still pushed prices downward. This has also resulted in significantly smaller differences compared with the prices in North America.

6.2 Major shift in fuel prognoses – more supply and less demand

Today, about 80% of world's energy consumption is from fossil energy sources[17], and this has remained relatively stable since 1990. Until recently, most prognoses assumed that the price of fossil fuels would increase. The theory was simple, and has been collectively termed "peak oil". Growing consumption in combination with limited fossil resources means having to use increasingly more expensive resources. This will in turn create higher prices, mainly for oil and gas, but also coal.

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[16] The reason for this is how the international energy markets work with a global market for coal and more regional markets for gas. It is easier to transport coal than gas over large distances. A lower American coal price therefore contributed to a fall in international coal prices as well, whereas lower gas prices marginally contributed to lower gas prices elsewhere.
[17] The IEA, see e.g. http://data.worldbank.org/indicator/EG.USE.COMM.FO.ZS

The development in recent years has significantly altered this perception. Most expect prices to increase over time, but there is a large degree of uncertainty concerning when and how much. Several players also have scenarios where the prices remain at the current low levels. The major drop in prices alone has most likely resulted in lower price prognoses for several years into the future. At the same time, the main reason is that the expectations concerning the fundamental conditions in the supply and demand side of the global energy markets has changed.

Firstly, the forecasts for use of fossil fuels have been lowered, quite significantly in some cases. The primary causes are lower and less energy-intensive economic growth in combination with increasing competition from renewables, and eventually electric vehicles in the transportation sector. Secondly, the supply of economically feasible oil and gas resources have been substantially increased. Overall, this results in more competition between different energy sources, and strong forces towards technology development and cost cuts.

In its long-term forecast, BP says that there will be more than enough financially recoverable resources to cover the anticipated increase in consumption of fossil fuels over the next 30 years. Most now talk about peak oil in the sense that consumption may reach peak levels by 2040. Some prognoses assume that this will occur before 2030. This trend is even clearer for coal, although the uncertainty is significant and the prognoses differ as regards the development in Asia. In any case, there is a widespread consensus that the consumption of coal in the wealthy part of the world has reached peak levels and will drop continuously.

In every scenario we have seen, gas consumption is higher than today.[18] Again, the uncertainty is primarily related to the extent of the growth in Asia. Europe could see moderate growth, but IHS does not believe that European gas consumption will be higher than it was before it started to decline in 2007.[19]

In its analysis, BP concludes that it is unlikely that the world's coal, oil and gas reserves can be fully exploited, even with contributions from CCS. On the other hand, a key question is how an ambitious climate policy can lead to increasingly lower consumption of fossil fuels. This has been subject to little analysis so far, but we can see in some scenarios now that declining consumption after 2030 contributes to pushing the prices down. One example of this is IHS' Autonomy scenario.

6.3 Fuel prices are expected to increase, but to a lower level than previously assumed

We have significantly lowered our forecasts for fuel prices over the past two years. In the Grid Development Plan from the autumn of 2015 we used a coal price of $ 100/tonne and a gas price of € 30/MWh in 2030. This was based on the IEA's New policy scenario and other acquired forecasts at the time that for all intents and purposes confirmed the IEA's view. We also wrote that, over the course of the last 6 months, most players had adjusted down their long-term price forecasts, and that we were therefore going to adjust our projections, particularly for coal, in the next update.

The development since then has consistently pointed in the lower direction, e.g. with the significant fall in gas prices. Virtually all external price forecasts have been further decreasing, partly substantially. Based on our assessment, a new consensus is forming, which is significantly lower than the prognoses

[18] In its last long-term report, Statoil includes a scenario where gas consumption in 2040 is the same as today, but in this scenario global energy consumption hardly grows.

[19] Gas consumption in Europe fell by approx. 25% in the 2007-2015 period.

in the IEA's last WEO from autumn of last year, which has been marginally downgraded. We have therefore chosen to depart from the IEA as a primary source when we determine fuel prices.

The figures below summarise our assumptions for coal and gas prices in our Baseline scenario towards 2040. We will return to our established range of uncertainty in the next chapter.

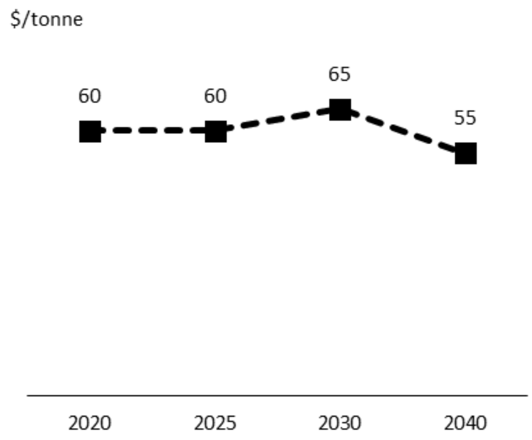


Figure 6-4: Coal prices in the baseline scenario. All prices are real 2016 figures.

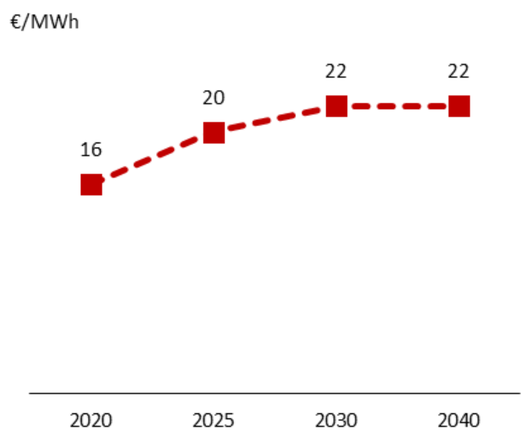


Figure 6-5: Gas prices in the baseline scenario. All prices are real 2016 figures.

Until 2020, we base our scenarios on the future price contracts of coal and gas
Until 2020, we assume the future price contracts as coal and gas prices as they were in mid-September 2016. Most agree that the prices we have observed in recent years for coal and oil are lower than the long-run production costs. There have been several major bankruptcies in the coal industry and oil investments have been cut dramatically. The prices of coal and oil have also started to rise. From the bottom in February 2016, the price of coal has increased from less than 40 $/tonne to more than 65 $/tonne in September, and is now closer to what many analysts believe to be the long-run production cost.

A major global surplus is in the process of developing in the gas markets, as we have already seen in the coal and oil markets. The primary causes are that gas consumption in Asia has grown far less than previously assumed, in combination with a plentiful new option in the form of LNG, mainly from Australia and the US. Global LNG capacity will increase by approx. 50% towards 2019. There is therefore a broad consensus that the day-ahead prices on the exchanges in Western Europe will remain low towards 2020, even if the oil price should increase substantially, and somewhat elevate the price of oil-indexed gas. Several analysis firms, for example IHS, are of the opinion that the global surplus will make gas prices lower in 2020 than what is indicated by the future price contracts.

Then the prices will rise moderately to reach the long-term costs for deliveries to Europe
Until 2030, we have stayed close to what purchased forecasts believe are long-term equilibrium prices, this means the total cost of recovery plus transport to Europe. We believe that a new consensus is forming among the prognoses we have access to, following considerable differences in 2013-2015. They indicate that coal prices are in the interval 60-70 $/tonne in the period from 2020 to 2030. Gas prices are rising as the surplus capacity is disappearing, but as we will discuss below, how long the global surplus that is developing will last beyond the 2020s is very uncertain. We have presumed a gas price of 22 €/MWh in 2030.

The trend in which prices rises after 2030, which most analyses previously presumed, has also largely disappeared. As regards coal, several forecasts show declining consumption and prices. Based on this, we have chosen to reduce the price of coal until 2040, but as we will return to later, the coal price after 2030 has a minor impact on power prices in our scenario. We have kept the gas price at the same level as in 2030, as most prognoses do not show a clear trend after 2030.

6.4 The range of uncertainty for fuel prices is lower, but still considerable

There is, of course, still a considerable range of uncertainty in the forecasts of fuel prices. Analysis firms have high and low scenarios, but also have different expectations. Below we will discuss the most important price drivers in the markets for oil, coal and gas. In the low scenarios, the prices are approximately at the current level towards 2040. In the high scenarios, the equilibrium is higher than in the baseline scenario, but they also return to this level quicker.

There will always be analyses that distinguish themselves both in the high and low direction. However, we attempt to limit this and provide a range of uncertainty that is as realistic as possible, based on the information available to us. The prices can also periodically be both higher and lower than the range of uncertainty we outline. Over time, we nevertheless believe it to be most likely that the prices will fluctuate back within this interval.

Coal: More stringent climate and environmental policy put pressure on prices
The graph below shows the coal prices we presume in our scenarios for the power price. In the Baseline scenario, the price rises to 65 $/tonne in 2030, before it falls toward 55 $/tonne. This is at the low end of what many believe to be the anticipated price. At the same time, we have chosen to emphasise scenarios with a more ambitious climate policy and thus lower consumption than what many have included in their reference scenario.

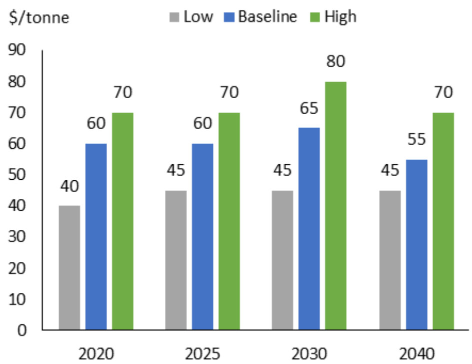


Figure 6-6: Presumed coal prices in Low, Baseline and High.

In our Low scenario, we presume that the current prices will fall back to the level we saw earlier this winter. Bloomberg assumes that the prices will remain at 40 $/tonne until 2040[20]. They emphasise that continuously declining consumption will result in a continuous pressure towards lower prices. Nevertheless, current bankruptcies in the mining industry, and the rise in prices, show that such a level presumes that the producers can further cut costs compared to today. On the other hand, the IEA has relatively high prices even in a scenario where coal consumption is significantly reduced. The underlying logic is that investments halt and thus result in a steeper supply curve in the long term, in

[20] The forecast was from a time when coal prices were lower.

addition to the fact that the operating costs account for the greatest costs in the recovery of coal, while capital costs are more modest.

In the High scenario, the price increases to 80 $/tonne in 2030, before it drops to 70 $/tonne. The price is higher than this in several of the scenarios we have seen. We have chosen our prices this way because we e.g. emphasise a tougher climate policy over time than what is presumed in scenarios with a higher price. Neither do we believe that the growth in Chinese coal consumption, which was an important cause of the rising price of coal in 2000-2011, will return to the levels from this period. Coal consumption in China may still grow, but not as much as in previous forecasts.

Finally, we want to mention the significant uncertainty surrounding the production costs for coal. Oil price is a factor, although it does not affect the costs as much in many of the most expensive and price-setting mines, since they are often deep and more labour-intensive. However, the oil price does affect the cost of shipping, and not least the exchange rate of many of the major exporters. Moreover, the mining industry is important for both energy security and employment in many countries. State subsidies can therefore keep mines running that should have been shut down on commercial terms.

Gas: European gas prices most likely strongly linked to LNG deliveries from the US

Figure 6-7 shows the range of uncertainty we assume for gas prices in our scenarios for High and Low power prices. In the Baseline scenario, we assume that the price will rise from around 15 €/MWh in 2020, to 22 €/MWh in 2030. We have stable prices until 2040. The range of uncertainty over time is between 15 and 27 €/MWh.

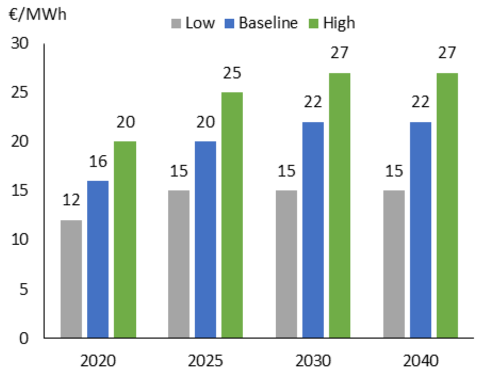


Figure 6-7: Assumed gas prices in Low, Baseline and High.

There is thus a broad consensus that the gas market is headed toward a global surplus capacity. In this situation, many point out that the price on the gas exchanges in Western Europe will be closely associated with the short term costs of LNG deliveries from the US. This, in turn, is the price on the US gas exchange, Henry Hub, plus shipping and a small fee[21]. This level is most likely around the current prices of gas in Europe, possibly somewhat lower. Regardless, the opportunities for cheap imports from the US will mean that the prices in Western Europe will most likely remain low, even in a scenario where oil-indexed prices rise. One important question is therefore how long the surplus capacity in the global gas markets will last. Most of the analyses we have access to presume that this will disappear during the 2020-2025 period.

The next key question is what the price will be when the market is again in balance and fresh investment is needed. One form of consensus is that this will be the long-term costs of delivering LNG

[21] The cost of transport is estimated at approx. 0.45 $/MMBtu and the fee is linked to compressing the gas and is estimated at 15% of the gas price on Henry Hub.

from the US. The reason is that the estimates of competitive US gas resources are now so vast that many players believe they can cover both domestic consumption in the US and considerable export over the next 30-40 years. The price of gas deliveries to Europe is then investment costs associated with new LNG plants, in addition to Henry Hub and transport. Depending on what one presumes as a Henry Hub price, most indicate that the total cost of deliveries to Europe is between 20-27 €/MWh. In the Baseline case, we have a price of 22 €/MWh in 2030. The price forecasts we have access to show a less clear trend after 2030. We have therefore chosen to keep the price stable until 2040.

Two drivers that may yield higher gas prices in Europe are higher US gas prices, or that it becomes more expensive to develop LNG plants. For example, the EIA has higher US gas prices over time in their reference scenario than many others. The IEA emphasises that there is significant uncertainty surrounding the cost of new LNG plants, especially in a scenario where LNG from places other than the US sets the price more often in Europe. In a scenario with greater growth in global gas demand, the latter is more likely.

An alternative interpretation of the high price scenario is that Russia to a greater extent can exercise market power over European prices. Nevertheless, some high price scenarios have been downgraded somewhat significantly compared to previous years, precisely because the likelihood of Russia exercising such market power has been significantly weakened. Several claim that Russia must balance the consideration of maximising price against keeping market shares. The reasoning is that a high price and high Russian income for a brief period may trigger investments in new LNG plants, and thus have a detrimental impact on Russia's income later. It is therefore likely that Russia will choose a strategy where they compete on price in order to retain the market share. Low domestic growth in consumption and a greater gas surplus gas in Russia increase the probability of this.

Low gas prices over time will most likely primarily result from matters on the supply side. In our Low scenario, the prices continue at approximately the current level. This is far lower than what most players believed to be possible only a few years back, and presumes that the industry is able to further cut costs. Several point out that this is necessary in order for gas to compete with coal and renewables. Another driving force towards lower prices is that other countries with significant unconventional resources can repeat the development in the US. BP points out that unconventional generation will grow in several areas. One key uncertainty in the gas market is thus how significant this growth will be.

Oil: Less consumption growth, shale oil and cost reductions have reduced the price forecasts

As mentioned before, the oil price has a lesser direct impact on the power price due to the fact that virtually all oil condensing in Europe has been phased out[22]. We therefore do not have an explicit assumption as regards the price of oil. The oil market is nevertheless important in that it affects the coal and gas markets. Most forecasts are between 50 and 100 $/barrel. Within this range, the majority are between 60 and 80 $/barrel.

The IHS says that upstream oil and gas investments are expected to fall by 2 trillion dollars since the major price decline. Not all of this is due to lower activity, some is also the result of cost cuts that, over time, will yield a lesser supply of oil. On the other hand, global oil consumption is still expected to grow, driven by consumption outside the OECD. In sum, this will most likely result in higher prices than today. At the same time, several factors are preventing a rise to the level indicated by the forecasts just a couple of years back.

[22] There is still some oil condensing in reserve in e.g. Sweden and France. Swedish oil condensing is not part of the day-ahead market.

- According to BP, new discoveries will rise faster than the existing are consumed.
- The shale industry in North America will be a key player over the next 30 years, with substantial and competitive resources. There will also be more shale development globally, but it is uncertain to what extent the phenomenon in the US can be transferred to other countries, for example China.
- The technology development that has made it possible to develop shale also shows that traditional generation can be made cheaper. The shale industry saw productivity gains of 30% per year during the 2007-2014 period. This development is about to transfer to conventional recovery, driven by low oil prices.
- IHS has the oil consumption starting to fall before 2040 in all scenarios, and emphasise there will be increased competition in transport as well, which has so far been almost entirely dominated by oil.

We are already seeing the contours of major producers, both countries and private companies, being in the process of changing their strategy on the basis of this development. It has become more important to retain market shares and cut costs. The pressure to continuously increase one's reserves has been significantly reduced from the situation when the oil price was above 100 $/barrel and the consensus was that it would increase. Many claim that the markets for oil and gas will be more similar to other markets, with prices closer to development costs and lower profit.

7 Trends and Assumptions for Europe

The European energy sector is in a comprehensive transformation process as a result of the need to reduce greenhouse gas emissions. Our anticipation is that this will result in the following changes towards 2040:

- Halving the current emissions from today to 2040, entails a 62% reduction compared with 1990
- Moderate growth in the CO_2 price
- Significantly more renewables, mainly solar and wind power
- Less thermal generation capacity – tighter capacity margins
- Increased consumption, mainly driven by electrification of the transport and heating sectors

The most important factors for the market development, beyond fuel prices, are how quickly the share of renewables grows, the degree of electrification of other sectors and how important EU ETS will be as an instrument for emission cuts. In addition, future capacity margins and the development within demand response and energy storage are considerable uncertainty factors. In spite of the uncertainty, the message in the bullet points above is largely shared by the baseline scenario and the variants for high and low power price.

7.1 Overall energy and climate policy

The climate goals are highly prioritised, but must be balanced against costs and security of supply
Both the EU and the individual member states have several different energy policy goals. The most important are to contribute to reduced greenhouse gas emissions, improve energy and supply security, reduce energy costs and contribute to increased value creation. The goals are contradictory to some degree, and the policy mainly entails balancing various considerations. New main goals for 2030 were adopted in the autumn of 2014:

- 40% reduction in emissions from 1990 (have already cut 24% compared with 1990)
- 27% of overall energy consumption is renewable (currently 14%)
- 27% improved energy efficiency compared with a forecast for development without any energy efficiency measures

The goals are binding at the EU level, but the specific policies are still under development, both at the EU level and in the individual member states. The ongoing discussions mainly revolve around how the goals can be achieved and how the reorganisation costs will be divided between member states. At the same time, there is also a question concerning raising the ambition level for 2030 in light of the Paris Climate Agreement.

In recent years, it has become highly probable that the development towards increasingly stricter goals and lower emissions will continue after 2030. The key question now is how quickly and how far this will go. Both the EU and many of the most important member states base their climate policy on an objective of 80% emission reduction by 2050. In order to achieve this, the energy sector must be virtually emission-free as early as in 2040. This is not very realistic given the current situation. The adopted goals for 2030 are not ambitious enough and the costs associated with restructuring power generation are too high. There is also considerable opposition against setting strict emissions requirements from different countries and stakeholders internally in the EU. Poland and several Eastern European countries represent the strongest opposition. At the same time, the cost issue has also received significant focus in countries with ambitious national goals, such as Germany, the UK and

Denmark. Altogether, this means that an emission-free energy sector is unlikely in 2040, although development will probably go far in this direction.

We assume achievement of the climate policy goals
Our scenarios assume that EU countries will achieve the goals for 2030, and that climate policy will be stricter towards 2040. At the same time, we expect a more moderate development from 2030 to 2040 than what the long-term emission goals for 2050 will most likely require. Based on our own estimates, this will entail the following for the power sector:

- Emissions will drop by 45-50% to 2030 and more than 70% to 2040, compared to 2005
- The share of renewables will increase from 20% in 2013, to 33, 50 and 64% in 2020, 2030 and 2040, respectively

The emission reduction figures, share of renewable energy and the distribution of these between the various European countries are associated with significant uncertainty. At the same time, the decisions made by market players are influenced by climate policy, even though it is uncertain. For example, rational market players take into account that gradually stricter emission requirements may become relevant in their investment decisions. This reduces the opportunity for major investments in coal power, as one example.

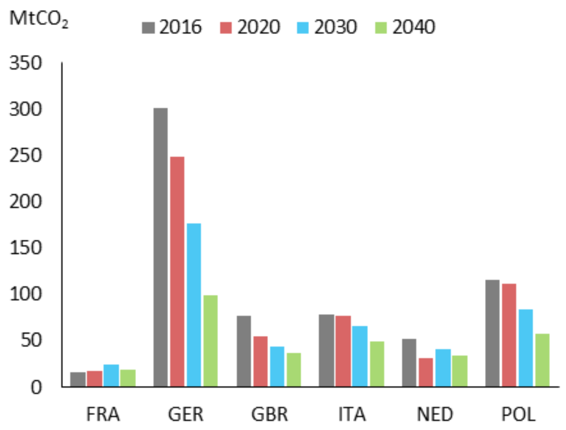


Figure 7-1: Total CO_2 emissions from our model simulations of the Baseline datasets.

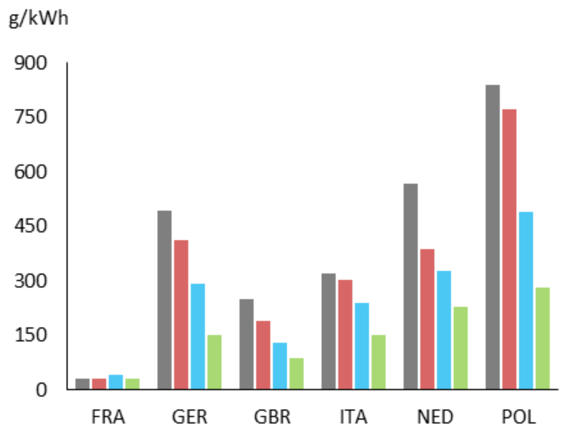


Figure 7-2: Simulated CO_2 intensity in the form of average emissions per produced kWh

7.2 Policy instruments and EU ETS

Continued use of several policy instruments to achieve energy and climate policy goals
How the EU and member states design and emphasise different policy instruments to achieve the various goals within energy and climate policy has a large impact on long-term market development. We expect that the practice of using a combination of several policy instruments will be continued:

- Existing coal power plants will be phased out as a result of age and emission regulations
- The development of renewable power generation is based on subsidies
- Energy efficiency measures come from both subsidies and various regulations
- EU ETS is a "safety net" to ensure goal achievement, but will gradually take on a larger role

We expect that new thermal generation capacity that can be dispatchable will come in the form of gas power and not new coal power plants. This will take place through a combination of regulations, higher carbon prices and that expectations of gradually stricter emission requirements will make it unprofitable to invest in coal power.

EU ETS will become more balanced, but the impact on prices is uncertain

Import of quotas from countries outside the EU, lower energy consumption and development of renewables have contributed to a considerable surplus of quotas in the EU Emissions Trading System, EU ETS. This has resulted in low prices and made EU ETS more or less redundant as a policy instrument for emission cuts. The EU has therefore adopted, and is in the process of adopting, different reforms that will provide both higher and more stable prices, and will thus contribute to making ETS a more essential tool for generating emission cuts and development of renewables. The key measures are introduction of a stability reserve, that it will no longer be possible to import quotas from countries outside the EU and larger cuts per year in the overall quota ceiling after 2020. Several external analyses show that this will increase the prices from the current low level.

The long-term development in quota price depends on a number of uncertain factors – the annual reduction in the quota ceiling, the fossil fuel prices, technology development and to what degree other policy instruments are being used to cut emissions. Altogether, this results in a considerable range of uncertainty, particularly after 2030 when the costs of additional emission cuts are expected to increase. Strong prioritisation of other policy instruments would result in relatively low prices. This also applies if we experience a prolonged period with a low gas price, relative to the price of coal, as this will result in more use of gas power instead of coal power. On the other hand, the quota price will increase if the use of other policy instruments is toned down and we again end up with a relatively high gas price. However, a fuel swap in the energy sector will have less significance for the quota price as coal power is phased out.

Most likely, the biggest impact on the quota price in the long term will be how far the EU, and the rest of the world, will go to reduce greenhouse gas emissions after 2030. In order to be able to fulfil the Paris Agreement, most external analysis reports show that a much higher CO_2 price will be necessary. This is partly due to the fact that the costs of additional emission cuts will increase as the cheapest measures have already been implemented. At the same time, there are many indications that there is a limit for how high the quota price can be with regard to redistribution effects and the desire to continue using multiple policy instruments. In the EU, the greatest resistance against the quota system is in the east, led by Poland.

Moderate increase in quota prices – considerable range of uncertainty

In the baseline scenario, we assume a uniform and moderate increase from the current level € 5/tonne to € 25/tonne in 2040. This implies that EU ETS will gradually become more important, but that this alone is not a major driver for emission cuts. A somewhat lower price trend is used in the low scenario, but higher than the current level. A substantially higher price path is used in the high scenario, which is either driven by EU ETS or in the form of national price floors, which France is planning to implement and the UK has already introduced. In this scenario, the CO_2 price is a driver for emission cuts.

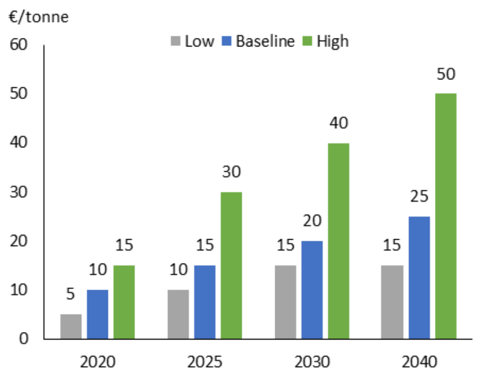


Figure 7-3: Assumptions concerning price trends within EU ETS for Low, Baseline and High.

7.3 Consumption – more electrification will most likely yield growth

Energy and power consumption in Northwest Europe has been on the decline since 2008. The financial crisis and subsequent economic downturn can be blamed for much of this decline, but it is also a result of a larger trend where the fundamental correlation between economic growth and power consumption has gradually become weaker over the course of the last 10-20 years. In combination with expected relatively moderate economic growth (World Bank Group 2016) and growing efforts within energy efficiency, this indicates that there will be a decline in power consumption towards 2030-2040. This message is also substantiated in several external forecasts. At the same time, a number of factors could cause an increase in consumption. Examples include growth within electrification of the heating and transportation sectors, and within data storage.

Several reports and political objectives have expressed that increased electrification within heating and transportation is a necessary measure to reduce greenhouse gas emissions. This has not had a significant impact on consumption so far, but it is likely that the volume will increase in light of the overarching climate objectives, development of renewables and the technological development.

In the heating sector, consumption may increase with more use of heat pumps, both directly in residences and in district heating plants, and through flexible utilisation of surplus generation during periods with a lot of sunlight and wind. In the transportation sector, electric cars are most important with regard to consumption growth. The technological development is rapid and it is possible that electric cars will become competitive without subsidies within a few years. In a forecast from January 2016, Bloomberg believes that this will most likely take place over the next decade. This results in a substantial increase in power consumption in the 2030s and a Bloomberg forecast estimates that the overall power consumption from European electric cars will constitute 450 TWh in 2040. (Bloomberg 2016).

The future development in consumption is uncertain and our baseline scenario presumes that consumption on the Continent and in the UK will increase by 25% up to 2040. Figure 7-4 outlines how the electrification of transportation and heating surpasses the effect of energy efficiency measures.

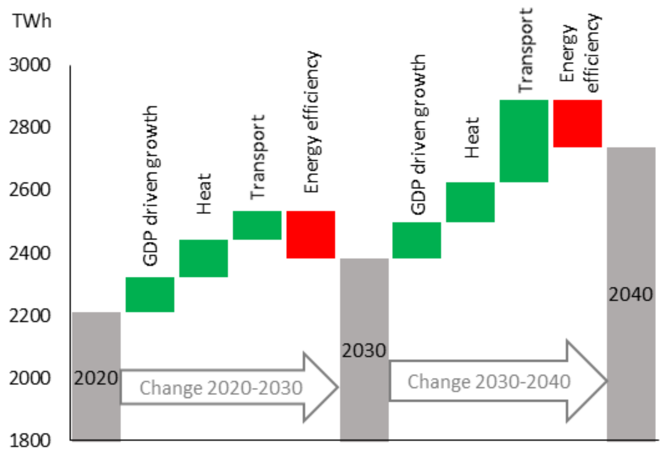


Figure 7-4: Consumption development in EU10 in Baseline.

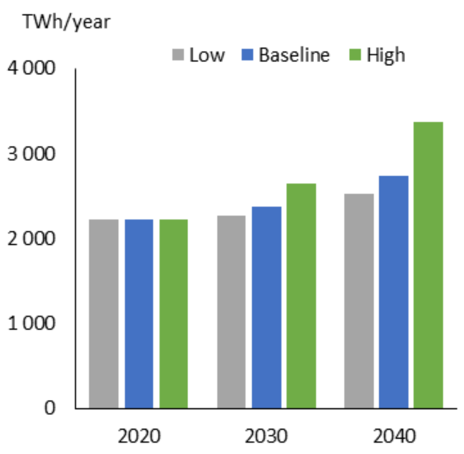


Figure 7-5: Consumption development in EU10 in Low, Baseline and High.

Considerable uncertainty in 2040 – electrification and energy efficiency measures
Figure 7-5 compares the total consumption in our three scenarios in the EU10 area[23]. The primary difference in High and Low compared with the Base scenario is the degree of electrification and energy efficiency measures. In High, consumption is almost 400 TWh higher than expected in 2040. From this, electrification of transportation and heating amounts to approximately 300 TWh, and electric cars constitute more than 200 TWh of this. In the Low scenario, consumption is approx. 300 TWh lower than expected. This is primarily due to more energy efficiency measures, but also somewhat lower electricity consumption within the heating sector. The electric car consumption is at the same level as in the Base scenario.

Several external analyses have an actual decline in power consumption. We do not have this, in part because we expect that electric cars and heat pumps will grow considerably, even in our low scenario. However, it is important to remember that we presume a certain correlation between development in consumption and generation, and particularly the renewables development. Less consumption would probably also result in less growth in renewables. The share of renewables that is covered by renewables in our scenarios is high, but is on par with external scenarios that go about as far as us with regard to emission cuts.

7.4 More renewables – less coal, lignite and nuclear power

We anticipate a fundamental change in both the capacity and generation mix towards 2040. The development of renewable generation capacity, mainly solar and wind power, will continue at a rapid pace, whereas conventional thermal capacity will decrease. In the baseline scenario, the share of renewables for EU10 increases from 27% today to 64% in 2040, driven by the growth in solar and wind. In 2040, solar and wind will represent about half of power generation. Nuclear power will decrease from more than 30% to approx. 15%, whereas other fossil generation will drop from more than 40% to less than 25%.

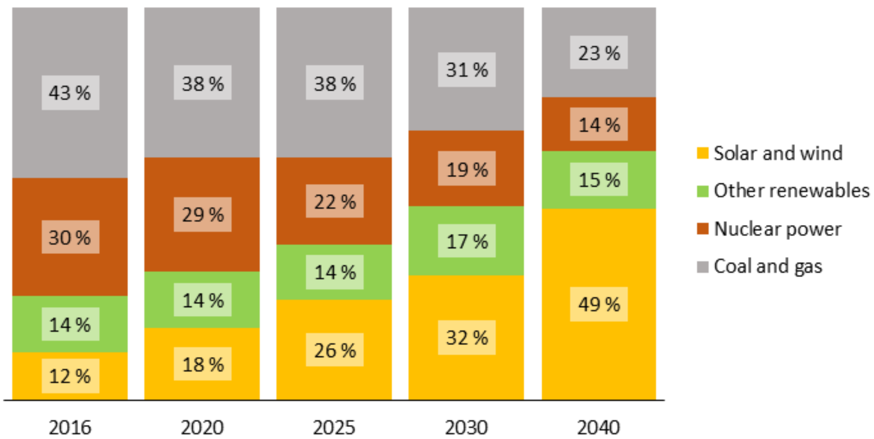


Figure 7-6: Simulated generation composition in Baseline 2016-2040.

Solar and wind power account for half of generation in 2040
Today, solar and wind power appear to be the winners in the competition to become the preferred emission free power generation. Just five years ago it was more unclear if, for example, nuclear power or CCS[24] could be better alternatives, but there has been a strong development towards lower

[23] EU10 means the parts of Europe we have modelled in detail, with the exception of the Nordic region and the Baltics. This means Germany, Poland, the Czech Republic, Austria, Switzerland, Italy, France, Benelux and the United Kingdom.
[24] Carbon Capture and Storage – coal and gas power with CO_2 capture and storage.

development costs and improved efficiency for both solar and wind power in recent years. At the same time, the future pace of development and how far this will go are associated with considerable uncertainty.

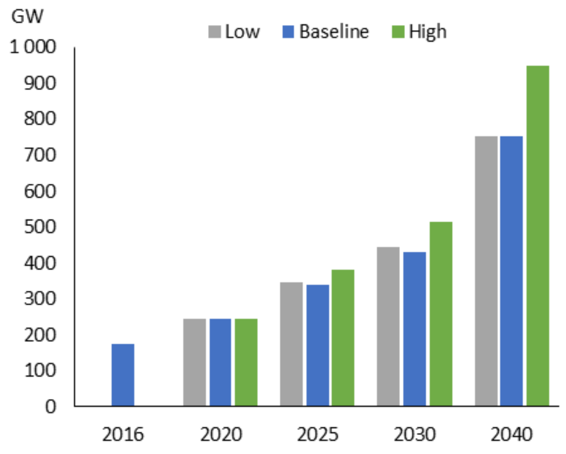


Figure 7-7: Installed capacity solar and wind power in EU10 for Low, Baseline and High.

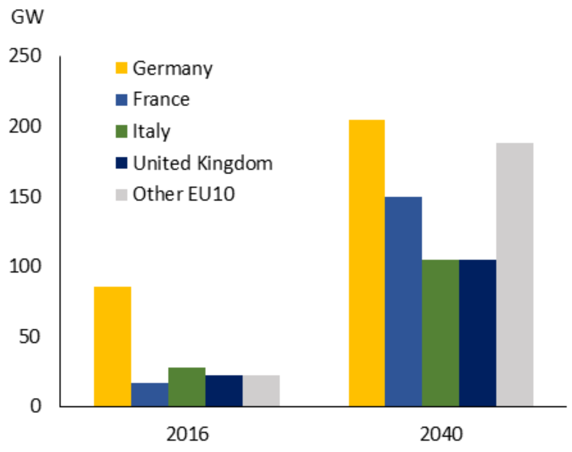


Figure 7-8: Distribution in each country for installed capacity solar and wind power in 2016 and 2040 in Baseline.

Figure 7-7 shows the development in installed capacity from wind and solar power in our three main scenarios towards 2040, in total for EU10 in our model. As illustrated by the figure, there is a high development pace in all three scenarios. However, we believe the growth is at a feasible level, also in the High scenario. In the Baseline scenario, there is an overall annual increase in installed capacity for wind and solar in EU10 of 18 GW up to 2030. For comparison, just over 20 GW of solar and wind power was installed in all of the EU in 2015. For 2040, the speed of development will increase to 32 GW per year. Due to relatively low number of full-load hours, the installed capacity will eventually become much greater than the maximum consumption. For example, in 2040 we have presumed an overall installed capacity of 750 GW in the baseline scenario. For comparison, maximum consumption in the same area is only 450 GW. This results in very significant over-generation during some periods, which we will address again later. As regards the allocation between solar, onshore and offshore wind power, we use the distribution in table 7-1.

Table 7-1: Installed capacity in the baseline scenario per category for EU10, all figures in GW

	2016	2020	2025	2030	2040
Offshore wind	9	22	39	57	97
Onshore wind power	83	110	135	161	271
Solar Power	82	114	164	213	385
Total solar and wind power	174	246	338	431	753
Average consumption	250	254	261	272	313

More deployment of renewables in countries with ambitious climate goals – driven by subsidies

We presume that all European countries will contribute to the development of renewables, but that the majority will come in countries that already have ambitious national climate goals. Figure 7-8 shows how countries such as the UK and Germany are leading the development. As an example, in 2040, solar and wind power represent 60% of the overall power generation in Germany in our baseline scenario.

Lower development costs, gradually improved solar cell efficiency and increasingly larger wind turbines with better number of full-load hours will reduce the overall costs per produced MWh for both solar and wind power. We expect this development to continue towards 2030-2040. Combined with increasing power prices, we may thus have a situation where solar power and onshore wind power, with favourable locations, become profitable without subsidies at some point between 2020 and 2030. This could potentially cause some changes in the geographical distribution, as it would then be more profitable to develop the solar and wind power in the locations with the best conditions and lowest costs. For example, there could be greater development in the Nordic region, which has some of the best onshore wind resources in Europe. As we discuss further in Chapter 14, we do see a clear need for subsidies for renewable energy in our baseline scenario.

Gradual closure of thermal generation capacity
Many of Europe's coal, gas and nuclear power plants are relatively old and will therefore be shut down towards 2030-2040, if there are no reinvestments. Many coal and nuclear power plants are also being forced out as a result of various regulations and political decisions[25]. Updated data from Pöyry[26] indicates that around 80–120 GW of the existing thermal capacity will lapse by 2040 as a result of emission regulations and reaching their expected lifetime, in the part of Europe that is represented in our models. This will create a considerable need to invest in new capacity.

