CenSES

Centre for Sustainable Energy Studies

FME
FORSKNINGS-
SENTER FOR
MILJØVENNLIG
ENERGI
Norges forskningsråd

Norway's role as a flexibility provider in a renewable Europe

A position paper prepared by FME CenSES

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2 Executive Summary

In the research centre FME CenSES, one of the main activities is scenario studies, in which we analyse transition of the European energy system. This report focuses on the European power system and its transition towards 2050, whereby 90% of the emissions will be removed compared with 2010. Norwegian energy resources can potentially play a role in this transition, both in terms of flexible hydropower, natural gas, and new wind power developments. For the studies, we use the EMPIRE model developed in CenSES to handle both the long-term investment decisions and the operational uncertainty of the power system with large amounts of renewable generation from water, wind and solar PV sources. The model is tailored to determine how short-term uncertainty in inflows, load, and generation will affect the energy mix of the future in a setting in which the European countries cooperate to build a cost-efficient power system. The model has also been used to study the role of carbon capture and storage (CCS) in the European power system in cooperation with the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP). When discussing the potential for Norwegian value creation we include a short discussion on previous results from NTNU's and SINTEF's analyses of the value of European cooperation for short-term balancing services and point to relevant results from the HydroBalance project in FME CEDREN.

The increase of the renewable share in the European power system provides Norway with the possibility to provide flexible energy to Europe at different time horizons. Although the renewable sources in Europe will be able to replace large amounts of fossil energy, scenario studies indicate that we will see periods ranging from minutes to several weeks with large amounts of deficit energy and similar periods with large amounts of surplus energy. Due to the variability of wind and solar power, Europe will see larger variations in power generation leading to needs for flexible alternative capacity over multiple time scales, including minutes, hours, days, weeks, and seasons, to ensure stable and reliable power supplies.

In this report we present two different CenSES scenarios. In one scenario we assume that CCS technologies are implemented commercially, and in the other we assume CCS is not available. In both scenarios, we focus on the role of Norwegian renewable resources and natural gas in the European power mix. The power generation technology mixes in Europe in 2050 in the two CenSES scenarios are shown in Figure 1a. At a European level, the analysis shows that a balanced deployment of wind and solar, along with some natural gas power production is a cost-efficient pathway for a deep decarbonization of European power production. When CCS is allowed, the use of natural gas is substantial, effectively doubling the share of natural gas in the mix compared with the situation without CCS, but the system is still dominated by intermittent renewable and hydropower production.

2.1 The role of Norwegian hydropower and wind

Our studies confirm that in both CenSES scenarios, Norwegian renewable resources are attractive. As an assumption, we have limited the amount of new potential installed capacity in Norway of onshore wind to 28 GW and the total regulated hydropower to 25 GW. The analysis suggests that a full development of this onshore wind potential along with some investments in new regulated hydropower will provide the optimal strategy for utilization of Norwegian resources when decarbonizing European power. In addition, a substantial amount of offshore wind is suggested, in particular in cases where CCS is not an available technology. The Norwegian resources are attractive because of the good conditions for energy production and the covariation pattern with European resources. Table 1 shows installed capacities (GW) in Norway in the two scenarios.

Table 1: Installed capacities in (GW) the Norwegian system in 2050 in the two CenSES scenarios. For reference, the 2015 numbers are included.

	2015	Baseline 2050	NoCCS 2050
Hydro regulated	22	25	25
Hydro RoR	8	8	8
Pumped hydro	1	1	4
Wind onshore	1	28	28
Wind offshore	0	20	81

A substantial part of the value of Norwegian resources comes from flexible hydropower. The CenSES studies show that hydropower reservoirs are used actively to maximize the value of flexibility by:

- Utilizing price variations during the day that coming from both variations in European wind power generation and the uneven generation from solar PV sources, with its daily peak in the middle of the day. The studies show that the cables are used actively to import and export energy during the day, utilizing price differences to generate a net profit for Norway due to the flexibility of our system.
- Utilizing the fact that a major percentage of the needs for supplementing generation in Europe occurs due to variability in wind resources on a weekly scale, with periods of high and low winds, typically ranging from a few days to a couple of weeks. There are long periods when there are significant imbalances between renewable generation and the load in the Northern European power system, making the flexibility of hydropower reservoirs and natural gas systems valuable.
- Utilizing the fact that there are differences between the seasons in European load and generation, making it attractive to change the import and export patterns based on time of the year and using the hydropower reservoirs to store water between the seasons. A main difference is that during summer there are more pronounced effects of high solar PV power generation in Europe, with more import and less exports in those hours.

In addition, other studies by SINTEF and NTNU show that there is a high potential for creating value by European cooperation on short-term balancing services related to reserves and regulation of power. This would require European countries to increase cooperation on these services. Markets should be developed such that values the services are high enough to incentivize investment in and reservation of the cable and generation capacity needed to collect this value.

The existing Norwegian hydropower system is flexible, mainly due to the large storage capacity of 85 TWh in the Norwegian reservoirs. This storage volume has at least 10–20 TWh free capacity much of the time (see Figure 5). Studies by FME CEDREN show that it will be necessary to build new Pumped Storage Hydro (PSH) and to increase capacity in existing plants, but there is no need to build new reservoirs. All storage will use existing reservoirs within existing operational limits, which have either no or fewer environmental impacts and social conflicts compared with the construction of new reservoirs.

In conclusion, Norwegian resources are attractive for development and of potentially high value for Europe, both because of their flexibility and because of the attractive characteristics of the wind resources. We do not study any changes in Norwegian energy demand, for example increased national use. Rather, this would be an alternative to the net export suggested by the model studies and could potentially increase the value of Norwegian resources further.

2.2 The role of Norwegian natural gas in the power system

The balancing and flexibility capabilities of hydropower are well known, but the potential to provide the same kind of services in the natural gas systems (fields and pipelines) is potentially equally high but has been less explored. A predicted variation in the consumption patterns for natural gas in the power system in typical weeks in 2050 is illustrated in Figure 1b, and shows how natural gas can play a role as an important flexibility provider for the European power market. The large variations in electricity production from natural gas indicate that it could be valuable to offer flexible deliveries to Europe from the Norwegian natural gas pipeline system. The flexibility is needed in addition to the balancing from the hydropower system. For seasonal balancing, the production levels in the field can be varied. In the short term (hours) and medium term (weeks), conventional natural gas storage facilities as well as the storage capacity in the natural gas pipelines can be used to smooth variations in demand. We see in particular, in summer the effects of high solar PV penetration. In some weeks, the natural gas use declines in the middle of the day, and in other weeks it is only present as peak generation.

Norwegian natural gas pipelines that provide a cost-efficient energy supply network to Europe are highly utilized and will continue to be in the coming decade. Hence, the utilization of the storage capacity in the pipelines may offer additional value in the future. To achieve this, commercial flexibility services would need to be developed. We recommend that the trade-offs between increased costs and the potential value provided by such storage services should be further investigated and that relevant business models should be explored.

2.3 Recommendations

Our analysis shows that Norway can contribute to European flexibility and storage needs regarding both hydropower and natural gas at many different time horizons. Hydropower can be used for providing flexibility in most time horizons, ranging from seconds to seasons.

Renewable energy:

If Norway wants to have a larger role as a provider of flexibility, more investments in HVDC[1] cables to Europe are needed. To utilize the Norwegian resources fully, European cooperation on investments in the energy system needs to be increased. By the introduction of the Energy Union, cooperation on market integration in intraday and spot markets and to some extent short-term balancing markets is increasing. Still, investment decisions by individual countries tend to be based on national interests related to welfare, jobs or security of supply. For countries such Norway, which would invest to provide energy or services for other countries, that creates policy uncertainty related to the demand for the products. The policy uncertainty could prevent full utilization of the Norwegian resources, as potential investors would face uncertainty on the demand side coming from political choices rather than from the markets.

We recommend entering into EU-wide collaboration agreements or multilateral agreements between countries in order to reduce uncertainty by addressing the division of costs, revenues and risk between the participants in the relevant time horizons.

Capacity markets[2] for generation can be used to promote coordinated investments. **We recommend** that Norway should take an active role to ensure that these markets are coordinated and not introduced nationally. This is a major governance challenge that must be addressed.
In order to provide balancing services in the very short term, capacity must be reserved in cables and in generation. The trade-off related to using the capacity for energy exchange must be considered in terms of pricing of such services, reflecting that the energy volumes are small but the value is high:

- If capacity is going to be built to provide more short-term flexibility, **we recommend** cross-border markets for such services to be further developed and secured in the long term.
- **We recommend** decisions on tariffs to be used both for direct transmission of energy between countries and for cross-border transit, as well as for system services mainly established to provide flexibility in the very short term. There is a policy risk involved in this respect because the tariffs are linked to risk, revenue and cost sharing.

The full utilization of Norwegian renewable resources requires more cables for import and export, and a strengthening of the Norwegian grid. Traditionally, Norwegian consumers have borne the cost of grid investment. It can be argued that this is fair for parts of the infrastructure investments needed for domestic offering of balancing services and reducing security of supply issues. Parts of this new capacity will most likely benefit the consumers through increased security of supply and increased stability in prices.

[1] High-voltage, direct current (*høyspent likestrømsoverføring*)
[2] In a capacity market, suppliers are required to have enough resources to meet their customers' demand plus a reserve amount.

However, with regard to the net export of energy, capacity services, and balancing services provided to other countries, it is more difficult to argue that Norwegian consumers should cover the cost. **We recommend** the development of a new regime for cost distribution related to the building of new cables for this purpose if the Norwegian renewable potential is to be fully utilized.

Natural gas in the power system:

Our studies show that without CCS, natural gas may still play a major role in the power sector in 2030 and 2040, but in 2050, the volume of natural gas used by the power sector in the NoCCS scenario will only be half the volume suggested if CCS proves successful as a commercial technology.

Natural gas with CCS somewhat reduces the share of renewables in the generation mix but provides system benefits:

- The availability of CCS reduces the need for over-investments in renewables, which tend to cause substantial amounts of curtailed generation, even when inexpensive energy storage and demand response measures are available as investment options.
- The need for transmission investments is reduced, saving system costs and thus reducing consumer prices.
- Controllable generation capacity in the system will increase security of supply.

We recommend further support of the commercialization of CCS value chains in order to secure the use of Norwegian natural gas as a flexibility source for the European power system.

Natural gas complements hydropower with the capability of pipelines to provide substantial flexibility in the time horizon ranging from hours to a few weeks and between seasons, using the storage capacity of pipelines as well as the seasonal storage capabilities in reservoirs. Natural gas power production in a system dominated by fluctuating renewable generation will be highly varying, with steep ramps and significant differences between production peaks and valleys. This will require a flexible and secure fuel supply and generation capacity.

We recommend that more research should be directed towards developing flexible power generation technologies for natural gas with CCS.

For natural gas, new services, business models, commercial terms, and legislation are needed to promote flexibility services in the pipeline system. Today, the gas storage capacity in the pipelines is reserved for security-of-supply purposes. It may require a change in legislation to offer part of this capacity as a commercial service. **We recommend** that Norway should take an active stance in identifying viable pathways for further development in Europe.

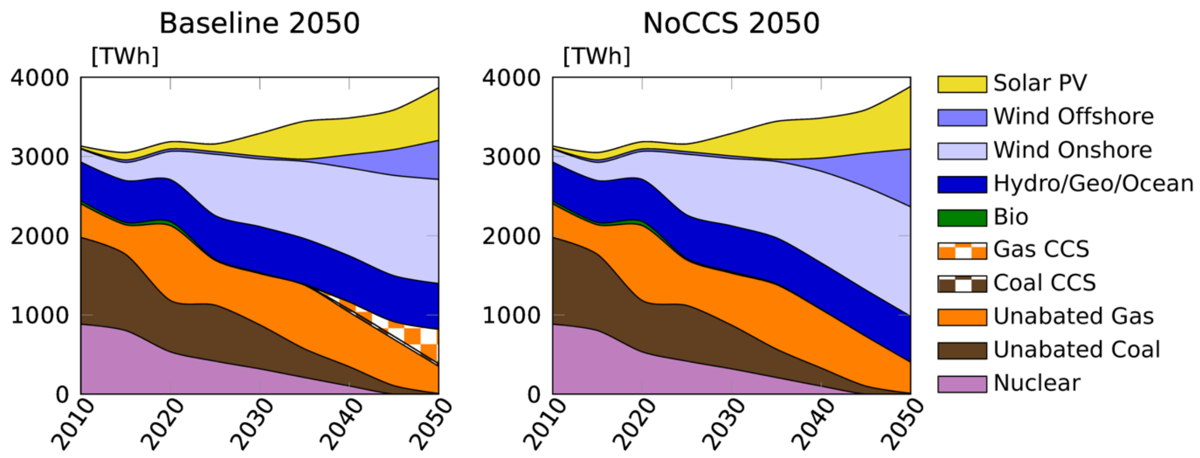

Figure 1a: Power generation mix in Europe in 2050 in the two scenarios based on EMPIRE analysis.

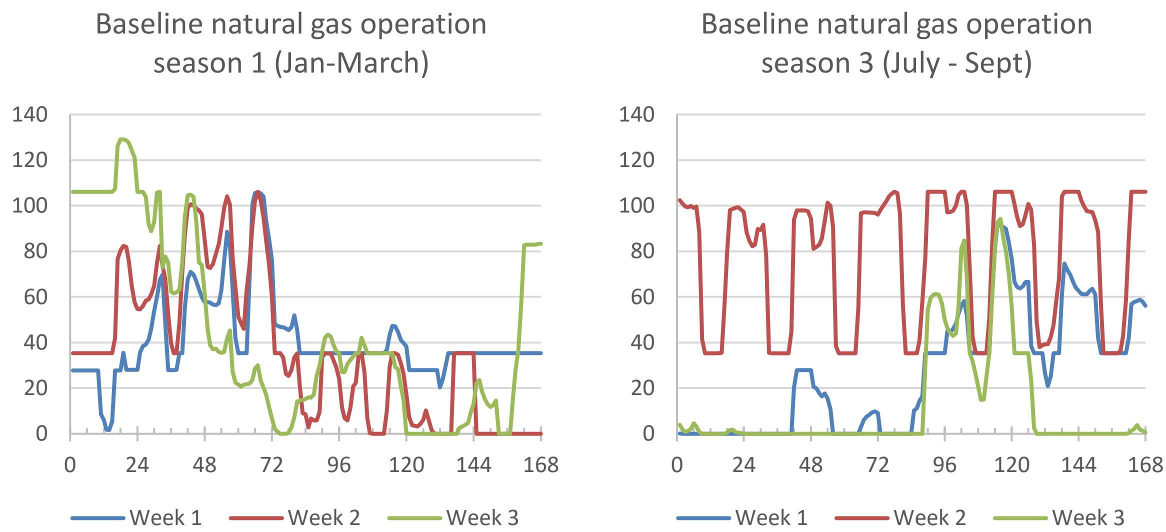

Figure 1b: The electricity production from natural gas in the four countries to which Norway has an export pipeline (UK, Germany, France and Belgium). The graphs show the variation in production (GWh/h) over 168 hours for three different typical weeks within the seasons of January–March and July–September in 2050.

3 Introduction and scope

Many scenario studies describe the development of the European power system until 2050. They all include a large increase in power generation from renewable sources such as wind and solar energy. The EU's ambitious energy and climate change objectives aim to reduce greenhouse gas (GHG) emissions by 40% in 2030 compared with 1990 levels. One of the main measures to achieve this is by increasing the share of renewable energy to 27% in 2030. In addition, the policy includes a 27% improvement in energy efficiency by 2030 compared with projections. Further, the European Council has made a long-term commitment to reduce carbon emissions by 80–95% by 2050.

In FME CenSES, one of the main activities is to perform model-based scenario studies where we provide a foundation for transition pathways for the European energy system. This report focuses on the European power system and its transition towards 2050, by when 90% of the emissions will have been removed. Norwegian energy resource can potentially play a role in this transition in terms of flexible hydropower, natural gas and new wind developments. For the studies, we use the EMPIRE model developed in CenSES to handle both the long-term investment decisions and the operational uncertainty of the power system with large amounts of renewable generation from water, wind, and solar PV sources. The model is tailored to determine how short-term uncertainty in inflows, load and generation will affect the energy mix of the future in a setting in which the European countries cooperate to build a cost-efficient power system. The model has also been used to study the role of CCS in the European power system (ZEP, 2013, 2014, and 2015). When discussing the potential for Norwegian value creation, we a include a short discussion on previous results from NTNU and SINTEF analyses of the value of short-term balancing services and point to results from the HydroBalance project in FME CEDREN.

The variability in wind and solar power implies that we will see larger variations in power generation over multiple time scales, including minutes, hours, days, weeks, and seasons. Although the renewable sources in Europe will be able to replace large amounts of fossil energy, scenario studies indicate that we will see periods of different durations, ranging from seconds, minutes, and hours, up to several weeks, with large amounts of deficit energy, and similar periods with large amounts of surplus energy due to variability in the weather. Consumer measures such as demand response and demand-side management constitute one of the tools to reduce this challenge suggested in the 'Clean Energy for all Europeans' package (European Commission, 2016). Still, more capacity for dispatchable energy generation capacity is needed to ensure a stable and reliable power supply. This report looks at the role that flexible Norwegian energy resources could play in the horizon towards 2050. Access to two different flexible energy sources – hydropower and natural gas – places Norway in a unique position in the long-term perspective, when renewable intermittent power production will become a larger part of the European energy supply. The flexibility is complemented with potential utilization of Norwegian wind resources, which have an attractive covariation with the power generation in the rest of Europe.

3.1 Flexible energy exchange and balancing

New energy storages, flexible energy sources, and flexible energy carriers are vital enablers for increased renewable power production. They will contribute to the EU ambition of a low emission energy system. It is likely that new flexibility and storage services linked to Norway's gas pipeline system and hydro reservoirs will be among the more attractive solutions in terms of capacity and cost. This could generate potentially high revenue for Norway from the export of flexibility and balancing services. The flexibility of hydropower is well known, whereas the potential to provide the same kind of flexibility services in the natural gas systems (from production fields and pipelines) may be equally high but has been less explored.

Balancing services: Often the literature contains terms and expressions such as balancing, energy exchange, and Norway as a green battery. There are various ways to interpret the term flexibility and balancing of energy. In this report, we consider balancing as services provided in a balancing market, typically services for short-term, automatic, balancing in the power network (often called ancillary services). They can be delivered via flexible producers that can adjust their production levels (and consumers who can adjust their consumption) in the short term. The total energy content of such services is often low, whereas the peak energy content and capacity needed may be high. The potential economic value is much higher than the value of the energy content, as the services provide stability and security of supply. Such services need high capacity reserved for the services on the generation side and in cables.

Flexible energy exchange: When electricity is traded between two geographical markets, the term exchange of energy is used. Value for society is created by importing from markets at lower prices and exporting to markets at higher prices. The value creation from energy exchange can benefit generators, consumers, and cable owners, depending on market design and regulation. The capability to exchange energy between locations depends on the flexibility available in the system, including generation capacity and available import and export capacity:

Short-term flexibility: Flexibility whereby load or generation can be adjusted in periods ranging from minutes to hours. Hydropower and demand response are two examples. Alternatively, the same capacity can be used to deliver balancing services.

Medium-term flexibility: In systems with high wind penetration, periods of several weeks with low generation from the intermittent resources are often observed. This requires access to alternative generation capacity with flexibility to generate for several weeks and to store energy. Examples are hydropower plants with reservoirs or natural gas power plants.

Seasonal flexibility: Hydropower systems with reservoirs, natural gas in reservoirs, and some thermal heat storage systems are examples of ways to store energy between seasons to smooth out seasonal differences in price, thereby creating value in similar ways as exchange between different price regions.

In a system with high renewable penetration, flexibility is needed to avoid extreme variations in price and potential energy shortages resulting in blackouts when intermittent generation is much lower than the load. The purpose of this report is to study how and at what capacity Norwegian resources can provide flexibility for Europe in a cost minimizing integrated European energy system and how that would interact with the development of Norwegian wind resources.

3.2 Limitation of scope

This report summarizes our knowledge with respect to the following important questions:

- How will different policy and technology scenarios influence Europe's need for balancing and flexibility at different time horizons?
- Which Norwegian capabilities are to be part of the solution in terms of providing flexibility to the European energy market, both from the natural gas system and from the hydropower system?
- What uncertainties do potential investors face in energy infrastructure and generation capacity with respect to providing flexibility to Europe?
- How could this uncertainty be reduced and by whom?

The report is limited to a study of the flexibility in the Norwegian natural gas and hydropower systems in terms of providing balancing services and flexibility at different time horizons to complement intermittent power generation in Europe.

Additionally, the study considers how to invest in Norwegian wind resources. As we do not consider increased demand for energy in Norway, new investments in generation, leads to a situation in which Norway is a net exporter of energy. We do not discuss whether Norway should consider developing a larger demand side within the county by using the energy locally instead. Similarly, we do not consider prioritization between power production and energy savings and/or efficiency.

The trade-offs mentioned above are definitively relevant for policymakers and companies and indicate a prioritization that needs to be made in future years. However, they are outside the scope of this report. Our focus is on presenting different alternative developments for the European power system and discussing the need for Norwegian flexibility in these scenarios.

Another limitation of scope of this report is that we only study the power market. This means that natural gas power plants represent the only intersection between the natural gas system and the power system. A large amount of the natural gas delivered from Norway is used for purposes other than power production, but we have not covered this in our discussion. Furthermore, this report contains several elements that are still works in progress, and thus new results will follow as and when we gain a better understanding of European climate policy and the role of renewables.

3.3 Structure

In Section 4, we present the status of the Norwegian natural gas and power systems. In Section 5, we discuss the need for flexibility in the European power system. In particular, we focus on the difference between yearly and monthly averages and the high short-term variability. Section 5 focuses on the long-term scenario studies towards 2050. Section 7 concerns how Norway can contribute flexibility and balancing to Europe at different time horizons. Section 8 contains the summary and a short description of challenges and opportunities. Finally, we conclude with our recommendations in Chapter 8.

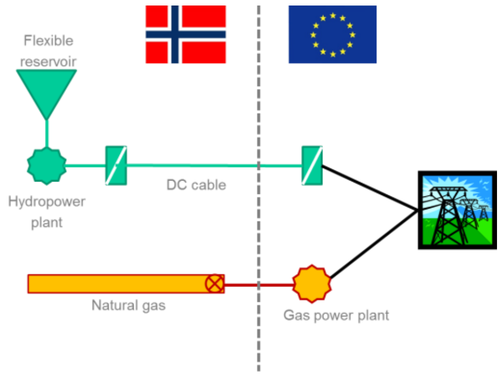

Figure 1 The connection between the Norwegian hydropower system and the natural gas system. The figure highlights the potential interplay when offering flexibility services to Europe.

4 The Norwegian power and natural gas system – status and expected developments

In this section, we present the status of both the power system and the natural gas system in Norway. We focus on the capacities and special characteristics of the two systems. Expectations for further development in the coming decade are also included. The section serves as a basis for our discussion of the Norwegian potential to offer flexibility services to Europe from hydropower and natural gas (Figure 1).

4.1 The Norwegian power system

Electricity production in Norway has been based on hydropower from the very start more than one century ago, and this is the main explanation for the high share of renewable energy in Norway's total energy consumption, which reached 69% in 2014 (Statistics Norway, 2016). In recent years, many small hydropower projects have been developed, but the potential is still large, with many projects on the drawing board, in the application pipeline, or simply put on hold waiting for grid development.

Hydropower production varies during the year and from year to year, depending on hydrological conditions and demand for electricity. The average power generation in Norway in 2015 was approximately 132 TWh per year, which was 60% of the total economic potential, which in turn has been estimated as 214 TWh (at a cost of less than NOK 4–5 per kWh). Since approximately 51 TWh of the potential is protected, the remaining undeveloped potential amounts to 31 TWh (NVE, 2015).

By the beginning of 2016 there were almost 1550 hydropower plants in operation throughout Norway, with a total installed capacity of 31,223 MW (Table 2). The vast majority of these plants can be considered small: close to 80% of the new hydropower plants were classified as having a capacity of less than 10 MW, which thus gives an overview of Norwegian hydropower plants, their installed capacity and yearly production. Since the beginning of 2018 there were 1599 plants, 31,837 MW installed with additional 2200 MW in construction, and an additional

5800 MW approved (https://www.nve.no/energiforsyning-og-konsesjon/vannkraft/vannkraftpotensialet/).

Table 2 Norwegian hydropower plants at the beginning of 2018 (NVE, 2018c).

Installed capacity per plant (MW)	Number of plants	Total installed capacity (MW)	Average yearly production (TWh/y)
< 1	569	182	0.8
1–10	690	2389	9.5
10–100	259	9643	43.1
> 100	81	19,623	80.7
Total	1599	31,837	133.9

An important characteristic of the Norwegian hydropower system is its large energy storage capability, which amounts to approximately 85 TWh (NVE, 2018b). This is equivalent to almost half of the total hydroelectric storage capacity in Europe (NVE, 2011). The storage in Norway is important due mainly to three factors: (1) a large seasonal variation in inflow, (2) no thermal backup in the system, and (3) low cost of reservoirs due to favourable natural conditions. Most of the hydropower system and nearly all the storage were constructed before 1995. Since then, mainly small hydropower stations without storage have been put in operation. The largest reservoir in Norway measured by energy storage capacity is Blåsjø, with a capacity of 7759 GWh (NVE, 2018a). In total, the 10 largest reservoirs have an energy storage capacity of 25,400 GWh. The rest of the storage capacity is distributed over nearly 800 reservoirs located all over the country.

The large storage capacity was mainly designed for seasonal storage of water. In Norway, the largest inflow usually occurs during spring and summer, when electrical energy consumption is at its lowest. In the winter, the inflow is very low, while the electrical energy consumption is at its highest. The reservoir capacity is usually large enough to store all the energy needed during the next winter, except in exceptionally dry years. This is illustrated by Figure 5, which shows the actual energy content in Norwegian hydropower reservoirs during the period 2005–2015. The seasonal variation is evident, with a maximum in late summer and a minimum at the end of the winter. However, Figure 5 also shows that the reservoirs nearly always had some free capacity, especially during autumn and winter.

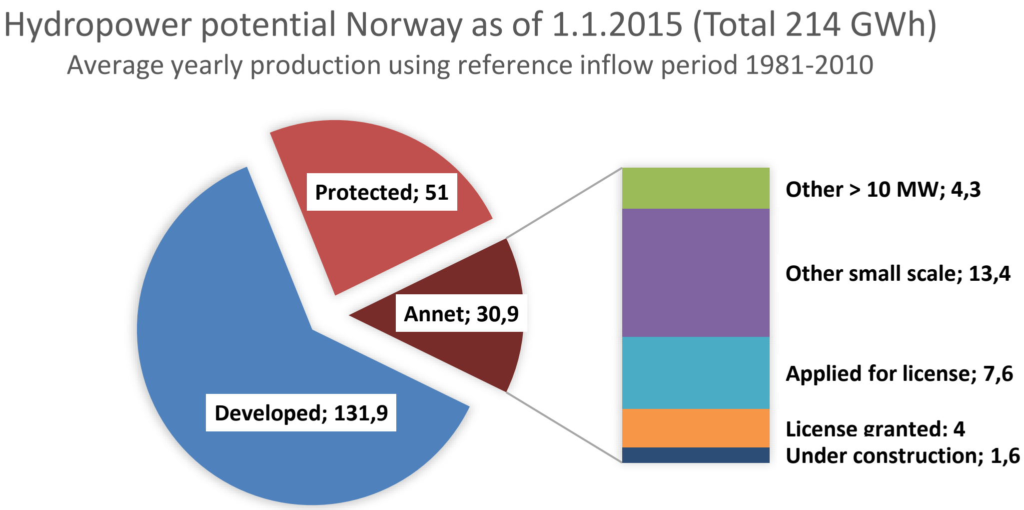

Figure 4: Hydropower potential in Norway 1/1-2015 (NVE, 2015).

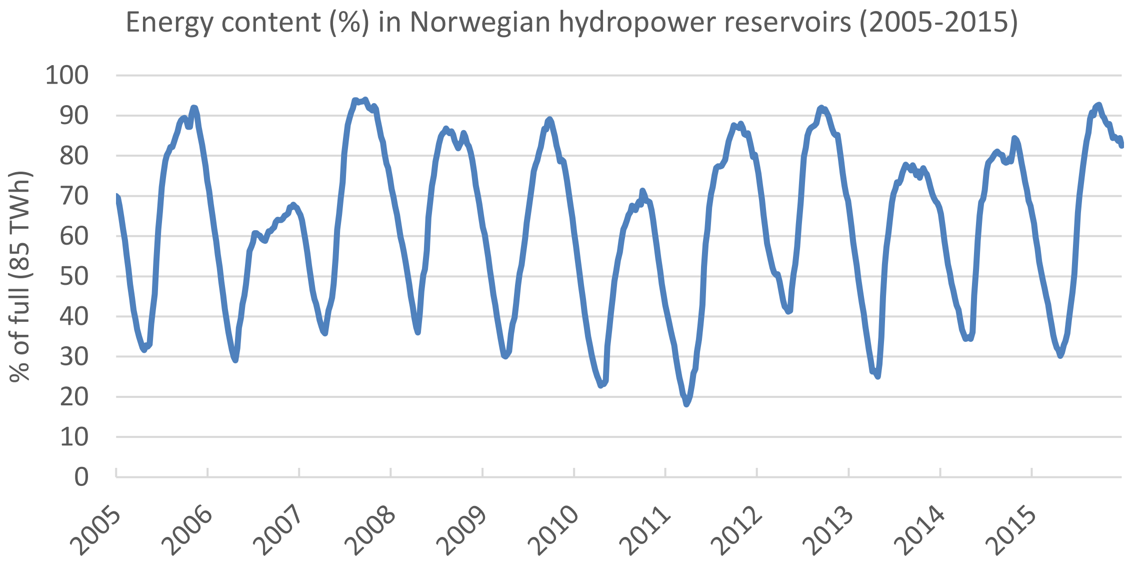

Figure 5: Energy stored in Norwegian hydropower reservoirs (data sourced from (NVE, 2018d)).

Norway and Sweden agreed on a joint el-certificate scheme (‘Green-certificates’) in 2012 in order to promote development of more renewable energy to meet the EU’s renewable energy resources (RES) directive target for 2020 (NVE, 2017). The agreement specifies the development of 26.4TWh renewable energy in the two countries combined, and it is believed that most of this will be implemented as wind power, hydropower, and bioenergy. Later, Sweden increased its ambition, and the target is now 28.4 TWh. Based on the cost structure, the target was mainly estimated to be implemented as hydropower in Norway and mostly wind power and bioenergy in Sweden (OED, 2012), and this has since been confirmed by awarded certificates (NVE, 2017).

Transportation and distribution of electricity is done in the electricity grid, the connection between generation facilities, most of which are large hydropower plants, and the end users.

The main grid in Norway (11,000 km in total) consists of overhead lines (99%), underground cables, and some submarine cables. The grid is mainly (96%) owned and operated by Statnett (the transmission system operator) and a few other large grid companies.

The major power flow in Norway is from the large generation facilities in the west to the main demand centres in the east. However, with an increasing number of international links, there will be a gradual change to a north–south flow. Currently, Norway is connected internationally by overhead power lines to Sweden (3700–4000 MW),[3] Finland (50 MW) and Russia (50 MW), and by submarine HVDC cables to Denmark (Skagerak 1–4, in total 1700 MW) and to the Netherlands (NorNed, 700 MW). Two new submarine cable connections were licensed in 2014 and are now under construction: a 1400 MW cable from Tonstad to Schleswig-Holstein in Germany and a 1400 MW cable from Kvilldal to Blythe in England. The cable to Germany is scheduled to be completed in 2019, while the cable to England is scheduled to be completed in 2021. By 2020, the total transmission capacity from Norway to other countries will therefore be about 9200 MW, of which 5200 MW will be supplied via submarine cables and 4000 MW via overhead power lines. Investments in the high voltage power system infrastructure are expected to reach record high levels in the period 2018–2022, with a total estimated value of NOK 35–45 billion (Statnett, 2017).