Thermal power plants currently achieve very low earnings. This is largely due to the increased share of renewables that will generate both lower prices and a lower number of full-load hours for thermal power plants. This means that with a continued high rate of development for solar and wind power, it will not be very profitable to invest in new thermal power plants. As we will discuss further in the next sub-chapter, we do not expect the income from capacity markets to be sufficient to maintain the capacity in the power plants at the current level. We therefore assume, as shown in figure 7-9, that there will be a substantial downscaling of the overall thermal capacity towards 2030-2040. In the Baseline scenario, we have a net reduction of 100 GW up to 2040 in EU10.

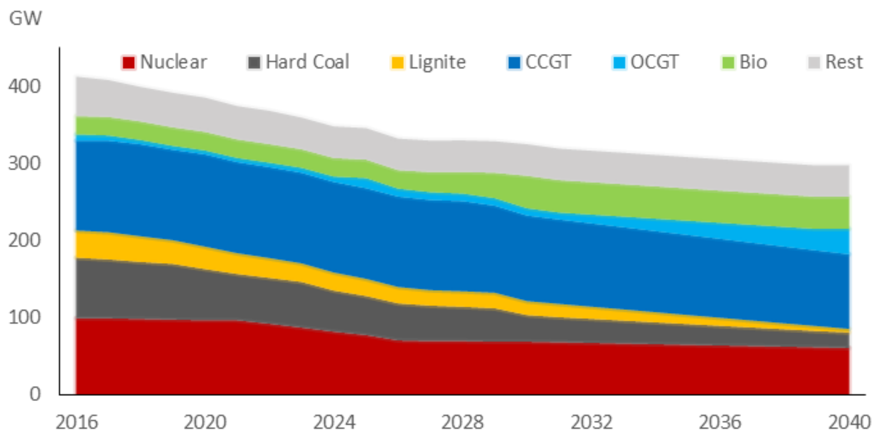


Figure 7-9: Development in thermal generation capacity in our baseline scenario towards 2040.

We assume that new capacity will mainly come in the form of biopower and gas turbines. We have also added some CCGT gas power and a few new nuclear power plants, for example in the UK. Overall,

[25] LCPD and IED at the EU level and national regulations such as EMR in the UK and the decision to ban nuclear power in Germany.
[26] We purchase updated data for all power plants in the part of Europe we model from Pöyry and their power plant database. This includes information about expected remaining lifetime.

there will still be a net decline in both categories. This particularly applies to nuclear power, where many countries have decided to phase out or downscale nuclear power[27]. Finally, we have assumed a relatively slow phasing out of coal in Poland. In other European countries, we do not expect any new coal power plants beyond the few that are already under construction.

Table 7-2: Installed generation capacity in France, Germany, the UK and Poland in our baseline scenario for 2016 and 2040. All amounts in GW.

	2016				2040			
	France	Germany	UK	Poland	France	Germany	UK	Poland
Coal	3	47	13	27	0	7	1	11
Gas	19	35	34	2	18	39	33	8
Nuclear	63	11	10	0	40	0	11	3
Solar power	6	40	9	0	80	95	45	20
Wind power	10	45	14	6	70	110	60	25
Hydropower	24	11	4	3	31	21	9	5
Biopower	2	7	5	1	6	13	8	4
Total	**128**	**197**	**89**	**39**	**245**	**285**	**167**	**76**

7.5 Tighter margins and increased need for flexibility

Considerable need for flexible capacity to balance renewable generation

The main challenge with solar and wind power is the substantial variation in total generation. On one hand, generation could become very low for relatively long periods, even when we consider the overall contribution from large parts of Europe. At the same time, generation could reach very high levels and could eventually become higher than consumption during some periods.

Figure 7-10 shows total generation from solar and wind power in EU10 in our baseline scenario for 2030, based on our historical solar and wind series.[28] Generation will frequently be significantly below average for a whole week, and can in individual hours be down to 10 GW, even though total installed capacity is more than 400 GW. Figure 7-11 shows consumption and residual demand[29] in Europe in 2020, 2030 and 2040 in our baseline scenario. As the share of renewables increases, we can see that the distance between the two curves is growing increasingly larger and the curve for residual demand is becoming increasingly steep. However, the maximum residual demand remains at approximately the same level from 2020 to 2040. This is because there are periods in weather history with high consumption and little solar power and wind power. Hours with negative residual load entail that generation from solar power and wind power is larger than overall consumption for Europe as a whole.

[27] France aspires to reduce the volume of nuclear power in the power system. In 2014, they set a goal for nuclear power to cover no more than 50% of the generation mix in 2025, but they still lack specific measures to achieve the goal. Moreover, the more conservative parties that may gain power following the election next year are critical to the plans.

[28] Our solar and wind series produce a historical generation pattern for most of Europe, hour-by-hour, during the 1962-2012 period. The series are based on weather data from satellite measurements and were prepared by Kjeller Vindteknikk for Statnett.

[29] Residual demand is consumption minus renewables generation hour-by-hour.

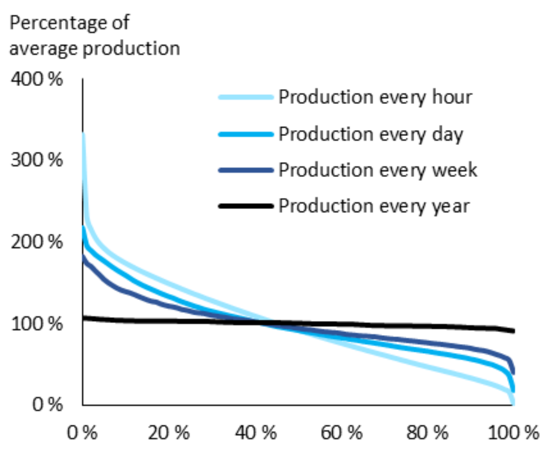


Figure 7-10. Aggregated European solar power and wind power generation at weekly, daily and hourly levels.

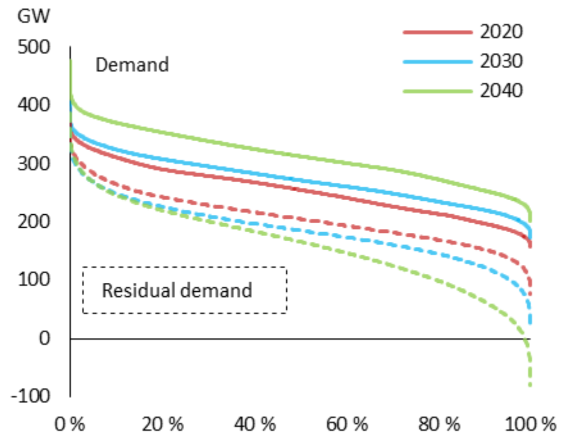


Figure 7-11. Consumption and residual demand in EU10 in Baseline. The consumption here includes some flexibility, which understates the effects somewhat in the most extreme hours.

The curves in the above figures clearly show that although we are developing considerable new generation in the form of solar and wind power, there is still a need for approximately the same amount of generation that can be flexible or other types of flexibility. Firstly, there is a considerable need for flexibility during hours with high residual loads. Secondly, there is a need for flexibility that is able to use over-generation when there has been a lot of generation from wind and solar power, but low consumption. Finally, it is likely that there will be a greater need for short-term regulation resources as a result of forecast errors and short-term leaps in generation.

More transmission capacity between areas clearly contributes to more effectively integrating solar power and wind power, but is not enough by itself. There will also be a need for flexible thermal generation, demand response and different types of energy storage.[30]

The term flexibility is key and is used frequently in several of the upcoming chapters. Our definition of flexibility is the controllable parts of installed generation capacity, consumption or energy storage that have the ability to change their supply or their demand, so that we achieve a continuous balance between supply and demand in the overall market and system operation. Flexibility can be both long-term and short-term. However, this report focuses more on flexibility that is relevant for balancing the day-ahead market, and less on short-term regulation in system operation.

We expect tighter capacity margins after 2020 and demand reductions in the event of scarcity
Weaker earnings will eventually lead to the phasing out and shutdown of thermal power plants, and thus increased likelihood of rationing in hours with high residual demand. This creates a dilemma. How to ensure acceptable security of supply at a reasonable cost? So far, different countries have chosen different solutions. The UK and France have introduced capacity markets[31]. Germany, on the other hand, has chosen to let the market secure investments itself, but establishes a strategic reserve separate from the ordinary power market in order to secure the supply. The different solutions are most likely somewhat dependant on the point of departure. The UK currently has a tight margin and extreme price peaks, whereas Germany has significant surplus capacity.

[30] This has been analysed in detail in our report from 2015: A European Energy-Only Market in 2030.
[31] In a capacity market, adequate capacity in the power system is secured by giving thermal power plants, and other providers of output, earnings in a separate market or auctions outside the energy markets.

The consequences from the different solutions for prices and future capacity margins are uncertain. For example, it is uncertain how strict the margin requirements will be in the long term in countries with capacity markets, to what extent consumption will contribute and whether the countries without capacity markets will stand by their decisions not to introduce capacity markets. At the same time, we believe it is probable that the current thermal generation capacity will be scaled down and that there will be tighter capacity margins in the day-ahead market, both in countries with capacity markets and in countries with strategic reserves. This is firstly because it will be too expensive to maintain the current thermal generation capacity as the share of renewables increases. Secondly, both consumption and energy storage will probably help cover the peaks in residual demand to an increasing degree, thereby reducing the need for thermal generation capacity.

We presume in the baseline scenario that Germany will stand by its decision to not have a capacity market. At the same time, we assume that countries such as France and the UK will govern according to a relatively low capacity margin through their capacity markets, and that the consumer side will participate actively therein. The latter will, in practice, result in a lower margin between available generation and consumption in the day-ahead market, compared to a situation where only generation capacity participates. The implications are both that capacity margins in the day-ahead market will eventually become relatively similar in countries with capacity markets and in countries with strategic reserves and a significantly tighter margin from 2025-2030. In 2040, thermal power plants will still cover most of the consumption during strained hours, but the shedding of industry loads and storage will also increasingly contribute to balancing the power system during these hours.

Increased contribution from batteries, large-scale storage and demand response

Table 7-3 summarises our assumptions concerning different types of storage and demand response. Overall, we expect the contribution from flexibility and storage to increase from about 40 GW in 2025 to 200 GW in 2040.

Table 7-3. Total estimates for flexibility and storage in Europe (EU10) in our data sets. All amounts in GW.

		2025	2030	2040		
				Low	Baseline	High
Load shifting	Load shifting - low cost	15	30	40	40	40
	Load shifting - high cost	5	10	15	15	15
Storage	Battery	5	15	60	60	90
	Large-scale storage	-	-	15	30	30
Net increase in consumption	Flexible hydrogen generation	-	-	25	-	25
	Flexible charging electric cars	-	20	70	70	80
Net decrease in consumption	Reduction potential industry	20	20	20	20	20
	Flexible charging electric cars		5	10	15	20
Overall capacity	**Net decrease in consumption**	**45**	**80**	**160**	**180**	**215**
	Net increase in consumption	**25**	**75**	**225**	**215**	**280**

There is already a significant potential for shifting demand in both households and industry. Studies indicate that the shifting potential is about 10-15% of average load today and that this can increase to up to 20%. We have assumed in our data sets that the available capacity for shifting will increase from 20 to 55 GW from 2025 to 2040, corresponding to 7-17% of average load. We also expect that increased frequency of price peaks will make demand with high willingness to pay more active in the day-ahead market. The extent and duration of reductions that can be achieved within industrial demand is uncertain. The same applies to which prices are needed before this consumption is reduced. Based on reports from Germany and the UK, however, we presume a potential for reductions in industry demand by about 20 GW overall for EU10, with demand shedding prices between 500 and € 5000/MWh.[32]

As regards batteries, we have presumed 15 GW overall in EU10 for 2030 and 60 GW for 2040. With a charging time of three hours, this provides a storage capacity of 45 GWh and 180 GWh, respectively. In High we have an increase to 90 GW/270 GWh in 2040. In a longer perspective we also see a need for storage sources with substantially greater storage capacity than is provided by lithium-ion batteries. In 2040, we have therefore also assumed that technology development will enable large-scale storage, e.g. power-to-gas or compressed air energy storage. In 2040 we have added a type of gas storage in underground facilities with integrated fuel cells[33] (in total 15-30 GW and 180-360 GWh storage capacity).

The growing volume of electric cars in Europe may help with flexibility in the power system, but the impact of this on the power market is highly uncertain. We have presumed that electric cars will contribute flexible charging, but not with the addition of power back into the grid. In our scenarios for high and low power prices in 2040 we have also chosen to model consumption with low willingness to pay in the form of hydrogen generation. We have presumed that these units can collectively increase the consumption by a total of 25 GW during hours with low power prices.

7.6 Grid capacity

The extensive development of renewable generation and the goal for a more integrated European power market increases the need and profitability for transmission capacity both internally in each individual country and between these. There are currently extensive plans in place for new grid reinforcements over the entire Continent, but it is also uncertain to what extent the plans will be realised and when this will potentially take place.

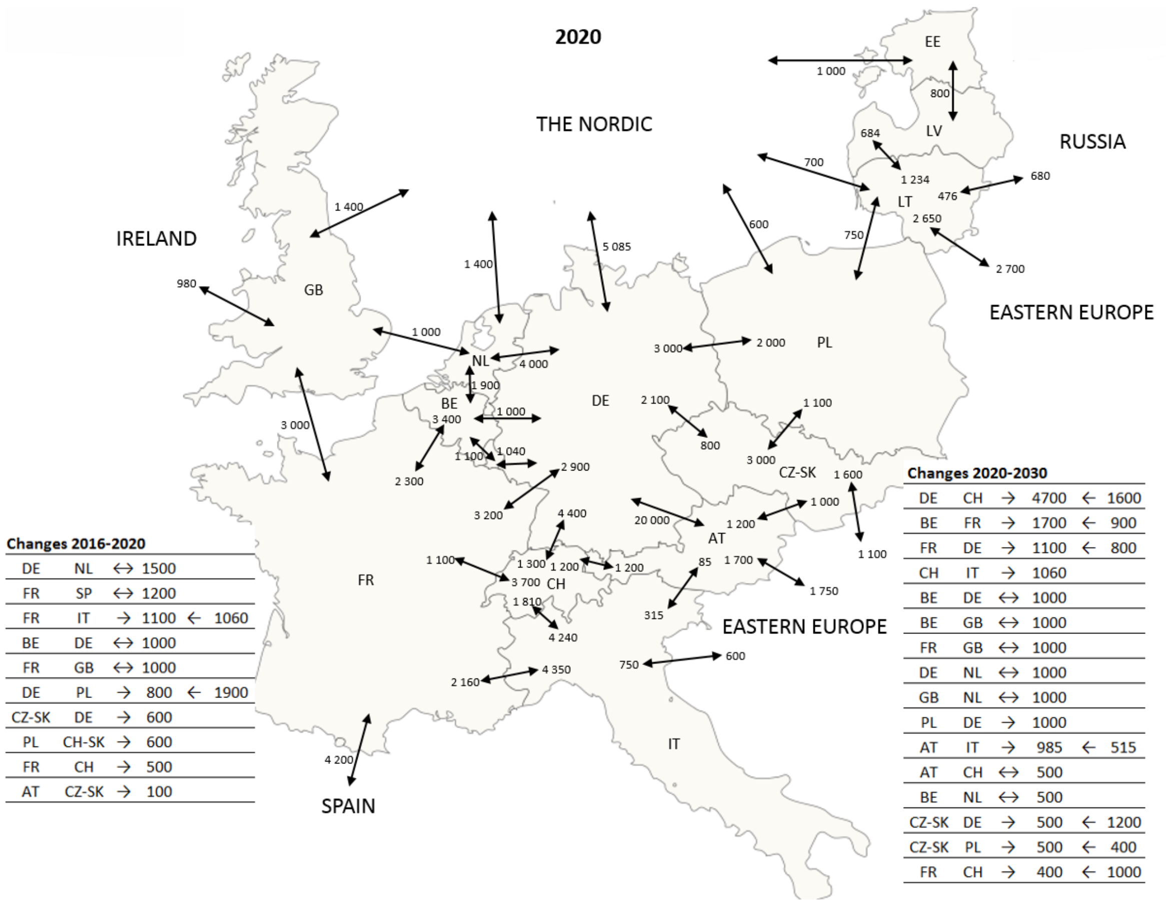
We have based the transmission capacities in our Baseline data sets on forecasts that the European system operators have delivered for the work on the joint European grid development plan (TYNDP 2016). We have also added some additional interconnectors for 2030-2040, partially based on price differences between countries and partially based on plans.

Constructing interconnectors is challenging and time-consuming. We have therefore made sure to enter conservative assumptions. We will address development from the Nordic region in Chapter 8.7. From the UK we expect that 1000 MW will be built going to France by 2020, while an additional 2000 MW going to Belgium and 1000 MW going to the Netherlands will be built for 2030. From Germany, we expect that 1500 MW will be built going to the Netherlands and 800 MW going to Poland in 2020. For 2030, we expect increased capacity to Austria, the Czech Republic, Belgium and France. All transmission capacity estimates in our data sets are shown in figure 7-12. Based on these assumptions, transmission capacities internally on the Continent will increase by about 25000 MW from 2016 to 2020 and by about 35000 MW from 2020 to 2030. Looking further ahead to 2040, we do not yet see large enough price differences to anticipate more capacity. However, this should not be

[32] For more detailed information and sources for our estimates concerning demand response, we refer to our report from 2015: A European Energy-Only Market in 2030.
[33] A storage system of a similar type as described in the article, but with somewhat poorer technical specifications http://pubs.rsc.org/en/Content/ArticleLanding/2015/EE/C5EE01485A#!divAbstract

interpreted as a prognosis to the effect that the grid development will stop. Our analysis is focused on market development, and we address bottlenecks and grid capacities at a relatively general level.

There are currently considerable internal bottlenecks in the German grid. Germany therefore has an extensive grid development plan. Construction is under way, but delayed. The German TSOs currently handle the bottlenecks by reducing trading capacity vis-à-vis neighbouring countries and through redispatch. In line with increasing bottlenecks, the costs associated with redispatch have risen substantially in recent years. The development going forward is uncertain, both as regards the size of the bottlenecks, how many years this situation will last and how they are handled. In the baseline scenario, we have assumed that Germany will continue to be a single bidding zone, and that there will be reduced capacity from the Nordic region to Germany up to 2025[34]. We expect full capacity after this. At the same time, there is a possibility that the bottlenecks will be handled by splitting Germany into two or more bidding zones. We have taken a look at what consequences this would have for German and Nordic prices in Chapter 11.5.



Changes 2016-2020

DE	NL	↔	1500		
FR	SP	↔	1200		
FR	IT	→	1100	←	1060
BE	DE	↔	1000		
FR	GB	↔	1000		
DE	PL	→	800	←	1900
CZ-SK	DE	→	600		
PL	CH-SK	→	600		
FR	CH	→	500		
AT	CZ-SK	→	100		

Changes 2020-2030

DE	CH	→	4700	←	1600
BE	FR	→	1700	←	900
FR	DE	→	1100	←	800
CH	IT	→	1060		
BE	DE	↔	1000		
BE	GB	↔	1000		
FR	GB	↔	1000		
DE	NL	↔	1000		
GB	NL	↔	1000		
PL	DE	→	1000		
AT	IT	→	985	←	515
AT	CH	↔	500		
BE	NL	↔	500		
CZ-SK	DE	→	500	←	1200
CZ-SK	PL	→	500	←	400
FR	CH	→	400	←	1000

Figure 7-12: Our estimates for European grid capacities in 2020, as well as changes 2016-2020 and 2020-2030.

[34] We simulate with 1200 MW lower capacity overall for interconnectors from the Nordic region to Germany, compared with installed capacity.

8 Trends and Assumptions for the Nordic Region

We anticipate major changes in the Nordic power system towards 2040. Consumption will grow and generation from nuclear power and other thermal power plants will decline. At the same time, considerable new renewable generation will be developed, which will result in a significant increase in the share of intermittent generation. This will create major fluctuations in available capacity. There will be a moderate power surplus in the Nordic region throughout the period, but a substantial growth in Norway after 2030. The interconnectors, to Germany and the UK, that are under construction will further reinforce the connection between the Nordic region and Europe.

8.1 Overall energy and climate policy

The Nordic countries have ambitious climate goals. They are in line with the EU's goal to reduce emissions by 80% for 2050. We therefore expect a nearly fossil-free Nordic energy sector in 2040. The energy sector will also contribute to emission cuts in transportation and heating through electrification. At the same time, the Nordic region, like the EU, will need to balance the desire for emission cuts and reduced environmental impact against other factors such as energy security, reasonable energy costs and value creation.

Sweden, Denmark and Finland – ambitious climate goals and energy security
Denmark has the goal of covering 35% of energy consumption with renewable energy in 2020, which will in turn entail that 50% of the power generation must come from renewables. In 2035, the entire electricity and heating supply shall be renewable.

Sweden also has the goal for renewables to cover at least 50% of the energy consumption in 2020. A joint energy agreement for five of the eight Swedish parliament parties was presented in June 2016. The agreement has the goal of a 100% renewable power system by 2040, but did not stipulate a final date for the Swedish nuclear power. The government has appointed an energy commission that will provide recommendations concerning the long-term development in energy supply, with the most central question being how to handle a future with less nuclear power.

Finland's goal is 38% renewable energy by 2020. There is political acceptance for continued investment in nuclear power and a new nuclear power plant, located in the north, is in the planning stages. Finland has a considerable deficit in the annual power balance. The energy import of almost 20 TWh each year, about 25% of the consumption, is among the highest in Europe. Most of this is imported from Sweden, but a substantial portion comes from Russia, even though this has declined in recent years. This partly explains why Finnish public opinion is in favour of new nuclear power.

All of the three countries have challenges associated with a growing deficit in the capacity margin. Sweden will shut down a considerable amount of nuclear power capacity by 2020, and all reactors will most likely be shut down over the course of the next 30 years. Finland already has an output deficit and depends on imports to cover consumption on cold winter days, whereas Denmark is replacing flexible thermal capacity with renewables. This is why there is a growing discussion concerning whether the current market design will be sufficient for securing enough flexible capacity in the long term.

Norway – uncertain climate policy
In the Klimaforliket (Climate compromise deal) from 2012, Norway set the goal to be carbon-neutral by 2030, and two-thirds of the emission cuts shall take place domestically. Examples of Norwegian

climate policy include subsidies for electric cars, the decision to supply the platforms on Utsirahøyden with electricity from shore and the CO_2 tax for emissions from oil installations.

However, the deal has not resulted in any emission cuts yet. From 1990 to today, domestic emissions have increased by approx. 4%. Although the trend in recent years has been a slight reduction, it is improbable that the goals to cut domestic emissions can be achieved without the adoption of more specific and binding measures. In early 2015, the Government decided that Norwegian climate policy shall be in line with the policy in the EU towards 2030. This is in many ways a continuation of the current policy. Norway is a member of the EU ETS and the participation in the Swedish-Norwegian electricity certificate market was the main policy instrument for achieving the renewables goal. The consequences that will be brought on by a further reinforcement vis-à-vis the EU's policy are still unclear and under negotiation.

The Norwegian Government published a white paper on energy policy in April 2016 (Regjeringen 2016). The paper clarifies the focus for the upcoming decades and focuses on four main areas:

- Strengthened security of supply – development of market solutions and new technology
- Development of profitable renewable power generation – the electricity certificate system will be phased out after 2021
- Efficient and climate-friendly consumption of energy – linked to climate goals
- Increased value creation by utilising the power – new industrialised consumption based on renewable energy

8.2 Consumption growth outweighs energy efficiency measures

We expect the consumption in the Nordic region to grow towards 2030 and 2040. This is a reversal of the trend that has been in place since 2008. Consumption in both Sweden and Finland has declined during this period, for example as a result of closings in the wood processing industry, while consumption in Norway has remained reasonably stable. The two most important reasons for the increasing consumption in Norway are growth within industry and electrification of transportation. The growth is moderated somewhat by improved energy efficiency in new and renovated buildings. Overall, we expect Nordic consumption to increase by more than 50 TWh during the period 2016-2040, where 15 TWh will come from Norway.

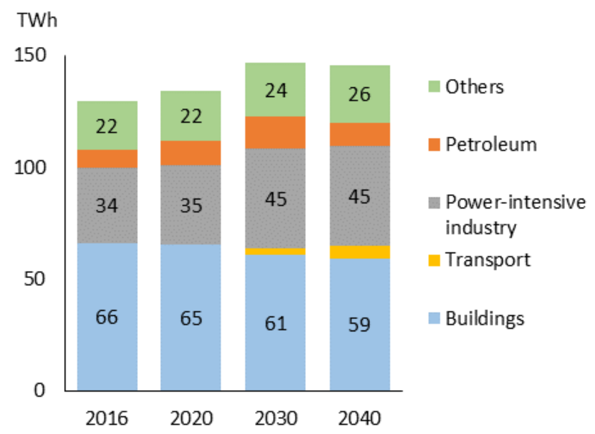


Figure 8-1: Expected development in Norwegian power consumption 2016-2040.

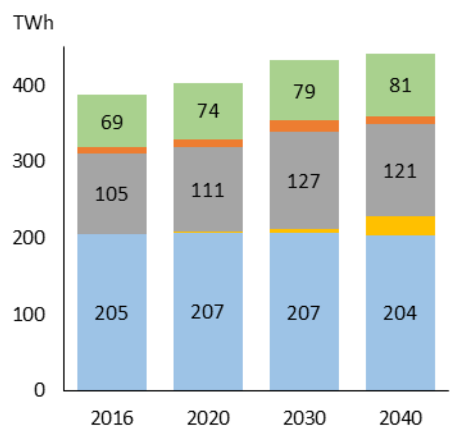


Figure 8-2: Expected development in Nordic power consumption 2016-2040.

In addition to our own analyses, we have used several external sources in the work on preparing a forecast for development in consumption. We divide consumption into three main categories: general consumption, power-intensive industry and electric cars. In order to estimate industrial consumption we have used the specific plans that are available and have also used INSA's prognosis, which provides detailed analysis of the different industry sectors in Norway, Sweden and Finland. We have also obtained a forecast and a model for general consumption and electric car consumption in Norway and Sweden from Optimeering. This model enables us to prepare our own analyses and forecasts for national and regional consumption development in Norway and Sweden.

General consumption will decline in Norway – remains stable in Sweden and Finland
We expect general consumption in Norway to decline by about 6 TWh from today until 2040. Seen in isolation, economic growth, population growth and more residences result in increases. On the other hand, stricter construction rules will reduce the consumption in both new buildings and in renovated older buildings. An increased housing stock would, for example, lead to a 10 TWh higher consumption were it not for more stringent energy requirements. More energy-efficient appliances and urbanisation reduce the consumption per citizen. Climate change causes reduced consumption for heating, but the impact is weakened by the improved construction quality. We expect a 2 TWh reduction towards 2040 as a result of a warmer climate.

District heating is used widely in Sweden and Finland and electrical heating constitutes a smaller portion of the heating sector than in Norway. Sweden in particular has made more progress as regards extracting the potential for improving energy efficiency. General consumption in these two countries is therefore reasonably stable throughout the period. One downside is that Sweden is increasingly planning to reduce consumption as a measure to cover significantly reduced nuclear power capacity.

Strong growth in electric transport after 2025 – Nordic electric cars to consume 24 TWh in 2040
Our forecasts presume that electric cars will become a competitive alternative without subsidies between 2025 and 2030. In 2020, consumption from electric cars will be less than 0.5 TWh for the entire Nordic region. In 2030, the consumption has increased to 6 TWh and 24 TWh in 2040. Of this, 3 and 6 TWh, respectively, will be in Norway. This growth will be particularly strong immediately after electric cars break into the market, since all new electric cars will then replace cars with a combustion engine. The shift in the car fleet will constitute a significant portion of the consumption growth for 2040, but exactly when electric vehicles will break through and the pace of this transition are uncertain.

Hydrogen cars may also become more popular by 2040. We believe that they will be sharing the market with electric cars. We presume that hydrogen fuel will come from electrolysis, which means that the total efficiency will be lower than for pure electric cars. A larger share of hydrogen cars therefore means that the power consumption for transportation will increase more.

Significant growth in power-intensive industries until 2030 – but uncertainty is high
There is a major potential for growth in both old and new industry sectors, while major consumption units may also be closed down. Overall, we expect industrial consumption in Norway to grow by 16 TWh towards 2030, and then it will decline slightly towards 2040. The increase towards 2030 is primarily driven by more petroleum and a new full-scale aluminium facility on Karmøy. Declines in wood processing and petroleum are the reason why consumption will decrease again towards 2040. In Sweden and Finland, the growth for the entire period will be 4 TWh.

In Norway, we expect that consumption within the petroleum sector will increase by about 6 TWh for 2030, and will then decrease by 4 TWh for 2040. About half of the growth expected by 2030 is associated with Utsira. Based on the current information, the potential for further growth over time, is primarily located in Northern Norway. However, the drop in oil and gas prices in the last year has caused uncertainty concerning the profitability of these projects.

Power-intensive industry in Norway will increase by 10 TWh in 2040, and 8 TWh of this will be in place as early as 2030. Much of this growth is associated with Hydro's new full-scale aluminium plant on Karmøy that will use 4-5 TWh each year. In both Sweden and Finland, we presume that industrial consumption will increase by 2 TWh. INSA highlights the chemical industry, steel and mines as possible sectors for growth. Furthermore, underground data storage facilities is a new industry sector with considerable potential and favourable terms in the Nordic region. We have presumed a 4 TWh consumption from underground data storage facilities in Norway and 12 TWh overall in the Nordic region by 2040.

Today, consumption in the wood processing industry amounts to about 40-45 TWh each year, but only 3 TWh of this is in Norway. Consumption has declined by more than 15 TWh since the peak in 2007. Most of this decline took place in Sweden and Finland, but the decline has also been significant in Norway. We keep consumption in wood processing stable at the current level until 2030, before reducing this by 3 TWh in both Sweden and Finland for 2040. In Norway, we have presumed that the remaining consumption of 3 TWh will be phased out between 2030 and 2040.

It must be emphasised that all development is uncertain. With a consumption of several TWh each year, decisions related to individual installations may have an impact on the Norwegian and Nordic power balance. Furthermore, which sectors will experience growth and decline is obviously also subject to uncertainty. Our specific decisions for individual installations, especially over time, are somewhat random. However, we still believe, based on the current information that it is clearly most probable that overall industrial consumption will grow. Consumption may also slow to a halt, but a significant decline is considered less likely. In its low scenario, INSA presumes that overall Nordic industrial consumption will decline by about 20 TWh by 2035, whereas it will increase by just over 50 TWh in the high scenario.

8.3 Nuclear phase out in Swedish – while Finland builds new capacity

The nuclear power in Sweden and Finland plays a key role in the Nordic power system. Annually, it represents 25% of the overall Nordic power generation. Nuclear power delivers stable and predictable base load near consumption centres, and the contribution during dry years is important. Moreover, the power plants contribute to system stability in the Nordic grid and many of the power plants also have strategic locations to support the power grid.

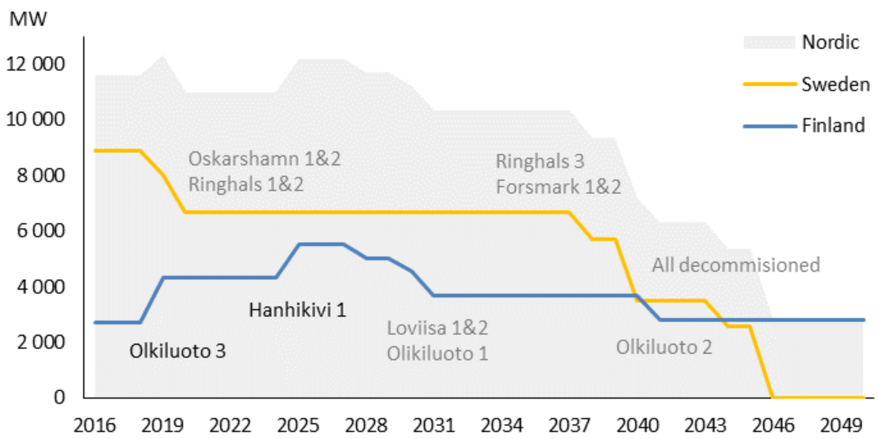


Figure 8-3: Expected development in Nordic nuclear power capacity 2016-2050.

Therefore, what will happen with nuclear power in Sweden and Finland is a key uncertainty in the Nordic power system and power market. All of the current active reactors started operating between 1972 and 1985. Planned lifetime is generally between 50 and 60 years. In Sweden, reactors can be used for as long as they fulfil the authorities' safety requirements, whereas they have a licence to operate for 50 years in Finland. The licence can be extended to 60 years.

Swedish reactors will be shut down as they reach expected lifetime
Swedish nuclear power plants have been under financial strain in recent years. The reasons for this are a low power price, increased taxes and high capital cost from earlier investments in maintenance and capacity expansion. The result is that the owners have decided to shut down four reactors with a total capacity of 1600 MW, as early as 2020. This means that energy generation will decline from approx. 60 TWh a year today to about 45 TWh.

We assume that the remaining six reactors will remain in operation until the end of their lifetime. There are several reasons for this. Firstly, the power prices in our baseline scenario will increase to a level where operations are profitable. Less nuclear power will, in and of itself, contribute to higher prices. Furthermore, the Swedish energy agreement from the summer of 2016 includes the decision to remove the special tax on output, which has had a severe impact on nuclear power. This improves the economy, but also highlights the fact that nuclear power is entirely essential in the Swedish power system. It is therefore unlikely that a continued rapid phase-out can proceed without there being real alternatives that will ensure that security of supply, especially in Southern Sweden, will remain at an acceptable level. In practice, shutdown after lifetime means that generation will be the same in 2030 as in 2020, whereas the installed capacity in 2040 is 3500 MW, and power generation is down to 25 TWh each year – see figure 8-3.

The Swedish energy agreement also opens up for the possibility of building new reactors to replace the existing ten. At the same time, there is a political consensus to not grant subsidies to new reactors. This means that new development is, in practice, unlikely, and there has been little commercial interest in building new plants. The most probable scenario, according to the current view, is therefore that all Swedish nuclear power will disappear over the course of the next 30 years. The last reactors will reach the end of their lifetime in 2046.

We expect a new nuclear reactor in Finland – followed by phase-out according to expected lifetime
There is political support in Finland for further investment in nuclear power, despite the fact that Olkiluoto 3 is delayed by at least 10 years and has enormous cost overruns. Our baseline scenario presumes that Olkiluoto 3 will start operating before 2020 and that Hanhikivi 1 will be built by 2025. We anticipate that Loviisa 1 and 2 and Olkiluoto 1 will be shut down around 2030.

In 2014, the authorities granted a licence for engineering of a new nuclear power plant in northern Finland. The consortium that will invest in the Hanhikivi 1 power plant consists of Finnish power-intensive industry and a number of energy companies. They will invest according to the so-called Mankala principle, where the investors are not entitled to ordinary return, but can instead purchase power at cost price. This low required rate of return is what makes the investment possible, despite the fact that Finland is also not subsidising new nuclear power. The government will make a decision on the final permit for the project in 2018.

This means that overall installed capacity for Finnish nuclear power will increase from about 2700 MW today to a peak of almost 5500 MW after 2025. By 2031, however, the three oldest reactors will be shut down, representing an overall capacity of 1800 MW. In 2040, we have a capacity of more than 3500 MW.

8.4 Continued growth of renewable power generation

We presume that development of renewables in the Nordic region will continue after 2020. We expect more than 70 TWh to be developed. There are many strong drivers behind this development. Firstly, new generation will be necessary to cover consumption growth, and the decline in thermal generation. With the exception of nuclear power in Finland, renewables are the only real alternative today. Furthermore, there are clear national goals, especially in Sweden and Denmark, and the EU's policy will require that all countries contribute. This also applies to Norway. We are currently a part of the Renewables Directive and the Government has signalled that it will link its climate policy even more closely with the EU. Rising power prices and further decreases in the costs associated with renewables also mean that profitable development without support is probable, to some degree.

Norway and Sweden will reach the goal of the common certificate market

Norway and Sweden will develop 28.4 TWh in the joint electricity certificate market after Sweden decided to increase its commitment to 15.4 TWh. So far, 13 TWh has been developed in Sweden and 2.4 TWh in Norway (NVE 2016). Furthermore, about 6 TWh is under construction, of which 2.3 TWh is in Norway. This means that the development of 7 TWh of certificate power remains until 2021. Of this, investment decisions have been made for 3.8 TWh of wind power in Norway (Fosen and Hedmark). We expect the remaining 3 TWh to be relatively evenly distributed between Norwegian hydropower and Swedish wind power.

Table 8-1. Expected distribution of certificate power in 2021. Normal year generation in TWh.

Power type	Norway	Sweden	Total
Water	6.0	0.7	6.7
Wind	4.2	12.7	16.9
Biopower	-	3.8	3.8
Solar power	0.2	0.8	1.0
Total	**10.4**	**18.0**	**28.4**

In Denmark we expect 6 TWh of new wind power by 2020 and 1.5 TWh of solar power. Offshore wind accounts for most of the increase in wind power. Vattenfall has just started the development of 400 MW at Horns Rev 3, and we expect that the park will be completed by 2020. The tender process just started for the park at Kriegers Flak, and we therefore expect that it will not be completed until 2022 (Energistyrelsen 2016). There will also be some new construction onshore, but this mostly concerns upgrades and reinvestments in old turbines to larger turbines with improved number of full-load hours.

Finland has a national goal of 6 TWh new wind power by 2020 and 9 TWh by 2025 (Finlands arbets- och näringsministerium 2014). We expect that Finland will achieve its wind power goals and will also develop 0.5 TWh solar power. Finland has good sunlight conditions with a number of full-load hours equal to Northern Germany (Joint Research Institute 2012). Finland also has good resources within biomass and has a goal to reach 25 TWh forest fuel within electricity and heating production in 2020. We therefore expect some of the existing coal-fired combined heat and power plants to be converted to biopower.

Strong drivers for further development of renewable energy after 2020

In the longer term, the Nordic region will need considerable new generation in order to avoid a substantial power deficit. This particularly applies to Sweden and Finland. The reason for this is the development described above with phase-out of considerable nuclear power, some thermal generation in Finland and Denmark, as well as substantial consumption growth. Our baseline scenario can illustrate an example. Given our assumptions for 60 TWh growth in consumption and net reduction in nuclear power of about 30 TWh, the Nordic region will need about 60 TWh of new generation during the period 2020-2040 in order to achieve balance. Just how quick consumption growth and the shutdown of old power plants will take place is naturally difficult to say, but there is no doubt about the general direction and that new capacity will be needed.

Furthermore, it is clear that new generation in the Nordic region must be emission-free. This is why the majority of new power plants must be renewable. There are three factors that emphasise this:

- We already have specific political goals and resolutions, for example, Sweden's government has presented a proposal to continue expanding the electricity certificate market by 18 TWh up to 2030
- The EU's climate and energy policy – there could be direct or indirect development requirements
- The Nordic region has among Europe's best renewable resources, particularly as regards wind power

In order to reach its goal for 27% renewable energy in 2030, the EU must most likely build more than 1 000 TWh of renewable energy. It is difficult to imagine that the Nordic region, with its vast renewable resources and ambitious national policy, would not take part in achieving this. Regardless of whether the goal becomes binding at a national level, or continues to be open for all of the EU, we expect strong political pressure for the Nordic countries, including Norway, to take part in the development.

The Nordic region is home to many of Europe's best onshore wind power resources. Moreover, the technology development towards larger turbines means that areas previously considered unfit for wind power are now among the best locations. The best example of this is the forests in northern Sweden that have gone from approx. 2000 hours of operation to between 3000-4000 hours. With additional decreases in costs, it is likely that renewables will become the cheapest way to cover much of the demand. There are conditions in the Nordic power supply that make wind power more favourable here than on the Continent:

- Consumption is more correlated with wind power production (seasonal increase in winter)
- The hydropower system may contribute to balancing out the variation in wind power generation
- Still relatively little wind power penetration compared to Europe

Overall, we therefore expect that the attained price for wind power is higher in the Nordic region than on the Continent, although average prices may be somewhat lower at certain points during the year. In our baseline scenario, the prices will rise high enough for both wind power and hydropower to become profitable without support. Lower prices in the beginning and the genuine uncertainty over time; however, do entail that support or guarantee schemes will most likely still be needed. In a scenario with low fuel and CO_2 prices, it will be necessary to achieve greater development. Whereas higher fuel and CO_2 prices will most likely trigger greater development based on the power prices.

We expect 75 TWh new renewable energy generation in the Nordics between 2020-2040
Our baseline scenario presumes that more than 30 TWh solar, wind and hydropower will be developed in the Nordic region by 2030, and an additional 40 TWh by 2040. Along with our other assumptions for

generation and consumption, this will result in minor changes in the overall Nordic balance during the period, although Norway will experience a substantial power surplus in 2040.

Wind power accounts for approximately 80% of this growth, and most of this is onshore wind power. The bulk of the development is in Sweden. In 2040, we expect that solar power will produce 15 TWh annually from approximately 20 GW of installed capacity. In Norway, we expect some new hydropower between 2020 and 2030, both in the form of small-scale power and rehabilitation/expansions, and in the form of increased inflow. In Finland and Denmark, there will be conversion of fossil to biopower in thermal plants, but this does not contribute to net increases in generation. In Sweden, we have anticipated some new construction of biopower as one of the measures to cover the loss of nuclear power.

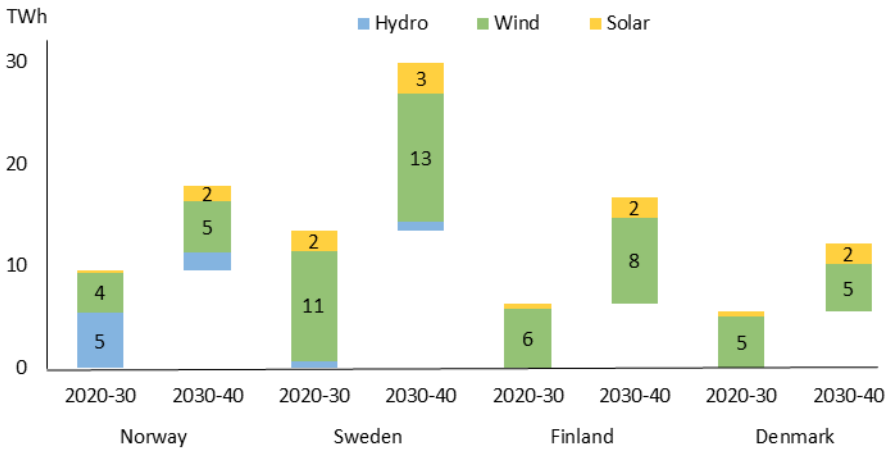


Figure 8-4: Development of Nordic renewables after 2020 in the baseline scenario.

The white paper on energy policy from April of this year clearly stated that the electricity certificate system in Norway would not continue after 2020 (Regjeringen 2016). The report emphasises that the renewables that will be developed in Norway must be profitable. With expected price development in the upcoming ten years, it is uncertain how much new power can be developed without subsidies. We still believe that there will be considerable new renewables in Norway by 2030. From a political standpoint, there is likely a desire to achieve a surplus in the power balance. Furthermore, several parties want Norway to build renewables as part of the goal to reduce domestic emissions of greenhouse gases. Both goals make sense in light of the presumed increase in consumption from electrification. Furthermore, there will most likely be a development requirement from the EU, although the manner in which this will happen is still unclear.

As we approach 2030, hydropower and wind power projects also become profitable without support in our baseline scenario. The development towards 2040 is therefore largely driven by the fact that power prices are higher than the long-term development cost.

8.5 The annual Nordic power balance is uncertain – although a deficit is still unlikely

Today, we presume that, during a normal year, Norway has a surplus of approx. 9 TWh, whereas the total surplus in the Nordic region is 5 TWh. A large surplus in Sweden is offset by a deficit in Finland. Our assumptions described above mean that the balance at the Nordic level increases somewhat towards 2020 and will then be reasonably stable until 2040, although it will, of course, vary over the course of such a long period. In Norway, the surplus will increase somewhat until 2020, and will then return to today's level in 2030, followed by yet another fairly significant increase. The Swedish-Finnish balance will remain relatively stable over time since a smaller Swedish surplus is offset by a smaller deficit in Finland.

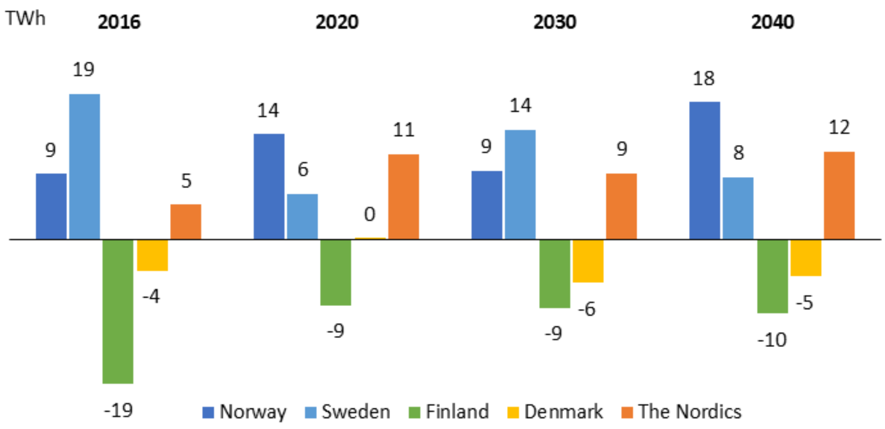


Figure 8-5: Nordic power balances in the baseline scenario.

The known uncertainties that we have discussed previously result in a considerable range of uncertainty for the power balance. Major decisions surrounding individual facilities within nuclear power and industry could quickly change the balance by many TWh. We nevertheless consider it to be extremely likely that the Nordic balance will remain positive. This is due to the desire for energy security in dry years, good renewable resources, more efficient use of energy and the impact of a warmer and wetter climate.

We have changed the Nordic balance in our scenarios for high and low power price. In the interest of simplicity, we have chosen to change this through the rate of renewables development. In the High scenario, we have a greater development based on power prices rising to a level where a lot of wind power is profitable with a good margin. In the Low scenario, we have reduced development, but this is still in line with consumption. Figure 8-6 shows the range of uncertainty for the power balances in Norway, Sweden and Finland because these three, overall, are most important for the impact on the power price.

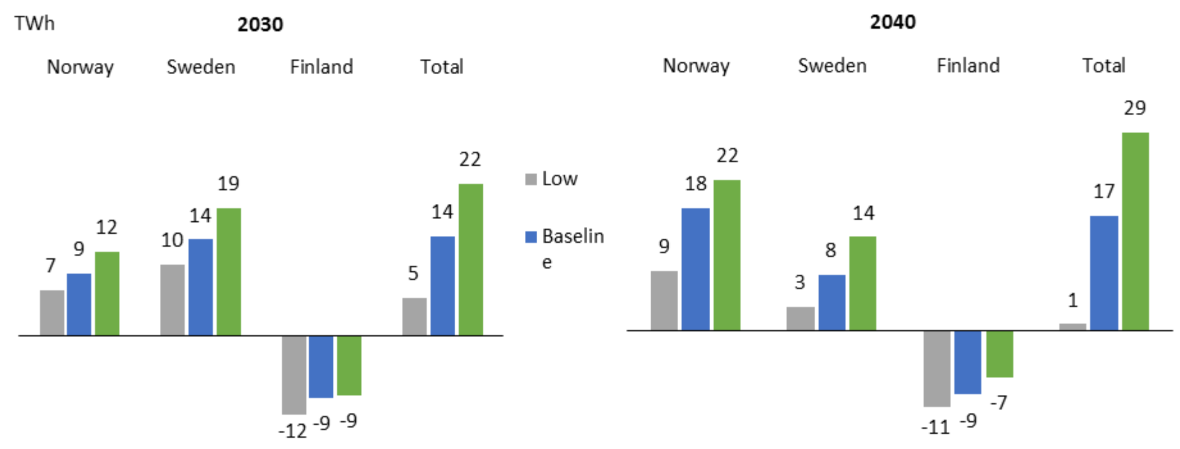


Figure 8-6: Range of uncertainty for the power balances in Norway, Sweden and Finland in our three scenarios in 2030 and 2040.

8.6 Variable generation becomes increasingly important

Wind, solar and small-scale hydro amount to half of the generation capacity in the Nordics in 2040

The figure below compares overall installed capacity from variable and flexible generation with maximum and minimum consumption for the Nordic region in 2016 and 2040 in our baseline scenario. We anticipate that the installed capacity from solar, wind and small-scale hydro will more than triple from today to 2040. Today, these generation types amount to about 20% of the total, but will increase to 50% in 2040. We also see that dispatchable (flexible) generation will decline by about 10 GW, whereas peak load will increase by 5 GW. The development with increasing volumes of intermittent (variable) generation will have a substantial effect on the Nordic power system and power market.

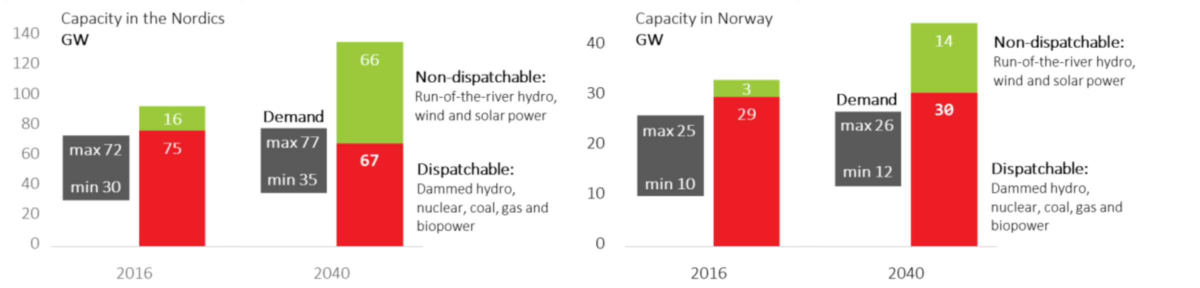


Figure 8-7: Installed capacity for dispatchable and non-dispatchable (intermittent) power plants in Norway and the Nordic region in 2016 and 2040, as well as minimum and maximum consumption.

The solar and wind power that will be developed will have a high installed capacity, but cannot always deliver power. The Nordic TSOs normally estimate that only 5-12% of the wind power is available during the hour with the highest consumption.

In Norway, our baseline scenario foresees minor changes. Consumption growth in industry and transport is partly offset by efficiency improvements and less consumption in buildings. It is difficult to precisely determine how the consumption changes will affect the maximum and minimum output, and the changes may exceed what we see in figure 8-7. Changes on the Nordic and European side also have an impact in Norway because the markets are integrated. In periods with high intermittent generation and low consumption, we see an increased need for exports. In the reverse, we also see periods with more demand for output. At the same time, there is a significant potential for developments in the dispatchable hydropower system. As a point of departure, we have not added either more output or pumps, but with the development we see in both Baseline and High, this may be profitable.

Growing share of variable renewable generation

Maintaining a continuous power balance will be more demanding in the Nordic region when the share of intermittent generation grows. During hours with little contribution from renewables in the winter, shortages will occur. In the summer months, non-dispatchable hydropower, wind and solar power will more frequently cover all or almost all consumption. The variations over shorter periods that must be balanced is also considerably larger. Figure 8-8 compares overall contributions from intermittent generation in the Nordic region 2016 and 2040. Today, maximum generation in the Nordic region is around 30 GW, and in normal situations, the contribution varies between 20 GW to just under 10 GW. In 2040, maximum generation will rise to nearly 60 GW, and the variation is normally between 50-15 GW.

The graph in figure 8-9 shows residual demand in the Nordic region, i.e. consumption minus the contribution from wind, solar and non-dispatchable hydropower in the same hour, in 2016 and 2040. The decline in residual demand is substantial, but less than the increase in intermittent generation due to consumption growth. In 2040, intermittent generation covers the entire consumption for more than 5% of the time. As we will return to later, much of this overproduction takes place in the summer. At the other end of the scale, we see a slight increase in the maximum consumption that must be covered by sources other than non-dispatchable renewables. A steeper curve indicates greater variations that must be balanced out by dispatchable generation, exchange, consumption or storage.

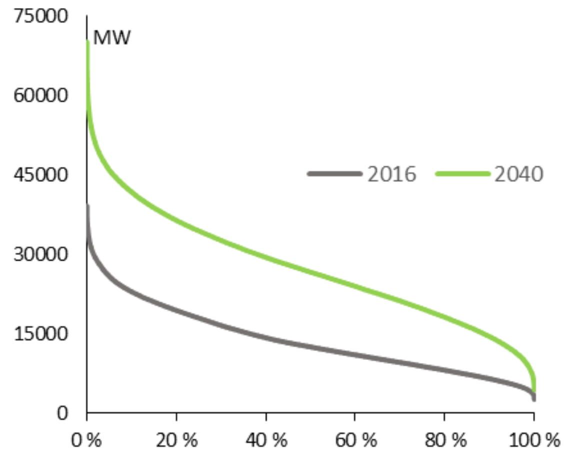


Figure 8-8: Simulated contributions from intermittent generation in the Nordic region in 2016 and Baseline 2040.

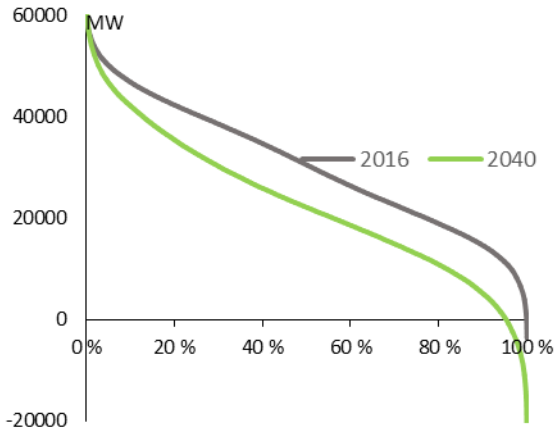


Figure 8-9: Simulated residual load in the Nordic region in 2016 and Baseline 2040.

Tighter capacity margin incentivises flexibility in both demand and supply

The Nordic capacity margin is already tight in hours with high consumption in the winter. Further development toward more consumption and less flexible generation results in a significantly tighter balance in hours with little renewables. This applies particularly for Southern Sweden, as the nuclear power will be phased out. Table 8-2 shows the output balance in a hypothetical tightest hour in the winter, given maximum load and anticipated available generation capacity.[35]

[35] Available and installed capacity are not the same. The available output has been negative for several winters, and lowest in January 2016. The negative values mean that we need imports in order to cover all of the consumption, or must reduce consumption.

Table 8-2: Output balance in Norway and the Nordic region overall for our scenarios. Hydropower is considered to be 87% available, wind power 5%, solar power 0% and thermal power plants and nuclear power as 100% available.

	2016	2020	2030	2040
Norway	2100	3000	3900	5300
Nordic region	-400	-4400	-6500	-8700

Norway currently has a surplus output of approx. 2000 MW[36] during the hours with the highest consumption. At the same time, increased maximum load in recent years has reduced the surplus, and more consumption will result in a further weakened balance. Furthermore, increased transmission capacity to the Continent and the UK, as well as a tighter balance in Sweden, means that Norway will, for an increasing number of hours, be linked in price to the other countries during hours of scarcity.

In Europe, we have presumed that flexible consumption with high willingness to pay will disconnect and set the price in hours of scarcity. The same will most likely happen in the Nordic region. One key question is then how much consumption will disconnect at different prices. Since much of the consumption is used for heating and industry, the potential for flexibility may be greater here than elsewhere in Europe. Larger price fluctuations, the usage of smarter energy meters and output tariffs may contribute toward triggering the potential. We have not conducted more detailed analyses of this, but have in our simulations assumed that industry loads in the Nordic region will disconnect when the price is 375 €/MWh. Consumption will most likely have both a lower and higher willingness to pay than this.

In Norway, we can also develop both more capacity and pumped storage. We will address this further in Chapter 14.

Non-dispatchable generation will cover all consumption for an increasing number of hours

The share of consumption that is covered by intermittent generation is clearly the highest in the summer months, both because consumption is lower and generation from river and small-scale hydro is clearly the highest. Figure 8-10 compares the residual demand in a typical summer week in 2016 and 2040. Today we see that the consumption that must be covered by flexible hydropower, thermal and potentially imports is typically around 20 GW through the day until it drops to approx. 15 GW at night. The situation is quite different in 2040. The main reason for this is more solar power. This means that the residual demand in 2040 is lowest at mid-day, averages less than 10 GW on weekdays, and as little as 5 GW on the weekends. In years with high inflow, residual demand is almost always below 10 GW, and negative for about 20% of the time. In certain periods, intermittent generation may exceed consumption in the Nordic region by more than 20 GW.

[36] The available output eventually declines as reservoir water levels fall through the winter. This means that, in cold periods in the late winter, the output balance may also be tight although peak load is lower than previously in the winter.

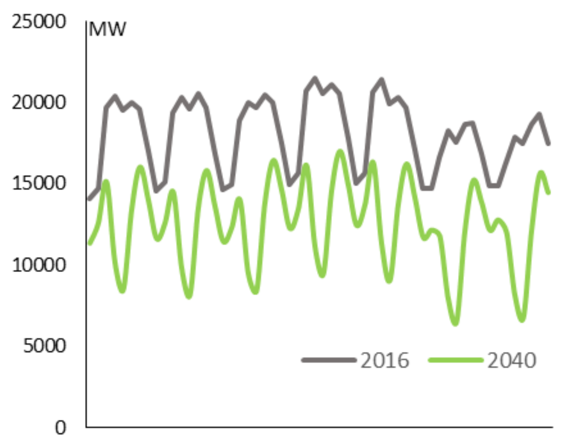


Figure 8-10: Simulated Nordic residual load in a representative summer week in 2016 and anticipation for 2040.

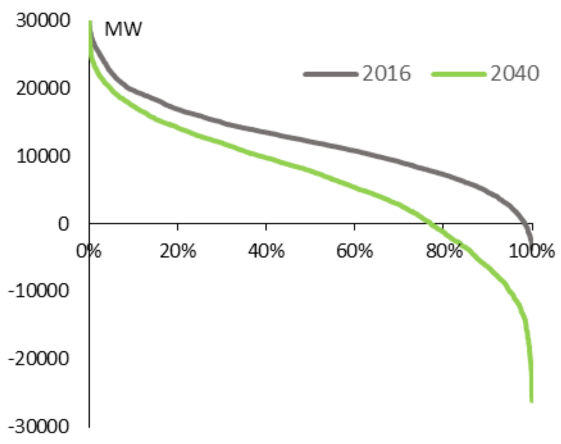


Figure 8-11: Duration curve for simulated Nordic residual load in 2016 and 2024 during the summer in the 5 years with the most inflow.

8.7 Grid development

There is a lot of grid development activity in the Nordic region with many national projects as well as projects between countries. We generally expect that adopted plans for new grid reinforcements and interconnectors will be developed. We also add more capacity if we see that this is technically and financially necessary. At the same time, we have somewhat adapted the placement of, for example, new generation, so that this is added to areas that already have good grid capacity. However, in the longer term, which is from 2030 and beyond, it is entirely possible that it will be profitable to build more grid capacity than what we have assumed in our scenarios.

Increased capacity in several cross-sections in the Nordic region

By 2020, we expect that Svenska Kraftnät (SvK) will complete the South-West link and increase the transmission capacity between bidding zones SE3 and SE4. Around 2020, we also expect that the capacity between SE2 and SE3 will be upgraded using reactive compensation. SvK and Fingrid are planning to build a third line between the countries in the north, and we assume that this will be constructed before 2030. They will also re-invest in one of the cables that links the countries in the south, FennoSkan 1, but we expect that the re-investment will be for the same capacity. Fingrid plans to reinforce their grid between the north and south with increased transmission capacity before 2030. For those who are more interested in grid development in Norway and Sweden, please refer to Statnett's grid development plan (Statnett SF 2015) and the Swedish grid development plan 2016-2025 (Svenska Kraftnät 2015).

Significant capacity growth between the Nordic region and Continental Europe – including the UK

The transmission capacity between the Nordic region[37] and the rest of Europe will increase quickly from today. Capacity two years ago was about 5 000 MW, today the capacity is about 7 000 MW, and in 2025 the capacity will be closer to 11 000 MW[38].

The development after 2025 is uncertain, and is dependent on the development in power prices in the various markets, among other things. Our fundamental assumption is that new interconnectors should be socioeconomically profitable. However, we have not implemented socioeconomic analyses of the profitability by expanding the capacity, as this would be too comprehensive, and since one of the key

[37] The synchronous area in the Nordic region, which consists of all of Norway, Sweden, Finland, and Eastern Denmark (DK2)
[38] These values do not include capacity between Finland and Russia, which is primarily only used for imports

objectives of this report is to provide a basis for precisely such analyses. We have still, based on simulated price differences and a rough calculation of profitability, presumed that another 1400 MW interconnector from Norway to the UK will be constructed by 2040. The price differences are greater in the High scenario, which is why we have assumed in this scenario that the interconnector will come in 2030.

Table 8-3: Increased capacity from the Nordic region 2017-2025

Interconnector		Capacity (MW)
NordLink	Norway-Germany	1400
NSL	Norway-UK	1400
Cobra	Denmark-The Netherlands	700
Viking Link	Denmark-UK	1000
Krigers flak	Denmark-Germany	600
HansaPowerBridge	Sweden-Germany	600

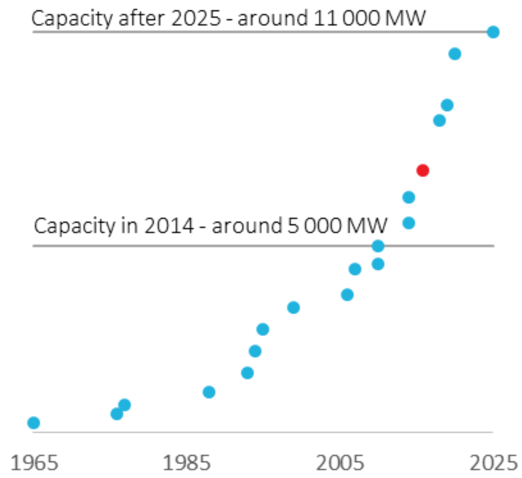


Figure 8-12: Historical development in capacity between the Nordic region and the rest of Europe. Does not include capacity to Russia.

Changes 2016-2020

NO3	SE2	→	400		
SE1	SE2	↔	900		
SE2	SE3	↔	700		
SE3	SE4	→	600	←	3900
SE3	SE4	↔	1200		
DK1	DE	→	900	←	1000
NO2	GB	↔	1400		
DK1	NL	↔	1400		
RU	FIN	→	350		
LIT	PL	↔	500		
DK2	DE	↔	600		

Changes 2020-2030

SE4	DE	↔	600		
DK1	GB	↔	1400		
SE1	FI	→	700	←	300

Changes 2030-2040

NO5	GB	↔	1400
SE2	SE3	↔	1200

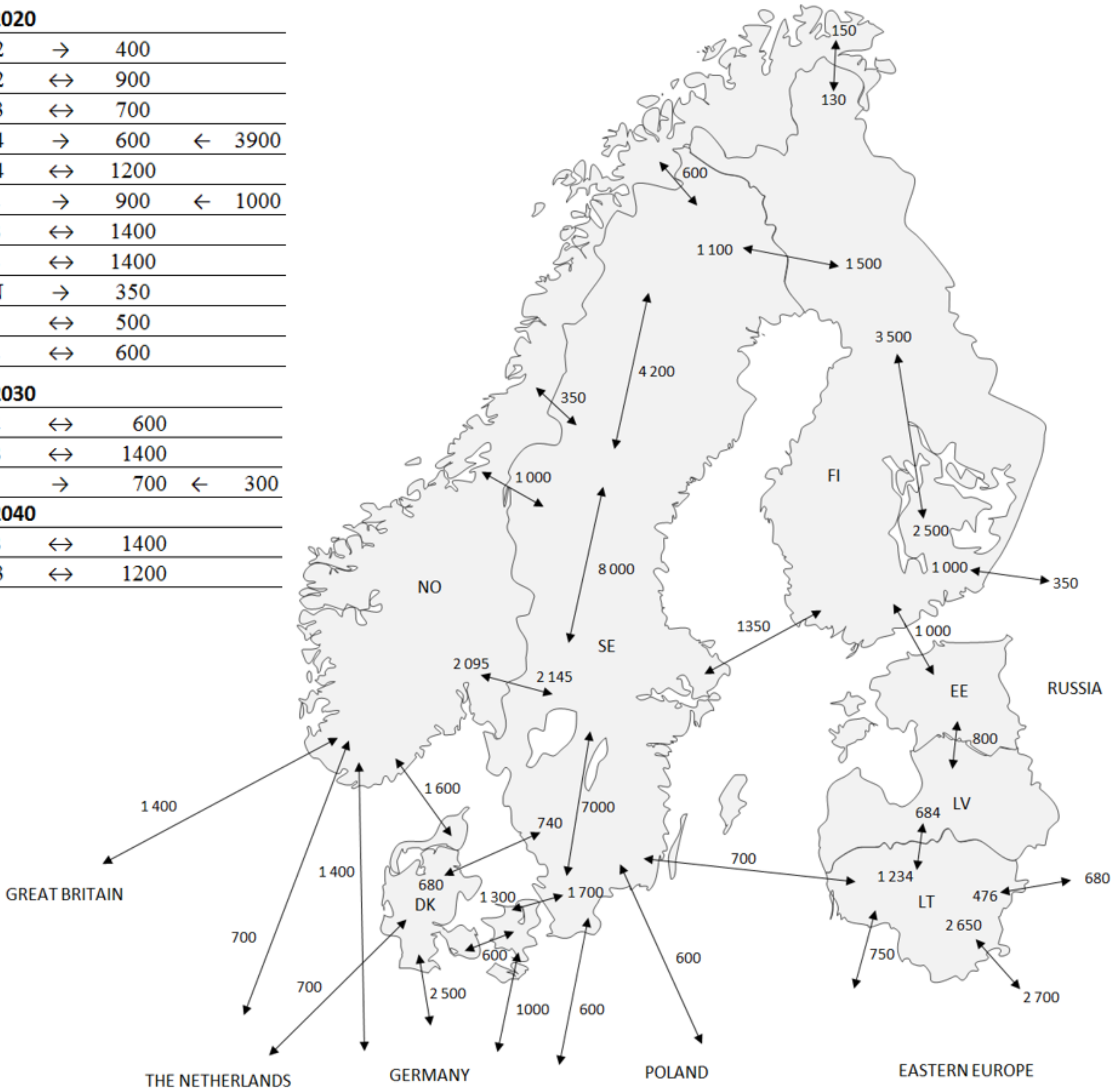


Figure 8-13: Our estimates for grid capacity going in and out of the Nordic region in 2020, as well as changes 2016-2020, 2020-2030 and 2030-2040.

Part III Analyses

In this section we will present results from model simulations and our assessments concerning average prices and price variation. We will address the most important uncertainties and present our range of uncertainty for future energy prices. We will look at the profitability of renewable and thermal generation in our various scenarios, and demonstrate how demand response and energy storage affect the system. Finally, we will discuss some issues that could potentially be crucial as we approach 2040 and beyond.

When we move the analysis horizon from 2030 to 2040, this increases uncertainty in a number of factors. This is also the first time we make fundamental model datasets for 2040. The analysis of 2040 nevertheless provides us with a useful overview of important trends and fundamental connections that, in our opinion, is valid in spite of the uncertainty.

9 Expected Average Prices

In the baseline scenario, average power prices will rise from the current level to € 45-50/MWh in Europe towards 2030. The prices remain stable until 2040, in spite of the fact that the share of renewables will exceed 60%. The increase is mainly caused by gradually rising prices for coal, gas and CO_2, and that many of the current thermal power plants will be closed down. This means that gas-fired power plants will more frequently set the price. Norwegian and Nordic prices will follow the prices on the Continent, but will be somewhat lower. The prices in Norway are about € 44 and 43/MWh in 2030 and 2040, respectively. All prices are listed in 2016 prices.

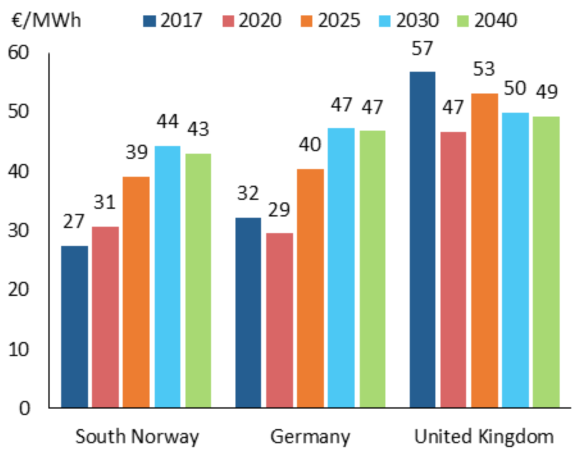


Figure 9-1: Simulated average power prices in the baseline scenario. The 2017 prices are equal to the future price contracts as of October 2016. All prices are real 2016 figures.

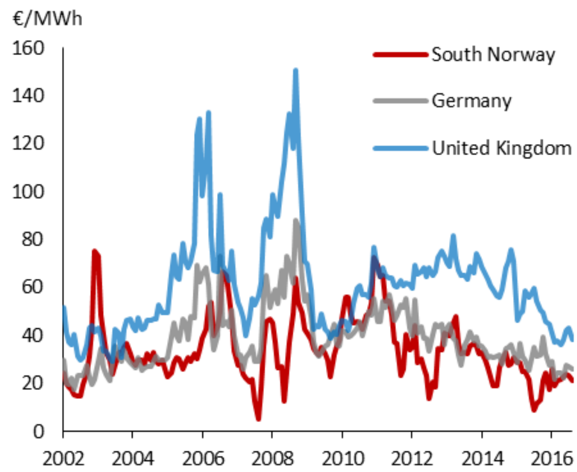


Figure 9-2: Historical monthly prices in Southern Norway, Germany and the UK.

We anticipate greater short-term price variation throughout all of Europe towards 2030-2040. We will come back to this in Chapter 10. Uncertainty and range of uncertainty in average prices and volatility are discussed in Chapters 11, 12 and 13.

9.1 Prices remain low in Continental Europe until 2022 – higher prices in the UK

We anticipate that the prices on the Continent will continue at the current level until 2020. Like today, the market will be characterised by surplus capacity, few and relatively low price peaks, and low earnings for thermal plants. Our simulations indicate that the price effect of new renewables and the shutdown of thermal power plants will mainly cancels each other. In 2020, we use the future contract prices for fuel and CO_2 in our energy market models. When we use these in simulations we see a weak increase in the prices from the current level.

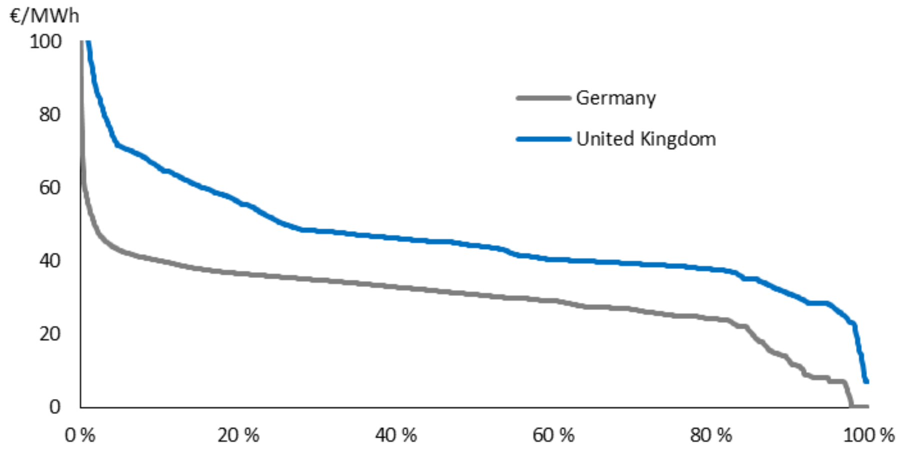


Figure 9-3: Simulated prices in Germany and the UK 2020.

We also expect stable prices in the UK, and in 2020 the price level in the UK will be about € 15/MWh higher than the level in Germany. In 2020, British carbon prices will be about € 20/tonne higher than the EU ETS price, and more than half of the difference in power price level can be attributed to the unique British carbon tax. Lower prices for gas relative to coal than what we presume in the baseline scenario will result in a price level that is more similar to that on the Continent. We also see that British prices are increasingly being influenced by the renewables development that has started. Towards 2020, this will have the isolated impact of reducing the prices somewhat more than on the Continent.

9.2 Increased prices towards 2025-2030 due to higher marginal costs and more natural gas

During the period between 2020 and 2025-2030, we expect a pronounced increase in the average power price on the Continent, despite increasing renewables. In our Baseline scenario, the average price in Germany will increase by nearly 70% from 2020 to 2030. The main reason for this is our anticipation of increased prices of natural gas, a higher CO_2 price and that gas-fired power plants will set the price during more hours once nuclear power, coal and lignite are phased out. The average price throughout the year is about the same level as the marginal costs in a CCGT power plant. The prices in the UK will remain at about the current level. This will cause the prices to converge in 2030 towards the level in the rest of Europe.

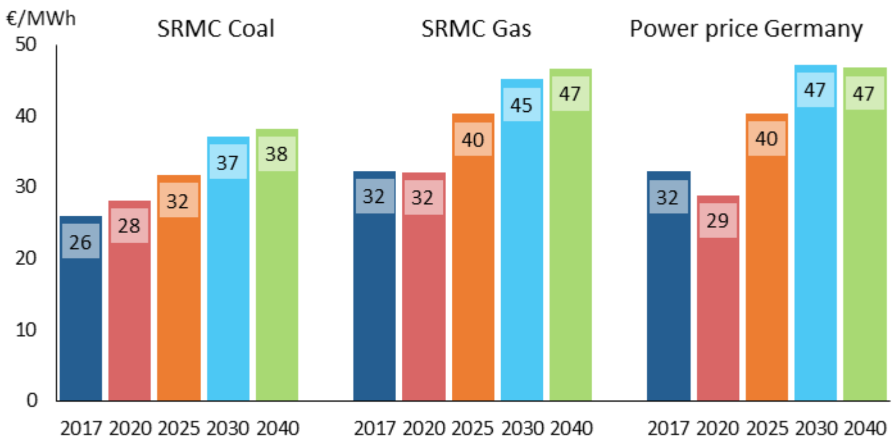


Figure 9-4: Marginal costs for a typical coal and gas-fired power plant and power price in Germany.