Figure 6 shows the typical weekly price profile in NOK/MWh for Norway and Germany, which serves as a good example of both the possibilities and challenges for hydro storage in Northern Europe. The profitability of a hydro storage facility depends on the price differences between day and night, and for facilities with large storage capacities, price differences during the week. For Norway, the storage capacity depends on the size and flexibility of reservoirs and the ability to hold back production in hydro plants. In this way, Norway utilizes the ability to import during the night when prices are low, such that hydropower can be exported during the day when prices are higher. The limitations for this strategy are generation capacity during the day and cable capacity, as well as its dependence on price variations in the European markets. To increase the storage capacity further, pumped storage power plants can be used, where the imported electricity is used to increase the water level in the reservoirs and, thus, also the export potential when prices are favourable. The attractiveness of both solutions decreases when European electricity prices have less variation and increases when they have more variation.

The observed daily price variation in Germany today is large, since the marginal production cost at night is low while the marginal production cost during the day is high. By contrast, in Norway and Sweden marginal production is normally by hydropower units both during day and night, and the price differences during the day and the week are much smaller. Thus, it is very difficult to find profitability for pumped storage power plants in Scandinavia. However, the price difference between the Norwegian and German systems, which could potentially trigger profitable exchanges between the systems with Norwegian export during day and import during

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[3] The Norway and Sweden interconnection capacity is calculated as the sum of net transfer capacities (NTC) across interfaces between several price areas in the two countries. This is not an accurate way of computing an NTC between countries, which should be done using power flow analysis. However, the value gives an indication of maximum capacity.

the night, may also reaching a level at which pump capacity should be installed. In the future, these patterns may change as solar PV providers take a central role in the European power mix.

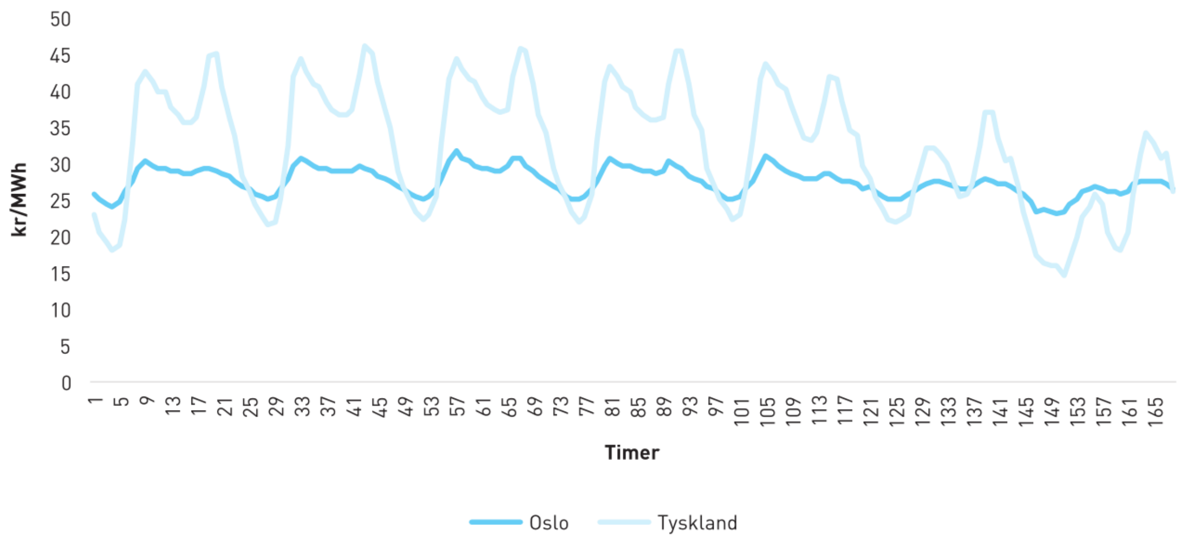


Figure 6: Average weekly power price profile (2011–2014) for Norway (bidding area NO1) and Germany.

4.2 The Norwegian natural gas system

Natural gas represents more than 20% of the energy demand worldwide, and Norway is the third largest gas exporter in the world (https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/). Norwegian gas covers approximately 25% of the EU gas consumption and, measured by energy content, its production is about 10 times the volume of the Norwegian power production. The expected pipeline gas export in the years from 2020 onwards is around 120 billion standard cubic metres (GSm^3). In 2017, the Norwegian export of natural gas was approximately 122 GSm^3 (approximately 1357 TWh), of which 117 GSm^3 were delivered to terminals in Europe. Figure 7 shows deliveries to several European countries by their energy content. In order to compare these values with electricity values, a conversion factor is needed, which typically varies between 0.3 and 0.6. Table 3 provides an overview of the conversion factors used for natural gas in this report.

Table 3: Conversion factors for natural gas. Note that the energy content of gas varies between different fields and varies over time. A typical energy content for Norwegian gas has been used.

1 GSm^3 o.e.	=	1000 GSm^3
1 GSm^3	=	11.12 TWh
Scaling factors		
T	=	1000 G
M	=	0.001 G

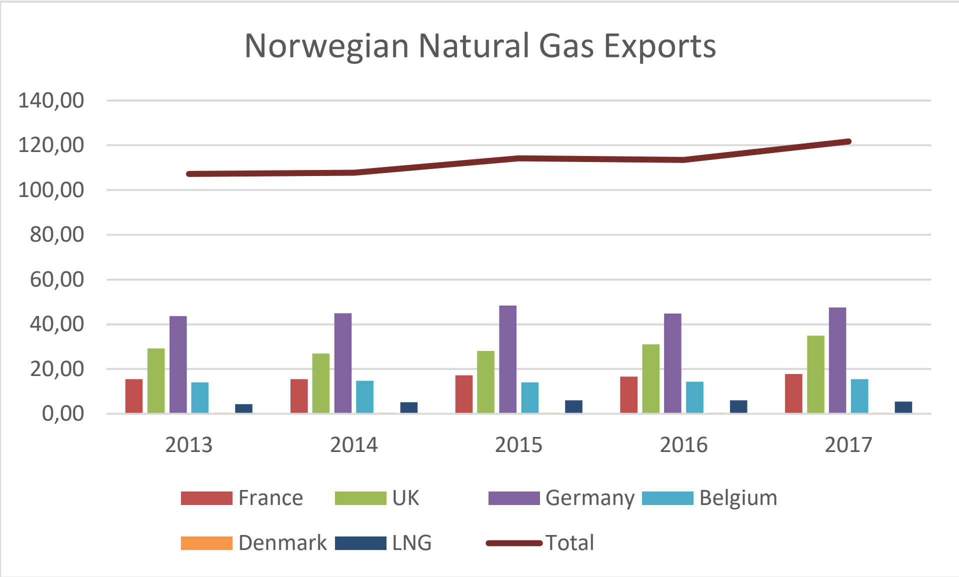


Figure 7: Natural gas deliveries from Norway in GSm^3 for the years 2013–2017 (data sourced from https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/).

From 2020 onwards, production levels will depend on unknown resources, which will have substantially higher uncertainty with regard to total volume, localization, timing, and size of each discovery. Figure 8 shows the expected production volumes for the period 2018–2015.

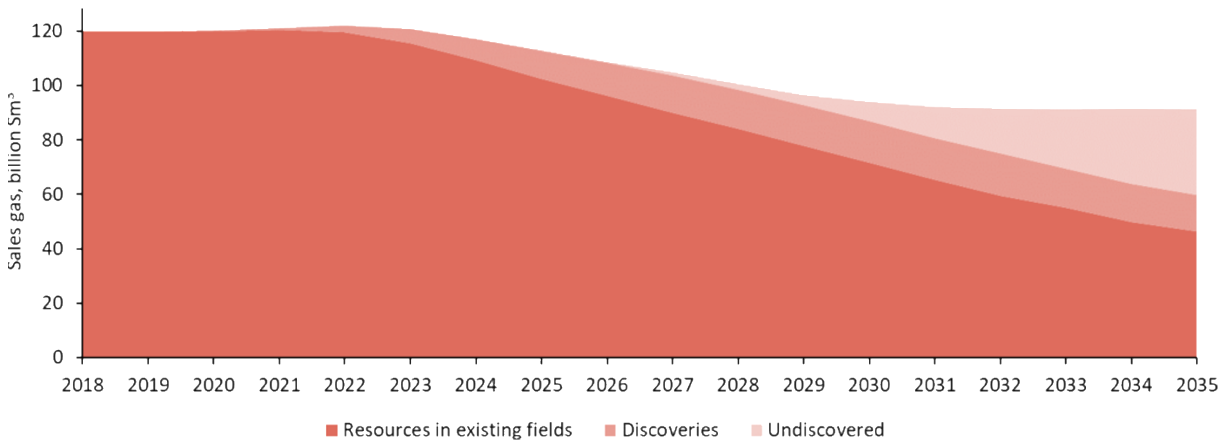


Figure 8: The expected production levels of natural gas in billion cubic metres per year for the period 2018–2035(https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/).

Natural gas is efficient to transport and easily storable. It can be stored by varying the production rates in the fields (using the reservoirs as storages), in conventional natural gas storage facilities, as liquefied natural gas (LNG), and in the transportation system itself. Production fields with a lot of flexibility in natural gas production are known as swing producers. The amount of flexible production capacity depends on the relation to oil production in the same field. Due to the superior oil price relative to the gas price, priority is given to oil production. The operational flexibility for natural gas production is therefore limited in fields where the gas is associated with oil. However, there are also fields with a high swing ratio, such as Troll and Ormen Lange.

Approximately 95% of the natural gas from the Norwegian continental shelf is exported through the pipeline network to terminals in Germany, Belgium, France, and the UK. This export system consists of nearly 8000 km of high-pressure subsea pipelines and three processing plants. The largest daily delivery achieved in this system is 356.9 million standard cubic metres (MSm^3), while the average daily delivery in 2012 was 294.8 MSm^3. In addition, the LNG terminal at Melkøya produced LNG from 5.5 GSm^3 of gas in 2017. Most of the pipeline network is operated by Gassco.

Traditionally, the sale of natural gas in Norway has been through long-term contracts. Long-term contracts are still dominant, but short-term markets have emerged since the liberalization of the European markets. The liberalization process has led to an unbundling of the ownership structure in the natural gas value chain and ensured third party access to the transportation system. The process is still ongoing and thus not yet completed. The National Balancing Point (NBP) has been established in the UK as a liquid trading point and has become a price reference for long-term contracts (instead of oil indexing) as well as spot trades.

4.3 Flexibility

The Norwegian natural gas pipelines are highly utilized and will continue to be so the coming decade, providing a cost-efficient energy supply network to Europe. Moreover, the shippers have flexibility with respect to booking levels and timing. In addition to long-term booking, it is possible to book capacity on a day-to-day and within-day basis. There are also instruments for reallocating unused capacity to new shippers. The storage capacity in the transportation system is due to the considerable inventory of natural gas in the pipelines. Currently, this flexibility is used primarily to maintain a high level of security of supply in the system, and to maximize the flow rate in the network. Some of the inventory in the pipelines is offered to the shippers in the network: Opflex and Lineflex. Opflex is used to handle unforeseen events in the network, while Lineflex is used to handle planned events (such as maintenance). The remaining margin between theoretical capacity and available capacity is due to a safety margin for handling uncertainties (such as variation in sea temperature, which will influence the flow rate) and transient flow that create dynamics in the system that are not captured through steady-state analysis.

Currently, a commercial service that offers booking of inventory in the pipelines to the shippers does not exist. Utilization of the storage capacity in the pipelines may offer additional value in the future, provided that a market for such services is developed. This could allow the shippers to use the pipeline inventory in the large export pipelines to offer flexible services to the European market. Volumes of natural gas could then be reserved and delivered if necessary (analogous to balancing or flexibility services in the power sector). The actual capacities available for such services would vary and depend on the current flow rate as well as the inventory levels. It is important to note that an increased use of the flexibility in the pipelines will affect the capacity utilization in the pipelines. If the flow rate is changed within a day, the daily capacity will naturally decrease. Additionally, some technical limitations to the changes in flow rates in the pipelines need to be taken into consideration.

With the current operational pattern whereby the network is run to the capacity limit in the winter time, there is limited capacity available for such services. However, if the flows were further from the capacity limit, the capacity might be substantial in terms of energy content. When considering energy scenarios towards 2050, in which the European demand for natural gas will increase in volatility and the demand patterns will change (due to a higher share of renewable production), the storage potential might become very valuable. The costs of operating the network will increase if the pipeline inventories are increased, and these costs would have to be covered by the premium given to the gas delivered as balancing energy.

It is also important to note that the gas pipeline inventory is only one part of the gas network that can be used to achieve flexible deliveries to the markets. The flexible gas fields have substantial capacity for varying production and given that the inventory in the pipelines is full, the transport to the market is fast. The conventional gas storage facilities will also deliver substantial flexibility. However, the gas pipeline inventory does provide access to a market-near storage that may have substantial value in the future European energy system.

The interactions within the value chain are complicated, and the links to quality of service and security of supply are very important, hence these issues need to be further studied. In Figure 9, we show the potential in one of the large export pipelines. We have used historical data (provided by the system operator Gassco), and looked at the changes in inventory level over one year of operation. We have not considered seasonal differences in this example, but instead we have focused on finding the potential flexibility for the pipeline inventory. In our example, we find that it is possible to change the inventory level in the pipeline by approximately 2% within an hour and by 15% in 12 hours. For the given pipeline, this means that the inventory could be changed by approximately 12 MSm^3 (which corresponds to approximately 133 GWh) within 12 hours. The pipeline is one of seven large export pipelines in the Norwegian system. The actual numbers presented should be treated with some caution, but the total capacity and ability to adjust the inventory in the system appear to be substantial. It should be noted that we have not considered seasonal effects or the connection between pipeline utilization and potential for inventory adjustments. This means that the numbers will not hold for all inventory situations and flow rates. However, we have only based our calculations on historical data and the real potential in the system for changing inventory levels could therefore be expected to be higher (given that the objective of network operation was maximization of flexibility).

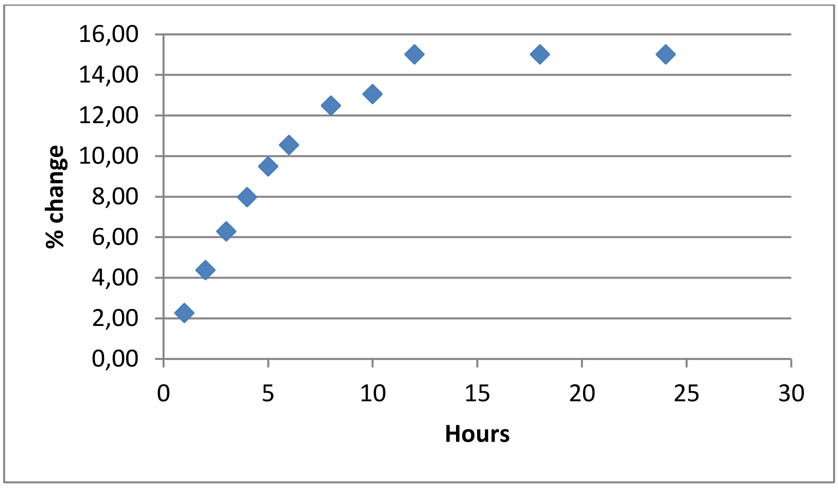


Figure 9: Flexibility to change the inventory level in one of the large export pipelines in the Norwegian system. The graph shows the largest observed percentage change in inventory as a function of the number of hours over which the change can be achieved. The change is relative to the average inventory level over a year of operation. The 15% change in inventory corresponds to an energy content of approximately 133 GWh. (Source: Gassco).

5 The need for flexibility, balancing services, and storage due to increased renewable energy production

In this section, we discuss the need for flexibility in energy systems with different energy mixes. We present the varying degrees of dispatchability, predictability and capacity factors for different energy sources, and discuss how the energy sources can interact to balance varying production levels at different time horizons. At the end of the section, we include a short discussion of different storage technologies for energy. In this report, the focus is on the easily storable energy sources natural gas and hydropower, but we also include a presentation of alternative storage sources for completeness.

5.1 Integration of renewable energy into the grid

The ease of integration of renewable electricity technologies into the power grid will depend on three main parameters: dispatchability, predictability, and the capacity factor. Technologies with high dispatchability have some capacity for storage, such as bioenergy and geothermal energy, whereas hydropower with reservoirs has a large capacity for storing energy. These technologies can adjust their output to varying demand, and will therefore have a high value for supporting the grid under variable load and supply conditions. There are still differences among the three ‘dispatchable’ renewable energy technologies. While hydropower systems can respond within seconds to minutes, the changes in output for bioenergy and geothermal energy systems takes longer time, typically minutes to hours.