Figure 9-5 and figure 9-6 illustrate how key changes to our Baseline scenario affect the prices in Germany during the period from 2020 to 2030. The exercise of looking at the isolated effects of changes to generation, demand, fuel prices and CO_2 prices provides us with insight into how the different factors affect the prices. It is also important to emphasise that the development takes place in an interaction with considerable dependence between the various changes. For example, it is difficult to imagine that the renewables development we anticipate from 2020 to 2030 can take place without there being adaptations in the form of shutdown of thermal plants and demand response.

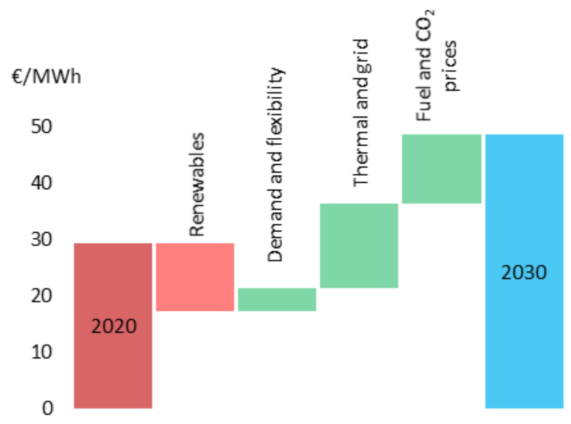


Figure 9-5: Gradual development in simulated prices from 2020 to 2030 in Germany.

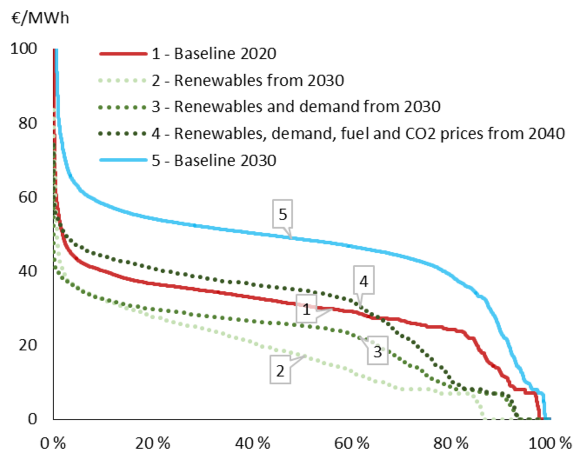


Figure 9-6: Duration curves for the various stages.

Seen in isolation, the development of renewables will result in a substantial decline in prices. This effect is somewhat alleviated by increased consumption. The next stage shows that the closing of coal, lignite and nuclear power plants will significantly increase the prices to 2030. This will happen through three mechanisms:

1. The phase-out of coal and lignite will mean that gas-fired power plants will more frequently set the price. This will increase prices because marginal costs in gas-fired power plants are higher than in coal power plants
2. Nuclear power and lignite are base loads with low marginal costs and a high number of full-load hours. The closing of such power plants will therefore increase power prices, especially during hours with a low price.
3. Overall, thermal capacity will decline. This results in a tighter margin during hours with few renewables and higher price peaks set by gas turbines, back-up plants and, in some cases, demand shedding.

Finally, increased fuel and CO_2 prices contribute to increasing the prices to the level we have for 2030. The increase in gas prices from 2020 to 2030 will amplify the effect of the first bullet point in the list above. The coal price will be less relevant towards 2030 in line with the phase-out of coal power, with the exception of Eastern Europe.

The fact that we do not achieve the same increase in average power price in the UK from 2020 to 2030 is primarily because gas power is already the price-setter for most of the time. Secondly, we assume that the unique British carbon tax will be gradually phased out towards 2030. Overall, the CO_2 cost that British power plants are required to pay will be about the same in 2020 and 2030

9.3 Stable average prices towards 2040 despite more solar and wind power

The development of both the power system and power prices far in the future become more uncertain. We discuss this in more detail in Chapter 16. However, the baseline scenario has reasonably stable average power prices on the Continent and in the UK during the period 2030 to 2040.

The prices of gas and CO_2 in our baseline scenario are essential to the power prices all the way up to 2040. The reason for this is that thermal power plants are still price-setting for much of the time, although solar and wind power account for more than 50% of total generation. In figure 9-4 we see that the average power price over the year is also close to the marginal costs in a gas-fired power plant in 2040. At the same time, there is a larger share of low and high prices. However, the effect of these will largely offset each other, so the overall effect on the average is minor. We will return to how this affects the variation in prices in the price volatility section.

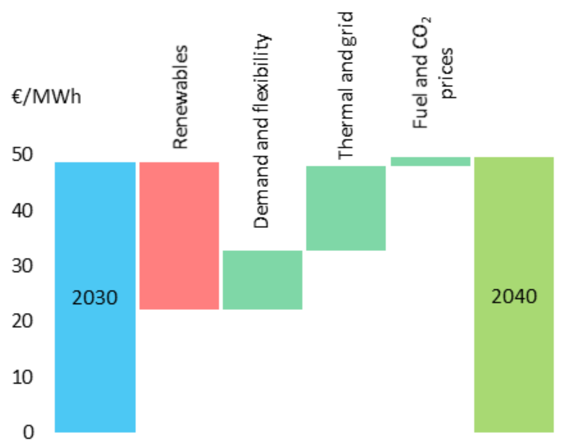


Figure 9-7: Gradual development from 2030 to 2040 for German average prices.

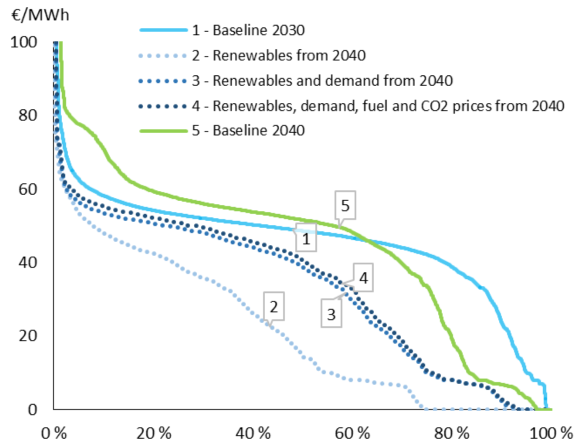


Figure 9-8: Duration curves for the various stages.

Figure 9-7 and figure 9-8 indicate how the various changes in fuel prices, the CO_2 price and the power system in general will affect the power prices on the Continent from 2030 to 2040 in the Baseline scenario. Compared with the changes for 2030, we see that renewables, seen in isolation, will drive the prices even lower. This is a result of faster development, and that the impact of more renewables becomes stronger as the share of renewables grows.

The next stage in the figure shows how increased demand and more flexibility counteract the effect of more renewables. For 2040, batteries and demand response will contribute to increased prices by boosting the prices during hours with high generation from renewables.

Nevertheless, the phase-out of thermal base load is the factor with the biggest impact on alleviating the price pressure from renewables. In the Baseline scenario, we have a net reduction of 100 GW in thermal generation capacity up to 2040 in EU10. This includes nuclear power in many countries, lignite in Germany and Eastern Europe, as well as the remaining coal power in Western Europe. This results in many more hours where peak load plants, such as gas turbines and diesel generators, set the price. This largely offsets the effect of several very low prices.

The marginal costs in gas-fired power plants are thus still important for the power price in 2040, but since these remain relatively stable from 2030 to 2040, they do not provide much explanation for changes in the power prices. However, we will see in the next chapter that the power prices in our Baseline scenario are just as sensitive to changes in the gas price in 2040 as in 2030.

9.4 Nordic prices will follow the price increase on the Continent

Nordic prices will be close to German prices in 2020
The average power price in Norway and the Nordic region generally follows the German price. The new interconnectors from Norway to Germany and the UK respectively reinforce this link. The same does a higher utilisation of the interconnectors from Sweden and Denmark to Germany.[39]

Although the prices in Norway and the Nordic region are strongly connected to the Continental prices, variations in inflow and temperature will result in periods with considerable deviations from the price level on the Continent. With the development of more intermittent generation there is a larger likelihood of low Nordic energy prices in the summer months for the next few years, compared to the price level in Germany and otherwise on the Continent. The effect will still be temporary with the shutdown of 15 TWh of Swedish nuclear power by 2020.

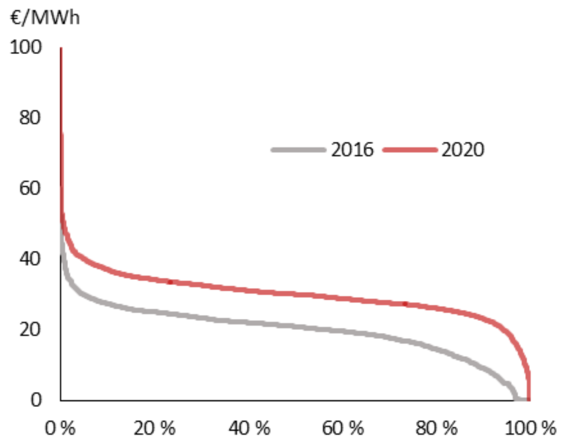


Figure 9-9: Simulated prices in baseline 2016 and 2020 for Southern Norway.

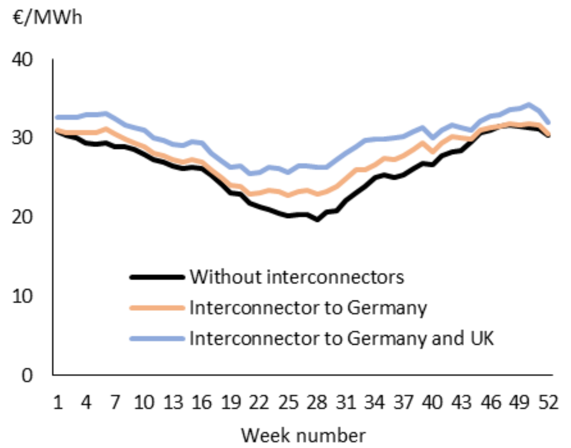


Figure 9-10: Average weekly prices in Southern Norway for 2020 with and without cables to Germany and the UK.

In Baseline 2020, the new cable to Germany will provide a modest increase with just over € 1/MWh in average prices in Norway and the Nordic region. The prices will increase the most during the summer months, especially during years with significant precipitation. The UK interconnector will result in a somewhat higher price increase of € 2-3/MWh in 2020[40] because the high British price level yields a high net export. These are contributing factors for the similar average prices in Germany and Norway in 2020. Overall, the price effect of the two interconnectors is just under € 4/MWh. This is somewhat less than what we have previously communicated[41], because we expect a more moderate Nordic power surplus and that the price level in Germany will be reduced. However, we do anticipate a greater price effect from the cable going to Germany after 2020 as a result of a higher price level and more intermittent generation in the Nordic region.

Nordic prices will increase towards 2025-2040 – but somewhat less than on the Continent
Rising prices on the Continent towards 2030 will also create higher prices in Norway and the Nordic region. From 2020 to 2030, the average price in Norway will increase from approx. € 30/MWh to

[39] Capacity on these interconnectors is currently significantly reduced as a result of internal bottlenecks in Germany.
[40] We have included the interconnector in our Baseline dataset for 2020, although the interconnector will not be operational until somewhat later.
[41] In the licence application for NordLink and NSL, we estimated that the two cables provided an overall capacity of 5 €/MWh in 2020.

approx. € 40-45/MWh. Towards 2040, Norwegian prices will decline by € 1-2/MWh driven by low prices during the summer months.

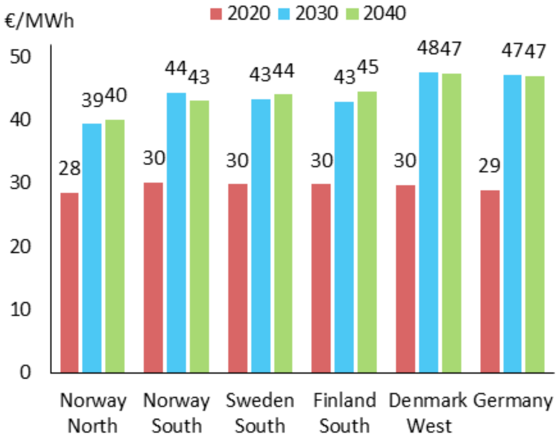


Figure 9-11: Average price 2020-2040 for selected areas in the Nordic region compared with German development.

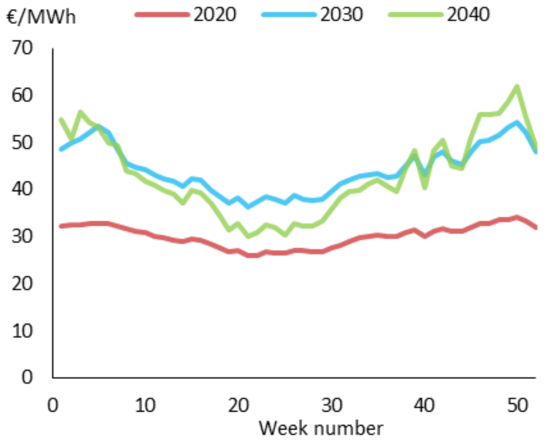


Figure 9-12: Average price per week throughout the year in 2020, 2030 and 2040 in Southern Norway.

Figure 9-12 shows that the price variation throughout the year increases significantly from 2030 to 2040. In 2030, the average prices during the summer are about € 10/MWh lower than winter prices. By 2040, this difference will increase to about € 20/MWh. The main reason is that the strong growth in intermittent generation, for example from solar power, creates low prices during the summer months. On the other hand, average prices will increase somewhat during the winter. The reason for this is that the number of instances where Norway and the Nordic region import continental price peaks when capacity is scarce will increase.

The low prices during the summer months will cause the average price in Norway to decline somewhat for 2040, despite the prices on the Continent and in the UK remaining stable. In 2030, the average price in Southern Norway is approx. € 2/MWh lower than German prices, whereas this will increase to € 5/MWh in 2040. Furthermore, the main reason why power prices will decline more in Norway than in the rest of the Nordic region is that Norway's surplus will increase from 9 to 18 TWh. However, the larger surplus will be somewhat offset by the addition of a new UK cable in 2040. As we explain in Chapter 11, this interconnector will increase Norwegian prices by approx. € 2/MWh in our baseline scenario, primarily through increasing the prices during the summer months.

The prices in the Nordic region are relatively similar in our data sets. We see a clear tendency indicating that the areas in the north will eventually have lower prices on average than in the south. The reason for this is the shutdown of nuclear power, as well as new southward interconnectors. The development of renewables in the surplus areas in the north, especially in Sweden, comes in addition. We will return to price differences in Chapter 15. Note that price differences internally in Norway and the Nordic region are not the primary focus of this analysis, but rather the trends in the market that affect prices and thus also price differences.

10 Price Volatility in Baseline Scenario

The short-term price volatility on the Continent has declined in recent years. We expect this trend to reverse after 2020, and to have gradually growing price variation all the way up to 2040, both on the Continent and in the UK. The main reasons for this are an increasingly larger share of renewable power generation, decommissioning of thermal plants and increasing fuel and CO_2 prices. Towards 2040 we see that storage will curb the daily variation in prices. At the same time, the growth in storage capacity is not sufficient to offset the price effect of major variations in wind power generation over longer time periods.

We also expect greater short-term fluctuations in the prices in Norway and the Nordic region. The reason for this is increased price contamination from the Continent through higher transmission capacity, a lower Nordic capacity margin[42] and more hours where nuclear power and variable renewable generation cover the entire consumption.

10.1 Reduced price volatility on the Continent in recent years

In the years towards 2008, most countries on the Continent had a much higher short-term price volatility than today. However, several factors have contributed to less price volatility after 2009:

- There has been a growing surplus capacity, particularly in Germany
- Solar power has slashed the prices during traditional peak hours in the period from March to October
- Lower fuel prices and a convergent cost between coal and gas power has resulted in a flatter supply curve

The development of renewables has, overall, led to less price variation. The reason for this is that major surplus capacity has reduced peak prices. The best example is Germany, where the massive deployment of solar photovoltaics has resulted in the lower prices during the middle of the day, contrary to some ten-fifteen years ago, when these hours usually had the highest prices. Solar power has also flattened the residual demand curve[43] , and has thus reduced the need to regulate thermal plants. More hours with extremely low prices and in some cases also negative prices, have done little to offset the trend towards less volatility. One reason is that the effect that extra low prices have on volatility declines when the price level drops. German prices have been cut in half from 2011 until today.

The short-term price volatility was previously very closely related to the variations in consumption throughout the day. Prices were highest during the middle of the day and low at night. This pattern is still apparent, but much weaker than before. At the same time, the impact from solar and wind power is more clear, particularly in Germany.

10.2 Increased volatility on the Continent from 2020 – a trisection of the market

We expect that the trend towards less price volatility on the Continent will reverse over the course of the upcoming years and that it will increase substantially after 2020. The below figures show duration curves for power price based on all simulated weather years for 2020, 2030 and 2040 in Germany and the UK. A steeper curve indicates that price variations are increasing. This is especially clear in the UK, where the actual price level changes less. Towards 2040 there will be a clear trisection of the market:

[42] The difference between available capacity in the overall power plant system and consumption.
[43] Consumption minus simultaneous contributions from renewables.

1. Top section: The price is set by demand response with high a willingness to pay, emergency power units and power plants with high marginal costs. This typically takes place in winter during hours with high residual demand.
2. Middle section: Normal thermal power plants will set prices – moderate contribution from renewables
3. Lower section: The price is set by renewables, nuclear power or demand response with a low willingness to pay - occurs when renewable generation is relatively high.

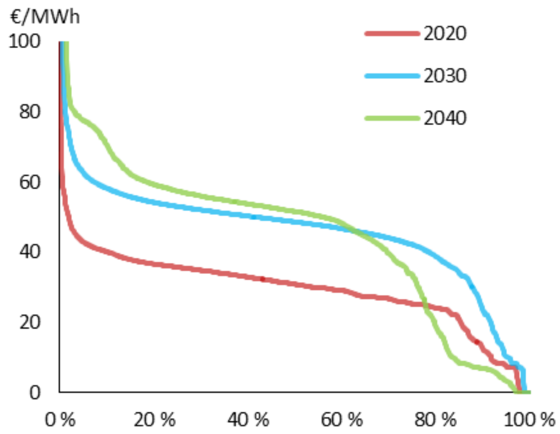


Figure 10-1: Duration curve for power price in Germany in Baseline.

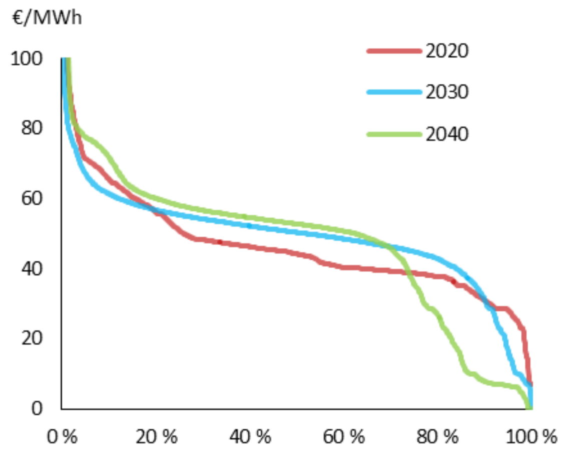


Figure 10-2: Duration curve for power price in the UK in Baseline.

More wind power, tighter margin and higher marginal costs result in greater prices variations

A wider deployment of renewable energy will cause greater short-term variability in residual demand, and the variations from hour to hour will gradually become more significant. The greater part of the consumption will be covered by renewables for a larger number of hours. This results in more hours with extremely low or even negative prices if the system with feed-in tariffs is not changed quickly enough[44]. And since already developed solar power has cut peak prices so much, the impact of further development will be far less than what we have observed thus far. Otherwise, Germany, the country with the most renewables by far, has so far been able to partially equalise the variation in renewable generation through import and export. It will become more difficult when all countries have more renewables, and there is also a significant correlation in the renewable generation in large parts of Europe. This pushes the prices even further down during hours with high renewable generation.

More renewable generation results in more surplus capacity and less utilization for both coal and gas power. Even today, the earnings from thermal power plants are much too low to trigger investments, and are in many cases also insufficient to cover the full operating costs for existing power plants. We therefore have a net reduction in our baseline scenario of just under 100 GW of thermal capacity towards 2040. This does result in more price spikes, which is necessary in order for the remaining power plants to earn a sufficient profit, and so that it will be profitable to build new gas-fired power plants[45]. Exactly when the major downscaling of overall thermal generation capacity will take place is,

[44] "Feed-in" tariffs provides the power plant owner with a guaranteed surcharge on the price per produced unit regardless of the price in the market. The power plant owners therefore do not have an incentive to stop generation when the price is zero. They will not stop until the price is negative and the same amount as the tariff.

[45] As discussed in Chapter 7, we presume that capacity markets only cover parts of the income of thermal power plants. This implies that a significant share of earnings must come from the ordinary power market.

however, a key uncertainty that we will return to in Chapters 11 and 14. Although this takes place gradually in our baseline scenario, it could also happen earlier.

Even though solar and wind power is becoming an increasingly important driver for price volatility, our analyses show that marginal costs for thermal power plants, and in particular different types of gas power, will still be quite significant for price formation all the way until 2040. Higher marginal costs result in greater differences between the hours with prices down towards zero and the hours when normal CCGT power plants are setting the price. We can clearly see this in the figures above where the middle section of the duration curves, when gas power sets the price, becomes higher after 2020. Increased gas and CO_2 prices will also have the greatest impact for gas turbines with low efficiency that set the prices during hours with low renewable output, typically in the winter.

Increased volatility is primarily caused by successive days with high or low prices
Figure 10-3 shows how the short-term price volatility in Germany has developed historically over the last 15 years, and how this will develop further to 2040 in our scenario. The curves show how the trend towards lower volatility will reverse in Germany. This is repetitive for all countries on the Continent and the UK. At the same time, the curves show that the volatility in our baseline scenario will not increase beyond the level we had during the period from 2005-2010.

We have two measures for short-term price volatility. Either calculated as average absolute difference hour by hour compared with the average price for the relevant day or the relevant week. The measure of volatility during the day largely detects variations that are caused by changes in consumption, but also eventually the contribution from solar power. Until now, short-term price volatility has mainly been driven by this.

The other measure detects variations that have a longer duration. These are primarily driven by uneven contributions from wind. As the share of wind power increases, this will result in periods with low and high prices that last from less than one day to more than one week. The curves in Figure 10-3 clearly show that the main reason for the prices varying more than today is driven by this type of variation.

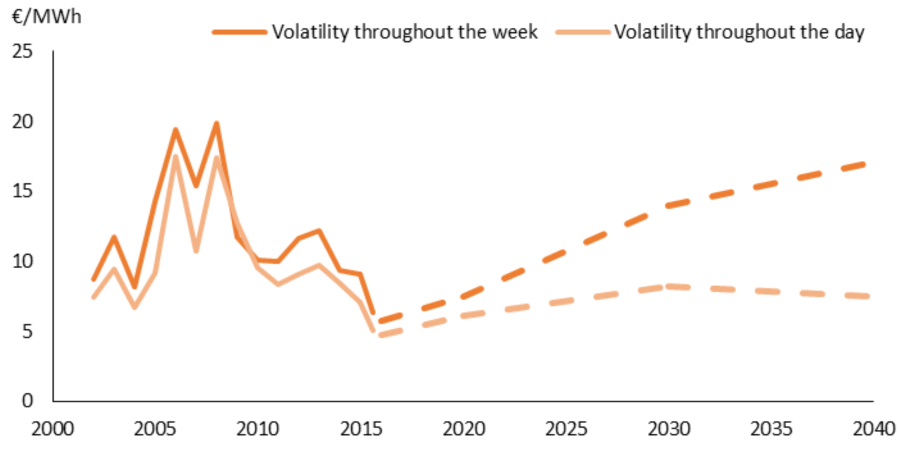


Figure 10-3: Price volatility measured throughout the day and week for Germany. Historical prices 2002-2015 and simulated prices 2016-2040 in the Baseline data sets. The price volatility throughout the week is calculated by taking the average deviation for prices hour by hour in one week and then the average from every week.

Regarding the traditional volatility throughout the day, this also increases somewhat until 2030. The cause is both a higher price level as a result of higher marginal costs and the transition to gas, but also additional price peaks as a result of tighter margins. Over the even longer term, however, we see that this trend will reverse, as the contribution from batteries and storage is considerable. Batteries, for example, are effective in equalising prices over shorter periods. This is why long-term price fluctuations will be more important for power prices than variations throughout the day in consumption and solar power generation, as a result of uneven contributions from wind.

Winter Prices vary significantly – more stable during summer
With the development in renewable energy in recent years, we have seen a trend where the short term price volatility is greatest in wintertime, during the period from November to February. This is because, statistically, there is greater and more variable wind power generation in this period, in addition to low solar power generation. This will yield more hours with very low prices, but also more price peaks, although they have been significantly reduced in recent years. In parallel, more generation from solar power and less wind power, means lower price peaks and fewer hours with extra low prices in the summer. Towards 2030 and 2040, our simulations show that the trend with more price volatility in the winter will be stronger. We see this clearly in the duration curves below, where the curves for winter prices show an increasingly greater variation than summer prices, as we approach 2040. As battery capacity increases in our Baseline scenario, this also contributes toward a larger difference between summer and winter. This is because the batteries are, to a greater extent, able to even out the variations in solar power generation during the summer than the larger and more long-term variations from wind power in the winter.

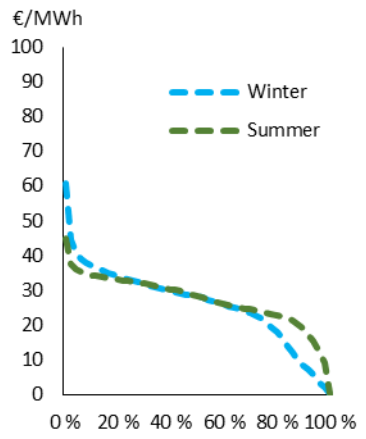


Figure 10-4: Duration curve for power price in Germany, Baseline 2020.

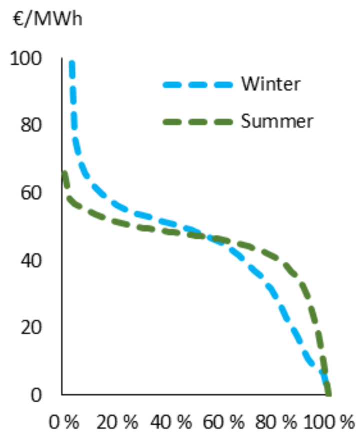


Figure 10-5: Duration curve for power price in Germany, Baseline 2030.

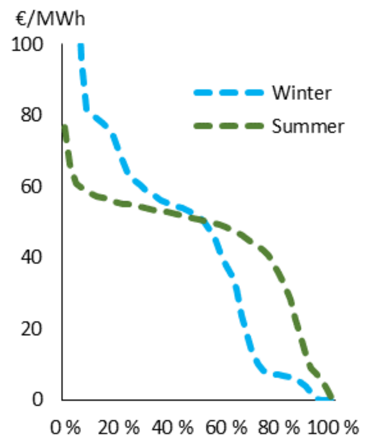


Figure 10-6: Duration curve for power price in Germany, Baseline 2040.

A wider deployment of storage and demand response reduces volatility – does not prevent growth
Our analyses and simulations show that there is a need for considerably more flexibility from consumption and various forms of storage in order for the renewables development to continue in the scope we presume. In our baseline scenario, flexible consumption and storage therefore has an increasingly important role towards 2040. Consumption both disconnects in situations of scarcity and consumes more in hours where renewables cover all or large parts of the consumption. Batteries with considerable output largely offset short-term variations from solar power generation. We have also presumed growth within different types of large-scale storage, which contributes towards evening out greater and more long-term variations in wind power. In isolation, both result in less price variation.

Figure 10-7 shows the duration curve for price in the anticipated 2040 scenario compared with a simulation where we have removed flexibility from storage and consumption. The sensitivity without flexibility is obviously not a relevant scenario in and of itself, but it illustrates the importance of this in our baseline scenario.

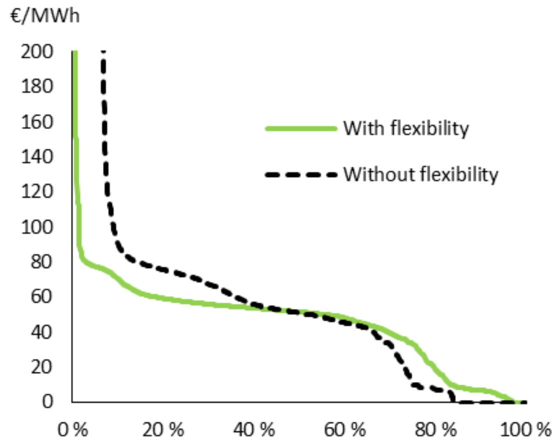


Figure 10-7: Duration curve for power price in Germany in Baseline 2040 and a version where we removed all demand response and storage.

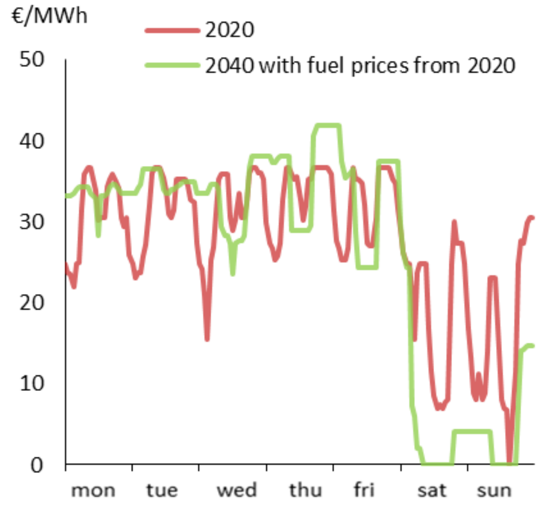


Figure 10-8: The German power price is a random summer week in Baseline 2020 as well as in Baseline 2040 simulated with fuel prices from 2020.

At the same time, we believe it is improbable that storage and more flexible consumption can prevent the overall price volatility from increasing over time. Figure 10-8 illustrates how price volatility in a random summer week changed from 2020 to 2040. We have simulated with the same fuel price in 2040 as in 2020, in order to more clearly illustrate the point. At the start of the week in question, we see that the price is almost flat in 2040 despite considerably more renewables. In the weekend, when the generation of renewables is far greater compared with 2020, the price drop is nevertheless both greater and of a longer duration.

We have conducted several sensitivity analyses for both 2030 and 2040 where we have included considerably more battery capacity and other forms of flexibility than what we have presumed in the Baseline. The simulation results show that it may be technically feasible to avoid an increase in volatility, if only we have sufficient levels of flexibility with low operating costs. At the same time, we see that there will then be a very significant surplus capacity in flexibility for large portions of the year that offset the variations in price. The simulated profitability of investing in new batteries or other forms of flexibility is then so low that it is most likely not financially feasible. Towards to 2040, there will furthermore most likely be a need for large volumes of consumption that occur in just a few hours each year, in order to avoid zero prices during hours with the highest renewables generation. Overall, this yields increased price volatility as the share of renewables increases.

10.3 Price volatility increases in Norway and the Nordic region as well

We also anticipate increased short-term price volatility in Norway, Sweden and Finland towards 2030-2040. One important reason is that intermittent generation will grow significantly, whereas nuclear power and thermal will be shut down. Increased volatility on the Continent after 2020 will also affect Norwegian prices. We will also have greater transmission capacity between the parts of the Nordic region where hydropower is dominant, which means Norway and Northern Sweden, and the rest of the Nordic region, the Continent and the UK. In sum, this means that interaction between the output situation in the Nordic region and the prices on the Continent, hour-to-hour, will be more important.

In Norway, the prices are generally stable over shorter periods, such as a days or a week, whereas the level varies over time with inflow and the share of intermittent generation. Short-term volatility caused by prices being either lower or higher than the water values in the dispatchable hydropower plants is therefore largely imported from the neighbouring countries. This means that the price changes on the Continent in our low and high scenario spread to Norway.

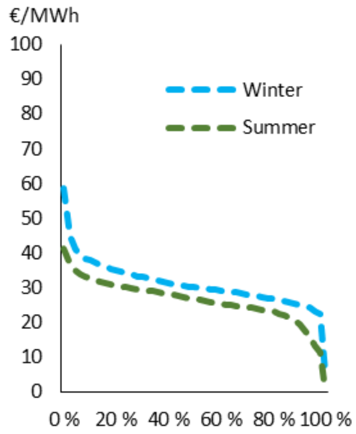


Figure 10-9: Duration curve for power price in Norway, Baseline 2020.

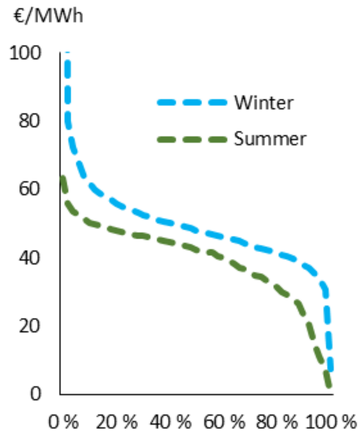


Figure 10-10: Duration curve for power price in Norway, Baseline 2030.

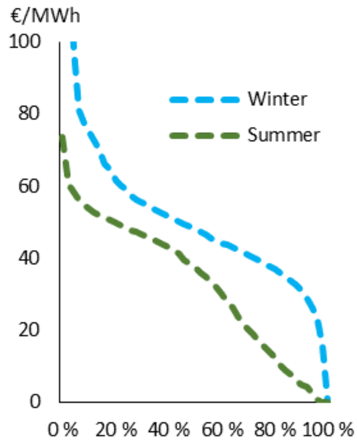


Figure 10-11: Duration curve for power price in Norway, Baseline 2040.

Declining market share for dispatchable hydro power in the Nordic market

What is normal today is that the price in Norway is set by the marginal values of stored water in dispatchable reservoir-based power stations. The duration curve below shows how often our simulated power price in 2016 and 2040 for Southern Norway deviates from the water value in the same hour. We see that simulated prices in 2016 deviate significantly from the water value during relatively few hours. Towards 2040, however, we see that the number of hours where the price deviates from the marginal value of stored water increases considerably. This applies both to hours where the price is higher and lower than the water value. As the water value is stable through the week, this results in a significant increase in price variation over the short term.

There are multiple weaknesses in our model which cause insufficient variation in simulated prices. It can be observed that the prices actually deviate from the water value more frequently in the real market than in our model, and also that there is a greater variability in individual water values among different reservoirs. Price variation due to the latter is not captured in figure 10-12. The development towards 2040 will lead to greater differences in water values for reservoirs with different degree of regulation. This, in turn, will increase price volatility more than is shown in the simulations. As regards hours where the price deviates from the marginal value of stored water, the simulations particularly understate the number of hours with imported peak load prices from neighbouring countries. Nevertheless, they show a clear trend toward more price variation as a result of direct imports of both low and high prices, as well as intermittent generation within the Nordic region setting the price.

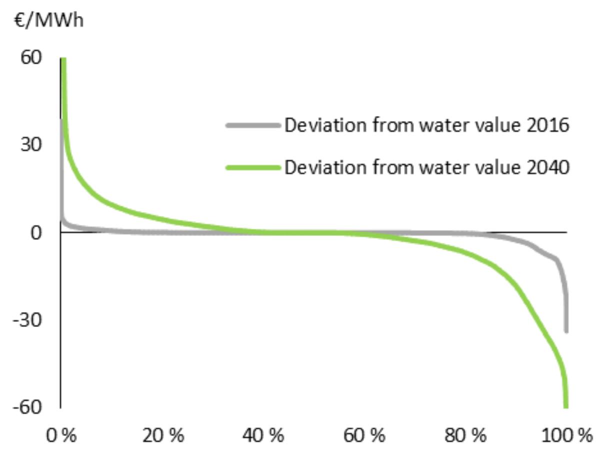


Figure 10-12: The figure shows the deviation between the simulated power price in Southern Norway and the water value in the area hour-to-hour in 2016 and 2040. Positive values show hours where the power price is higher than the water value, and negative values show hours where the price is lower than the water value. In hours with zero deviations, the water value sets the price directly.

Scarcity in winter leads to import of European prices

Scarcity in the winter is an important cause of increased price volatility. This means that installed generation output on the Norwegian and Nordic side will not be sufficient for full export on all channels, and simultaneously covering internal consumption. This typically results in brief price spikes approaching the Continental prices and thus less export. This can already be observed in many days during the winter, and we also expect this to happen more frequently and yield even higher price spikes in the future:

- Increased transmission capacity out of Norway results in increasing demand for Norwegian power
- The decommissioning of nuclear power plants increases the Swedish demand for Norwegian generation
- More wind power, small-scale hydro and consumption growth in Norway will, in isolation, weaken the output balance
- European price peaks will be significantly higher towards 2030 and 2040

Figure 10-13 and figure 10-14 show the effect of this in the same simulated weather week in 2020 and 2040. In 2020, Norwegian prices rise with the German prices in several high-load hours, but the effect is moderate because the price peaks in Germany are rather low. When the price spikes in Germany and other neighbouring countries increase, this has a direct impact on Norwegian prices. In our scenario, shedding of industry loads in Norway will set the price in hours with the highest prices. Load shedding prices for Norwegian industry will then be a price ceiling. There is uncertainty linked both to which prices that will lead industry to shed and how often this will happen. The latter e.g. depends on how often price peaks occur around us, and investments in output and other types of flexibility in Norway.

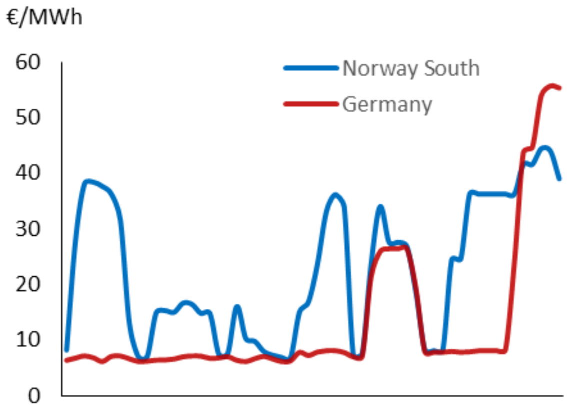


Figure 10-13: Simulated prices in a random winter week in 2020. Periods with high consumption will yield brief price peaks in Norway. Peak prices in Germany are price-setting.

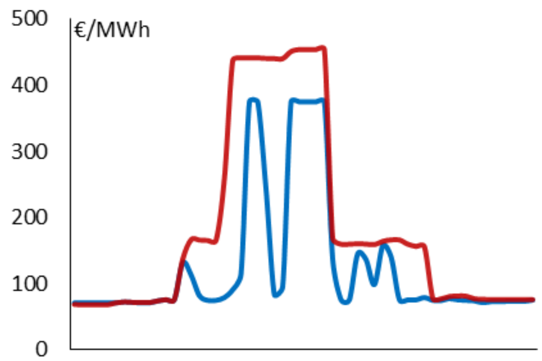


Figure 10-14: Simulated prices in a random winter week in 2040. Periods with high consumption will yield brief price peaks in Norway. Peak prices in Germany or shedding of industry sets the price.

Variable renewable energy, nuclear power or imports settle the price more frequently

The number of hours where intermittent generation, nuclear power or cheap imports yield low prices will increase considerably towards 2040. These hours primarily occur in the summer months when consumption is low and the contribution from non-dispatchable hydropower is also high. This normally results in a short-term price drop, often down toward zero, but towards 2040, the periods will last longer. We also see that more solar power results in price dips during the day even in Norway and Sweden, although the overall power generation from solar power is modest. Figure 10-15 shows prices for the same summer week in 2020 and 2040. In 2020, low water values set the price on weekdays, but price dips down toward the load shedding price for nuclear power occur during the weekend, when consumption is lower. In 2040, however, intermittent generation is so high that the price is set by nuclear power, whereas in hours with low consumption or considerable wind, the price is set by intermittent generation within the Nordic region and the price is zero.

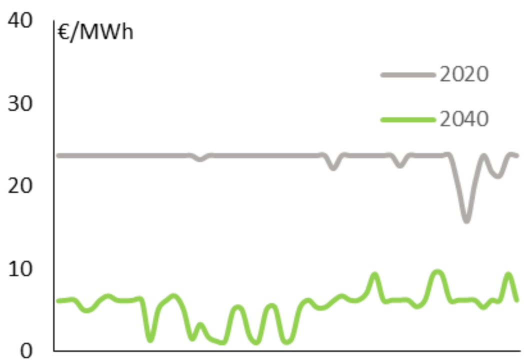


Figure 10-15: Prices in Southern Norway from random summer week in 2020 and 2040.

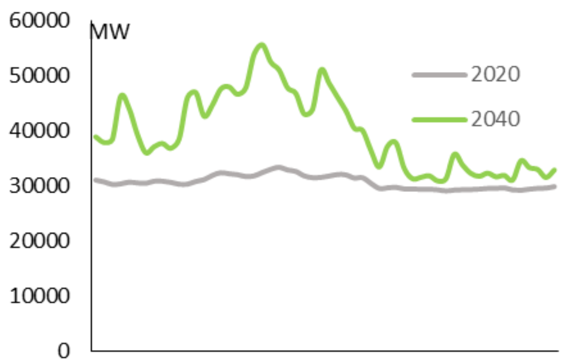


Figure 10-16: Non-dispatchable generation in the Nordic region in the same week.

Hours with low energy prices on the Continent primarily occur in the winter. They have a lesser impact on the Norwegian price, since dispatchable hydropower normally sets the price in these periods. Nevertheless, we see that the number of hours with extremely low prices will increase in the winter, compared with 2040. This happens when intermittent generation in the Nordic region and imports cover the entire consumption. Figure 10-17 and figure 10-18 illustrate the point with the same weather week simulated in the 2020 and 2040 datasets. In 2020, the water value sets the price throughout the week, whereas in 2040, Norwegian prices follow the German prices down during most hours. This is thus not the normal, but something we see happening more and more often.

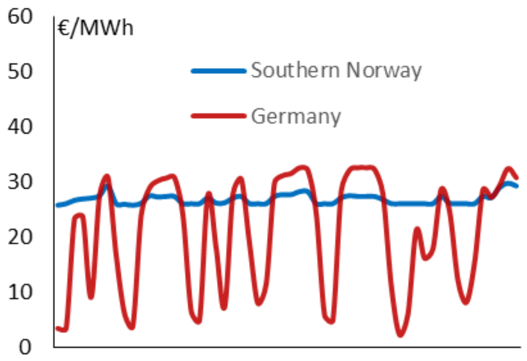


Figure 10-17: Prices in Southern Norway and Germany from a random winter week in 2020.

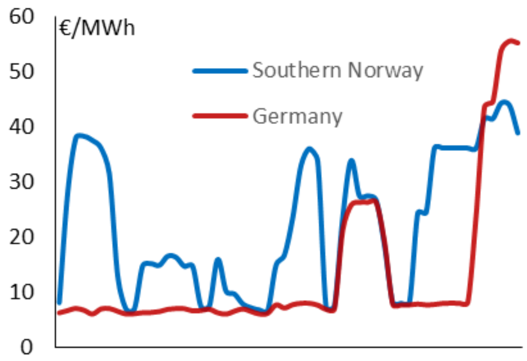


Figure 10-18: Prices in Southern Norway and Germany from the same winter week in 2040.

Increased energy output and pumped storage hydro power may curb variation in Norwegian prices
Larger fluctuations in power prices make it more profitable to invest in more output and new pumped storage hydropower plants in the hydropower system. This may also contribute to more demand response and possibly also make it profitable to install batteries. Overall, this may suppress price volatility, but it is uncertain how much. In our baseline scenario, we have a certain increase in demand response e.g. through substantial flexibility in consumption from electric vehicles. However, we have neither presumed any major changes in capacity in the hydropower system nor any new pumped storage hydropower plants. This is discussed in more detail in Chapter 14.

11 Key Elements of Uncertainty

The future development of power prices is characterised by significant uncertainty, both as regards average level and volatility. In this chapter, we show a selection of sensitivity analyses in order to illustrate how changes to key assumptions affect power prices in Europe and the Nordic region.

- Fuel and CO_2
- The share of renewables on the Continent
- Capacity margin
- Storage and flexibility
- Power balance and cables in the Nordic region

The sensitivities we present in this section will obviously not cover all uncertainty in our baseline scenario, nor is this achievable. The range and scope of uncertainty will be discussed in further detail in Chapters 12 and 13.

Sensitivities are useful in order to illustrate the uncertainty in important assumptions surrounding an operating point. The results should also be interpreted with a measure of caution. Firstly, the results depend on the point of departure. The magnitude of the effects can therefore not automatically be generalised to apply for other scenarios. Secondly, changes we add may lead to other adaptations. This is especially relevant when changes are made that, in isolation, have a significant impact on the profitability of other investments in the power market. One example is the introduction of batteries. A substantial change in battery capacity based on what we assume in the baseline scenario will affect the profitability of thermal plants and other types of flexibility, and therefore yield a different balance in the power market.

11.1 Thermal plants will still set the price towards 2040

There is significant uncertainty surrounding future fuel and CO_2 prices (discussed in Chapter 6). At the same time, they have a significant impact on power prices, and are therefore perhaps the most important uncertainty factor for the development of power prices towards 2040. For example, a hypothetical instance where the prices of coal, gas and CO_2 remain unchanged from today to 2040, will reduce the average German price from approx. 50 to just above 30 €/MWh in 2040.

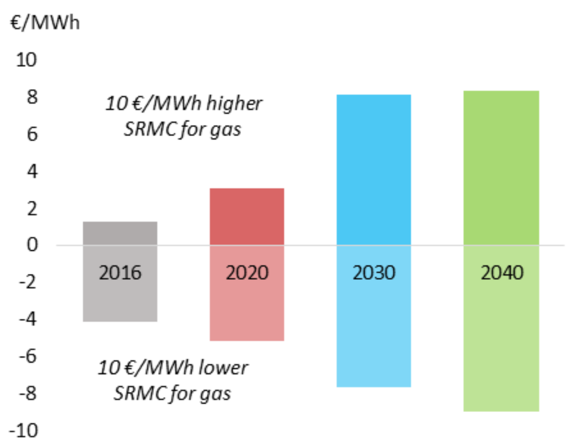


Figure 11-1: Change in German average price by isolating the effect of a 10 €/MWh changed marginal cost for gas.

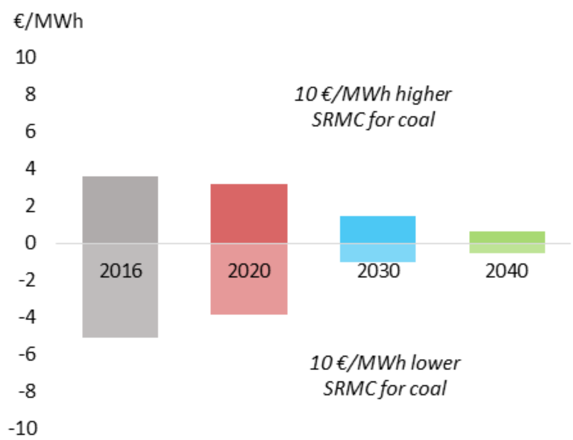


Figure 11-2: Change in German average price by isolating the effect of a 10 €/MWh changed marginal cost for coal.

The above figures show how much a net change of € 10/MWh in marginal cost for gas power and coal power changes the German power prices in 2016, 2020, 2030 and 2040. It may seem counterintuitive that power prices appear to be less sensitive to changes in fuel prices today and in 2020, compared with 2040. The reason for this is that similar marginal costs between coal and gas, along with considerable opportunities to shift generation between coal and gas-fired power plants, yield less sensitive power prices up to 2020. However, if the marginal costs in both coal and gas power were to increase by € 10/MWh, the power prices will experience a corresponding increase.

As coal power is being shut down, the sensitivity to changes in the gas price will increase. In both 2030 and 2040, a € 10/MWh change in marginal costs for gas will result in an approx. € 8/MWh change in average power price throughout the year. In 2030 and 2040, a € 10/MWh change in marginal costs for gas power results in a change in the gas price of about 30%. This is well within the range of uncertainty that we use in our low and high scenarios. The quota price will have to increase by € 33/tonne, or more than 100% from the expected level, in order to see a corresponding increase in marginal costs. In our baseline scenario, coal power only has a marginal effect on power prices after 2030. An exception is some parts of Eastern Europe where the share of coal will last longer.

France plans to introduce a national price floor of € 30/tonne CO_2 in 2017. However, this measure will have little impact on power prices in France and in neighbouring countries. This is because the country has few coal and gas-fired power plants, and because the tax will only apply to coal power based on the proposal as of September 2016. On the other hand, a similar measure in Germany would have a significant impact on power prices on the entire Continent and in the Nordic region. Our simulations indicate that a price floor of € 30/tonne in both France and Germany would increase the power price on the Continent by € 3-5/MWh and € 2-3/MWh in the Nordic region. So far, however, German authorities have rejected the French initiative.

The average power price in Norway and the Nordic region is largely determined by the level on the Continent. This means that Norwegian prices are nearly as sensitive to changes in fuel and CO_2 prices as in Germany. However, towards 2040, Nordic prices will become somewhat less sensitive to changes in marginal costs for gas-fired power plants than on the Continent. This is because Nordic prices in the summer months are to a greater extent on par with the low price hours on the Continent. They are less dependent on the marginal costs in gas-fired power plants.

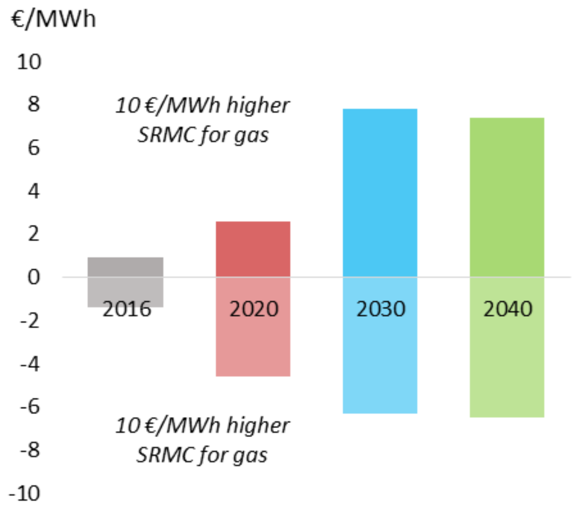


Figure 11-3: Change in Norwegian average price by isolating the effect of a € 10/MWh changed marginal cost for gas.

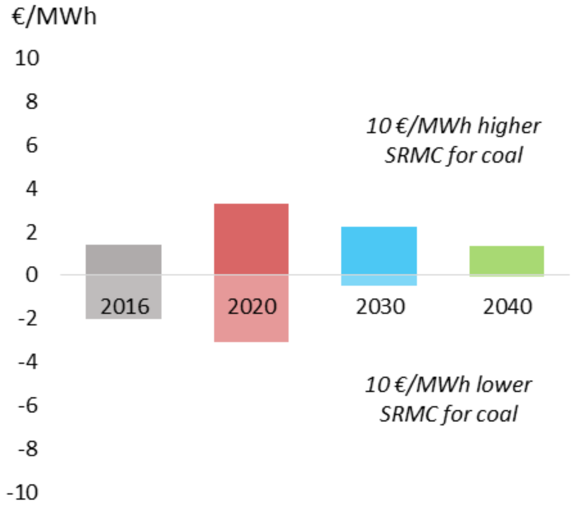


Figure 11-4: Change in Norwegian average price by isolating the effect of a € 10/MWh changed marginal cost for coal.

11.2 Renewables increasingly impact prices

We expect that the share of solar and wind power on the Continent will increase significantly up to 2040. At the same time, the pace of this development is uncertain. Most external analyses that examine how the EU can achieve its long-term emission goals assumes the share of renewables in the energy sector to be between 50-90% by 2050. Our baseline scenario has 60% in 2040, of which solar and wind power constitute 50%. We have conducted simulations where we reduced and increased the development of solar and wind power on the Continent by 10% in 2030 and 2040. This corresponds to approx. 75 TWh in 2030 and 120 TWh in 2040. The Nordic region was kept at the same level as in the baseline scenario.

In 2030, changes in the share of renewables will primarily affect hours with the lowest prices. More renewables create both lower average prices and greater variation as a result of more hours with very low prices. The hours with the highest price will not change significantly. The effects in 2040 are naturally greater, both because the share of renewables is higher and because a 10% change represents many TWh. Again, the effects are largest during hours with the lowest prices, but now there are also changes in the hours with the highest prices. However, these results should not interpreted literally as such significant price changes will affect other variables, for example the development in the thermal power plant stock.

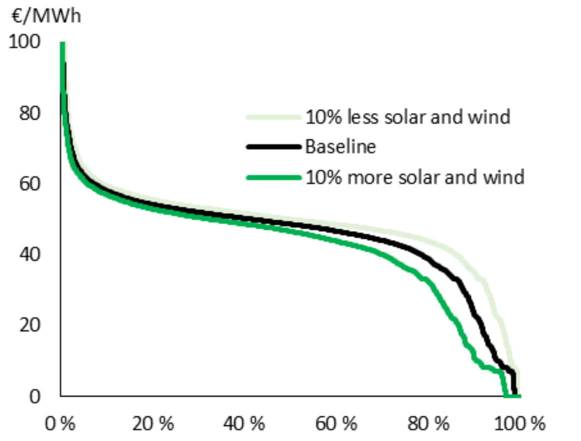


Figure 11-5: Price duration curve for Germany in 2030 with 10% more or less installed capacity from solar and wind power.

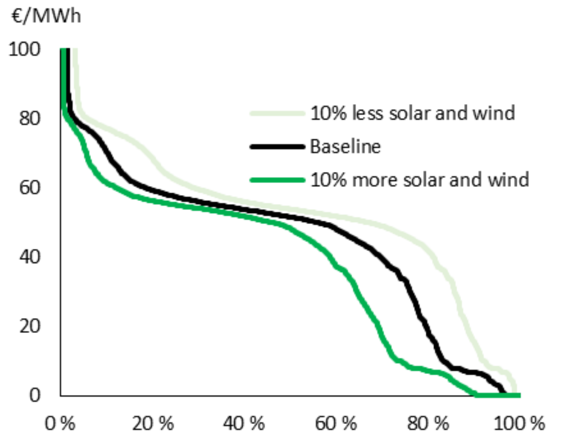


Figure 11-6: Price duration curve for Germany in 2040 with 10% more or less installed capacity from solar and wind power.

The below curves show how more renewables on the Continent will influence Norwegian prices. All factors on the Nordic side are unchanged from the baseline scenario. We see that less renewables will have a bigger impact by increasing Norwegian prices than more renewables will push the prices down. Furthermore, the effects are not symmetrical. Less renewables will largely increase the lowest prices, whereas more renewables has a more even impact on all prices.

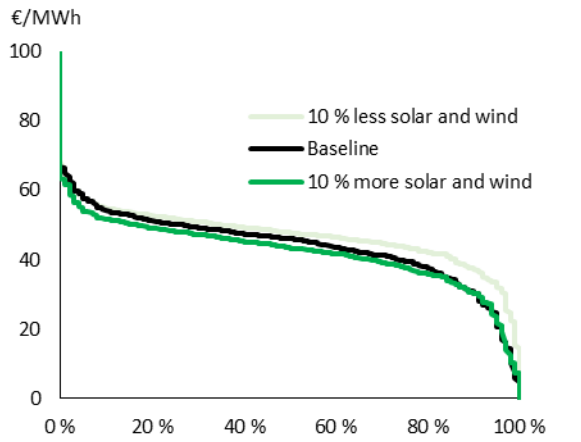


Figure 11-7: Price duration curve for Norway in 2030 with 10% more or less installed capacity from solar and wind power.

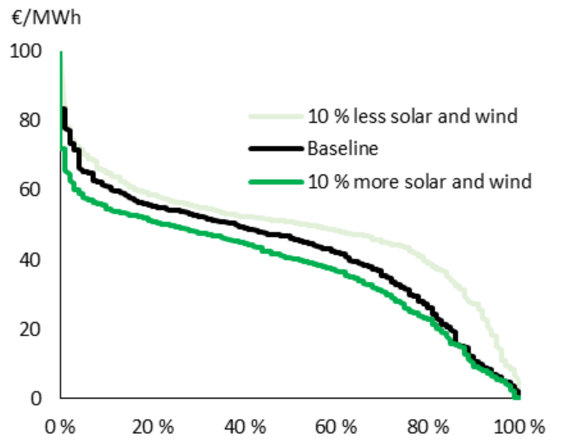


Figure 11-8: Price duration curve for Norway in 2040 with 10% more or less installed capacity from solar and wind power.

11.3 Capacity margin and generation capacity mix

In the Baseline scenario, we presume that the current surplus capacity in the Continental market will gradually diminish. This entails that price spikes will eventually occur, which will provide thermal plants with substantial earnings from existing day-ahead markets and markets for balancing power. We also expect some earnings from capacity markets. We therefore do not have a pure long-term market balance that is only driven by supply and demand in existing power markets. However, this is associated with many uncertainties.

On the one hand, there could be a tighter Continental market with more and higher price peaks, if there is a more rapid downscale of the thermal generation capacity. On the other hand, there could be fewer and lower price peaks if, for example, Germany[46] changes its position and introduces a capacity market, and that capacity markets both in Germany and in the rest of Europe contribute a larger share of the necessary income for the power plants that participate in the power market, than what we have assumed. In addition to this, there are several other factors that contribute to uncertainty concerning capacity margin and price peaks:

- When the capacity margin is smaller, unexpected events can result in more hours with very high prices than what we can see in our model simulations.
- Other volumes and costs for demand response and storage could change the results.
- Investment decisions for new power plants are made many years before commissioning. Before the power plants are even operational, incidents could occur on the consumption side, within storage and the development of renewables that will affect price formation during the hours with the highest prices.

The future capacity margins are associated with considerable uncertainty. We will restrict ourselves to a review of two sensitivities here. In one, we removed the price peaks in the Baseline data set for 2040 by adding more thermal plants. Without price peaks beyond the marginal costs of CCGT, the average price drops from € 49 to 43/MWh in 2040 in Germany, and there is significantly less price volatility. It is not very probable that a situation with this much surplus capacity over time would occur. At the same time, it illustrates a scenario where the power plants receive more income from capacity markets, or a situation with considerable surplus capacity like today. The vast annual growth in renewables increases the probability of lasting surplus capacity in the market.

In our baseline scenario, installed coal power capacity in EU10 will drop from 100 to 55 GW between 2020 and 2030. If we keep the same volume of coal power in 2030 as in 2020, this will reduce the price by € 4-5/MWh compared with the baseline during the hours where normal thermal plants set the price.

11.4 Storage and flexibility

We clearly see that storage and different types of flexibility on the consumption side will be key in a power market with a significant share of solar and wind power. In Chapter 14, we will take a closer look at the interaction between storage, demand response and renewables. We will illustrate a simple sensitivity where we have doubled the volume of batteries in our base data sets for 2030 and 2040. This corresponds to 135 GWh and 540 GWh of storage capacity, respectively. It is challenging to isolate the effect of different types of storage because storage has such a significant impact on the profitability of investing in thermal power plants, which will in turn shift the long-term market balance.

[46] We presume that Germany has a strategic reserve. The power plants here cannot participate in the power market until the prices are very high. The size of the reserve thus has little impact on price development in the power market. If the Germans should reconsider and introduce a capacity market that supports power plants in the market, this results in a change in prices compared with our baseline scenario.

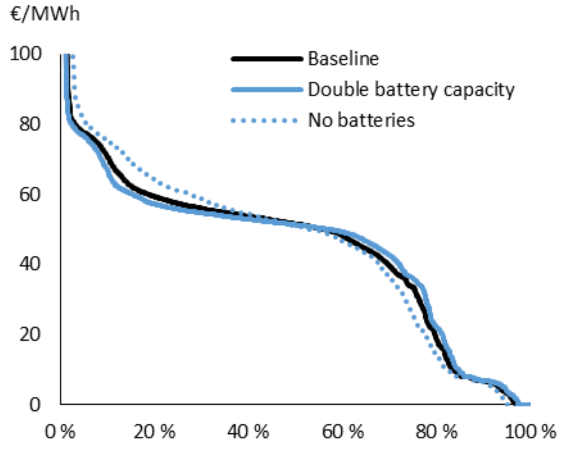


Figure 11-9: Baseline 2040 compared with scenarios with doubled and no battery capacity.

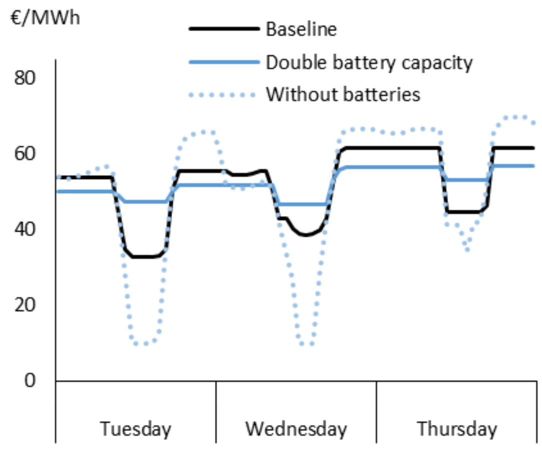


Figure 11-10: The German power price for three days in July 2040, for baseline, with doubled battery capacity and without batteries.

Figure 11-9 shows that a doubling of the battery volume in 2040 has a minor impact on the price duration curve. Nevertheless, this representation obscures the real effect that batteries have on the prices and the short-term price volatility. As an example, the volatility throughout the day in 2040 is reduced by about 40% when we double battery capacity. Figure 11-10 shows how batteries balance out the prices for three days during a random summer week and shows how more batteries largely offset the price dips caused by solar power.

11.5 Internal German bottlenecks and consequences of multiple bidding zones

Today, there are bottlenecks going north-south internally in Germany and as shown in figure 11-11 , the need for transmission increases substantially in our baseline scenario. At the same time, Germany is in the process of completing major grid reinforcements that will significantly increase capacity. In the baseline scenario, we assume that Germany will, over time, largely be able to coordinate the development of renewables in the north and the internal need for transmission, so that the use of separate bidding zones will not be necessary. However, this is uncertain.

Figure 11-12 illustrates the effect on price in Northern Germany in 2040, if Germany is split into a northern and southern bidding zone. We see that there will be multiple low prices in Northern Germany that will result in both lower average prices and more volatility. This will lead to a lower price level in the Nordic region as well, but to a less extent.

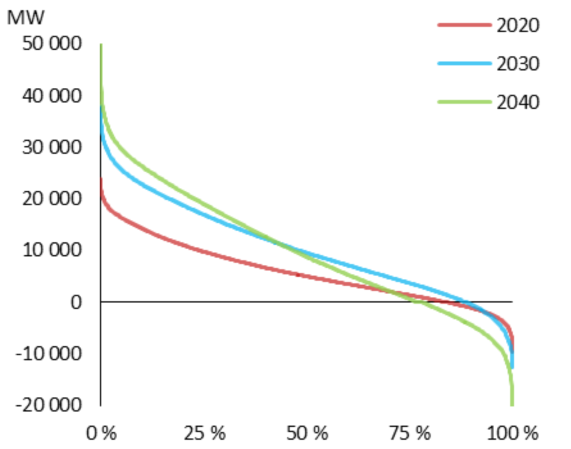


Figure 11-11: Simulated flow without restrictions north-south in Germany in our baseline scenario for 2020, 2030 and 2040.

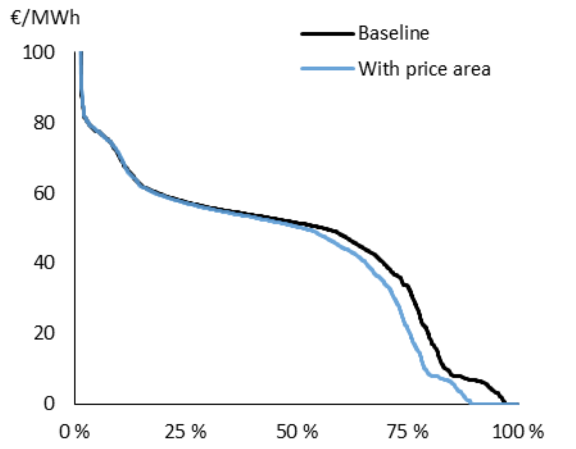


Figure 11-12: Price in Northern Germany for 2040 in baseline (single German bidding zone) and with two German bidding zones.

11.6 Uncertainties in the Nordic market

So far, we have looked at how changes on the Continent will influence Nordic prices[47]. This section will examine conditions in the Nordic region:

- Changes in the Norwegian and Nordic power balance
- The effect of solar and wind power
- More interconnector capacity to the Continent and the UK

Changes in the Norwegian and Nordic power balance will still influence the power prices even though more transmission capacity to the Continent and the UK will alleviate the price consequences of variations in inflow and temperature. Furthermore, it is clear that wind and solar power within the Nordic region will have an increasing impact on power prices. Finally, we have looked at the effect of changed exchange capacity from Southern Norway.

Price effect of changes in the Norwegian and Nordic power balance in 2030 and 2040
We have simulated how +/- 15 TWh in the overall Nordic balance will affect the prices in 2030 and 2040. The balance was changed by adding or removing 5 TWh of flat industrial consumption in Norway, Sweden and Finland.

[47] Changes in fuel and CO_2 prices affect Norwegian and Nordic prices almost exclusively through Continental and British prices, as virtually all price-sensitive thermal generation in Denmark and Finland will be shut down towards 2030.

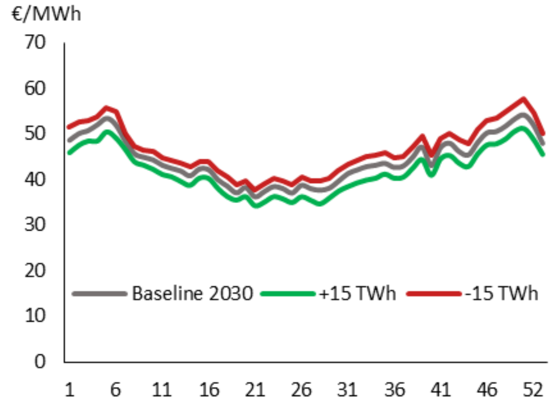


Figure 11-13: Average weekly energy prices throughout the year in Baseline 2030, and in simulations where the Nordic balance is changed by +/- 15 TWh.

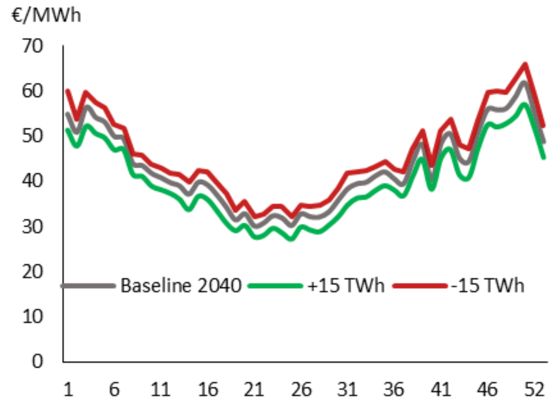


Figure 11-14: Average weekly energy prices throughout the year in Baseline 2040, and in simulations where the Nordic balance is changed by +/- 15 TWh.

In 2030, a balance that is 15 TWh weaker will increase Norwegian prices by about € 2/MWh. The effect of an increased surplus is somewhat stronger. The price sensitivity for changes is somewhat higher in 2040, despite the addition of a new interconnector going to the UK. A balance that is 15 TWh weaker will lift prices by just over € 2.5/MWh, whereas an increased balance will reduce prices by just over € 3/MWh. Another perspective would be that a 30 TWh decline in the Nordic balance in our baseline scenario will increase the prices by € 5-6/MWh.

By 2040, the surplus in Norway will increase from 8 to 18 TWh. We have conducted a simulation where we have reduced the balance back to the level in 2030 by adding 9 TWh of industrial consumption. This will increase Norwegian prices by about € 2-3/MWh.

Wind and solar power increasingly impacts Nordic prices

We have seen that the development towards more intermittent generation significantly affects Nordic prices. We have conducted a simulation where, instead of removing 15 TWh of industrial consumption, we increased the surplus by increasing wind power generation by 15 TWh. The duration curves compare the prices in the two simulations. The price curves are naturally the same, but the duration curve with more wind power is somewhat steeper. This indicates that more wind power will result in greater price variation. The 40% lowest prices are somewhat lower in the simulation with more wind power, so that the average price is approx. € 0.5/MWh lower.

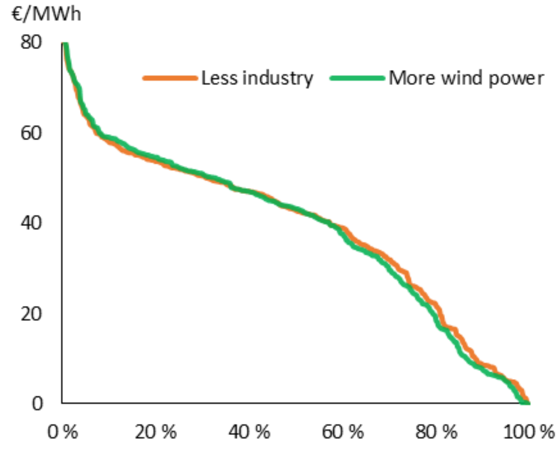


Figure 11-15: The price duration curve in two simulations where we have increased the surplus in 2040 by 15 TWh either through a smaller industrial load or more wind power.

In our baseline scenario we added more than 10 TWh of solar power in Norway, Sweden and Finland for 2040. Our simulations show that the major capacity contribution from solar power will eventually have a significant impact on power prices in the summer months. We have carried out simulations where we replaced the growth of 7 TWh of solar power from 2030 to 2040 with a corresponding volume of wind power. We also carried out a simulation where we doubled the growth in solar power during the period, but reduced the growth in wind power correspondingly. The difference in the volume of solar power in the two simulations is thus approx. 14 TWh.

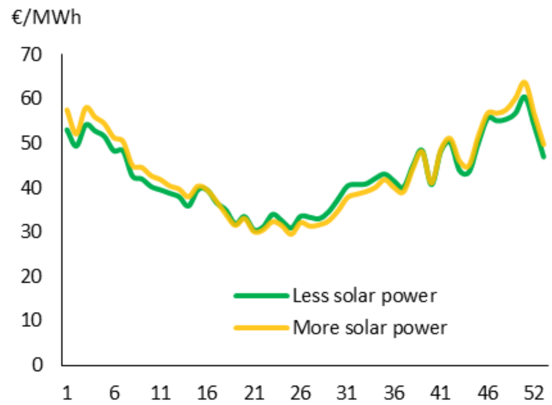


Figure 11-16: The effect of solar power on average prices during the week in 2040. In Less solar power, 7 TWh of solar power was replaced by wind power, whereas in More solar power, 7 TWh of wind power was replaced by solar power.

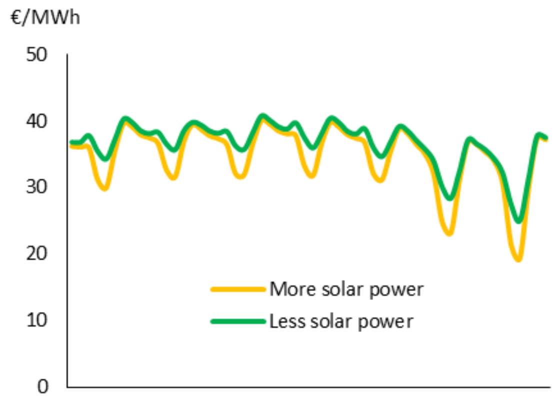


Figure 11-17: The power prices in Southern Norway during an average summer week.

Naturally, the power prices in the winter are higher in the simulation with more solar power, while they decline somewhat during the summer. On average, the transition from wind to solar power results in somewhat higher prices. We clearly see that more solar power results in a pronounced price dip in the middle of the day during the summer. In these simulations, the impact on power prices is greater in Sweden and Finland than in Norway, because there is a larger volume of solar power there. This e.g. results in even more pronounced price dips during the summer, but also a higher price level in the winter. It is important to clarify that we did not add battery capacity in the Nordic region. In a scenario where solar power increases, this will most likely be followed up by more batteries, or more active use of batteries in electric cars. This would alleviate the price drop created by solar power in the middle of the day.

Increased cross-border transmission capacity raise prices moderately during summer months
The capacity from Norway from 2020 to 2030 is unchanged in the baseline scenario. For 2040, we have increased capacity to the UK by 1400 MW. We have conducted three simulations with changed capacity from Southern Norway:

- Added the UK cable in 2030
- Removed the UK cable in 2040
- Additional 1400 MW to Germany in 2040

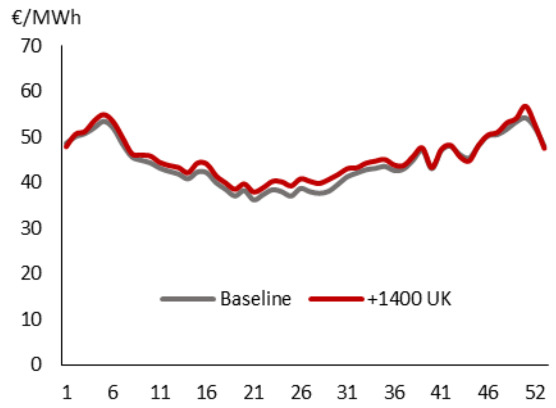


Figure 11-18: Power prices throughout the year in Baseline 2030 for Southern Norway and in a simulation with an additional 1400 MW UK interconnector.

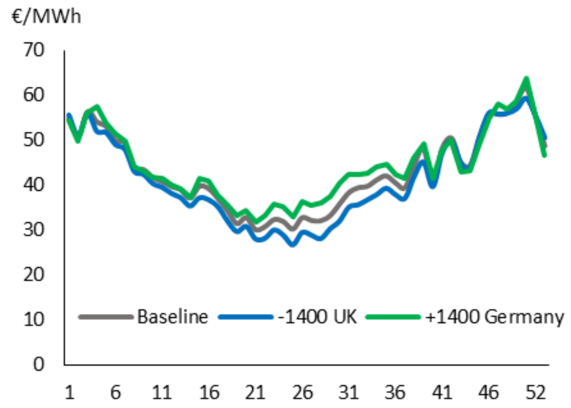


Figure 11-19: Power prices throughout the year in Baseline 2040 for Southern Norway, with 1400 MW less capacity going to the UK, and with an additional 1400 MW going to Germany.

We see that an additional cable to the UK has a moderate impact on the prices in Southern Norway in 2030. On average, the prices are raised by just over € 1/MWh. The price effect is greatest during the summer. If we go to 2040, we see that the effect of the same interconnector becomes somewhat larger, as the prices in Baseline are about € 2/MWh higher than without the interconnector. At the same time, we see that the price effect in 2040 is almost exclusively during the summer months. The reason for this is that the cable primarily raises the price during hours that already have high intermittent generation and low prices. We see the same outcome if we add an additional interconnector to Germany. This raises the prices by about € 1/MWh, and the impact is again concentrated in the summer months in this scenario.