Technologies with low dispatchability, such as solar PV, wind power, and ocean energy do not have storage components and the power must be produced instantly following the resource and its variability (i.e. wind, sun, and waves). They are also typically more difficult to predict and therefore more difficult to integrate, especially as their share increases. Small hydro and run-of-river hydro systems fall somewhat in between: they are better than wind and solar PV, but not as good as reservoir hydro or bioenergy and geothermal energy. Pumped storage hydro is a special case of reservoir hydro and is mainly used for balancing and energy storage in many electricity systems.

Variability is introduced from both variable load and variable input from non-dispatchable renewable energy. In addition, sudden changes due to technical failures may generate variability. In order to maintain a stable frequency in the grid, the total generation and total consumption must balance. If a deviation occurs, countermeasures will be needed in order to restore the balance. In this report, the term balancing services is used to describe power production that can be stepped up or down quickly to counteract any imbalance and to support stability in the grid, whereas we use the term flexible energy or flexible energy exchange for longer time horizons.

5.2 Sources of variability in generation

Electricity production from renewable energy sources is generated from natural sources such as wind, waves, solar radiation, and water flow, all of which have characteristic variations in time scales ranging from minutes to years. For some (i.e. wind and sun), short-term variations can even be on a scale of seconds for individual plants, but are usually averaged to slow variation by spatial averaging when many plants are combined (e.g. in wind parks). Unregulated river flow can have variability over a few hours, but also on longer time scales of days, seasons, or even multiple years ("dry and wet years").

It is interesting to note that the three most important renewable energy sources – hydro, wind and solar PV – have very different patterns of variability, but when combined, they can give a more seasonally even distribution. This is illustrated by some examples in the following section.

5.2.1 Seasonal variability

Figure 10 shows the average seasonal (monthly) variability for wind power in the North Sea region compared with energy inflow in Norway. It can be seen that the two technologies have very different seasonal profiles but when combined they can give a better match to demand.

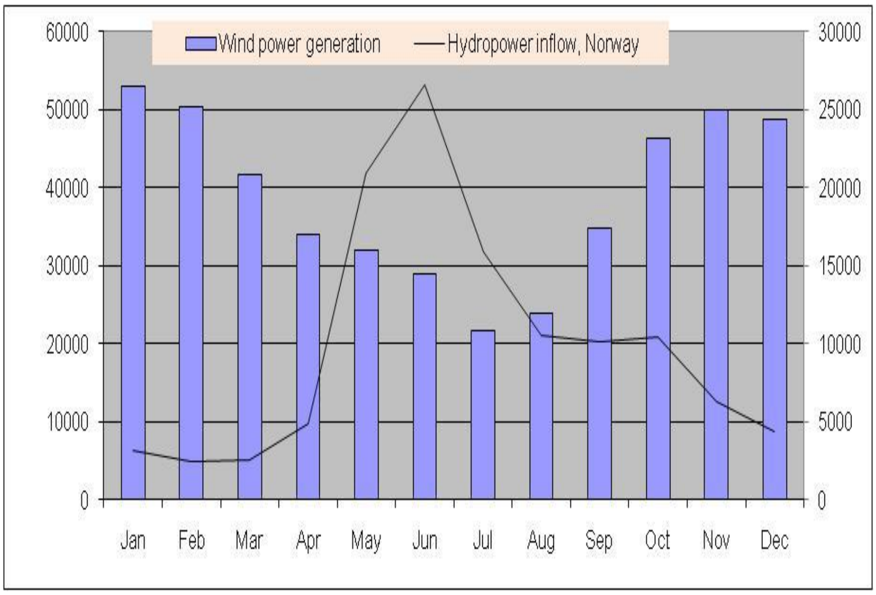
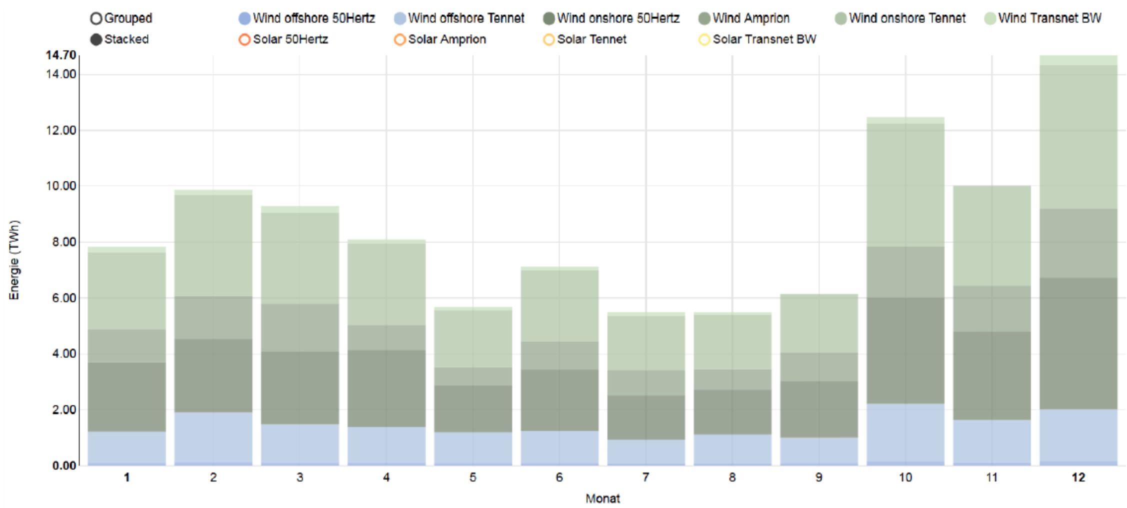


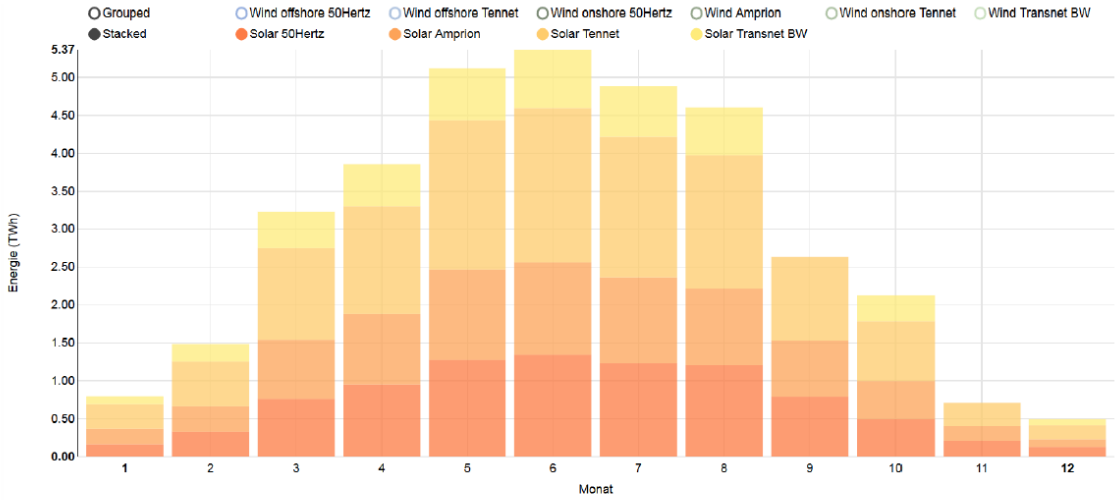
Figure 10: Average wind power generation (GWh/month, left y-axis) in a simulated North Sea wind power system of 94,000 MW compared with average observed energy inflow (GWh/month, right y-axis) in the Norwegian hydropower system with a capacity 30,000 MW (Source: Tande et al., 2008 for wind power generation, and NVE for energy inflow to the hydropower system).

Figure 11 shows the wind and solar PV generation in Germany in 2017.The seasonal variability is very clear. However, the average monthly generation picture does not show the whole truth, hence short-term variability needs to be considered (as discussed in Section 4.2.2).



Source: B. Burger, Fraunhofer ISE; Quelle: https://www.energy-charts.de/energy.htm?source=solar-wind

Figure 11a: The wind and solar PV generation in Germany in 2017.



Grafik: B. Burger, Fraunhofer ISE; Quelle: https://www.energy-charts.de/energy.htm?source=solar-wind

Figure 11b: Average wind and solar PV power generation in GWh/month for Germany in 2017.

5.2.2 Variability at intermediate time scales

The variability in wind power is illustrated in Figure 12, for which the data are taken from a hypothetical wind power system with an installed capacity of 94,000 MW in the North Sea region, the same data set as shown in Figure 10 (Tande et al., 2008). This time, the computed generation is shown with a time step of one hour. The simulated output is spatially averaged over a large region, yet still there are very large and rapid variations in total generation with ramping up or down of several thousand MW during a few hours. The variations seem random but are explained by varying wind conditions on many different time scales.

Of some particular interest is the tendency for week-long high and low generation events, during which generation can be sustained for a week or more with 30,000 MW positive or negative deviation compared with average generation. In order to balance such events, it will be necessary to store very large volumes of electrical energy, up to five TWh for one or several weeks, and then return them to the grid during next low event. This amount of storage cannot be contained in ordinary pumped-storage reservoirs, where the typical storage capacity is a few (< 10) GWh. Such variability in wind power generation has been found in many other studies in Europe, America, India and China.

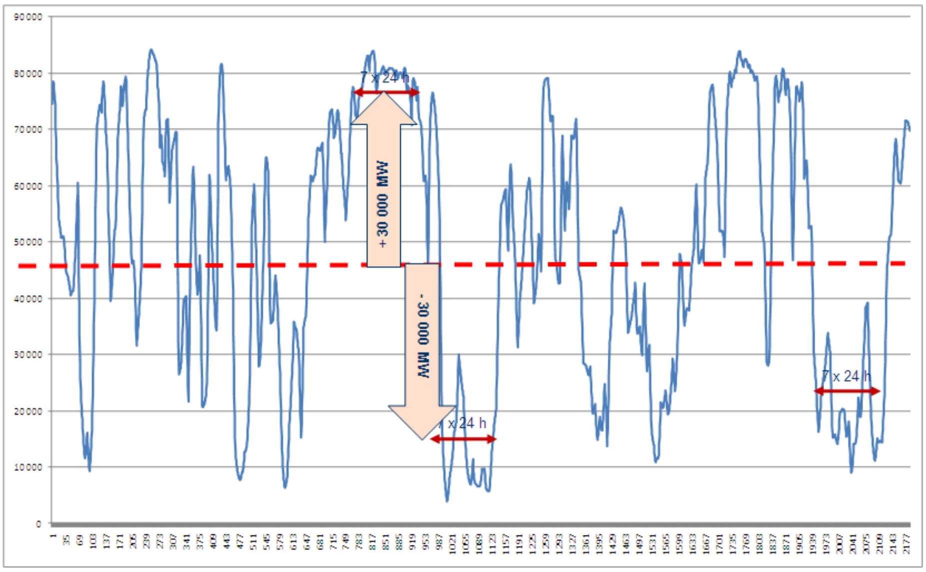


Figure 12: Simulated generation (MW) in a North Sea wind power system during three months (Jan–March) in 2006. Average generation was 45,000 MW. Typical one-week events of extra high (+30,000 MW) and extra low (-30,000 MW) are indicated (Tande et al., 2008).

5.2.3 Short-term variability

Although wind power generation mainly fluctuates between high and low production following weather patterns at a weekly (synoptic) scale, it may also change within hours from almost full load to almost no load (Figure 12). This challenges the energy system, and requires short-term balancing capacity. Solar PV energy has a different type of short-term variability, first due to the deterministic diurnal signal in solar input. This is clearly evident in Figure 13, which shows hourly generation in all German solar PV plants during one day, 1 May 2013.

During the months with high solar irradiation (April to September), the generation varies from 0 up to 16,000 MW or more during a few hours, and back again to zero equally fast. The maximum ramping up and down speeds can exceed 5000 MW/hour.

The quite deterministic diurnal cycle in solar radiation is modified by atmospheric conditions, primarily by clouds. Even if some radiation were to reach the ground, the power generation will be strongly reduced and this would create elements of low predictability in generation and would increase the need for balancing power from other sources. As an example of day-to-day variability in solar PV generation, we present Figure 14, which shows the generation for all solar PV plants in Belgium during April 2013. On most of the days the generation was very high and close to maximum capacity of 2211 MW, but on some days, such as the 26th, it dropped to less than 200 MW, and then increased to 1500 MW on the 27th.

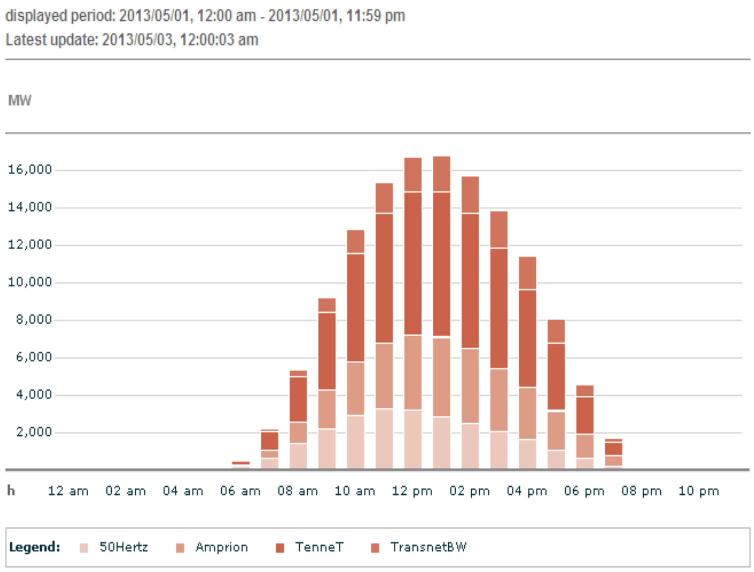


Figure 13: Total generation in MW from all solar PV power plants in Germany during one day (1 May 2013) (Source: EEX, 2013).

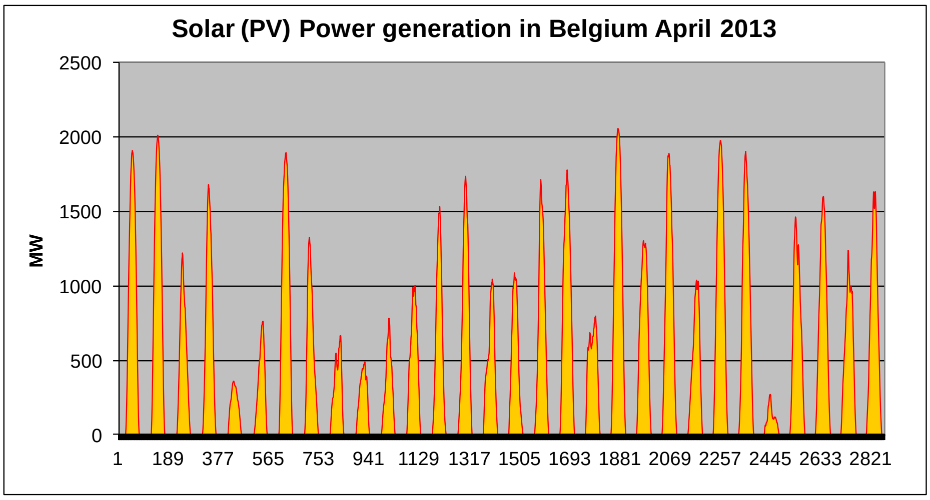


Figure 14: Total generation in MW from all solar PV power plants in Belgium during one month (April 2013) (Source: EEX, 2013).

5.3 Energy storage

There will always be a mismatch between energy demand and energy supply, and therefore energy storage is needed in all energy systems to ensure a secure supply. With growing penetration of non-dispatchable renewable energy generation, the need for energy storage will increase. While our focus is on investigating Norwegian flexibility services and energy exchange based on storage possibilities in the hydropower system and natural gas system, in this section we look at the alternative technologies for Europe, and focus on costs and the time horizon to which they relate.

Energy storage provides essential services along the whole energy value chain:

- Balancing demand and supply at many temporal scales from less than seconds to months and even years
- Managing transmission and distribution grids to ensure the quality of electricity delivered and optimizing the need for grid
- Security of supply to ensure back-up sources for energy and electricity production

Due to its cross-sector nature, energy storage will affect well-established markets such as the gas market (e.g. power-to-gas), local heat markets (e.g. heat storage), and the transportation market (e.g. electric mobility, fuel cells). Different energy storage methods and technologies can be categorized as follows:

- Electrochemical energy storage: mainly lead–acid, Ni-Ca and Li-ion, flow and redox batteries and super capacitors
- Electrochemical capacitors
- Chemical energy storage: hydrogen storage in gaseous, liquid and solid forms, ammonia, chemical hydrides, methane, methanol, and formic acid
- Thermal energy storage: salts, phase change materials, gases, liquids and solids
- Mechanical energy storage: hydropower, flywheels and compressed air
- Superconducting magnetic energy storage (SMES)

The storage methods all have different properties and a wide working range and high variation in use, costs, power, energy and applicability. The principle working ranges with respect to power and energy are shown in Figure 15.

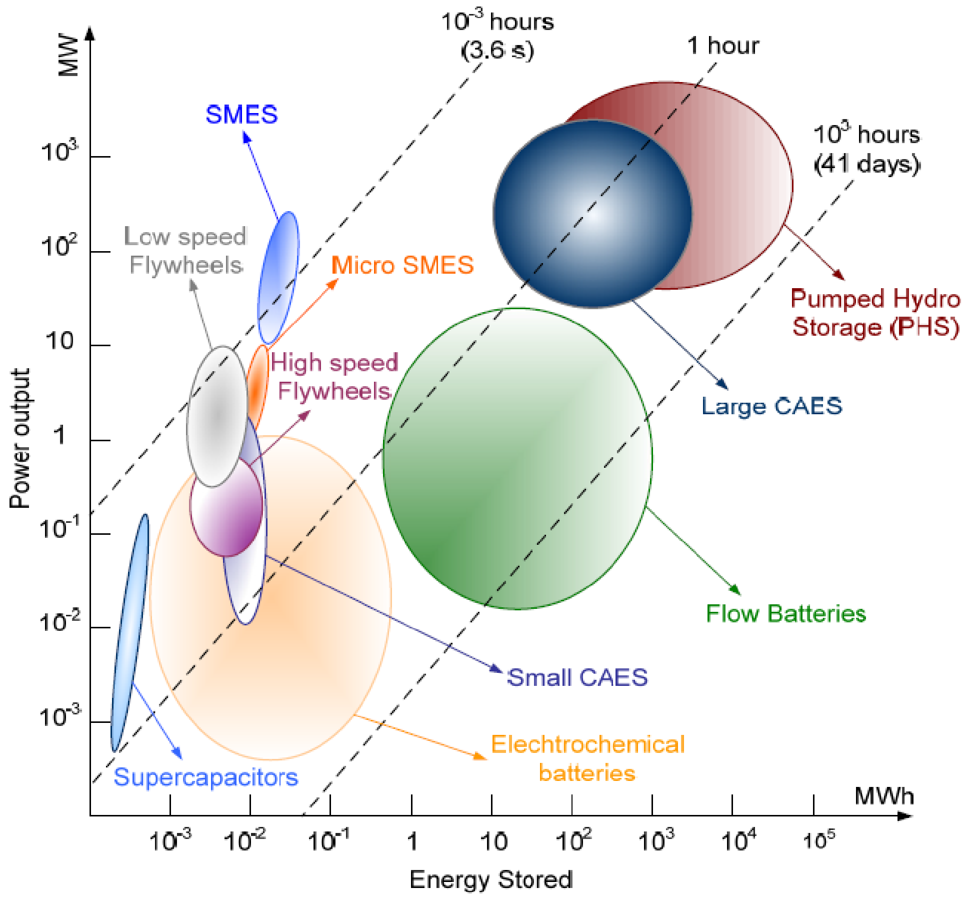


Figure 15: Different electricity storage technologies and with their typical power rating and discharge time (Source: Ibrahim and Ilinca, 2013).

The capital costs per unit for different energy storage technologies are shown in Figure 16, which clearly shows why pumped-storage hydro (PSH) is the most commonly applied storage technology.

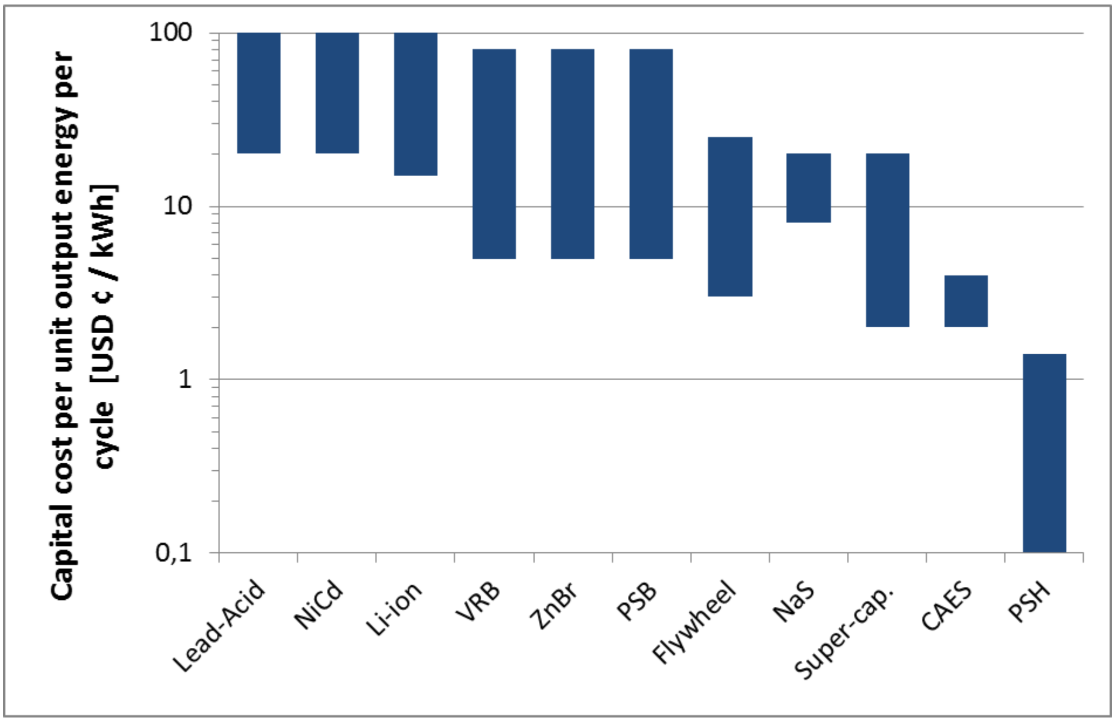


Figure 16: Capital cost per cycle for various storage technologiesCosts of operation and maintenance, disposal, replacement and other ownership expenses are not included (Data source: Chen et al., 2009).

As the Norwegian electricity system is dominated by storage hydros, hydropower is the only technology used for energy storage and balancing services at time scales from seconds to years. Hydro turbines can be used as flywheels and take care of the short-term balancing. Norway has large hydro reservoirs and may also store water between years. There is no real need for PSH. The few existing pumped hydro installations in Norway are mainly used for seasonal pumping and storage.

The use of 'linepack' in gas pipes as storage is not shown in Figure 15 and Figure 16. The cost will mainly be the additional cost of compressing the natural gas for storage purposes, which may be around 1–2% of the gas. The relevant time horizon for storage services from linepack would range from hours up to days. As indicated in Section 3, the volumes would be time dependent but in the order of more than 100 GWh for large export pipelines in a 12-hour horizon.

Based on the presentation in this section, we argue that there is an evident need for balancing services and flexible energy supply in energy mixes that contain a large share of non-dispatchable energy sources. Further, the status of current storage technology (and costs) indicates that the hydropower reservoirs and natural gas storage facilities can play an important part in offering such balancing services. The pumped storage facilities could then be used to increase the storage capacity in the hydropower system further.

6 Scenario studies of the European energy system

In order to assess the role of Norwegian hydropower and natural gas in a low carbon European power system, we applied the power market investment model EMPIRE, developed in CenSES. For this study, a baseline decarbonization scenario was constructed, in which assumptions about the main drivers of power system development were based on the most recently published reports by credible institutions such as the European Commission and the IEA. As one of the key uncertainties in the future development of the European power system is the availability of carbon capture and storage (CCS) for power generation, the baseline scenario was contrasted against a no-CCS scenario in which assumptions were identical except for a limitation of not having any CCS investment option.

EMPIRE is a multihorizon stochastic capacity expansion model for the European power system. Its objective is to minimize system cost of the European power system including investment cost and expected operational costs (Skar et al., 2016). The model has also been used to study the role of CCS in the European power system (ZEP, 2013; 2014; 2015). The model represents load and RES generation under short-term uncertainty, so that hourly variations and their correlations will be considered when a system is designed. This is particularly important when considering the technologies included in the energy mix and their actual role in the operations in terms of utilization factors. EMPIRE can therefore model the interplay between low carbon technologies with different characteristics such as solar PV energy, wind energy, CCS, and nuclear power. Additionally, flexibility options such as demand response, energy storage and grid expansion are included in the model.

6.1 Related scenario studies of European power decarbonization

A significant number of studies of the development of the European power system until 2050 have been conducted in recent years, and in this section we review a selection of the most notable ones. The EU Energy Road Map 2050 that was adopted as a Communication by the European Commission on 15 December 2011 and was the basis for the European Commission's ambition to reduce GHG emissions towards 2050. For reference, we compare it with EURELECTRIC and the European Climate Foundation Road Map from the same time. A more recent scenario is the EU reference scenario 2016 report published by the European Commission (European Commission, 2016). Our detailed analysis of the European power sector using the EMPIRE model takes this report as a starting point in Section 5.2.

6.1.1 EU Energy Road Map 2050

The EU Energy Roadmap 2050 is EU's basis for developing a long-term European framework together with all stakeholders. There are now discussions on an updated EU Energy Roadmap in 2019 or 2020. Based on the current roadmap, EU is committed to reduce GHG emissions to 80–95% below 1990 levels by 2050. In the Energy Roadmap 2050, the Commission explores the challenges posed by delivering the EU's decarbonization objective, while at the same time ensuring the security of energy supply and competitiveness.

Five low carbon scenarios, a reference scenario, and a Current Policy Initiative (CPI) scenario, are included in the Energy Roadmap 2050. The reference scenario is a projection of developments in the absence of new EU policies beyond those adopted by March 2010. The CPI scenario was added to consider the most recent developments (higher energy prices and the effects of the nuclear accident in Japan) and the latest policies on energy efficiency, energy taxation and infrastructure adopted or planned after March 2010. The five low carbon emission scenarios reflect alternative ways of implementing a low carbon energy system: 'Energy Efficiency', 'Diversified Supply Technologies', 'High RES', 'Delayed CCS', and 'Low nuclear' (European Commission, 2011).

6.1.2 European Climate Foundation Road Map 2050

In support of the objective of an 80–95% reduction in GHG emissions below 1990 levels by 2050, the European Climate Foundation (ECF) initiated a study to establish a fact base behind the goal and derive the implications for European industry, particularly in the electricity sector.

The result was the ECF Roadmap 2050, which is claimed to be a practical guide to a prosperous, low carbon Europe (ECF, 2010). Two scenarios from ECF are shown in Figure 18.

6.1.2.1 Comparison of the road maps

In this section, we discuss some of the differences between the above-mentioned scenarios. The comparison focuses on the power generation and demand in Europe in 2050.

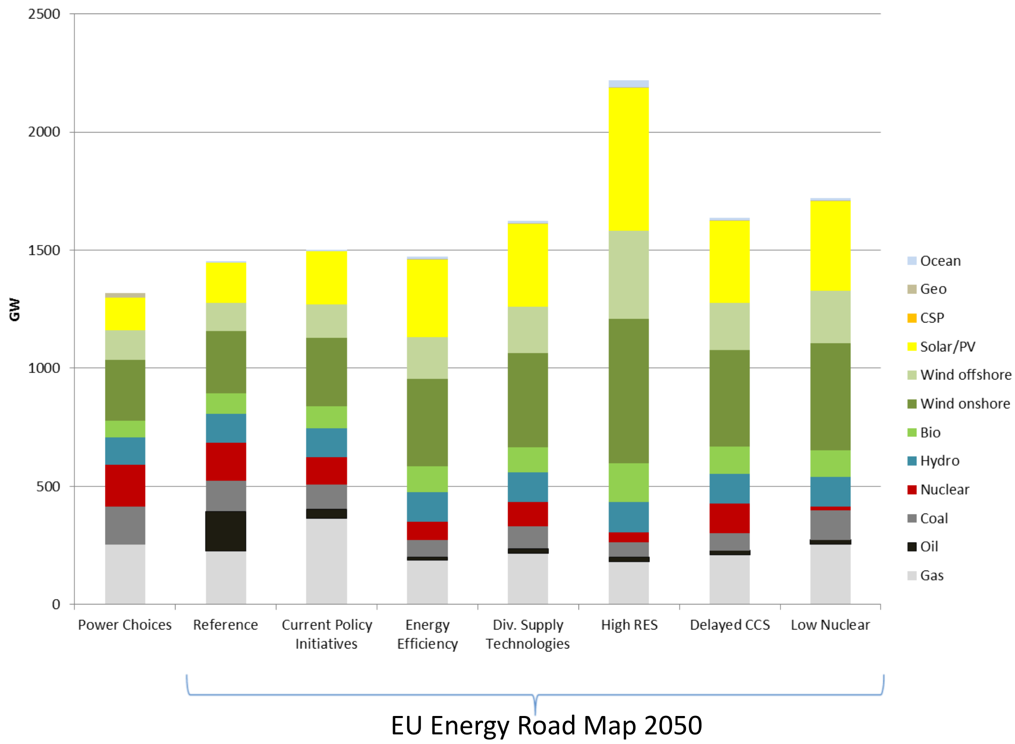


Figure 17: Installed generation capacities in Europe in 2050 for the EU Energy Road Map 2050 and Eurelectric's 'Power Choices' (GW) (Source: Eurelectric, 2010; European Commission, 2011).

The installed capacities for EU27 in 2050 for the EU Energy Roadmap 2050 are shown in Figure 17. Figure 18 shows the installed capacities for EU27 plus Norway and Switzerland in 2050 for two ECF Roadmap 2050 scenarios with 80% reduction in GHG. For reference, we include in Figure 19 Eurelectric's Power Choices scenario that examines how a carbon-neutral power sector in Europe could be a reality by the mid-21st century (Eurelectric, 2010). The Power Choices scenario sets a 75% CO_2 reduction target across the entire EU economy, and aims for an optimal power generation portfolio based on an integrated energy market. In this scenario, electricity becomes a major transport fuel as plug-in hybrid and electric cars are rolled out.

The electricity demand in all of the scenarios from EU Roadmap 2050, ECF Roadmap 2050, and Power Choices (including a baseline scenario with current policy) are summarized in Figure 19. One of the more important differences between the scenarios is:

- Some scenarios focus on energy efficiency and energy demand reductions, with the EU Roadmap 2050 Energy Efficiency scenario as the most ambitious with a demand just above 3000 TWh/y.

Since the Commission publishes the EU Energy Road Map, the scenarios discussed in this report are of particular interest:

- Figure 19 shows that there are large similarities between the decarbonization scenarios: except for the ‘High RES’ scenario, the scenarios have approximately the same range of installed capacity, the largest share of production is from wind, the share of fossil plus nuclear production is at the same level, and so forth.
- The share of wind and solar production together is more than 50% in all the decarbonization scenarios. The shares are varying from 58% in the ‘Div Supply Technologies’ and ‘Delayed CCS’ scenarios to 72% in the ‘High RES’ scenario.
- All decarbonization scenarios have equal or higher installed capacities and lower consumption compared with the reference scenario. Because of the varying production from wind and solar resources, it is necessary to increase the capacities compared with conventional production. This is particularly visible for the ‘High RES’ scenario, which has 30% more installed capacities compared with the second highest installed capacity.
- The same effect can also be observed in the ECF Road Map: the installed capacity is lowest in the scenario to the left in Figure 19, with 40% RES, 30% fossil production with CCS, and 30% nuclear. For the other scenario, there is 80% RES and a much higher installed capacity is needed.
- The share of production based on biomass is low: this is probably because biomass is mainly used for decarbonization of the transport and the heating sector.
- The installed hydropower capacity is approximately the same for all scenarios, reference as well as decarbonization. Installed hydropower capacity is increased from 2010 (107 GW) to 2050 (121–131 GW). There is no foreseen major increase in hydropower production in Europe up to 2050 and no other countries are expected to be able to contribute the same hydropower storage capacities as Norway.