In the final simulation, total capacity from Southern Norway is approx. 10 GW. Along with a highly fluctuating price scenario, it is likely that a development of this scope would be accompanied by more dispatchable hydropower capacity, and possibly also pumps. Nevertheless, they do demonstrate that it would take a lot to equalise the prices in winter/summer with the development that we expect will take place in the Nordic region and Europe.

12 High and Low Power Price Scenarios

Our two alternative scenarios, High and Low, are intended to provide a realistic range of uncertainty for average energy prices over the long term, based on the information we currently have. With this, we believe that the data sets are consistent enough to last. The scenarios indicate a range of uncertainty of € 30 to 60/MWh for Continental prices from 2025 and beyond. The range of uncertainty for Norway is from approx. € 30 to 55/MWh.

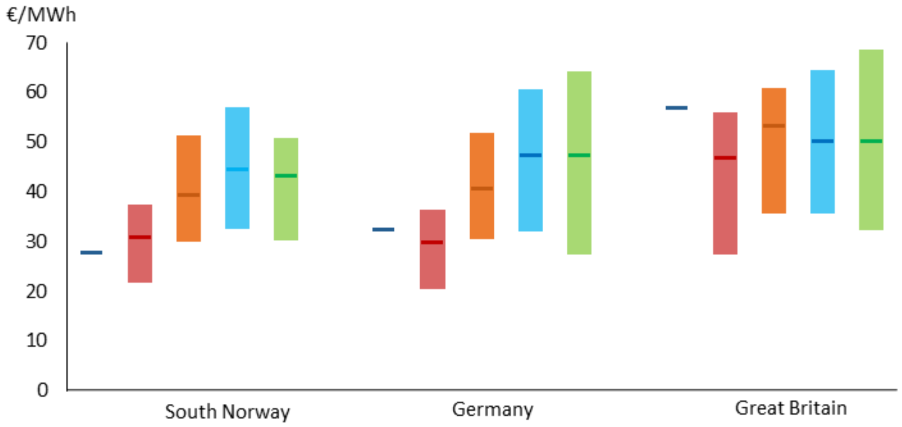


Figure 12-1: Average prices for 2017, 2025, 2030 and 2040 in Low, Baseline and High. All figures are real 2016 prices.

We must emphasise that one could compose several different combinations of assumptions that will yield the same prices as in our scenarios. As we are changing several factors and they must have a long time perspective, we have not taken each individual factor to the extreme. We still believe that our scenarios cover much of the uncertainty associated with the development in the power market in Europe and the Nordic region. At the same time, the power market is undergoing major changes, and the pace of change will increase up to 2040. This increases the likelihood of imbalances. Such imbalances can last a relatively long time, but the market will still swing back towards equilibrium in the long term. We believe that this will yield prices within the interval that we outline.

12.1 Main assumptions in High and Low scenario – an overview

The general scenario outline and the specific assumptions are described in Chapters 4 to 8. For the sake of clarity, we will also provide a brief summary here. The below table summarises our most important assumptions in our three scenarios

Table 12-1: Overview of assumptions for EU10 in our three scenarios.

		2020			2030			2040	
	Low	Base-line	High	Low	Base-line	High	Low	Baseline	High
Consumption, EU10 (TWh)	2222	2222	2222	2268	2381	2527	2310	2739	3164
Solar power, EU10 (GW)	114	114	114	215	213	253	354	385	488
Wind power, EU10 (GW)	132	132	132	230	218	263	339	368	463
Solar power annual prod., EU10 (TWh)	108	109	109	197	196	231	320	349	437
Wind power annual prod., EU10 (TWh)	303	303	303	591	562	680	897	987	1240
Battery capacity (GW)	-	-	-	15	15	15	60	60	93
Renewable energy percentage (%)	33	33	33	53	50	53	69	64	66

The figures below show the development in marginal costs for thermal plants in our scenarios. In 2040, we have a range of uncertainty of € 30-60/MWh for a typical gas-fired power plant.

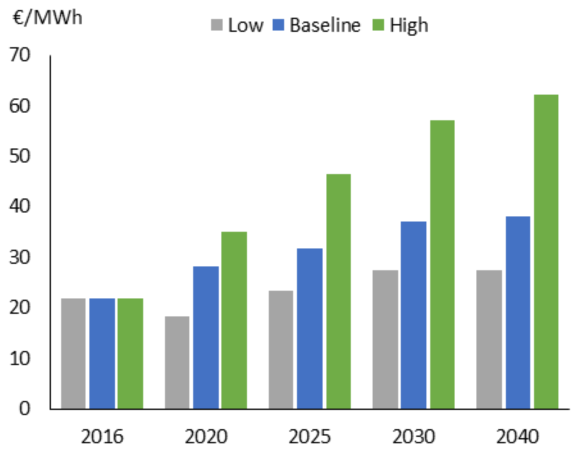


Figure 12-2: Marginal costs for a typical coal power plant in our three scenarios.

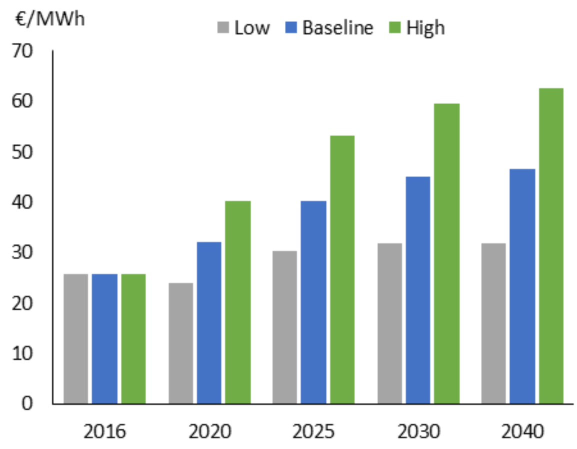


Figure 12-3: Marginal costs for a typical gas-fired power plant (CCGT) in our three scenarios.

We adjusted the power balance in Norway and the Nordic region by adding renewables in High and removing renewables in Low. We increased the surplus more in High than we reduced it in Low. We also added an additional cable going to the UK in 2030 in High. This is included from 2040 in the baseline scenario.

12.2 Until 2022 power prices will mainly be determined by prices on fuel- and CO_2

In 2020, only the fuel and CO_2 prices were changed in order to arrive at a range of uncertainty for the power price. This applies to both Europe and the Nordic region. The development within generation and consumption can also affect power prices within this time interval. However, over such a few years the slightly different development than what we presume in the baseline scenario has a relatively modest impact compared with the prices of fuel and CO_2.

The range of uncertainty for the German average price in 2020 is € 20 to 35/MWh. By comparison, the average price so far this year has been € 28/MWh. A major downscaling of thermal generation capacity is a potential upside in relation to our baseline scenario. Many power plants are losing money and the probability of shutdowns increased after the decision to not introduce a capacity market in Germany. Still, the surplus capacity is so significant that this most likely cannot raise the power prices much until the rest of the nuclear power is decommissioned in 2022.

The range of uncertainty in the UK is larger. This is primarily caused by uncertainty concerning the unique British CO_2 tax, but also because the prices are more sensitive to changes in the gas price alone. In 2020, the CO_2 price is expected to be more than € 20/tonne higher in the UK than in EU ETS. We removed the tax in Low. Seen in isolation, this will reduce the British average price by approximately 10 MWh.

As the power prices in the Nordic region are so closely linked with the Continental market, it is the fuel prices that constitute the largest uncertainty here as well, if inflow and temperature are disregarded. In Baseline 2020, we have a range of uncertainty of between € 21 and 39/MWh for the annual average Norwegian power price over 25 simulated weather years. During wet years, the average price may fall as low as € 15/MWh in Low, whereas it reaches € 47/MWh during dry years in High.

It is primarily the development within nuclear power and consumption that can affect the prices during the first years internally in the Nordic region. For example, another delay of Olkiluoto 3, in Baseline 2020, will raise the average price in Norway and Denmark by € 1/MWh. In Sweden and Finland, prices increase by 1.5 and 3.5 €/MWh, respectively.

12.3 Price uncertainty increases in the long term

The uncertainty in power prices increases after 2020. First of all, the range of uncertainty for gas and CO_2 prices will be greater. At the same time, uncertainty regarding development of renewables, consumption growth, contribution from different types of flexibility, decommissioning of thermal plants and margins will grow. In our Low scenario, German power prices increase from 20 €/MWh in 2020, to just over 30 €/MWh in 2030. Towards 2040, average prices fall below 30 €/MWh. British prices are somewhat higher than German prices throughout the period. In our High scenario, German power prices increase from 35 €/MWh in 2020, to around 60 €/MWh in 2030. After this, the prices slowly rise until 2040. As in Low, British prices are somewhat higher than the average price in Germany throughout the period.

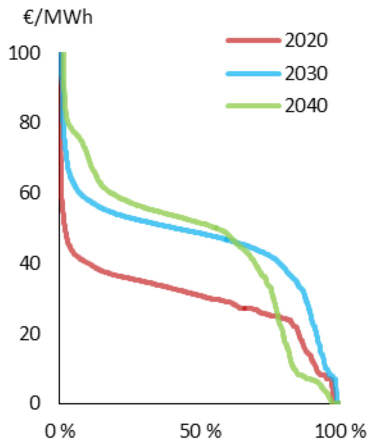


Figure 12-4: Duration curve for the German power price in Baseline.

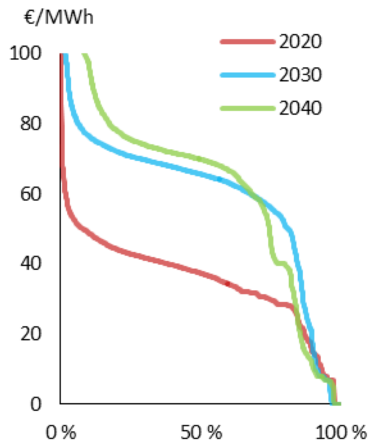


Figure 12-5 Duration curve for the German power price in High.

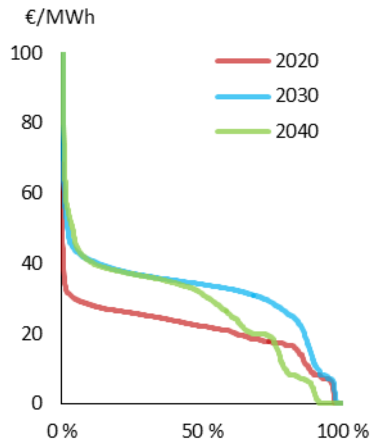


Figure 12-6: Duration curve for the German power price in Low.

The duration curves above show simulated German prices in 2030 and 2040 in our three price scenarios. What distinguishes the scenarios apart from marginal costs in thermal plants is what happens in hours with the highest and lowest prices. In our Low scenario, the share of renewables increases faster and there is less flexibility to lift power prices in hours where renewables cover the consumption. At the same time, lower consumption growth means less need for investments in thermal plants, an improved capacity margin and thus fewer price peaks.

More renewables are developed in High than in Baseline, but this is balanced by more consumption. Moreover, more flexibility from storage and consumption will elevate power prices in hours with significant renewables generation. The number of hours with very low prices thus increases less towards 2040 than in the two other scenarios, which contributes to higher average prices. Greater consumption growth and a tighter capacity margin also mean that there are additional hours where the prices are set by peak load plants and consumption. This also elevates average prices.

The duration curves for all three scenarios have several common characteristics. Firstly, prices will increase from 2020 to 2030 as a result of increased marginal costs and thermal base load being shut down. Thermal power plants will furthermore remain price-setting in many hours in 2040. This means that gas power has a relatively significant impact on average prices, even in our Low scenario. At the same time, the number of hours with very low prices increases in all scenarios from 2030 to 2040. Tighter margins results in an increase in the number of hours with price spikes beyond marginal costs of CCGT. In sum, this development results in more price structure, although more contributions from batteries and other types of flexibility curb the variations, especially over the course of the day. We will return to price variation in the next chapter.

12.4 Low scenario – emission cuts requires regulation and support schemes

In our Low scenario, the power prices remain at current low levels. Market prices in this scenario are thus, to a certain degree, a driver for transitioning to lower emissions from the power and energy sector:

- The achieved power price for solar and wind is most likely far below development cost
- Thermal plants have little earnings when there are few price peaks above marginal costs
- Relatively little price volatility results in low earnings for storage and other types of demand response

In the Low scenario, the production-weighted price increases on the Continent for onshore wind, offshore wind and solar from approx. 20 €/MWh in 2020 to 30 €/MWh in 2030. Towards 2040, it drops to 20 €/MWh as a result of the increased share of renewables. This is far below the expected long-term marginal cost, even in an optimistic scenario. In Low, there will therefore be a need for considerable subsidies for renewables throughout our analysis period. At the same time, the low CO_2 price entails increased use of other policy instruments, such as regulating how much each individual power plant can emit per produced unit of energy, subsidies and energy efficiency requirements.

The low price level in combination with fewer price peaks yields a significantly lower price volatility in Low, compared with the baseline scenario. This results in marginal profitability of batteries and other types of flexibility, in spite of many hours with very low prices. In order to make it possible to integrate the increased share of renewables, and ensure that new renewables keep contributing to reduced CO_2 emissions, it may therefore be necessary to also subsidise in or require more flexibility.

In Low, we have chosen to have a low CO_2 price, both because this is a real possibility and a significant impact on power prices. At the same time, it bears mentioning that there may be more political latitude to raise the price of CO_2 emissions in a scenario with low fuel prices than vice versa. When power prices are relatively low, it is easier to gain acceptance for increasing the price of CO_2 than if the power price is higher. This can either take place by tightening the quota market or by introducing more direct fees, and reduces the likelihood of remaining at a low price level over an extended, continuous period of time.

In principle, we have the same thought process behind how thermal power plants are financed in the Low scenario as in the Baseline. However, a better margin and fewer price peaks mean that earnings from thermal plants are weaker. One fundamental cause of this is that the need for new investments is less. With power prices as low as those in Low, however, there may be greater political acceptance for having a somewhat tighter margin and thus more price peaks where shedding of consumption sets the price. The probability of additional closures of thermal plants may therefore be greater in Low than what we have presumed.

12.5 High scenario – the market drives emission cuts

In our High scenario, the transition to lower emissions is more market-driven. Higher and more volatile prices result in stronger incentives for investments in both renewables, thermal power plants and storage. The price of CO_2 will eventually be high enough to ensure that gas power can compete with coal power on price. This reduces the need to use direct regulations to phase out coal power plants. At the same time, there will likely still be a need for guarantee schemes for developers of renewables in order to give them adequate long-term security. This is particularly important in the first 10-15 years to ensure that it is to be possible to develop the large volume of solar and wind power we have presumed in the scenario.

One key question in a scenario with high power prices is whether profitable development of renewables based solely on income from the day-ahead market can limit the rise in power prices. In its most optimistic scenario, for example, Bloomberg has the LCOE for solar and wind in Europe falling to 36 €/MWh and 41 €/MWh, respectively, toward 2040, i.e. far lower than the average power price in High. This may indicate that we should have included a greater development of renewables in this scenario, which would reduce average prices.

Although the opportunities for additional renewables development moderate the upside for the power price, several factors speak in favour of solar and wind not setting a definite price ceiling in a scenario with high gas and CO_2 prices. The most important factor is that the value of solar and wind power will fall as the share increases. In our high scenario for 2040, the production-weighted price in Germany is 50, 43 and 50 €/MWh, respectively, for solar, onshore wind and offshore wind. This means that, even though the power price is higher on average than the development cost, it will not necessarily be profitable to develop. Particularly offshore wind will need considerable support throughout the period.

At the same time, it is an open question whether it is possible, in practice, to have such a considerably higher development pace than what we presume in High. Here we add a total capacity of 44 GW of solar and wind power per year from 2030 to 2040 in EU10. For comparison, just over 20 GW of solar and wind power was installed in all of the EU in 2015. A development pace significantly above the level in High entails increasingly greater challenges in relation to integrating the new generation in a reasonable manner, both as regards grid development, system-oriented factors and avoiding energy losses.

12.6 Average prices – less uncertainty in Norway

In our Low scenario, the Norwegian average price is just above 20 €/MWh in 2020. Driven by higher European prices, the price in Norway rises to 30-33 €/MWh in 2030[48]. After 2030, the price drops to just below 27-30 €/MWh. In High, the prices nearly double to 55 €/MWh in 2030, before they fall toward 50 €/MWh to 2040.

High and Low give a somewhat smaller range of uncertainty for average prices in both Norway, Sweden and Finland than what is the case on the Continent.[49] The reason for this is that the prices in High do not increase as substantially as on the Continent. This, in turn, is the result of including a greater development of renewables on the Nordic side, and that prices in Norway fall relative to the Continent when the prices rise. The latter is due to the fact that years with considerable inflow to a greater extent lower Nordic average prices when price level increases.

[48] The prices are somewhat lower in Northern Norway than in Southern Norway.

[49] When we are talking about average prices we are thinking of the average prices based on simulations that include 25 different weather years. If you look at a single year the uncertainty in Nordic prices will be higher than in rest of Northern Europe due to variations in inflow.

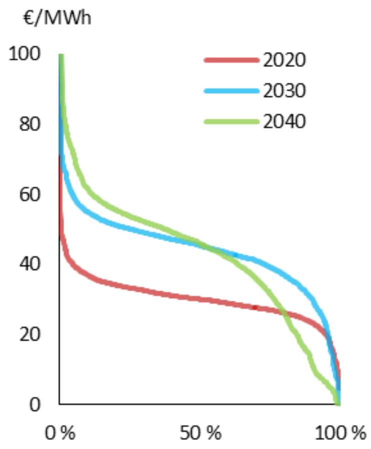


Figure 12-7: Duration curve for the power price in Southern Norway in Baseline.

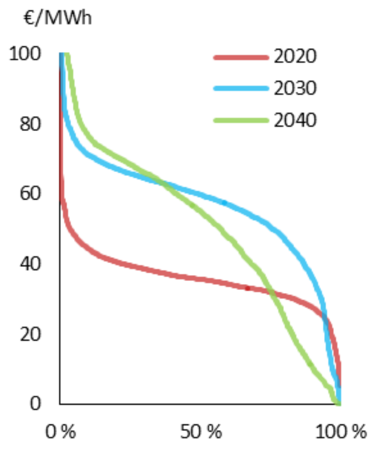


Figure 12-8: Duration curve for the power price in Southern Norway in High.

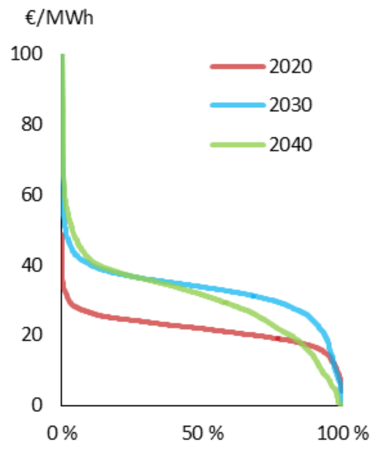


Figure 12-9: Duration curve for the power price in Southern Norway in Low.

Low – average Norwegian prices equals price-levels on the Continent

In Low, the average prices in Norway and the Nordic region are equal to the average price on the Continent. The reason for this is both that the price difference is smaller the lower the general price level is, and that there is a lower power surplus than in the baseline scenario, due to less renewables. If we had kept the balances unchanged, Norwegian prices would have dropped by an additional 2 €/MWh in 2030 and 3 €/MWh.

In 2040 Low, Norwegian prices on average are actually above the German average price, although Norway has a surplus of 8 TWh, and Norway, Sweden and Finland overall also have a small surplus. This is due to several hours of zero prices in the winter in Germany. This reduces the average German price, but has less impact on Norwegian prices. Lower summer prices in Norway than in Germany have the opposite effect, but not enough to reduce the overall price level. Our simulations actually show that Norway, Sweden and Finland must have an overall surplus of close to 20 TWh in order for average prices in Norway, Sweden and Finland to decline to the level of Germany in Low 2040.

High – lower prices in the Nordics than elsewhere in Northern Europe

In High, the difference in average power price between Norway and Europe increases substantially toward 2040. This is mainly due to the fact that Nordic prices in the summer months remain relatively far below the Continental average price. This development is seen clearly in all our three scenarios and is a result of intermittent generation accounting for an increasingly larger share of generation in the Nordic countries. The trend is nevertheless most clearly evident in our High scenario, where both the average price level is higher and the power surplus in the Nordic region is increased. Here we want to specify that there may be other adaptations which may result in a different development. At the same time, it would take a great deal to weaken the trend toward increased negative price pressure in the summer as a result of considerable intermittent generation.

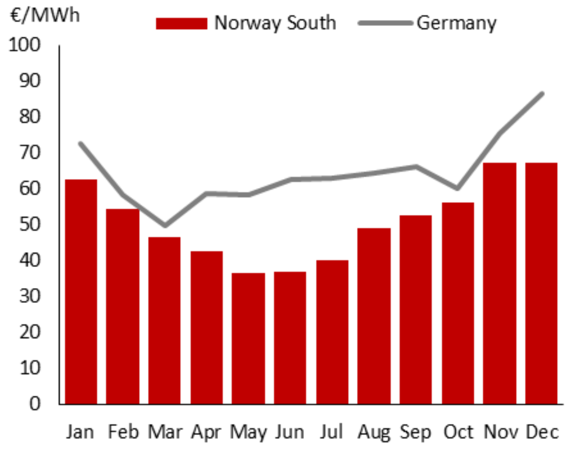


Figure 12-10: Simulated average price per month in Southern Norway and Germany in High 2040.

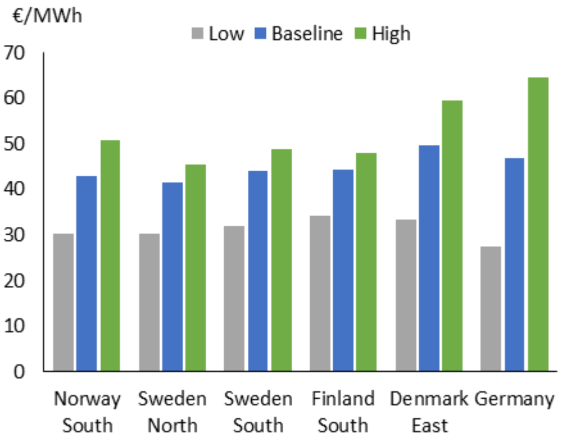


Figure 12-11: Simulated average prices per year in the Nordic region and Germany in Low, Baseline and High 2040.

Our simulations show that price differences within the Nordic region are also greater when average prices are higher. Figure 12-11 shows average prices for different areas in the Nordic region in High 2040. Here we see there are considerable differences within the area. In Denmark, the prices are near the level in Germany. Finland and the southern parts of Norway and Sweden are more than 10 €/MWh lower, whereas the northern parts of Norway and Sweden are even lower than this. However, here we want to emphasise that, in this scenario, it may be relevant to expand grid capacity more than what we have presumed. The geographical distribution of new renewable generation is also uncertain. A different distribution could most likely reduce price differences.

A large potential for onshore wind power limits high prices in Norway, Sweden and Finland

Towards 2040, we have presumed in High that 20 TWh more wind power will be developed in the Nordic region than in the baseline scenario. The reason for this is that prices on the Nordic side increase to well above what we assume will be the long-term development cost of onshore wind power. A rough estimate is that, over time, the LRMC/LCOE for onshore wind power in the Nordic region will be between 30 and 45 €/MWh. This results in profitable development of wind power in the Nordic region without the use of subsidies. In High, this curbs the price in both Norway, Sweden and Finland. In High 2040, when we simulate with only changed prices on the Continent and in the UK, the average price in Southern Norway increases from 42 €/MWh in Baseline to 56 €/MWh. When we add the extra wind power, the price in Southern Norway drops to 50 €/MWh.

It is nevertheless uncertain to what extent the considerable wind resources in the Nordic region could amount to a price ceiling for the average price in Norway, in a scenario where Continental prices are at a far higher level than the development costs for Nordic wind power. Although we do have a certain impact from this in our High scenario, we believe that there are several reasons why Nordic wind power will not constitute an absolute price ceiling.

Firstly, the value of wind power in the Nordic region will decline, although this happens more slowly than on the Continent. The production-weighted price of wind power in Norway in our high scenario is 45 €/MWh in 2040, which is 5 €/MWh lower than the average power price. Furthermore, there will be significant uncertainty surrounding future prices throughout the period. An investor will most likely therefore require relatively high returns in order to invest. Thirdly, a larger surplus in the Nordic region could make it profitable to increase transmission capacity to both the Continent and the UK. In High 2040, the average price in Norway is more than 10 €/MWh lower than on the Continent and in the UK.

This indicates that it may be profitable to have more transmission capacity than what we have presumed. If so, this would elevate Nordic prices, but somewhat reduce prices on the Continent. Alternatively, new consumption as a result of relatively low prices may have the same effect.

Finally, there are also other considerations that affect the size of a Nordic development, for example the environment. Our overall assessment is therefore that the costs of wind do not set a firm price ceiling in the Nordic region, but that it moderates the increase in a scenario with high gas and CO_2 prices.

13 Volatility in High and Low Price Scenarios

We see a trend toward a greater share of renewables resulting in greater variation in power prices after 2020. This is a shared characteristic of our three main scenarios, although the size of the variation is quite uncertain. We can use our two scenarios for high and low power prices to illustrate the uncertainty of the price variation. The reason for this is that price level and price volatility are correlated, and that we have adjusted factors that increase volatility in High, and vice versa in Low. Short-term price variation in Norway is largely linked to the price level and price variation in neighbouring countries. The prices thus vary considerably more on the Nordic side in High than in Low.

13.1 Greater variation in European prices in all scenarios – though uncertainties are high

Figure 13-1 and figure 13-2 show how the price volatility develops in our three power price scenarios through the week and day. We see the same pattern in all scenarios, although the range of uncertainty is considerable. Firstly, a growing share of wind power results in greater price variation over periods that typically last longer than a day. Volatility within the day also increases toward 2030, but is then moderated by more storage capacity, primarily from batteries.

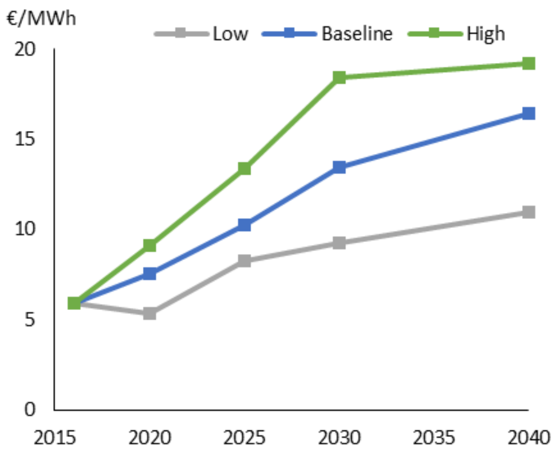


Figure 13-1: Simulated price volatility through the week in Germany in 2016, 2020, 2025, 2030 and 2040.

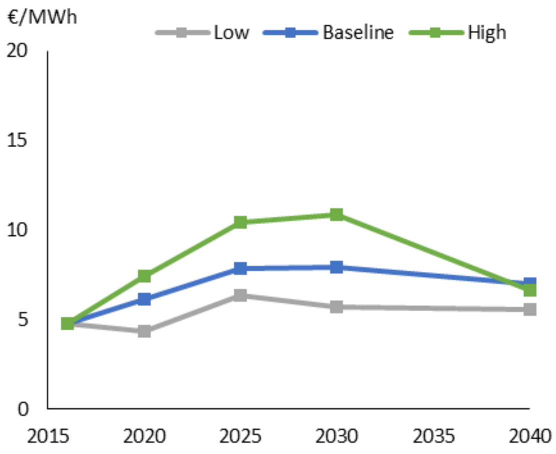


Figure 13-2: Simulated price volatility through the day in Germany in 2016, 2020, 2025, 2030 and 2040.

In the High scenario, the variation in power prices increases considerably towards 2030. The reason for this is that marginal costs in the scenario are significantly higher, in addition to a tighter capacity margin yielding more price peaks. These factors also mean that the variations in power prices within the day are significant.

In the Low scenario, the variation in prices is primarily driven by the fact that more wind power results in more periods with very low power prices. One reason why this does not contribute to even more volatile prices is that the marginal costs in thermal plants are so low. This means that there is a relatively small difference between hours where the price, for example, is zero, and hours where CCGT gas power sets the price.

The further development towards 2040 in High provides a good illustration of an interesting point that we have mentioned earlier. We see that the price variation during the day becomes significant lower towards 2040. In High, we increased battery capacity more than in the two other scenarios. This makes the capacity good enough equalise the price effect of variations in consumption and solar power in many cases. Overall, the volatility during the day in High in 2040 is therefore quite similar to Baseline and Low, despite both significantly more price peaks and a higher power price level. On the other hand, the increase in battery capacity is not enough to equalise variations over longer time periods that are driven by periods with little or considerable wind. We can see this as the measure of volatility during the week becomes higher.

The curve graphs below show the prices during an average winter week (figure 13-3) and summer week (figure 13-4) from the High scenario in 2030 and 2040. In 2030 we still see a clear price pattern throughout the day during the winter week. By 2040, this pattern has practically disappeared. This is because even though the price volatility is significant, it is virtually exclusively driven by random wind variations.

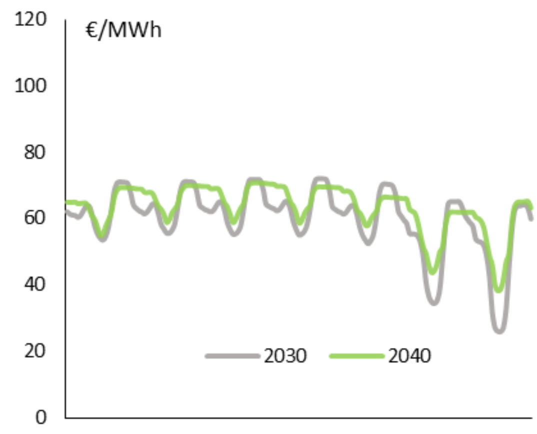


Figure 13-3: German power prices during a representative winter week in High 2030 and 2040.

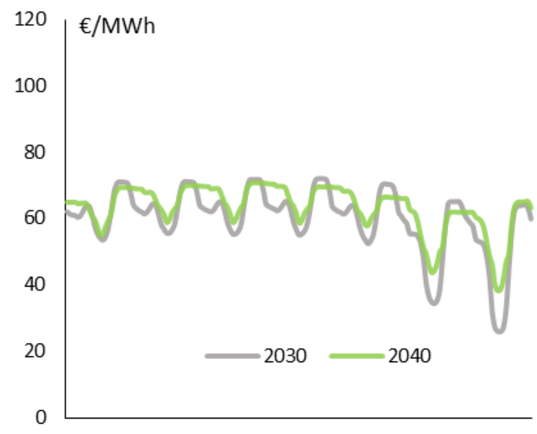


Figure 13-4: German power prices during a representative summer week in High 2030 and 2040.

In the summer, however, there is a very stable price pattern that is repeated almost every day. This is because batteries will capture the contribution from solar power and because wind power generation is lower and less variable. The changes from 2030 to 2040 are relatively small. The pronounced price dips in the weekends will actually become smaller by 2040 as the battery capacity will increase relative to the volume of solar power.

13.2 Price volatility in Norway is largely determined by continental prices

Generally, the prices in the hydropower system are[50] stable over shorter periods. The price volatility in Norway is thus largely a result of price contamination from neighbouring countries, and much of this is because dispatchable hydropower plants are not price-setting for much of the time. Changed Continental price volatility in High and Low therefore also creates changes in price volatility on the Norwegian and Nordic side.

Firstly, the price level in Europe directly affects volatility in Norway. A higher price level results in higher marginal values for stored water in Norway. This in turn means that the difference in price increases between hours where cheap import or non-dispatchable power plants and dispatchable reservoir power stations set the price. Naturally, the opposite applies if the price level in Europe drops.

Secondly, more and higher Continental price peaks in High contaminate the prices in Norway. These occur in the winter, and the Norwegian capacity surplus is usually not large enough to have full export

[50] This means the marginal value of stored water in the individual reservoir, i.e. the calculated price of producing an extra MWh at a given water level and time of year, and thus provides a maximum future income from the power plant.

in all channels at the same time during these hours. Dispatchable hydropower is thus not price-setting and there will be price peaks on par with the Continental the price peaks.[51] The opposite is the case in our low scenario.

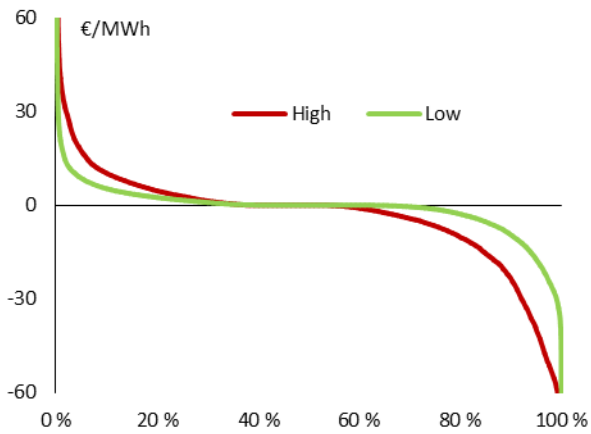


Figure 13-5: Deviation hour by hour between simulated power price and the water values in Low and High in Southern Norway in 2040.

Figure 13-5 shows the deviation in the power price in Southern Norway from water value in Low and High in 2040. The figure illustrates both points above. Positive values thus occur when the power price is higher than the water value. During these hours, the price is not set by dispatchable hydropower and we "import" the prices in neighbouring countries directly. The fact that the distance is greater in High reflects that the price peaks we import are higher than in Low. In the sections of the curves that are below zero, the power price is lower than the water values and dispatchable hydropower does not set the price here either. A greater distance in a negative direction illustrates the point that power prices will fall from a higher level during hours where non-dispatchable, nuclear power and cheap import set the price. The number of hours where the price deviates from the water value, which is hours where dispatchable hydropower does not set the price, is quite similar in both scenarios. A larger surplus in High will, however, result in more hours where the prices will drop below the water value.

[51] We want to specify that this is not about rationing, but that the prices initially rise to a level equivalent to marginal costs of starting and running more expensive thermal power plants in the Nordic region or on the Continent. Eventually, once all other and cheaper flexibility is utilised, the market will have to be cleared using demand reductions. What countries this happens in is dependent on the shedding prices of the various consumers. If this still does not yield a balance between supply and demand, any strategic reserves and rationing would potentially occur. However, in practice, the latter is absent in our simulations and not a key issue for the analysis.

14 Power Plant Profitability and New Flexibility in the Power Sector

In this chapter we will take a closer look at how the price situation we described above will affect the profitability of various investments in the power market. We will mainly cover solar and wind power, thermal power plants and new flexibility. We will also go into slightly more detail regarding how the interaction between these functions, particularly during periods with scarce capacity and periods with significant over-generation of renewables. We also discuss the opportunities for more capacity and pumps in the Norwegian hydropower system.

14.1 Renewables still need subsidies – despite reduced capital costs

The development towards increasingly lower costs for solar and wind power will most likely continue, given a growing global development pace. Along with increasing power prices, this means that it could become profitable to build solar and onshore wind power in locations with a high number of full-load hours after 2030. Nevertheless, we do see a need for subsidies all the way until 2040. There are two main reasons for this:

- Europe will build a considerable volume of renewables by 2040 – this presumes continuous high development
- The achieved power price for all wind and solar power producers will be lower with an increased volume, relatively speaking

The need for support varies in the three scenarios. In the baseline scenario, a considerable share of solar power and onshore wind projects can be developed without support after 2030, whereas this could happen as early as the 2020s in High. In Low, however, there is a need for subsidies throughout the analysis period. As regards offshore wind, there is most likely a need for subsidies in all scenarios. There are also substantial differences between regions, and Norway, Sweden and Finland will be among the first that can experience some development without subsidies.

The costs associated with renewables are decreasing – full-load hours is increasing

The development costs for solar and wind power have declined substantially as the technologies are becoming more mature. Figure 14-1 shows the cost reduction for wind power turbines for onshore wind power, from the mid-1990s to present day. Higher towers and larger turbine blades have increased the usage and are the main reason for the cost reduction per generated MWh. The cost reduction for solar power is largely driven by efficiency improvements in the supply chain and production processes for the actual modules. Over the course of the past five years, the cost per generated unit from solar power has been slashed in half, and has declined by 20-25% for onshore wind power. There have also been significant cost reductions within offshore wind in recent years. Both Dong and Vattenfall recently won tender competitions for coastal offshore wind farms at a cost that was much lower than the expected development cost.[52]

[52] Both projects may be so cheap because they are in shallow water near the coast. As regards Dong's project off the Netherlands, the cost of grid connection is also an indirect subsidy and for Vattenfall's project off Jylland, the distance between park and land is very short and will only require an AC cable.