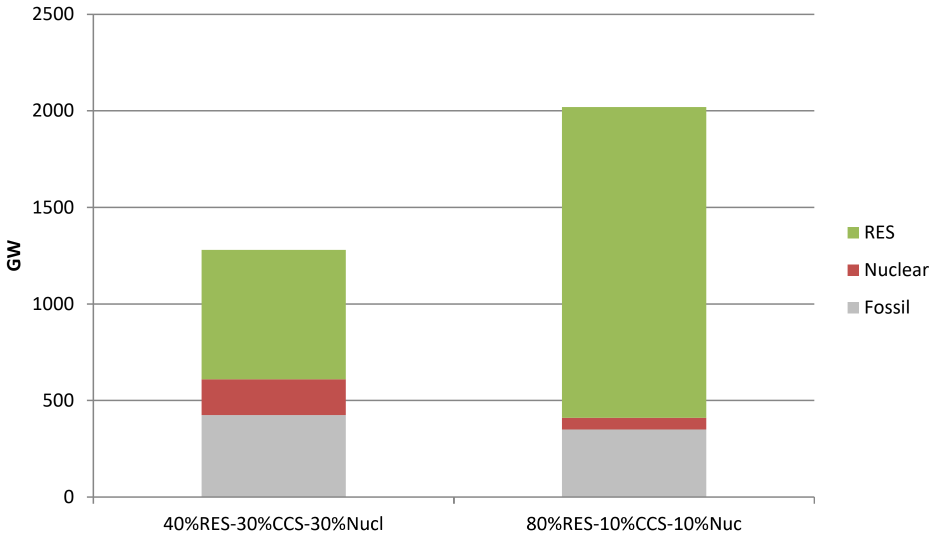


Figure 18: Installed capacities for two of the ECF Roadmap 2050 scenarios for 80% reduction in GHG emissions for EU plus Norway and Switzerland (GW) (ECF, 2010).

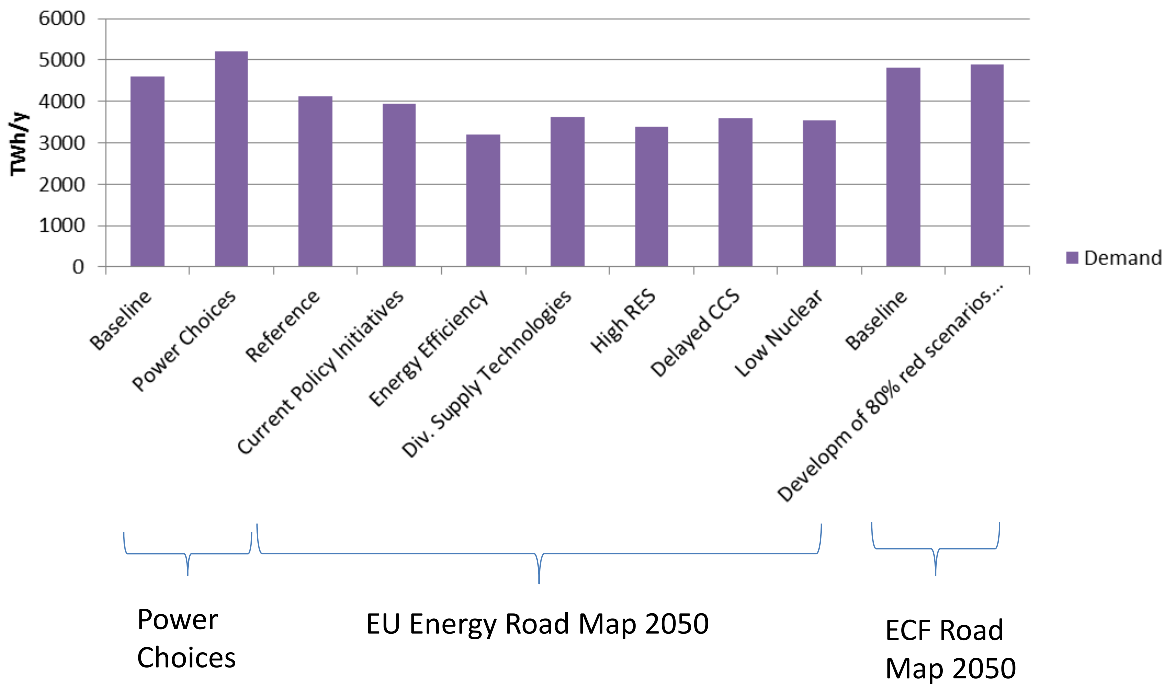


Figure 19: Demand in 2050 (TWh/y). The bar chart shows gross electricity demand for the two Power Choices scenarios. For the other scenarios, final electricity demands are shown. (Sources: European Commission, 2011; ECF, 2010; Eurelectric, 2010).

6.2 EMPIRE Baseline decarbonization scenario

The baseline scenario comprises a set of assumptions regarding parameters used in the system optimization in EMPIRE. Some of the most important drivers of the need for investments in a power system are development of demand for electricity and fuel prices. For this report, we have collected projections on annual demand for electricity for individual European countries from the EU reference scenario 2016 report published by the European Commission (European

Commission, 2016). Our fuel price projections are taken from the IEA's 2-degree scenario (2DS) in their report *Energy Technology Perspectives 2016* (IEA, 2016a), and the assumptions are shown in Figure 20. Comparing the end-point of the demand projection in Figure 20 with the 2050 demand used by the various energy scenarios in Figure 19, we see that our baseline scenario demand is within the range of the EU Energy Road Map scenarios, and lower than the scenarios by ECF and Eurelectric.

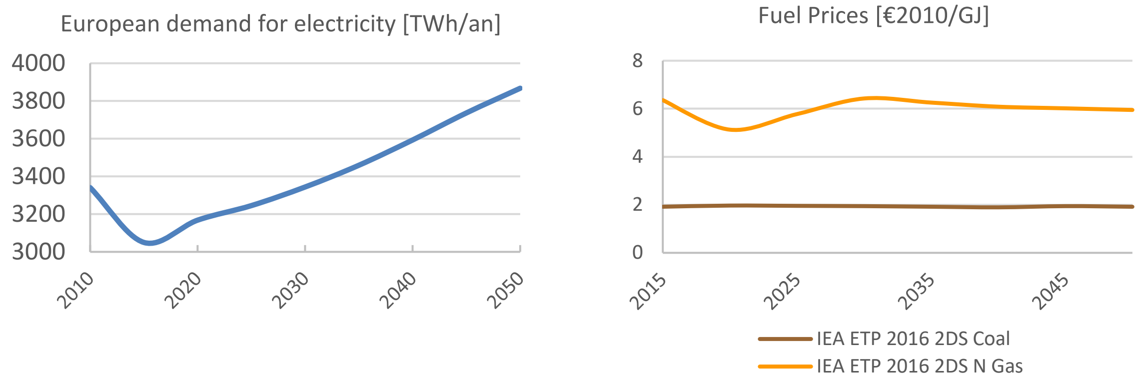


Figure 20: Assumptions about demand for electricity and fuel prices in the baseline scenario

The main emission reduction policy in the study is an emission cap specifically for the power sector in line with the EU Energy Roadmap 2050. A linear reduction of 90% direct emissions in the power sector from a 2010 base year to 2050 is assumed.

Another important set of assumptions with a strong impact on the optimal system design are technology-specific costs and features. We use the data from the report by Skar et al. (2016) as a basis, with some updates for selected technologies. The main sources in Skar et al. (2016) are the technology costs gathered for a report by ZEP (ZEP, 2013), along with ENTSO-E data portal data and some data from various European TSOs. In this study, the investment cost of solar PV technology has been updated using the medium cost projection scenario in Fraunhofer ISE (2015). Investment costs for onshore and offshore wind have been collected from the document by Gerbaulet & Lorenz (2017). Investment costs for nuclear power have been set at 6000 EUR/kW for all investment periods. The costs for natural gas-fired power plants have been updated from the report by Skar et al. (2016) in order to be flat for the whole period until 2050. Data for all CCS technologies remain the same as in Skar et al.'s report (2016).

Although there are usually few physical limitations on investments in cross-border interconnector capacities, there are barriers facing these types of investments that are challenging to include in a techno-economic cost optimization such as done by EMPIRE. In particular, complicating and long licensing and planning processes combined with potential public opposition are difficult to include and tend to restrict investments that would have otherwise been optimal if based solely on economic consideration. In the short term, we have therefore fixed the development of cross-border transfer capacities towards 2020 to follow the reference capacities in market modelling data published alongside the ENTOS-E's 10-year network development plan (TYNDP) from 2016. Beyond 2020, we have limited expansion on each interconnector to 4 GW every five years, which is close to the largest expansion found in the ENTSO-E's 2016 TYNDP market modelling data.

In addition to the limitations on transmission investments, we impose restrictions on total installed capacity for onshore wind and solar PV energy within each country. These constraints reflect limitations on suitable locations where such technologies can be deployed. For onshore wind, we base the capacity potential on the figures published in one of the appendices of the IEA's *Nordic Energy Technology Perspectives 2016* (NER, 2016). For solar PV energy, we have based our limits on Gils et al. (2017).

To account for national policies on nuclear power, we limit capacities for each country to not exceed the capacities found in ENTOS-E's Vision 1 and Vision 2 based on the 2016 TYNDP market modelling data. This constitutes a medium level of European nuclear power in the future, and respects stated national phase-out policies where relevant. For renewables, we only account for stated national policies in the largest countries included in EMPIRE. Renewable share targets, formulated as a share of total domestic demand that has to be covered by domestic renewable production, has been implemented for Germany, France, Spain and the UK. Lastly, the development of Norwegian hydropower is exogenously defined, and based on input from FME CEDREN.

6.2.1 Optimal development of the European power system computed by EMPIRE

In this section, we present the EMPIRE results from our Baseline and NoCCS scenarios with a focus on the European-wide implications of decarbonization of electric power.

Baseline results

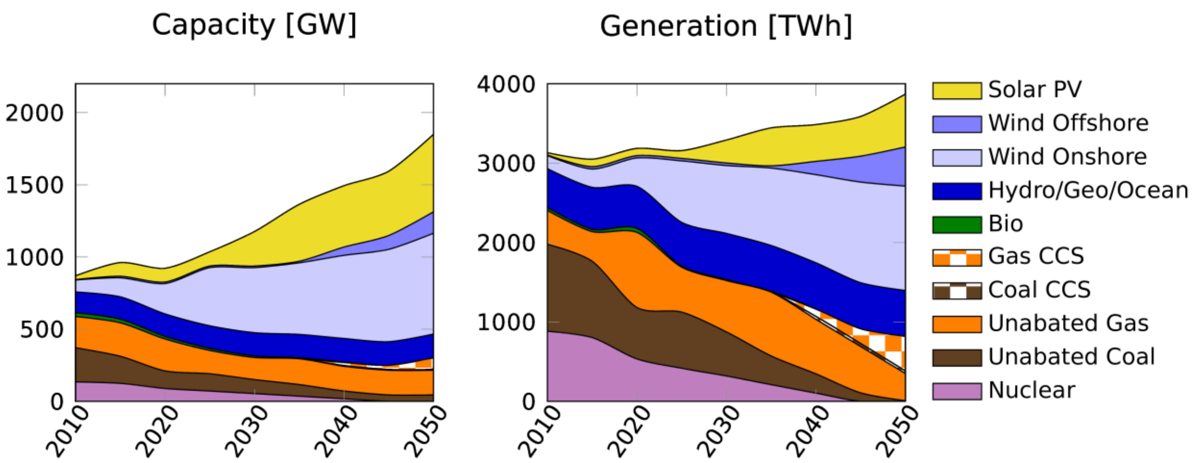


Figure 21: Generation capacity and energy mix in Europe in the Baseline scenario (from EMPIRE).

The development of the generation technology capacity mix and energy mix resulting from the EMPIRE optimization in the Baseline scenario are shown in Figure 21. In 2010 and 2015, most of the generated power comes from coal, nuclear, hydropower and natural gas. As the emission limit is progressively decreased, power production from coal is displaced by power produced by natural gas, wind, and solar energy. Nuclear power is steadily phased out from 2015. In 2020, there is a sudden increase in natural gas generation, which is an effect of the low gas price for this period found in the IEA ETP 2016 2DS data (Figure 22). Wind energy technology quickly gains the highest share of the energy mix in 2025 and onwards. Offshore wind only enters significantly from 2040, and in 2050, almost 50% of the total power generation comes from onshore and offshore wind. After 2030, a decrease in PV investment costs makes the technology competitive to the extent that a surge of new capacity enters the market.

In the period 2018–2030, natural gas continues to have a significant share of the generation mix. At the peak in 2020, almost 945 TWh/year are produced using natural gas. In 2040, fossil generation with carbon capture and storage begins to enter the system, while unabated natural gas power production remains at the same level, leading to an overall increase in natural gas power generation. Although a small part of the total CCS is used for coal, the total CCS portfolio is almost exclusively gas-fired power plants.

Although renewable technologies and batteries see remarkable drops in costs over the course of the analysed period, there is still a fair amount of natural gas production left in the system. On a purely individual assessment of costs for each technology using, for example, levelled cost of electricity (LOCE) calculations, the renewable technologies would be more competitive, and in this perspective the resulting mix shown in Figure 23 may seem somewhat surprising. In reality, the short-term variations in generation from wind and PV combined with variations in load require flexibility. The embedded hourly modelling of system operation in EMPIRE, combined with its geographical coverage makes it possible to study these 'profile costs' of wind and solar power technologies. Without considering such features of non-controllable renewable power production, the competitiveness of these technologies is overestimated, and is one of the drawbacks with the LOCE measure (see Hirth 2013 for a more detailed discussion on these issues). The effect explains why, even with formidable cost decreases for, for example, solar PV technology, other technologies are significantly present in the cost-optimal energy mix.

The total increase in capacity and generation from hydropower in Europe is negligible compared with the other technologies, although a slight increase is seen.

Table 4Table 4 shows the European capacity and generation mix results for 2050. By then, CCS power generation accounts for 12% of the total mix, while the share of wind power is 47%, including both onshore and offshore. By 2050 most of the conventional (unabated) coal-generation has been retired. Some conventional natural gas generation is still operational. However, the total production is low, which means that these power plants are idle for large portions of the year.

Table 4: Generation capacity and energy mix in Europe 2050 in the Baseline scenario (from EMPIRE).

Technology/fuel (2050)	Capacity (GW) (% share)		Generation [TWh] (% share)	
Solar	536	(29%)	665	(17%)
Wind onshore	698	(38%)	1314	(34%)
Wind offshore	149	(8%)	492	(13%)
Gas CCS	81	(4%)	436	(11%)
Coal CCS	6	(0%)	33	(1%)
Fossil unabated	215	(12%)	350	(9%)
Others (e.g. Hydro, Geo)	164	(9%)	577	(15%)

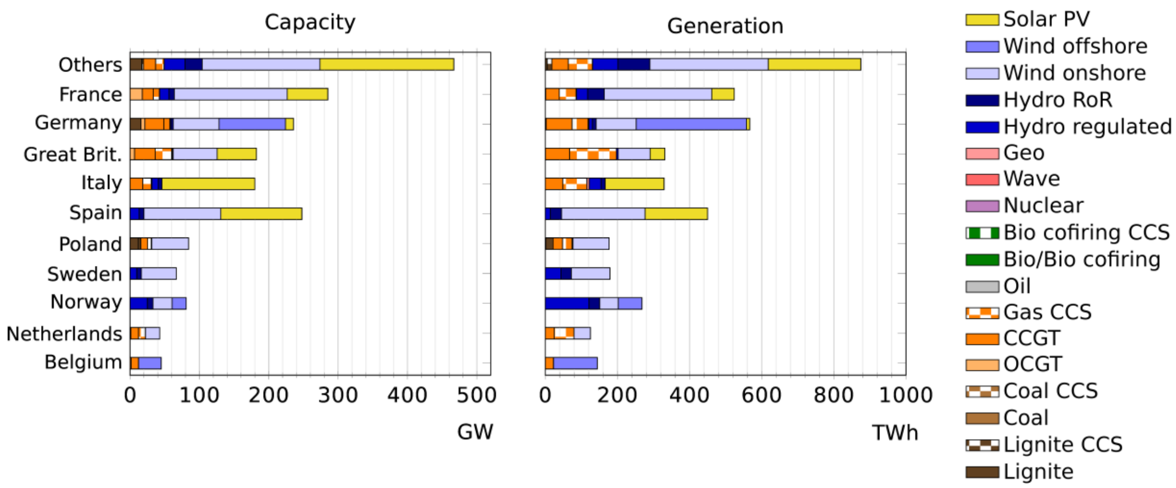


Figure 22: Country-level generation capacity and energy mix in 2050 for the ten countries with the highest installed capacity in the Baseline scenario (from EMPIRE).

Figure 22 shows results for generation capacity and energy mix in a selected number of European countries in 2050. In Germany, the energy generation comes mostly from offshore wind, and some onshore wind and natural gas generation. Very little solar PV capacity is installed in Germany, which is an indication that from a European perspective solar resources are more attractive elsewhere. France attains an energy mix dominated by onshore wind, solar PV energy and natural gas fired generation with and without CCS. In Great Britain, more than half of the generation comes from natural gas (split between unabated and CCS). In total, the net energy balance for Norway is about 112 TWh/year, as the total demand in 2050 is assumed to be about 150 TWh/an. This is a clear indication that the optimal strategy found by EMPIRE tends towards deploying new wind generation massively in favourable locations.

NoCCS results

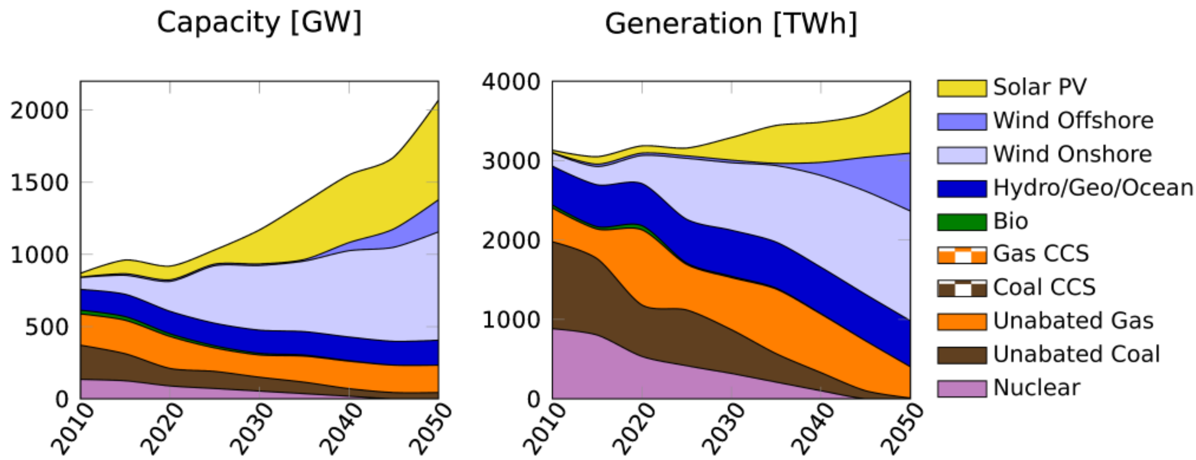


Figure 23: Generation capacity and energy mix in Europe in the NoCCS scenario (from EMPIRE).

Figure 23 shows the results for European aggregated capacity and generation in the NoCCS scenario where CCS is not an available technology. By comparing Figure 23 with Figure 24, it becomes evident that the NoCCS scenario closely resembles the Baseline scenario until 2040. After that period, when CCS capacity enters into the Baseline scenario, there are notable differences and some similarities. Conventional coal and nuclear power are still phased out. Conventional natural gas power production is somewhat higher than in the Baseline scenario. Naturally, all the renewable generation technologies have higher installed capacities in 2050, with a total addition of almost 300 GW.

Table 5: Generation capacity and energy mix in 2050 in the No CCS scenario.

Technology/fuel (2050)	Capacity (GW) (% share)		Generation (TWh) (% share)	
Solar	690	(33%)	788	(20%)
Wind onshore	751	(36%)	1381	(36%)
Wind offshore	222	(11%)	730	(19%)
Coal (unabated)	43	(2%)	11	(0%)
Natural gas (unabated)	190	(9%)	393	(10%)
Others	173	(8%)	580	(15%)

The European capacity and generation results for the NoCCS scenario in 2050 are shown in Table 5. By then, wind power (onshore/offshore) and solar PV energy have a total share of the generation mix of 75% (compared with 65% in the Baseline scenario). There is still a significant amount of natural gas power production in 2050, with a total of approximately 400 TWh/an, close to the corresponding level in 2010. For Norway, an interesting observation is that the installed capacity of offshore wind is much higher than in the Baseline scenario.

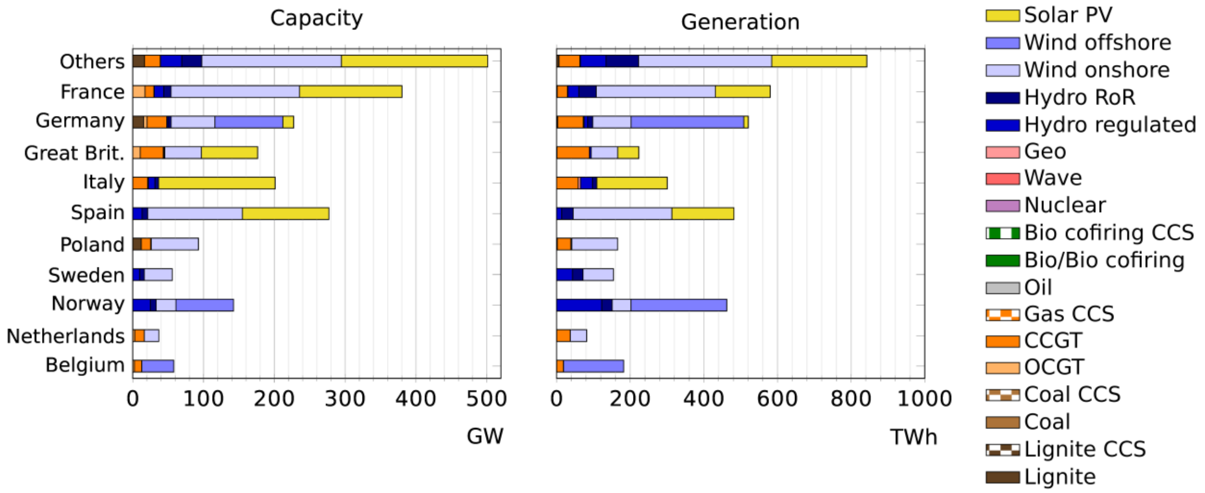


Figure 24: Country-level generation capacity and energy mix in 2050 for the ten countries with highest installed capacity in the NoCCS scenario (from EMPIRE).

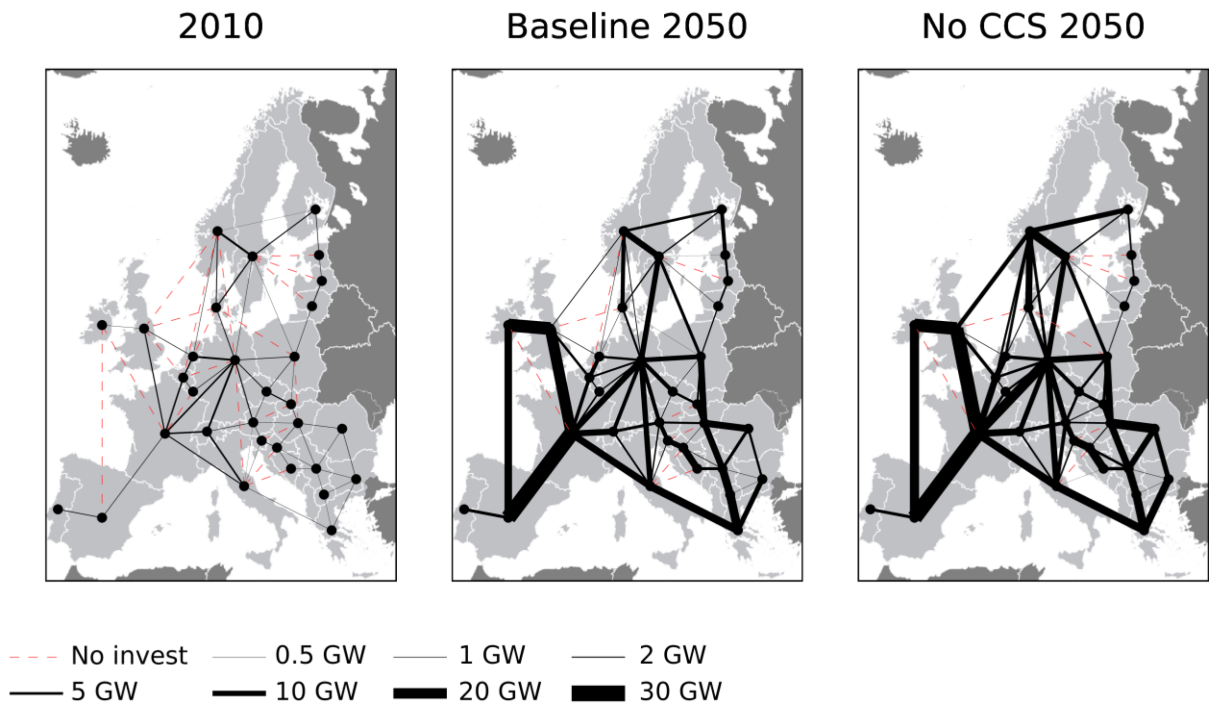


Figure 25: European transmission capacity in 2010, and the EMPIRE optimized infrastructure in 2050 for the Baseline and NoCCS scenarios.

Transmission system expansion:
In EMPIRE, both generation capacity and cross-border transmission capacity are co-optimized. Figure 25 shows the initial capacities in the European system in 2010 and the system in of 2050 from the EMPIRE optimization, both for the Baseline scenario and for the NoCCS scenario. As can be seen from the Figure, in both decarbonization scenarios there are substantial investments in interconnector capacities. Across all interconnectors, the total interconnector capacity in Europe was about 65 GW in 2010. By 2020, this had almost doubled to 120 GW, which was the aggregate of the capacities according the ENTSO-E TYNDP 2016 market modelling data. This also marked the starting point of the EMPIRE optimization of transmission system investments. By 2050, the total capacity in the system (across all interconnectors) is 456 GW in the Baseline scenario, and 527 GW in the NoCCS scenario, a 701% and 811% increase respectively from 2010. The percentages reflect that an optimal decarbonization relying on large shares of intermittent renewables requires significant transmission system expansion. The need for such infrastructure investments is lower when CCS is available, which is an indication that when dispatchable low carbon generation capacity is available throughout Europe there is less need for spatial balancing.

From a Norwegian perspective, it is interesting to observe that the expansion includes heavy investment in capacity towards Sweden and farther on to the rest of Europe. This is due to the model minimizing the system-wide cost, without considering country-specific interests. Depending on market design, direct cables may make more sense from an isolated Norwegian value creation perspective. This points to a central challenge in the transition of the European power system: how to share the benefits, costs and risk in the expansion.

6.2.2 The role of natural gas in a low-carbon European power system

Natural gas plays a significant role in the current fossil fuel mix of European power generation. According to ENTSO-E's 'Statistical Factsheet 2017', the total natural gas power production in the EU in 2017 was 644 TWh/an, which was 21% of the total generation mix, and 50% of the total fossil fuel share. In both of our decarbonization scenarios natural gas power production is seen to dramatically increase in 2020 due to low fuel prices. Beyond 2020, natural gas production is reduced from the record high level, but remains at a higher level than today until 2040. Thereafter, the total production remains almost the same in the Baseline scenario whereas in the NoCCS scenario it is reduced by almost 50%.

Table 6 shows a comparison between the progress of natural gas power production in our Baseline scenario and NoCCS scenario, with the statistics taken from the IEA's 'World Energy Outlook 2016' (IEA, 2016b) and the European Commission's reference scenario 2016 (European Commission, 2016). According to the published tables, the roles played by natural gas in the Baseline and the NoCCS scenarios are quite similar until 2040. They also bear resemblance to the EU reference scenario and that natural gas power generation increases from 2030 until 2040. In the EU, reference scenario natural gas power generation is expected to fall towards 2050, almost to the same level as in the Baseline scenario presented here.

Our analysis shows that without CCS the natural gas generation would have to be further reduced to achieve the emission reductions consistent with the limit.

Table 6: Comparison of European natural gas power production for the Baseline and NoCCS scenarios and those reported in publications by the IEA (2016) and the European Commission (2016). Numbers in TWh.

Year	Baseline*	NoCCS*	IEA WEO 2016 Current Policies	IEA WEO 2016 New Policies	IEA WEO 2016 450	EU reference scenario 2016
2030	647	656	876	708	591	655
2040	779	738	1068	642	240	925
2050	778	393				836

*The Baseline and NoCCS results are for Europe as defined by ENTOS-E members. The other studies have used EU-28.

7 The role of Norwegian energy resources for balancing and flexibility

In this section, we focus on how the results from our analysis and other studies indicate Norway's potential for offering flexibility and balancing services at different time scales. First, we use the model results from EMPIRE to discuss seasonal patterns of import and export in 2050, and how flexibility is used in different hours within a week in different seasons. Second, we summarize studies of short-term balancing services using flexible hydropower from the BM-MPM project and two PhD projects (Jaehnert, 2012; Farahmand, 2012; Aigner, 2013;

Gebrekiros, 2015). The subsection focuses on balancing in short time horizons ranging from seconds to minutes. Third, we discuss the study conducted by Harby et al. (2013), in which the focus is to investigate how Norwegian hydropower can contribute to large-scale balancing and energy storage mainly for time horizons ranging from one day to several weeks, and showing the technical potential to develop 20,000 MW of new hydropower capacity in Norway, where about 10,000 MW includes pumping.

7.1 Norway's role in a decarbonized European power system in 2050

This section focuses on the Norwegian results in the EMPIRE analysis introduced in Section 6.2. In both of our decarbonization scenarios, there are significant structural changes to the European electric power supply in the period 2010–2050. Between these two decarbonization scenarios, there are differences that become more and more noticeable towards 2050. When we isolate Norway, we see that, although there are changes to the electricity supply and a difference in the resulting system in 2050 between the Baseline and NoCCS scenarios, there are also similarities.

In Tables 7 and 8, the energy balance for Norway in 2050 is given for the Baseline and NoCCS scenarios respectively. By assumption, the demand profiles and the (normalized) generation profiles[4] for uncontrollable renewable technologies in these scenarios are identical. In addition, the energy limits imposed on seasonal generation from regulated hydropower are the same for both scenarios. The biggest difference between the scenarios with respect to Norway is the additional offshore wind power production, which is deployed in the NoCCS scenario, but not in the Baseline scenario. This is summarized in Table 7, which shows that without CCS, the deployment of offshore wind in Norway would be four times higher, at 81 GW in 2050.

Table 7: Installed capacities in (GW) the Norwegian system in 2050 in the two CenSES scenarios. For reference, the 2015 numbers are included.

	2015	Baseline 2050	NoCCS 2050
Hydro regulated	22	25	25
Hydro RoR	8	8	8
Pumped hydro	1	1	4
Wind onshore	1	28	28
Wind offshore	0	20	81

The production from offshore wind adds to the Norwegian power surplus, which is already significant in the Baseline scenario. As a result, more or less all of this new generation is exported to neighbouring countries.

[4] Normalized generation profiles (i.e. the hourly capacity factors, for renewables such as wind power, solar PV energy, and run-of-the-river hydropower) are taken as exogenous input into EMPIRE. The profiles are considered independent of decarbonization policy and are therefore the same in both the Baseline and the NoCCS scenarios.

The seasonal exchange in Table 8 is seen to be dominated by export all year round, with high export in wintertime (seasons 1 and 4) and reduced export during spring and summer. Clearly, this is an effect of hydropower production almost balancing demand in those seasons, while at the same time the wind production is high. In the current implementation of EMPIRE, the total amount of energy production within each season for regulated hydropower is based on exogenous data (meaning seasonal reservoir handling is predetermined outside the optimization). Therefore, we cannot easily address the opportunity of drastically changing the seasonal handling of reservoirs within this study. With this shortcoming in mind, we can still draw from these results that export patterns from Norway with this type of technology mix will be highly affected by the wind power production patterns (Table 9). This will particularly be the case for the NoCCS scenario, in which Norway will exporting twice its own consumption, mainly as offshore wind production.