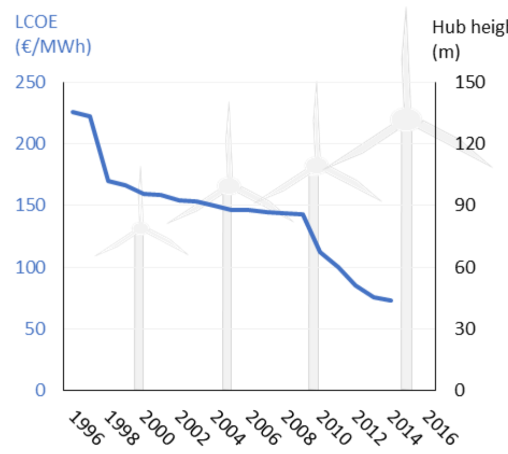


Figure 14-1: Historical development from 1996 until today for long-term marginal cost for the actual wind turbine (data from Bloomberg New Energy Finance) and for average hub height (data from Fraunhofer ISE).

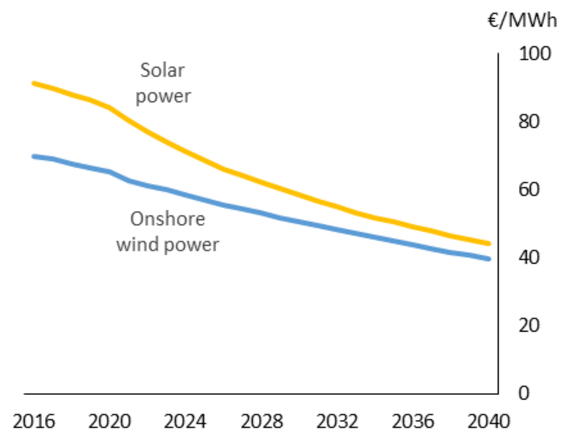


Figure 14-2: Forecasted development in long-term marginal cost from today until 2040 for development of onshore wind power and solar power (large-scale development in Germany). Data from Bloomberg New Energy Finance.

With an ever increasing global development pace, most prognoses indicate that costs will continue to come down. Figure 14-2 shows Bloomberg's prognosis for the long-term marginal costs for development of onshore wind power and solar power from today until 2040. Long-term marginal costs means energy cost per generated unit of energy over the lifetime.[53] This takes into account investment, financing and operating expenses and advantages, and discounts them over anticipated generation through the lifetime. This cost figure makes it easy to compare development costs with the expected achieved power price. Factors that have a considerable impact on the result for energy costs over the lifetime in individual development projects are the number of full-load hours, investment costs and required rate of return. Figure 14-2 reflects German projects with average estimates for all parameters.[54]

Estimates from Bloomberg New Energy Finance, IHS and others show that the long-term marginal cost for both onshore wind and solar power over time will drop down to € 40-50/MWh on the Continent. With a high number of full-load hours, for example for good wind power projects in the Nordic region, the development cost towards 2040 may drop down to € 25-30/MWh. At the same time, future cost development is associated with considerable uncertainty. Both the global development pace and technology advances can play large roles here. Regional differences in market conditions may also have an impact.

Increased market share reduces value of solar and wind power production

Despite our expectation for substantially reduced construction costs towards 2040, we do see that renewable energy will need subsidies. An important reason for this is that the achieved sales price for renewables generation drops when the share of renewables increases. Solar or wind power are often generated at the same time within a region, which will result in low prices during hours with high generation. In addition, price peaks occur exclusively during hours where the contribution from

[53] Translated from the English term Levelized Cost of Electricity, LCOE.

[54] Regarding wind power, the number of full-load hours changes from 2500 hours in 2020 to 3500 hours in 2040 and the required rate of return is 6% throughout. For solar power, it is just below 1000 hours and the required rate of return is 6% throughout.

renewables is far less than normal. The achieved power price therefore falls compared to the average power price in the relevant area.

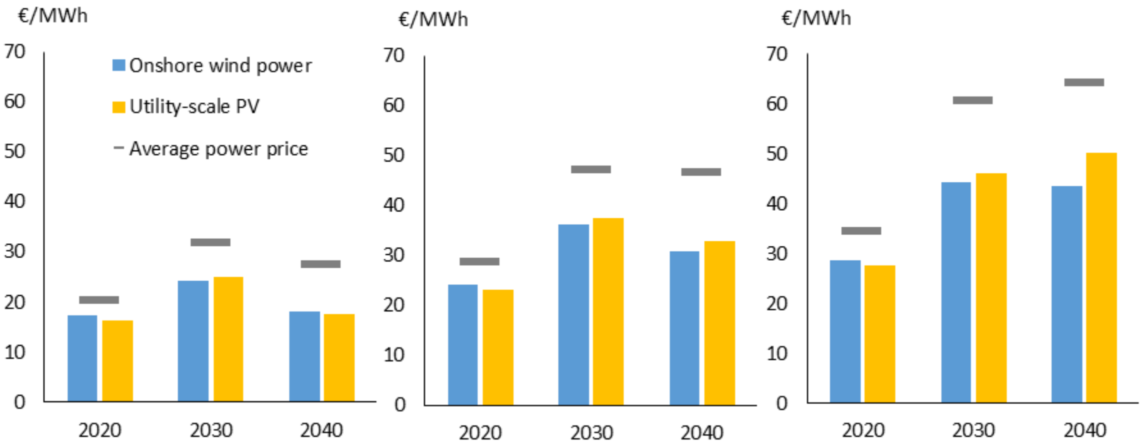


Figure 14-3: Average German power price and achieved power price for onshore wind power and large-scale solar power in our three scenarios.

In our baseline scenario, this is illustrated by the production-weighted price for wind and solar power increasing less than the average prices for 2030, and declining towards 2040. In the baseline scenario, the value of solar and wind power is about € 30/MWh in 2040 in Germany, whereas the average price is more than € 45/MWh. Seen in isolation, the value of solar power declines faster than wind power because the generation is even more concentrated. However, our scenarios compensate for this through the addition of more batteries.

In our Low scenario, the value of renewables is far lower than in the Baseline, whereas the opposite is true in High. There is also more battery capacity in High. This entails that the value of solar power increases relative to wind power, when compared with the baseline scenario.

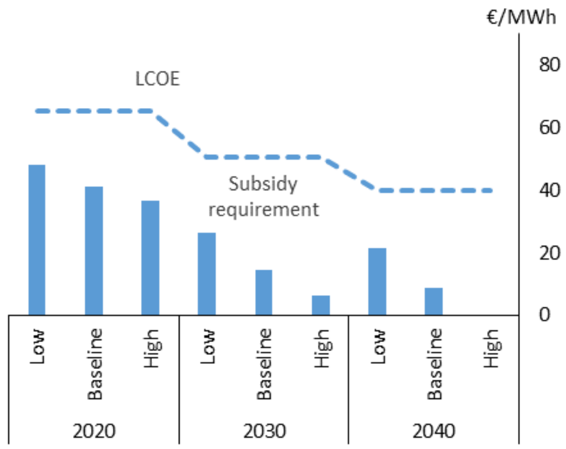


Figure 14-4: The need for subsidies for onshore wind power in Germany, given the achieved power price in our three scenarios and the prognosis for long-term marginal cost from Bloomberg New Energy Finance.

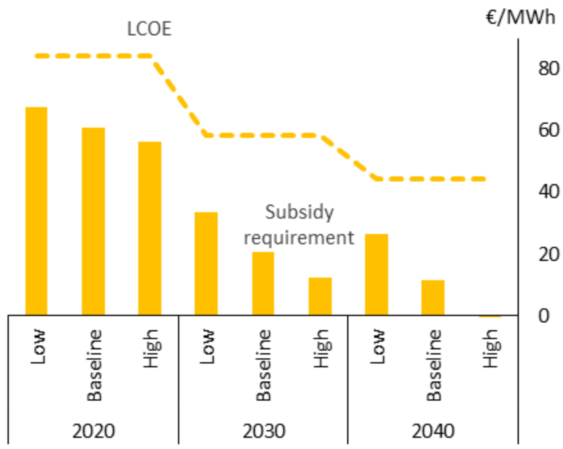


Figure 14-5: Development in the need for subsidies for solar power in Germany, given the achieved power price in our three scenarios and the prognosis for long-term margin cost from Bloomberg New Energy Finance.

Figure 14-4 and Figure 14-5 illustrate the development in the need for subsidies for solar and wind power in our three scenarios, if we use Bloomberg's prognosis for construction costs in Germany as a basis. The need will be lower towards the end of the analysis period, but is still noticeable, particularly in Low. Projects with higher number of full-load hours, lower investment costs or improved financing terms could be profitable without support by 2030-2040 in many locations.

There are also other considerations that indicate a continued need for subsidies. Firstly, it does not help if good projects become profitable by 2030 if Europe is already lagging behind and needs to build several hundred GW over just a few years. The ambitious goals will most likely require a steady and high development pace throughout the period. In addition, investors must have some certainty in order to maintain the level of investments in an uncertain and volatile power market.

Wind power is more profitable in the Nordics than on the Continent

The development of wind power is, as we have mentioned, more profitable in the Nordic region than in most other locations. The reasons for this are that good wind conditions provide a high number of full-load hours, the high share of dispatchable hydropower and that the generation is focused during the winter when Nordic power prices are highest. Wind power also constitutes a smaller share of the generation than on the Continent and in the UK. Overall, this results in a smaller decline in the achieved power price for wind power (figure 14-6). This increases the probability of a certain amount of development without subsidies over the course of the 2020s.

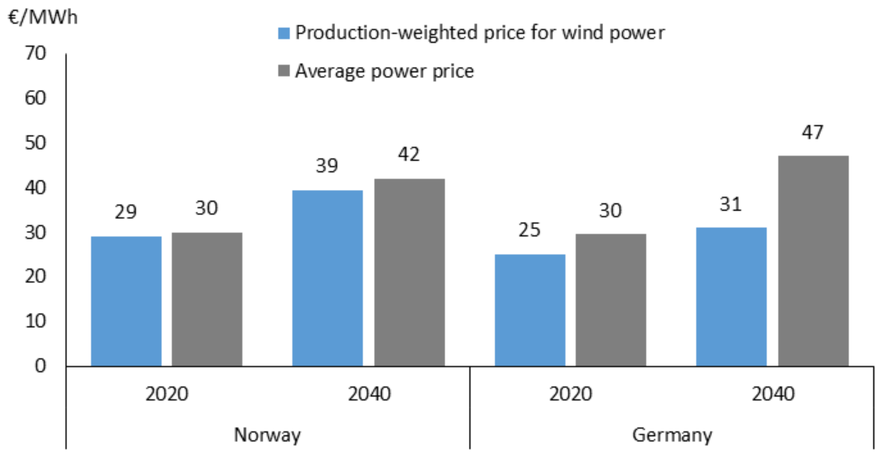


Figure 14-6: Simulated annual average price and simulated production-weighted price for wind power in Norway and Germany in 2020.

14.2 Low and uncertain thermal power plant profitability

Earlier in the report we pointed out that thermal power still plays a key role in the power system towards 2040, both in price formation and in the form of securing the supply during periods with less renewables. Our generation scenarios for solar and wind power show that the overall contribution from the area in Europe that we model outside the Nordic region could drop down to 10% of installed capacity over a full day. During these periods, thermal power plants must cover up to 80% of the consumption even though transfers and shedding of consumption, as well as storage, will help balance the system.

Increased earnings for thermal plants – but not enough to trigger investments

The profitability of thermal power plants increases as total capacity declines. This increases number of full-load hours for the remaining power plants and a tighter margin leads to more hours with price peaks. The hours where prices far exceed the short-term marginal costs are particularly important for earnings.

Figure 14-7 shows the development in simulated net income for four types of existing power plants over the course of our analysis period. Net income in this context means income from electricity sales in the day-ahead market, less both variable and fixed operating and maintenance expenses. When we take fixed costs into consideration, we see that some existing coal and gas-fired power plants will run at a deficit up to about 2025. They main reason why they are not closed down is because they also receive income from the balancing markets. Also, particularly in the German market, there appears to be a competition to be among the last to remain in the market – the owners of the power plants must balance some years with a deficit against the potential of being one of the players left with a profit when all others have closed down. The profitability of coal and lignite are better than for gas, but this has minor significance when we presume that they will be forced out through various regulations.

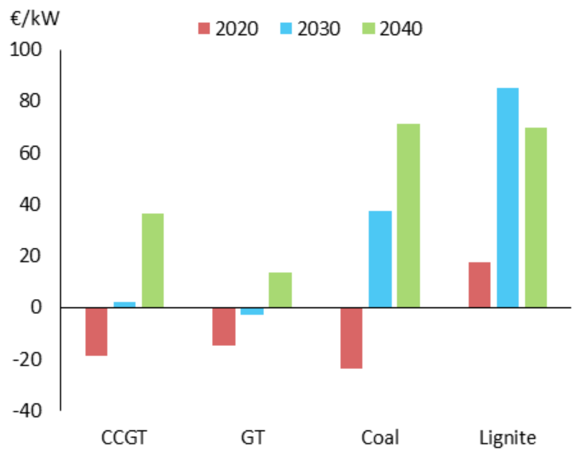


Figure 14-7: Annual operating profit (income from the day-ahead market, less operating and maintenance expenses) per installed kW for European thermal power plants in the baseline scenario.

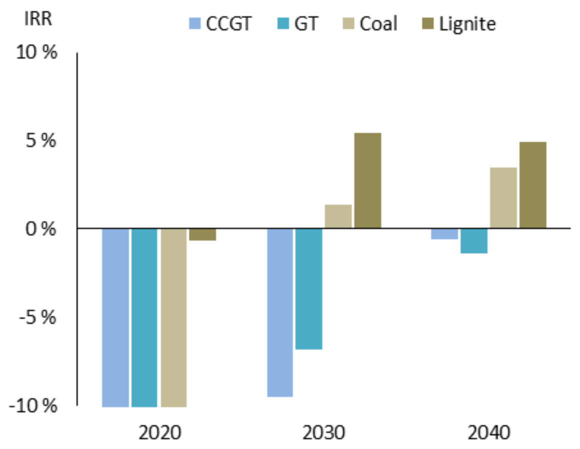


Figure 14-8: Internal rate of return for German thermal power plants in the baseline scenario. The Y axis is capped at -10%, no investments in new power plants are profitable in 2020 (except lignite).

Figure 14-8 shows the internal rate of return for an investment in CCGT (base load plant) and GT gas turbine (peak load plants), based on income in the day-ahead market on the Continent. This income is most likely not enough to generate investments. This particularly applies up to 2030. This is offset in countries with capacity markets through some earnings from participating in these markets. For example, in Baseline 2030, a newly built gas turbine must receive about 50% of its income from outside the day-ahead market in order to achieve an overall return of about 5%. At the same time, we see a moderate need for investments in new thermal generation capacity up to 2030 on the Continent. This particularly applies in Germany, which has a significant surplus capacity to consume. Towards 2040, the income from power sales will increase and the need for support or other income will decline. Profitability will also grow for investments in power plants based on coal and lignite. However, we do not expect any investments in these types of power plants as a result of different emission regulations.

We have added several new thermal power plants in Germany after 2030, although our simulations indicate that this is not sufficiently profitable without support through a capacity market. This indicates that we should perhaps have tightened the market balance even further. At the same time, there is considerable uncertainty associated with the development, as well as several factors that we do not detect in our simulations. We have therefore chosen to aim for an interim solution where total income from the day-ahead and balancing markets increases considerably, but without full cost coverage for new investments.

The situation in the UK is somewhat different. The capacity margin is already much tighter now, and the country also has a functioning capacity market. Nevertheless, we also expect a development with growing earnings for thermal power plants from the day-ahead and balancing markets here.

Reduced number of full-load hours increases share of gas turbines
In our data sets, thermal plants will have a reduced number of full-load hours and earnings will all be more concentrated to just a few hours. Seen in isolation, this is an advantage for gas turbines compared with, for example CCGT and other types of base load, because they have a lower investment cost, and are adapted to a low number of full-load hours and more variable operation pattern. We therefore expect that a solid portion of the investments in new thermal power will be gas turbines. Installed capacity in EU10 will increase from 5 GW in 2020 to 33 GW in 2040. The number of full-load hours will increase during the same period from less than 1% in 2020 to approx. 5% in 2040.

Volatile income from thermal power plants – sensitive to changes in the market
Despite the income for thermal power plants increasing further towards 2030-2040, the profitability is still very uncertain. There are two main reasons for this. Firstly, a considerable portion of the earnings is limited to a few hours. Secondly, the major changes in the power market that we expect all the way until 2040 will affect price formation during these hours.

Figure 14-9 shows income for a new investment in CCGT in Germany in 2030 per simulated weather year in our baseline scenario. On average, this income is sufficient to yield an internal rate of return of 0%. At the same time, we see that there are a few hours in certain years where the contribution from renewables is abnormally low, which generates most of the income. Earnings from thermal power will thus depend on rare weather situations. There is also considerable uncertainty surrounding what the price will be in hours with scarcity. In such hours, small changes in supply or demand may have a significant impact on price. Many of the factors that potentially have great significance for price formation in these hours will be in continuous flux during this period. Examples of this include the contribution from batteries and other types of flexibility. In sum, this results in a substantial risk and likely a high required rate of return for investors in thermal plants.

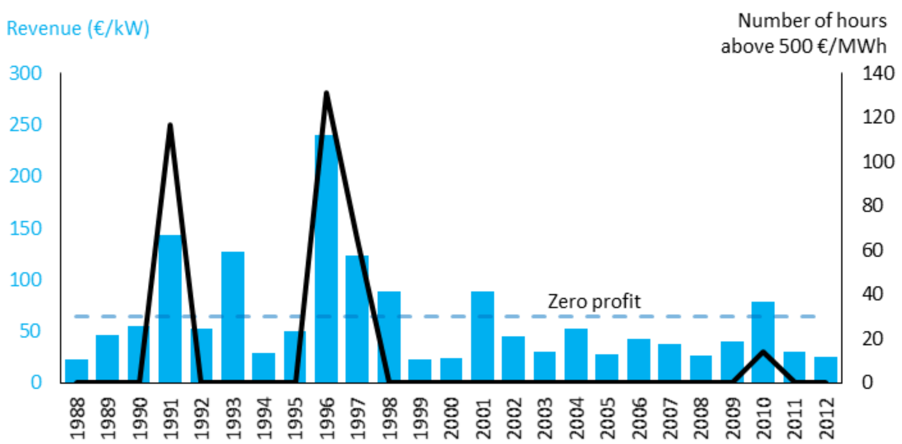


Figure 14-9: Earnings for a new CCGT power plant in Germany 2030 per weather year compared with the number of hours per year where the price exceeds 500 €/MWh. The broken line indicates the average annual income needed to reach break-even.

14.3 Demand response and storage will play a key role in Europe

Traditionally, the supply side has brought balance to the market by responding to changes in consumption. With increasingly variable generation due to solar and wind, storage and demand response will play a key role in balancing the market in our scenarios. Storage mainly moves energy, thus making thermal plants price-setting, whereas flexible consumption sets the price directly in many hours.

Demand response and storage contribute in several different types of situations
Batteries and demand that can be shifted to low cost are important in order to equalise short-term variations in renewables. The most typical example is to exploit the concentrated generation from solar. Figure 14-10 shows the average contribution from various types of flexibility in a June day in Germany in 2040. Residual demand has a clear decline at mid-day when the contribution from solar is high, which is directly reflected in the power price. Both charging of electric vehicles, batteries and other cheap load shifting will exploit this. In the winter, residual demand does not have the same day-profile, since wind power generation is more stochastic.

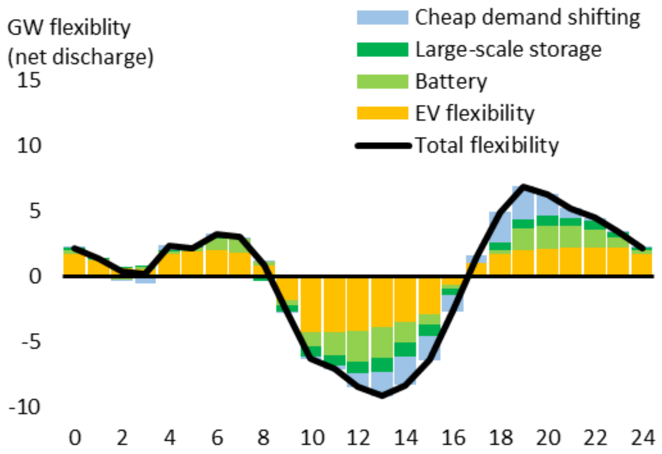


Figure 14-10: Average contributions from flexibility through the day in June for Germany Baseline 2040.

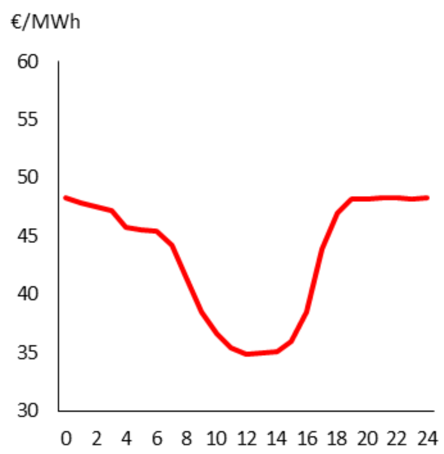


Figure 14-11: Average price through the day in June for Germany Baseline 2040.

With fluctuations in renewables generation of longer duration, we also see a need for storage with greater reservoir capacity. This type of storage is mainly used in the autumn and winter. This typically involves utilising significant volumes of wind power generation that comes over the course of one to three days. In High, where the share of renewables is greater, we also see more profitability in demand with low willingness to pay which only consumes in hours with considerable overproduction from renewables. This may e.g. involve hydrogen production or electric boilers in combination with heat storage.

Figure 14-12 shows a specific winter day in Germany where renewables generation is extremely low throughout the day. In the tightest hours in the morning and afternoon, all available flexibility must contribute to cover the demand. In order for batteries and demand response to charge overnight, back-up power generators must be running and demand with high willingness to pay must reduce its consumption. This accumulated energy will help balance the market in the tightest hours later in the day, when even industry loads with even higher willingness to pay must disconnect. Furthermore, the contribution from large-scale storage is concentrated in the tightest hours. Charging of electric vehicles is at its lowest throughout the day because the price is so high.

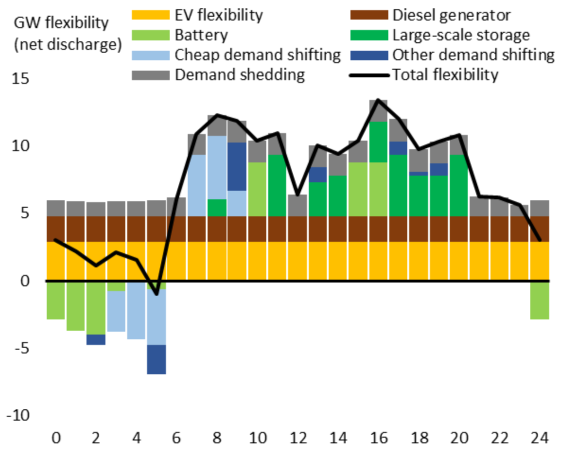


Figure 14-12: Contributions from flexibility during the tightest winter day in Germany Baseline 2040.

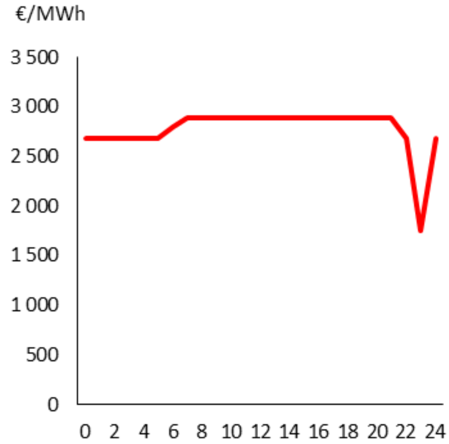


Figure 14-13: Price during the tightest winter day in Germany Baseline 2040.

It is uncertain whether the power market will be able to be as optimised in tight periods as is described by the figures above. In order to charge batteries or increase demand at night to a price exceeding 2500 €/MWh, it must be reasonably certain that the price will be even higher during the day. Nevertheless, the results from the model simulations are interesting. They indicate both that different types of flexibility and storage may pull in the same direction, but also that some of the flexibility may be inaccessible for longer periods of tightness.

Industry consumption contributes both in scarcity and oversupply situations

Towards 2040, flexibility on the demand side sometimes sets the price directly. Figure 14-14 shows the German power price during a week in August in our High scenario and in a variant where we have removed most of the flexibility from demand response and storage. We see more flexibility flattering the price primarily by elevating the lowest prices, but also by cutting price peaks where gas turbines set the price. At the same time, demand from hydrogen production will set the price directly in more hours. We have presumed that hydrogen producers have a willingness to pay 40 €/MWh. During the hours the contribution from renewables is greatest relative to demand, the price still approaches zero, despite more flexibility.

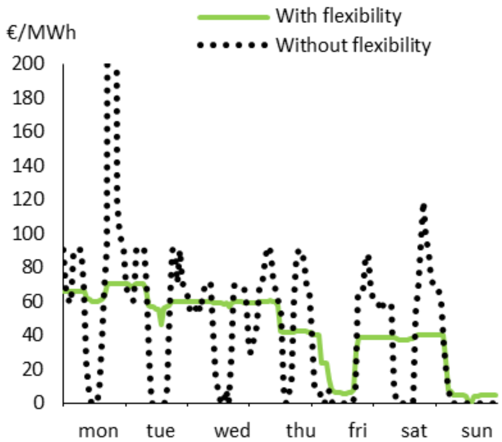


Figure 14-14: The power price in an illustrative summer week in Germany in High 2040, compared with a sensitivity without flexibility (demand response, batteries and other storage).

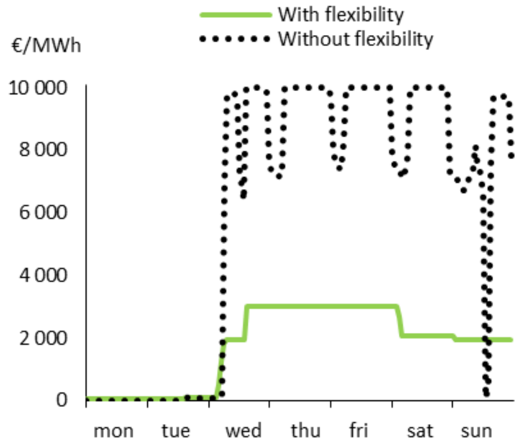


Figure 14-15: The power price in an illustrative winter week in Germany in High 2040, compared with a sensitivity without flexibility (demand response, batteries and other storage). Note: Scale on y-axis!

In all our three scenarios, we have presumed that the overall reduction potential in power-intensive industry amounts to a "shedding threshold" at the top of the demand curve, and thus sets the price in the tightest hours. This is important in order to supply earnings to peak load plants and provide a buffer against rationing through controlled and market-driven shedding. Figure 14-15 shows how shedding of consumption acts as a price ceiling and prevents rationing (in the model, the rationing price is 10,000 €/MWh). Additional peak load plants would, of course, further reduce the price, but the earnings of thermal plants, and especially remaining peak load plants, would thereby be significantly reduced.

The potential and profitability of flexibility and storage is uncertain

The technical and financial potential of flexibility and storage is uncertain. The volumes we have included in our specific data sets are based on both literature and our own analyses.

The investment cost of lithium-ion batteries has fallen radically in recent years. Several stakeholders estimate that the costs have declined by 15-25% annually since 2010.[55] Moving forward, one important uncertainty is how long the cost reduction will continue. Bloomberg estimates a continued reduction of about 10-15% annually compared with 2030, which corresponds to a cost for battery systems[56] of approx. 250-300 €/MWh.

We also see in our simulations that income from batteries in day-ahead and balance markets quickly declines when the volume increases, since they reduce short-term price volatility so efficiently. At the same time, they may provide other income, e.g. by optimising self-generation and/or utilisation of distribution grids. The batteries in our data sets are not profitable merely based on income from the day-ahead market, but this is the source of most of their income. Figure 14-16 shows earnings in Baseline and High for a battery system.

Because large-scale storage is still not a commercial technology, the uncertainty surrounding potentials and costs is greater than for batteries. It is uncertain which technology will prevail. In our simulations, we have based our assumptions on a few studies that examine power-to-gas with storage in underground facilities and use of fuel cells, but it may just as likely be about compressed air or chemical storage. The studies indicate long-term cost estimates that are approximately triple our projections of the investment cost of batteries in 2040. Despite the fact that large-scale storage has more robust earnings than batteries due to its greater storage capacity, our simulations show that they generally have substantially lower profitability. We have nevertheless chosen to include this in our baseline scenario, since there is obviously a considerable need for storage capacity with large reservoirs in our 2040 data sets.

[55] Bloomberg New Energy Finance, IHS and Rocky Mountain Institute (RMI).
[56] A battery system consists of battery cells in addition to converter installations. A simple rule indicates that the cost of the converter installation is just as great as that of the actual batteries.

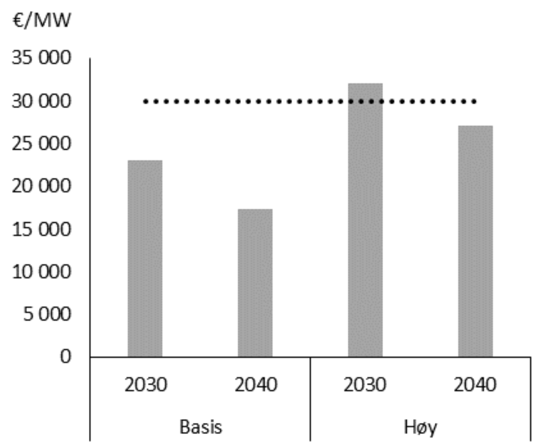


Figure 14-16: Average annual income from trading in the day-ahead market with batteries. The line indicates what income level is needed for break-even with an investment cost for 300 €/MWh of storage capacity.

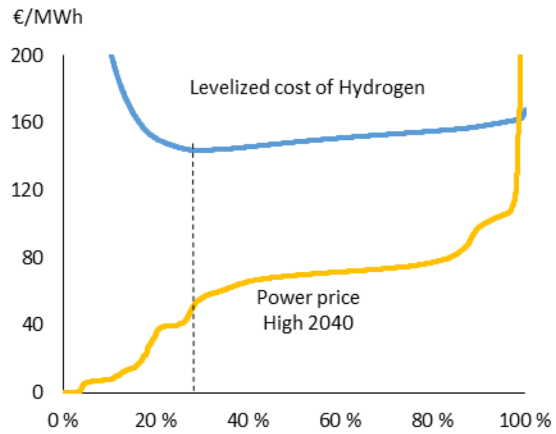


Figure 14-17: The production cost of hydrogen in a flexible electrolysis plant, given the price structure in the High scenario 2040.

Figure 14-17 shows the long-term marginal cost of hydrogen production in an electrolysis plant based on the power price in our High scenario 2040. Because of considerable volatility in the power price, we see a clear minimum point for the cost of hydrogen production. When we estimate a willingness to pay for power of 40 €/MWh for the hydrogen production, the optimal number of full-load hours of the plant is 25% and the production cost of the hydrogen is thus about 140 €/MWh. This corresponds to a fuel cost of about 0.3 € per travelled 10 km for a passenger car, compared with an average cost of 0.1 € per travelled 10 km for an electric vehicle in our 2040 scenario. The cost of such hydrogen production is primarily sensitive to the development within electrolysis technology, but also for how the future need for hydrogen will develop. Nevertheless, it is clear that a high preponderance of very low power prices may make it profitable to run some industrial processes with considerably more flexibility than is the case today.

14.4 Hydropower investments may moderate price fluctuations in Norway and Sweden

Greater price volatility could make it profitable to develop more output and pumped storage hydropower in dispatchable hydropower plants in Norway and Sweden. This may moderate price fluctuations. In Baseline and High for 2040 and High for 2030, we have presumed a 2,500 MW increase in the installed capacity in existing Norwegian hydropower plants. However, we have not presumed any greater development. This is due to the considerable uncertainty in both costs, future prices and potential, in addition to the fact that we currently do not have the capability to model pumped storage hydropower in an adequate manner. However, the price situation we see in our simulations of 2030-2040 indicates that there may be a basis for substantial investments in both pumps and more output.

Considerable technical potential

Many of the hydropower plants in both Norway and Sweden can be upgraded with more output in relation to inflow and reservoirs. The potential may be considerable, although the opportunities are limited by physical factors as well as licences, regulation and cost. In the report "Increased installation in existing hydropower plants", the Norwegian Water Resources and Energy Directorate (NVE) estimates a technical potential of 16,500 MW (NVE 2011).

Shifting of generation and price differences yield increased profitability
Power plants with more output produce the same volume of power in fewer hours. In other words, the power plant shifts generation from hours with a low price to hours with a high price when they have a higher maximum output. This not only gives the power plant greater revenues, but also leads to more hours with power price equalisation. With sufficient available output, prices through the day will be nearly the same, as has historically been the case in the Nordic region.

We have examined the impact in the power system of upgrading output in some power plants, without changing the reservoir size or inflow. The cost and profitability of upgrading the power plants are not part of our analysis, we merely examine the impact, as well as a look at the income from the upgraded power plants. Overall, we have increased the installed capacity by up to 20,000 MW of new output in Norway in Baseline 2040.

Figure 14-18 shows one of the results from this sub-analysis, in the form of a duration curve for generation in one of the hydropower plants where we have increased the installed capacity. The impact of the increased output is clearly evident in the figure. With low installed capacity, the power plant produces for most hours of the year and vice versa.

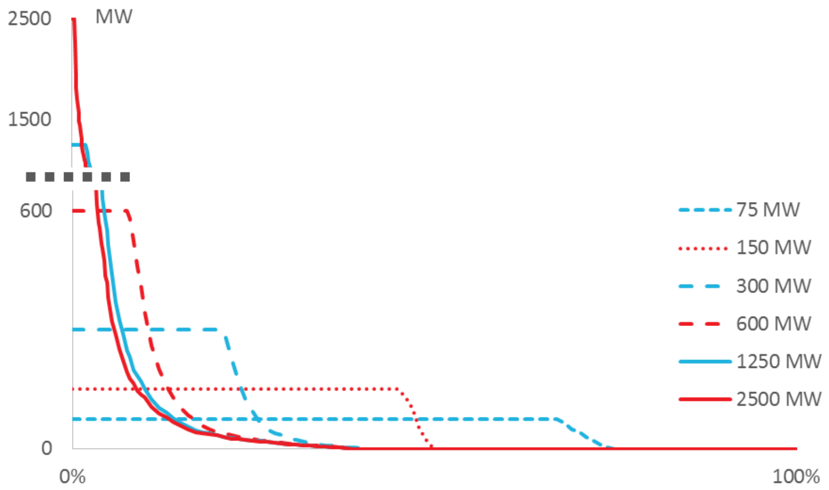


Figure 14-18: Simulated generation from a power plant with the same inflow and reservoir, but different installed capacity.

In order for greater output to be profitable, there must be price differences for the power plant to exploit. The price differences increase throughout the analysis period, and thus also the potential income from increased output. We have estimated the income potential with our data sets, and find an income of approx. 7,500 €/MW in 2020, 18,500 €/MW in 2030 and 30,000 €/MW in 2040.

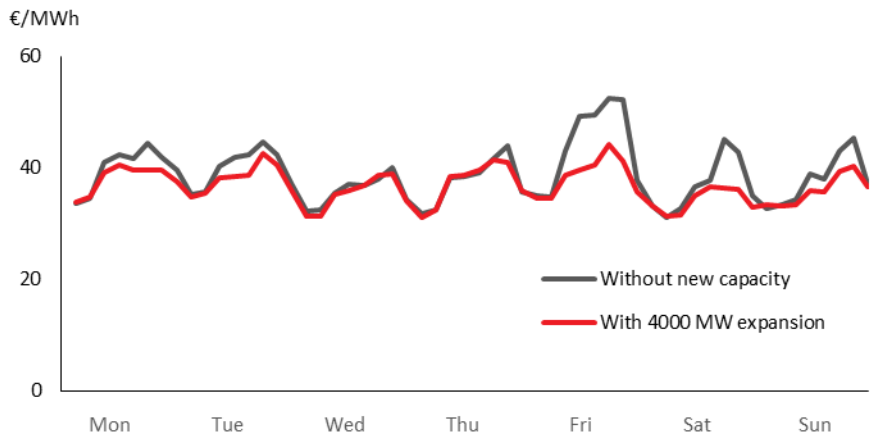


Figure 14-19: Illustration of price in Southern Norway with and without 4000 MW expansion in hydropower plants with low number of full-load hours.
The figure shows a simulated average week in the winter in a weather year.

We believe that growth in installed capacity in Norwegian hydropower appears realistic. This would be a natural response to increased price differences, and can be accomplished in connection with rehabilitations of the many power plants that reach their lifetimes in the 2020s and 2030s. With our price forecasts, such upgrades will be more profitable than today, but we emphasise that there is significant uncertainty surrounding this. Upgrading power plants exclusively to increase capacity may appear less realistic, but this will, of course, be strongly linked to the development in costs as well as income.

Pumped storage power plants may further increase flexibility

By investing in pumped storage hydropower plants, generators of hydropower may exploit short-term price differences somewhat differently than pure output upgrades. The power plant pumps water up in hours with low power prices and can generate power with the same water in hours with higher power prices. This process contributes even more toward equalising the prices than output installations alone, since they consume/pump power in hours with a low price, and produce in hours with a high price.

In order for it to be profitable, the price difference, and hence income, must be sufficient to cover energy loss in the process. The income must also be able to justify considerable investment costs. We have conducted a few very rough estimates of income for pumped storage power plants based on our Baseline dataset. The intention is primarily to say something about changed assumptions for pumped storage hydropower, and is not a real estimate of income.

The income is approx. 6,500 €/MW in our 2020 data set, 21,000 €/MW in 2030, and 54,000 €/MW in 2040. We thus see that the increased price fluctuations in Norwegian and Nordic power prices will have great significance for the income from pumped storage power plants, which is entirely in accordance with our expectations.

The income also increases more for pumping relative to greater installed capacity, which means that gains from pumping will be more important in the future. It is easy to envision that this is linked to a greater share of renewables generation, which yields very low prices in certain periods - prices that a pumped storage power plant can exploit, but which are more difficult to exploit for a peak power plant since it is already not generating in these hours.

The Nordic power system model we use today cannot adequately estimate the impact of output pumping. The reason is that there has not previously been a need for such calculations, and the model therefore does not fully optimise generation on an hourly basis. We are also working on several R&D programmes to improve the existing models and develop new ones, so that rapid price fluctuations, pumping and hydropeaking are taken into greater consideration.

Income differences between peak power plants and pumped storage power plants
Peak and pumped storage power plants both exploit price differences and contribute to even out prices, but there is nevertheless somewhat of a difference between the prices that are important for them.

A power plant with 4000 hours of operation typically generates in the about 4000 hours with the highest price over the course of a year, provided that it is adequately flexible. If the power plant is upgraded to double the output, and thus 2000 hours of operation, it can shift the generation to the 2000 hours with the highest price. The important factor is thus the price difference between the 2000 hours with the highest price and the 2000 hours with the second-highest price.

A pumped storage power plant pumps up water in hours with the lowest price, and produces water in hours with the highest price. The important factor is thus the price difference between, e.g., the 2000 hours with the highest price and the 2000 hours with the lowest price. This difference, as well as the fact that pumping results in a loss that generation shifting does not, means that the more profitable of the two expansions will differ in each situation.

15 Power Flow and Price Differences between Countries and Regions

With a growing share of intermittent renewables generation, we already observe greater power flow both between and within countries. This is a key driver for the extensive grid development plans throughout Europe. In the Nordic region, we see that the current north-south flow pattern is stronger.

15.1 More exchange and greater price differences on the Continent

Our simulations clearly show that the power flow between countries on the Continent will increase significantly towards 2030 (figure 15-1 and figure 15-2). The need for exchange will increasingly be driven by the weather. Our weather series show that the weather in Europe is correlated, but far from perfect. Trading between larger areas is thus important in order to effectively integrate renewable energy. How much the flow will increase will naturally also depend on how much grid capacity will increase.

The figures below also show that both Germany and France will go from being large power exporters in 2020 toward more balanced exchange over the longer term. In Germany, this is because nuclear power, coal and lignite are being decommissioned. France has traditionally been a major exporter due to a large share of nuclear power, but this will change gradually as the share declines. All countries will also have more renewables.

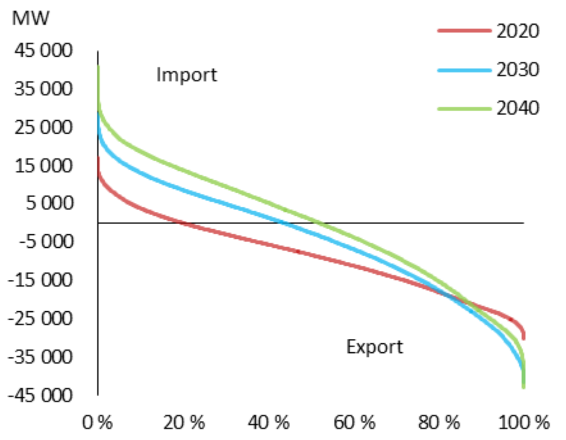


Figure 15-1: Duration for German power trading in our baseline scenario.

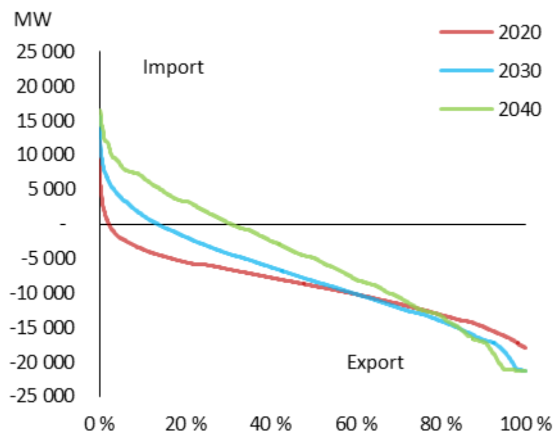


Figure 15-2: Duration for French power trading in our baseline scenario.

On average, a more uniform capacity mix in Europe towards 2030 also results in more equal average prices. This may give the impression that price differences between countries will be smaller, but obscures the fact that prices vary substantially between different areas in line with the renewable generation. Figure 15-3 illustrates how the price difference between Germany and four other European countries develops in our baseline scenario. We see a clear trend toward greater price differences[57]. Figure 15-4 shows the price differences in our three scenarios in 2040. The differences increase with the price level and more volatile prices. At the same time, we see that price differences in 2040 in our Low scenario are higher than in the baseline scenario in 2030, despite the significantly

[57] In 2020, the special CO_2 tax in the UK will make British prices substantially higher than in the surrounding countries. We presume that this will disappear towards 2030. This will result in a more equal price level and reduce price differences significantly.

lower price level. This confirms that more renewables, in isolation, results in increased price differences.

Detailed studies of price differences between countries on the Continent has not been the main purpose of this analysis. Reduced grid capacity and other incidents in the power system are often the origin of significant price differences for shorter periods of time. At the same time, more grid capacity after 2030 than what we have presumed may reduce the differences. In sum, there is nevertheless a clear trend towards increased value of transmission capacity.

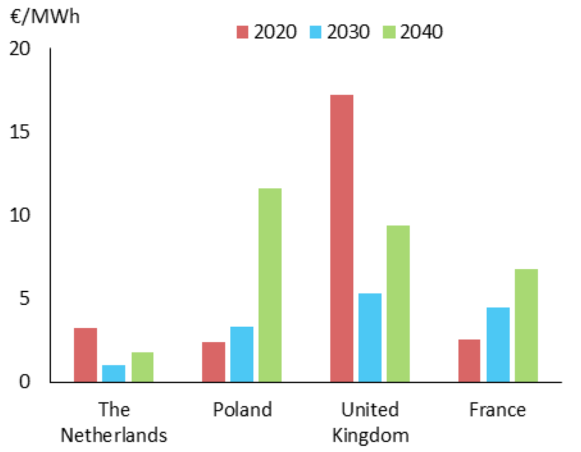


Figure 15-3: Absolute price difference between Germany and other areas in Baseline for 2020, 2030 and 2040.

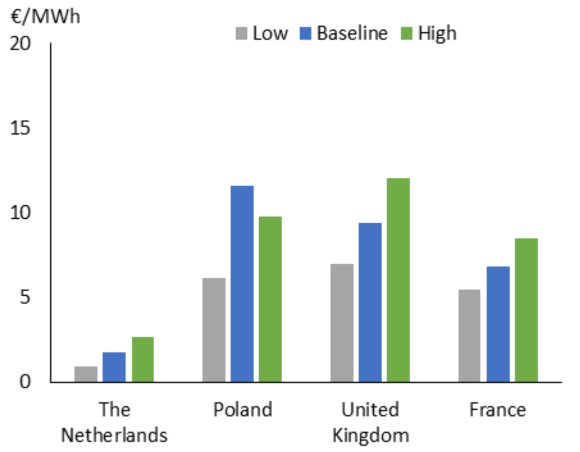


Figure 15-4: Absolute price difference between Germany and other areas in Low, Baseline and High for 2040

15.2 Increased power trading within and out of the Nordic region – greater price differences

An increasingly larger share of intermittent generation in the Nordic region will eventually result in much greater fluctuations in the output situation on the Nordic side. This yields both more flow within the Nordic region, but also to neighbouring countries. Table 15-1 summarises changes in annual import and export between Norway, Sweden and Finland and associated areas.

Table 15-1: Import, export and net export (TWh per year) between Norway, Sweden and Finland and associated areas in a normal year. Baseline 2020, 2030 and 2040.

	2020			2030			2040		
	↓	↑	Net	↓	↑	Net	↓	↑	Net
Denmark	8	9	0	7	12	4	8	11	3
Germany	10	9	-1	9	13	5	10	13	3
The Netherlands	1	3	2	1	3	1	2	3	1
The UK	0	12	11	2	7	5	7	14	7
Poland	2	2	1	1	3	2	1	3	2
The Baltic	5	4	-1	5	4	-1	4	5	1
Russia	4	0	-4	5	0	-5	4	0	-3
TOTAL	31	39	9	31	42	11	35	49	14

We also see a clear seasonal profile in trade out of Norway, Sweden and Finland. Figure 15-5 illustrates this. In the winter, there are often considerable imports driven by low prices on the Continent, but also in situations with scarcity at the Nordic level. In the summer months, non-dispatchable hydro, wind and solar power will increasingly cover whole hours of Nordic consumption as well as exports.

Most of the consumption in the Nordic region is located in the south, whereas a large share of the generation capacity is located in the north. This results in a considerable flow of power from the northern to the southern areas. Figure 15-6 shows that this flow pattern will amplify toward 2030 and 2040. The primary causes are further development of wind power in the north, decommissioning of nuclear power in the south and the location of the new interconnectors to Europe in the south and west.

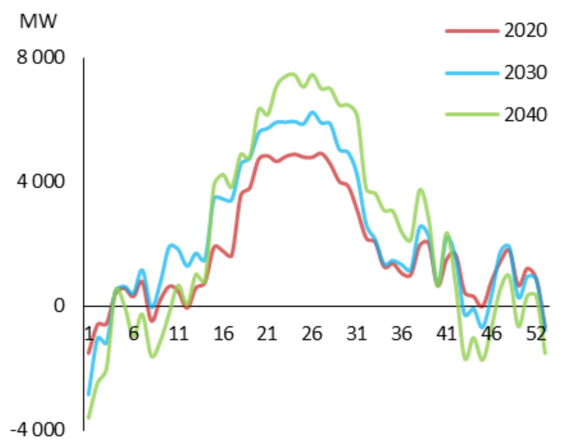


Figure 15-5: Total flow per week out of Norway, Sweden and Finland to the south in 2020, 2030 and 2040.

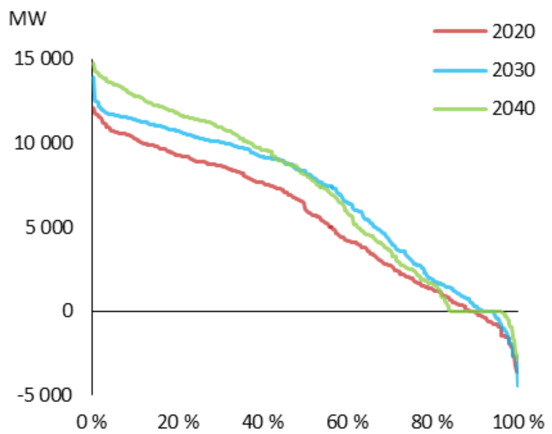


Figure 15-6: Duration of total north-south flow through Norway, Sweden and Finland in 2020, 2030 and 2040.

More power flow also results in growing price differences. Within the Nordic region, the areas in the north will likely approach a somewhat lower price level. The price differences in the Nordic region will increase with the price level. We expect rising price differences towards the Continent as well[58]. The magnitude of the price difference is nevertheless associated with considerable uncertainty, as illustrated through our different price scenarios. Again, we must emphasize that this analysis is not about price differences and the benefit of reinforcing the grid between specific areas.

[58] The high price difference compared with the UK in 2020 is due to the fact that the price level there will be considerably higher than in the rest of Northern Europe. Our assumption that the special British CO_2 tax will disappear and that the capacity mix will be more equal with the one on the Continent will remove most of the difference in the price level, and thus reduces price differences towards 2030.

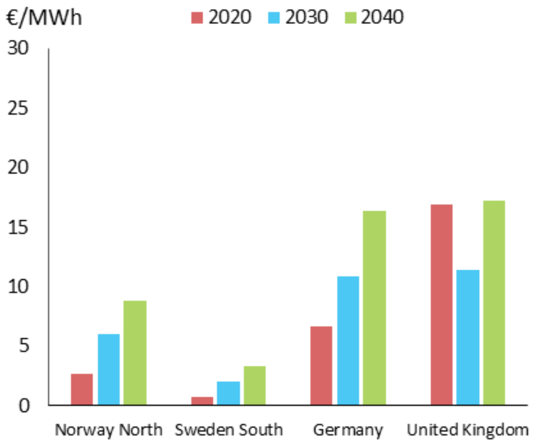


Figure 15-7: Absolute price difference between Southern Norway and other areas in Baseline for 2020, 2030 and 2040.

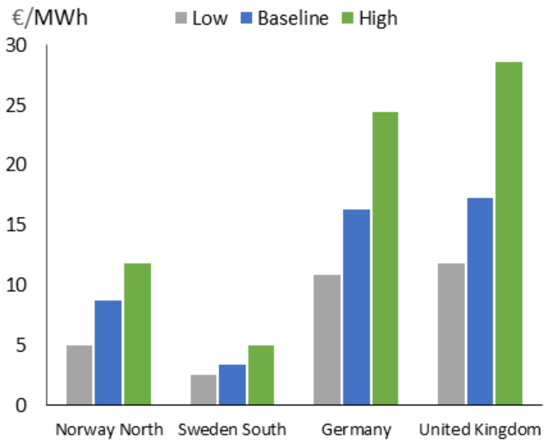


Figure 15-8: Absolute price difference between Southern Norway and other areas in Low, Baseline and High for 2040.

16 Key Issues in the Future Power Market

When we move the analysis horizon from 2030 to 2040, uncertainty increases for multiple factors. The analysis of 2040 nevertheless provides a useful overview of primary trends and fundamental connections that will dominate the power system and the market. We also have an improved basis for assessing what will be rational investments in the power system long before 2040, and thus a better basis for our assumptions for 2020 and 2030. In the same way, the development after 2040 is highly relevant for what will happen before we get that far.

In this chapter, we discuss a few issues we see coming after 2040. The point is not to provide definite answers and solutions, but to summarise possible challenges and important issues.

16.1 Demanding emission cuts despite rapid deployment of renewables

In 2040, there are still considerable emissions of CO_2 in both the power sector and the rest of the energy system in our scenarios. At the same time, solar and wind power now appear to be the technology winners. The question is how much progress can be made by cutting emissions primarily based on the development of solar and wind power.

The challenges in cutting emissions through the development of solar and wind become increasingly greater as the share increases. In 2040, the total installed capacity from these two technologies is more than twice as high as average consumption in our scenarios[59]. One pervasive theme in this report has been how this changes the power system. The greatest challenge is the enormous variation in generation from these sources, and that it is hardly correlated with the existing consumption profile. We have focused on the consequences for the power market, and power prices in particular.

When we increase the share of solar and wind power beyond the 2040 level, there is an increasing number of hours where intermittent generation covers the entire consumption. At the same time, there are still periods with negligible renewable generation. Figure 16-1 shows the development in residual demand in a hypothetical case where the share of solar and wind increases to 50 and 70% given the current consumption profile. Residual demand varies between +300 and -300 GW. Historically, this has varied between +300 and +150 GW, about on a par with the variation in consumption.

[59] This is in addition to intermittent generation from hydropower and thermal capacity with little regulating capacity.

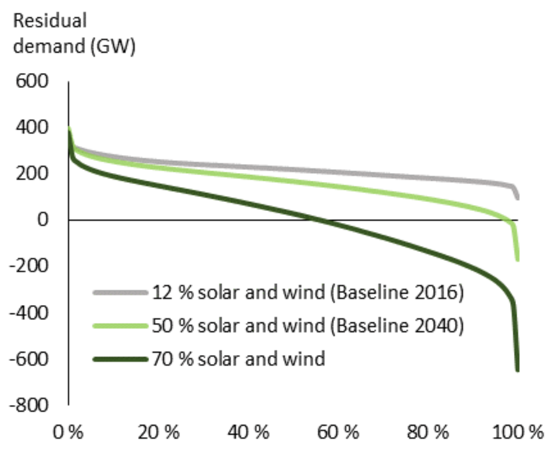


Figure 16-1: Residual demand in EU10 in 2016, and two possible data sets for 2040 where solar and wind account for 50 and 70%, respectively, of the generation given the current consumption profile.

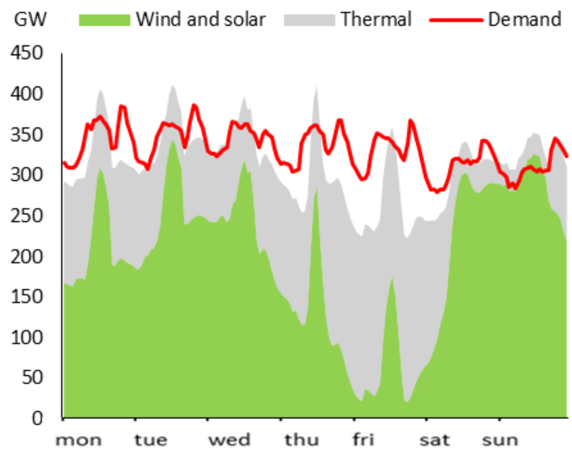


Figure 16-2: Total consumption, contributions from solar and wind, and thermal for EU10 in a random winter week from our baseline scenario 2040.

The question is how to balance a system with such considerable, rapid and volatile changes. The greatest challenge is most likely how to cover consumption in periods where renewables generation is considerably lower than normal for many days in a row. On the other hand, one must be able to move and exploit the energy in periods with enormous overproduction in order for such a development to be appropriate. There are also several other challenges. The variations within short periods of time will be at an entirely different level than today. Figure 16-2 shows an example from our baseline scenario for 2040. In this week, total generation from solar and wind power will go from nearly 0 to 300 GW in one day. Although the weather forecasts have improved, such extreme changes will most likely yield significant deviations between forecasts and real generation with the associated need for short-term balancing during the operating hour. One other factor is that, with our model simulations, we simplify and optimise the system too well. For example, in the model, a perfect forecast without uncertainty within a week yields a virtually optimal utilisation of all available flexibility from thermal power plants, storage and consumption. In our market model for Europe[60], we also have fewer and more simplified restrictions within grids and generation, as well as fewer unexpected events and less randomness than what is the case in reality. Our model simulations thus underestimate the challenges that follow from such high shares of solar and wind power as we are discussing here.

In the same way as for the period toward 2040, further focus on solar and wind obviously presumes significant growth within energy storage, in addition to even more consumption responding to both high and low prices. The question is to what extent this is possible, and whether or not other sources of emission-free generation are nevertheless successful. As of today, it is difficult to see good alternatives, given that nuclear power continues to be expensive and unacceptable in many countries, and CCS is far from able to assist on a major scale. However, we can still end up in a scenario where nuclear power and CCS play a key role, for example as emphasised by the IEA in its scenarios. Fuel cells with hydrogen may be an opportunity, particularly if the costs fall substantially. Biogas may also assist in periods of scarcity. Biogas can exploit the existing infrastructure and seasonal storage. It is also possible to use biogas in fuel cells – potentially in the form of distributed generation of power and heat. The improvement of geothermal power generation, wind power with a longer number of full-

[60] The BID model, which is described in detail in Chapter 2.1.

load hours and ocean energy may also provide certain contributions toward stabilising access to power.

If we view the entire energy system as one, it is clear that energy efficiency must play a key role. It will be considerably easier to reach the goal of decarbonisation if overall energy consumption is reduced significantly.

How further emission cuts will be implemented after 2040 is a key uncertainty. Without delving too deeply into this now, we can conclude that it will be increasingly more demanding to proceed based on the development of solar and wind power alone. At the same time, it is highly likely that the market share for these technologies will exceed 50%, as we have presumed for 2040.

16.2 Security of supply and load shedding

In our baseline scenario for 2040, we still have 300 GW of thermal capacity in EU10, and 200 GW of this is coal and gas-fired power plants. In periods with little renewables, these power plants will be the backbone of the system, although flexibility from storage and consumption play an increasingly important role. However, with further development of solar and wind power, the number of full-load hours of thermal plants will be increasingly lower. At the same time, a further phasing-out of coal and gas power, without replacing this with CCS, nuclear and biopower, entails that the contribution from storage and flexible consumption must increase considerably. This is in addition to the already high level we have presumed in 2040. Figure 16-4 shows that, during the most strained week in Baseline 2040, we have a total of just over 100 hours in a row with an overall reduction of 4000-6000 MW of industrial consumption in the EU10 area. A key question after 2040 is to what extent it is acceptable to have even greater, more long-term and more frequent reductions in consumption.

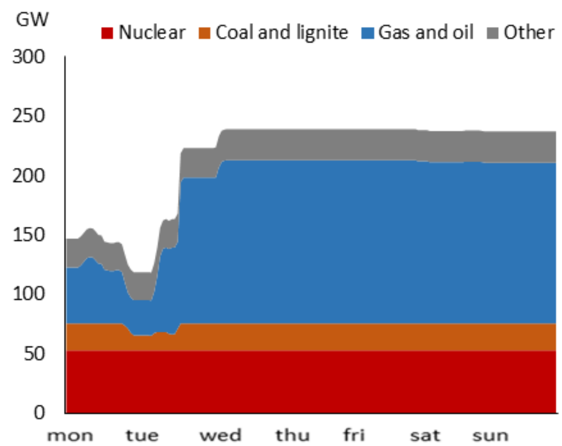


Figure 16-3: Thermal generation in EU10 during the tightest week in Baseline 2040.

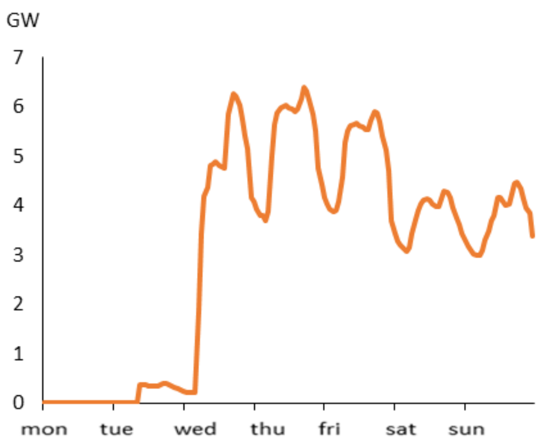


Figure 16-4: Total shedding of industry load in EU 10 in the tightest week in Baseline 2040.

Using capacity mechanisms to maintain several hundred GW of generation capacity that will only be used in exceptional cases will most likely result in disproportionately large costs. The total generation capacity from untreated coal and gas power will therefore most likely be significantly reduced from the level we have presumed in 2040, and the contribution from storage and demand response must grow further to avoid rationing. It nevertheless appears to be necessary to have some biopower, nuclear power and CCS as a basis. Within a scenario where emissions are cut by 80%, there may also be room for some untreated gas with a short number of full-load hours that will help during the scarcest hours. In any event, there will be a trade-off between having generation and storage capacity that is only used in extraordinary cases, and having a substantial market-based reduction of the consumption during the most strained hours, with associated high prices. The issue will arise long before 2040, but will become an even larger issue in the final part of the process towards a virtually emission-free power system.

This makes it more clear and likely that national authorities will eventually need to change their thinking when it comes to security of supply. The goal will still be to ensure that generation will cover consumption and that the system is operated with a high degree of stability and minimal risk of outages. However, the consumption that is being covered must be reduced during hours with high residual demand. The goal is thus to a greater extent to ensure a controlled and market-driven reduction of consumption during these periods. A precondition for this is greater acceptance that the power price will be very high for brief periods. This will ensure earnings for remaining thermal plants, and will make the system more robust in relation to faults. It is also becoming more evident that looking beyond one's own borders and sharing the available capacity holds a potential for vast cost savings.

16.3 Need new flexible schemes to acquire the full value of renewables

When the share of solar and wind power, measured as a percentage of overall annual production, becomes greater than 30%, our simulations show that a growing portion of the generation will be lost in the form of unused over-generation. Without storage and flexible consumption, approx. 20% will be lost if the share of solar and wind power increases from 40 to 50%. At 60% solar and wind power, the loss will approach 30%. Figure 16-5 shows loss per hour in sequence over a simulated weather year where the renewable capacity in theory produces 60% of the energy given the current consumption profile and without storage. In this example, there is a loss of energy for more than 25% of the hours, and the maximum loss is about 300 GW. Naturally, the loss of approx. one-third of new solar and wind power generation has a strongly diminishing effect on further emission cuts.

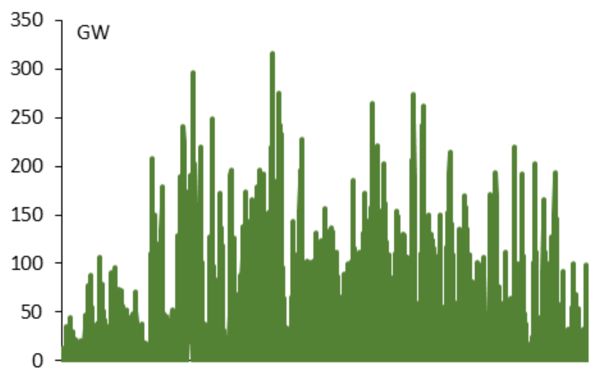


*Figure 16-5: Waste per hour during a weather year for a hypothetical scenario where solar and wind power covers 60%
of the consumption without new flexibility from storage and consumption.*

More flexibility in the form of consumption and storage will be essential in order to maintain the financial value of renewables generation, and the desired effect on CO_2 emissions. However, it will still not be profitable to invest in so much flexibility that energy loss is completely avoided. There will eventually be a balance between the costs associated with exploiting all generation during the most windy and sunny periods, and the costs of letting some of the generation go to waste. The cost development for new solar cells and wind turbines, relative to the costs of e.g. batteries and other storage technologies, will play a role here. The cheaper it becomes to develop new generation, the less important it becomes to keep all the generation. In the converse, very cheap batteries could yield major investments in such capacity, although a lot of this will remain unused for much of the time. Nevertheless, the contribution from solar and wind power is so concentrated during periods that in a system where renewables account for the better part of the generation, it will hardly be profitable to exploit all the energy.

16.4 Market design and investments

Over a time horizon as long as 2040-2050, both the manner in which the power market is currently organised and the role it has in the power system could change substantially. We will not discuss this at length, but will only briefly discuss two issues that we see could become more significant in a longer perspective.

Might be necessary to move market clearing closer to the operating hour – due to renewables
As intermittent renewable generation achieves larger market shares, we can expect greater deviations between the generation forecasts that form the basis for the bidding in the day-ahead market and real generation during the operating hour. Continuous improvements in forecast models and weather forecasts will limit this effect, but with the major volumes of solar and wind power that we predict 25-30 years in the future, even minor deviations in the prognoses can result in significant imbalances measured in MW. This will most likely entail a greater need for regulation resources during the operating hour. It will most likely also entail that more trade must be moved closer to the operating hour. The changes this may trigger in the organisation of the market are uncertain, but it could, in the most extreme outcome, make it necessary to move the market clearing from day-ahead to a type of continuous clearing hour by hour immediately before the operating hour.

We may experience a permanent disconnection of the short- and long-term market balance
The price formation in the market is currently generally based on the power plants' short-term marginal costs. Solar and wind power have negligible marginal costs, however, which results in prices near zero when they are price-setting[61]. The big question in the long term is whether a market based on marginal cost pricing could function satisfactorily when the share of solar and wind power grows to 40, 50 and perhaps 60%. With such vast volumes of generation without significant generation costs, the consumption side and storage will need to tackle an increasingly stronger role in the pricing. This is fully possible and in our Baseline data set for 2040 we have assumed that this is largely the case. At the same time, it is uncertain whether storage and demand response can provide a sufficiently high price level, so that we achieve the desired investments, seen from society's perspective.

Our analyses indicate that it will be difficult to have such a major renewable energy percentage while also having a market that yields prices where all players earn enough to cover their investment and operating expenses. In the simulations of our data sets for 2040, both consumption and storage largely contribute to lift the prices up from zero during periods with considerable solar and wind power. At the same time, we see a continued need for subsidies for solar and wind power due to a strong reduction in the achieved power price for renewables. The additional flexibility will not provide a large enough price boost when there is a lot of solar and wind power. Naturally, there is significant uncertainty associated with how the new flexibility will affect prices. At the same time, we believe there is a clear possibility that we may never end up in a situation where it becomes profitable to develop renewables on the Continent and in the UK based on the power prices alone. The situation is

[61] May also yield negative prices if the generation is linked to feed-in tariffs.

different in Norway, Sweden and Finland, where dispatchable hydropower to a greater extent helps maintain the prices during hours with considerable wind power.

We discussed in Chapter 14 how an unstable long-term market balance results in major uncertainty for investors in thermal generation and flexibility. This uncertainty will most likely grow even larger in the event of further development of solar and wind power after 2040. This could result in a situation with less flexibility available than is optimal from a societal perspective. The result could become both more hours with rationing and more hours with energy loss than what society is actually willing to pay for. This could bring about forced permanent solutions for paying for capacity outside the ordinary power market, either through capacity markets or that electricity customers who want stable deliveries will pay extra for this in the form of a package solution.

In summation, there is a real possibility that we will end up with a permanent partial disconnection between the prices provided by the short-term market balance and the investments that form the basis for the relationship between supply and demand in the long-term market balance. The power market would in this case have a role where the most important factor is the daily optimisation of the system. At the same time, auctions, capacity markets and subsidies constitute much of the foundation for investments.

16.5 Sweden without nuclear power is a key issue

Nuclear power is a key part of the Swedish power system, but also contributes stable power generation during dry years, which is also important for Norway[62]. Today, there are clear political signals that all nuclear power in Sweden will eventually be closed down. However, since nuclear power is so important for the Swedish power system, this presumes a gradual phase-out where the authorities will constantly assess the consequences in relation to ensuring an adequate security of supply.

As far as we know, a Swedish power system completely without nuclear power has not been subject to much analysis. In its future visions for the Swedish energy system in 2050, the Swedish energy authorities have presumed that all nuclear power will be closed down in three out of four scenarios. It is mainly different combinations of solar and wind power that will cover the loss of nuclear power. In addition to hydropower, there is some combined heat and power and small-scale biopower at the underlying foundation. In two of the scenarios, the consumption of power is about on par with the current level. The analysis does not go into detail about how the system will be balanced and how the transmission need will change, but says that flexible consumption and storage must play a key role. In one scenario, solar power covers approx. one-fifth of the consumption. This presupposes massive growth in storage capacity.

Swedish nuclear power is reduced to 4000 MW in our baseline scenario for 2040. Furthermore, we have used approximately the same measures as a basis as the energy authority, with an emphasis on wind power farms in Southern Sweden, more biopower plants, as well as limiting consumption growth[63]. There is still a substantial increase in import going to Southern Sweden. Figure 16-6 compares overall average simulated flow in to Southern Sweden during a winter day today and in 2040. On the tightest days, the average power flow going to Southern Sweden is more than 10 GW throughout the day in 2040, about twice as much as today. We have increased transmission capacity on SE2-SE3, which primarily supplies Southern Sweden, but have also increased the capacity from the Continent.

[62] Southern Sweden means bidding zones SE3 and SE4. After Barsebäck was shut down in 2005, all nuclear power is in SE3.
[63] We nevertheless have a growth in consumption driven by electric vehicles.

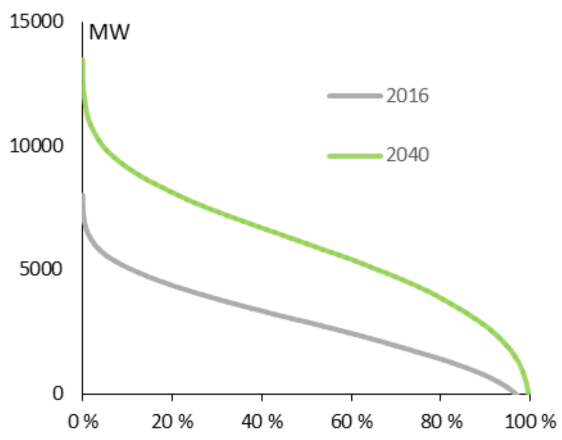


Figure 16-6: Overall simulated flow in to Southern Sweden during the winter in 2016 and Baseline 2040.

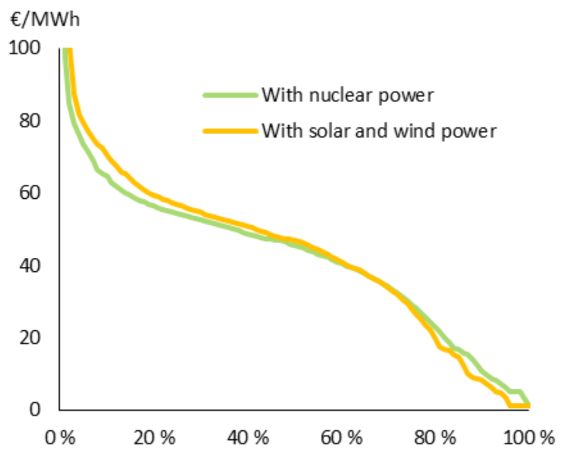


Figure 16-7: Duration curve for Swedish price in Baseline 2040 and a case without Swedish nuclear power, but with a corresponding increase in solar and wind power.

Figure 16-7 shows the price situation in Southern Sweden in a sensitivity where we have removed the remaining nuclear power in Sweden and replaced the reduced generation with an equal volume of generation in the form of local solar and wind power in Southern Sweden. We have, however, not added any other measures and market-related adaptations. As we can see, this results in high price volatility with more hours with rationing and more hours with prices near zero. At the same time, power exchange with areas bordering Southern Sweden will increase further. This supports the viewpoint that it is most likely not sufficient to replace nuclear power with solar and wind power alone.

Our market simulations probably underestimate the challenges associated with operating and balancing a Nordic system where Swedish nuclear power is significantly reduced or completely phased out. At the same time, all the measures we use as a basis are relevant and it is difficult to imagine that Southern Sweden in such a scenario would not become dependent on major import during hours without much renewables generation. Most likely, demand response will become as important as it is on the Continent, and in Baseline 2040 we have shedding of industry load to balance the market during the scarcest hours.

More interconnectors going to the Continent and the UK will make Norway less dependent on import from Sweden in order to cover energy deficits during dry winters. The impact of less nuclear power will primarily come in the form of a high willingness to pay for Norwegian capacity, also from Sweden. This will contribute to both more and higher price peaks in Norway as well. One consequence is that capacity between Southern Norway and Sweden will be more beneficial. However, whether it will be profitable to invest in a new interconnector depends on a number of uncertain elements. This will, however, most likely not occur for a long time, as we do not expect the phase-out of Swedish nuclear power to occur until the period 2035-2045.

16.6 Norway can export of both energy and flexibility

Our scenarios presume less changes in the Norwegian power system compared with our neighbouring countries. The basis for this is that the power system is already virtually 100% renewable, and we have little thermal generation or nuclear power that will be closed down. At the same time, Norway is part of a well-integrated Nordic market that will be more closely linked with the European, particularly through more interconnectors from Southern Norway. This means that the other changes in the Nordic region and in Northern Europe will also have consequences here. Along with the growth of intermittent generation as a share of the total in Norway, this will create significant differences compared with the present. We see two trends in particular:

- Demand for Norwegian flexibility increases during winter
- Norway needs flexibility in the form of export capacity during the summer months due to considerable intermittent generation

We see that the market situations in Norway and Europe largely supplement each other. During the winter periods when Europe has a large export need, Norway can receive this power during most hours because the marginal value of stored water in dispatchable reservoirs set the price. We export capacity during hours of scarcity. During the summer when Norway has a considerable and non-dispatchable surplus, surplus flexibility from batteries and other types of storage in Europe will yield a power price level that is higher and more stable than in Norway. Export from Norway and the Nordic region will then function more as base load.

Figure 16-8 shows overall flow in interconnectors from Southern Norway in 2040 to the Netherlands, Germany, Denmark and the UK, distributed among summer and winter, and illustrates the above points. The power exchange during winter is relatively balanced, with many hours with full import and full export. Overall, there will be weak net import. During the summer, there is export about 80% of the time, and for much of the time there is full export in all channels at the same time.

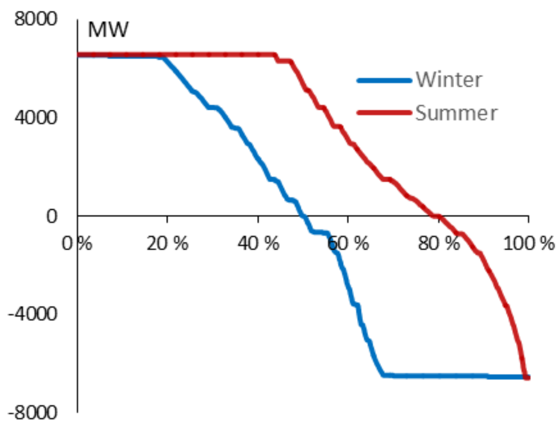


Figure 16-8: Duration curve for total simulated from Norway to the Netherlands, Germany, Denmark and the UK, distributed among summer and winter in 2040.

We have mentioned how this development could make it profitable to invest in the hydropower system, although we have not included this in our scenarios. In our baseline scenario, Norway also eventually becomes a major net energy exporter. In High, net exports increase to nearly 25 TWh on average because the development of onshore wind power is profitable with a good margin. At the same time, the value of flexibility in the hydropower system will increase as a result of more volatile prices. The exchange pattern where net export is largely concentrated in the summer months, whereas the demand for flexibility occurs in the winter, nevertheless means that there is likely no great contradiction between Norway as a major exporter of energy and as a supplier of flexibility.

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