Table 8: Seasonal energy balances for Norway in 2050 for the Baseline scenario (in TWh).

Type	Season 1	Season 2	Season 3	Season 4	Total
Demand	46	35	30	42	152
Generation	81	60	46	79	266
Hydro regulated	43	20	20	37	120
Hydro run-of-river	3	13	7	7	30
Wind onshore	19	14	6	13	51
Wind offshore	16	13	14	23	65
Export	39	29	22	39	128
Import	4	4	6	2	16
Net export	35	25	16	37	112

Table 9: Interconnector capacity between Norway and connected European countries. Numbers rounded to nearest 100 MW.

Type	Season 1	Season 2	Season 3	Season 4	Total
Demand	46	35	30	42	152
Generation	131	97	86	145	459
Hydro regulated	44	20	20	37	121
Hydro run-of-river	3	12	7	7	28
Wind onshore	19	14	5	12	50
Wind offshore	65	50	54	89	258
Export	87	67	62	104	320
Import	3	6	7	1	16
Net export	84	61	55	103	304

The exchange capacities between Norway and its connected neighbours are shown in Table 10. The 2050 results for both the Baseline and the NoCCS scenarios are included, along with the capacities for 2020 found in the ENTSO-E 10-year network development plan (TYNDP) 2016. In terms of connections between Norway and the rest of Europe, there is a significant difference between our two scenarios. In the Baseline scenario, none of the long-distance cables to Germany, Great Britain and the Netherlands is expanded beyond the 2020 capacities. However, the interconnectors to Denmark, Finland and Sweden are reinforced, and the total exchange capacity is tripled from 2020 to 2050. It should be noted that the strong reinforcement of the cable between Sweden and Germany is partly driven by the value of exporting Norwegian power surplus to Continental Europe through Sweden. The significant increase in exchange capacity between Norway and Sweden should therefore be considered with this in mind. Depending on market design, a direct cable may be preferable from a Norwegian value creation perspective, but that is outside the scope of the studies of short-term balancing services using flexible hydropower from the BM-MPM project and two PhD projects. The model looks at total European welfare, not Norwegian welfare.

In the NoCCS scenario there are huge expansions of all interconnectors. The 2050 total interconnector capacity is increased sevenfold from 2020 in the same scenario. The large difference in interconnector capacity between the Baseline and NoCCS scenarios can easily be explained by the additional offshore wind investments in Norway in the NoCCS scenario. This generation adds the total power surplus in Norway, which is more than 307 TWh/an in 2050 (compared with 114 TWh/an in the Baseline scenario). The additional interconnector capacity is used to export this surplus to Continental Europe.

Table 10: Interconnector capacity between Norway and connected European countries. Numbers rounded to nearest 100 MW

Connection to	2020 (ENTSO-E TYNDP 2016)	2050 Baseline	2050 NoCCS	Unit
Sweden	4000	11,800	16,900	MW
Denmark	1600	7 600	12,900	MW
Finland	100	4900	9800	MW
Germany	1400	1400	5400	MW
Great Britain	1400	1400	8100	MW
Netherlands	700	700	4900	MW
Belgium			4000	MW
Total	9200	27,800	62,000	MW

7.1.1 Hourly utilization of Norwegian resources and exchange with Europe

In Figure 26, Hourly exchange from Norway and the operation of Norwegian hydropower is shown in 2050 for two selected seasons in the Baseline scenario. In EMPIRE a full year of operation is represented by four typical weeks, each of which represents a different season of the year. To capture differences in operational conditions between years, such as for renewable generation and load, EMPIRE considers several stochastic scenarios of typical weeks in the optimization.

As can be seen from Figure 26, there are some clear trends in the exchange patterns between Norway and the neighbouring countries. In winter (season 1) Norway is a net exporter for much of the time in a typical week, but the full potential export capability is used only for a small share of the time. For Week 2, the exchange varies between 15 GW and 25 GW for much of the week, while for the two other representative weeks there are much larger variations. For instance, for Week 3 there are two instances when the difference in exchange exceeds 20 GW over the course of just a few hours.

In the summer season (season 3), the representative week profiles show some distinctive features. For the first three-and-a-half days, the Norwegian system is in net balance, exporting in some hours and importing in others. The exception is Week 1, for which there is continuous net import in these hours. For the remainder of the week there is a sudden change to the exchange pattern: Norway becomes a large exporter, with several periods and significant changes in import across short durations of time. For Week 2 the sudden drops in export during mid-day and rapid ramp-ups in evening for several days in a row are unmistakable. The flexibility of the Norwegian system adapts to the European solar PV production. Although solar PV energy only comprises 17% in the generation mix, it has a strong impact on the operation of flexible generation resources due to the single sharp diurnal peak in solar generation.

There is a clear positive correlation visible between hydropower production profiles and the exchange in both seasons 1 and 2. High export periods coincide with periods of high production from hydropower, and low export periods (and import periods) coincide with low hydropower production. This is a strong indication that the hydropower production pattern is driven by the operation of the European generation portfolio (to a large extent wind and solar), not by Norwegian load. If the opposite were the case, one would at least expect, for example, to find some situations with net import and high hydropower generation. In general, the hydropower generation profiles of our Baseline scenario show irregular variation over much of the week, with some distinctive days when the production is almost entirely shut off to give room for solar power. The ramps before and after such periods are incredibly steep, as the regulated hydropower capacity changes from full production to zero and then back to full production over the course of half a day.

In the NoCCS scenario the exchange and hydropower production profiles, shown in Figure 27, look strikingly similar to the Baseline results, albeit with much higher absolute variation and peaks in the exchange. This is as expected, due to the increased exchange capacity in the NoCCS scenario compared with Baseline scenario. Apart from increased exchange, the NoCCS profiles are much sharper in the sense that the shifts from one level to another in exchange and hydropower production are more radical, which will require extensive ramping capabilities in both generation equipment and cables.

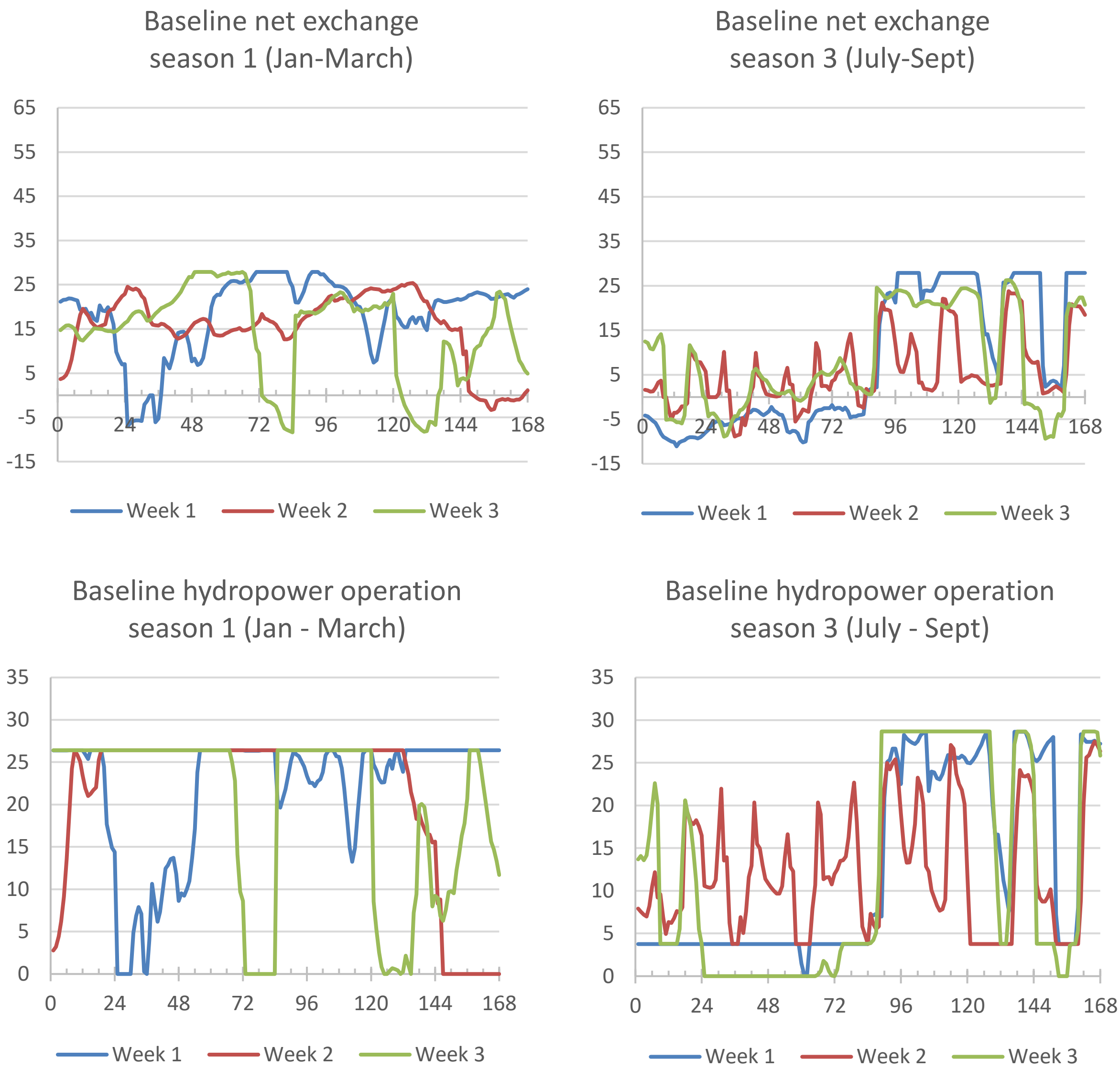
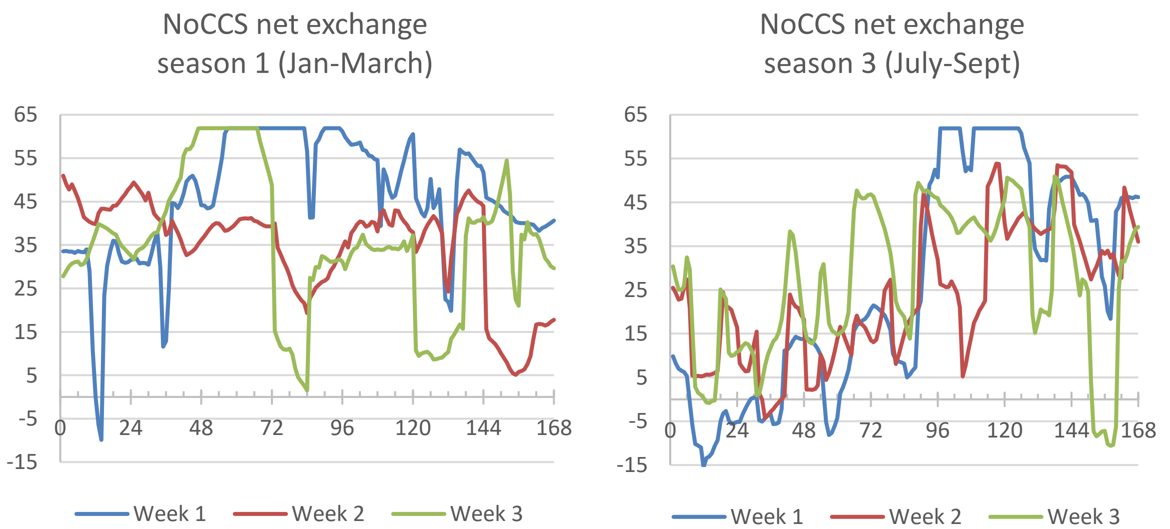


Figure 26: Baseline scenario: hourly profiles in 2050 for three typical weeks in season 1 (Jan–March) and in season 3 (July–Sept). The exchange of electricity to and from Norway (in GWh/h) (Top). Hydropower generation in Norway (in GWh/h) (Bottom).



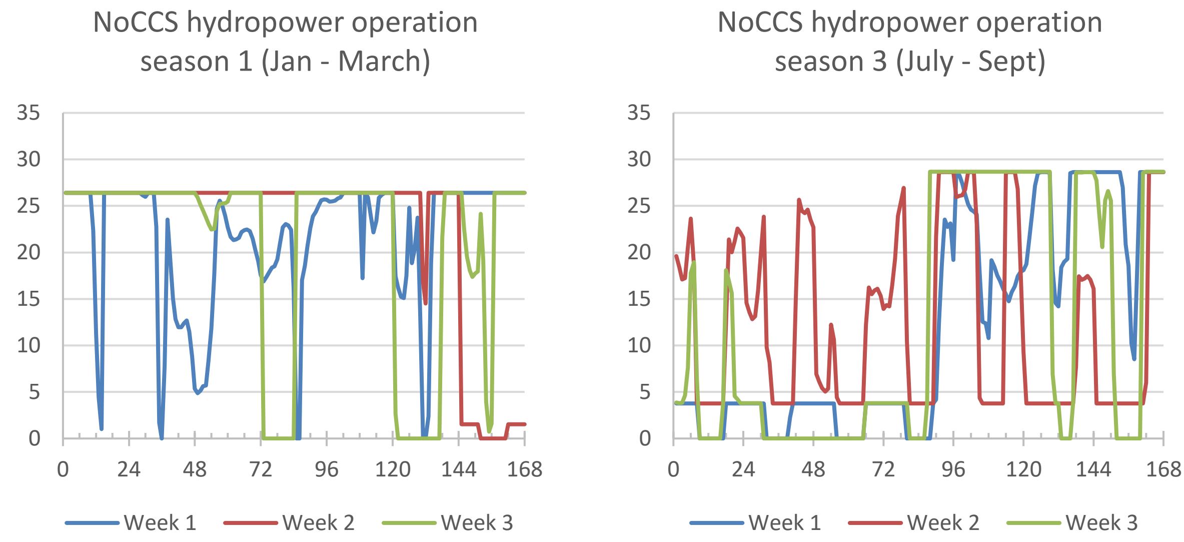


Figure 27: NoCCS scenario: hourly profiles in 2050 for three typical weeks in season 1 (Jan–March) and in season 3 (July–Sept). The exchange of electricity to and from Norway (in GWh/h) (Top). Hydropower generation in Norway (in GWh/h) (Bottom).

7.2 Within-day flexibility in the natural gas network

As with hydropower, natural gas power generation can be a flexible resource in a low-carbon power system. This section takes a closer look at how natural gas power plants (CCGT, OCGT, and gas CCS) are operated in 2050 in Belgium, Germany, France and Great Britain. These are connected to Norway through natural gas pipelines. Given that Norway can remain an important supplier of natural gas to them towards 2050, the operation of natural gas power plants in those countries is a strong indication of how flexible the Norwegian supply system must be. Figure 28 shows the total generation from natural gas power plants in Belgium, Germany, France and Great Britain in two seasons (each with three representative weeks) in 2050 for the Baseline and NoCCS scenarios.

The operation in each season shows a clear dependency on the short-term uncertainty (i.e. the realized production from intermittent renewables and load, as presented in the different representative weeks). It is difficult to point out a clear seasonal trend in these results, as variations appears to be just as large between different weeks in a season as between seasons. One clear effect is that high solar production during mid-day forces flexible plants to shut down for a duration of several hours, causing steep ramps. Frequently, the natural gas portfolio of the four countries ramps a full cycle from full production to almost no production and then back to full production over the course of one day. The magnitude of each ramp is about 60–70 GW over 4–5 hours.

A comparison of the Baseline and NoCCS scenarios shows that natural gas with CCS is typically utilized as baseload generation. This is evident from how the generation levels in the Baseline scenario appear almost the same as in the NoCCS scenario, except for a slight shift upwards. The most significant (rapid) changes in generation from natural gas are found at the unabated power plants. In both scenarios, two findings are evident. First, unabated natural gas power plants (for the most part CCGTs) must be designed and configured for a highly flexible operation with steep ramps, heavy cycling and potentially frequent start-ups and shutdowns. Second, the natural gas fuel supply to these plants must be able to handle this large variation in production, otherwise local fuel storage has to be considered.

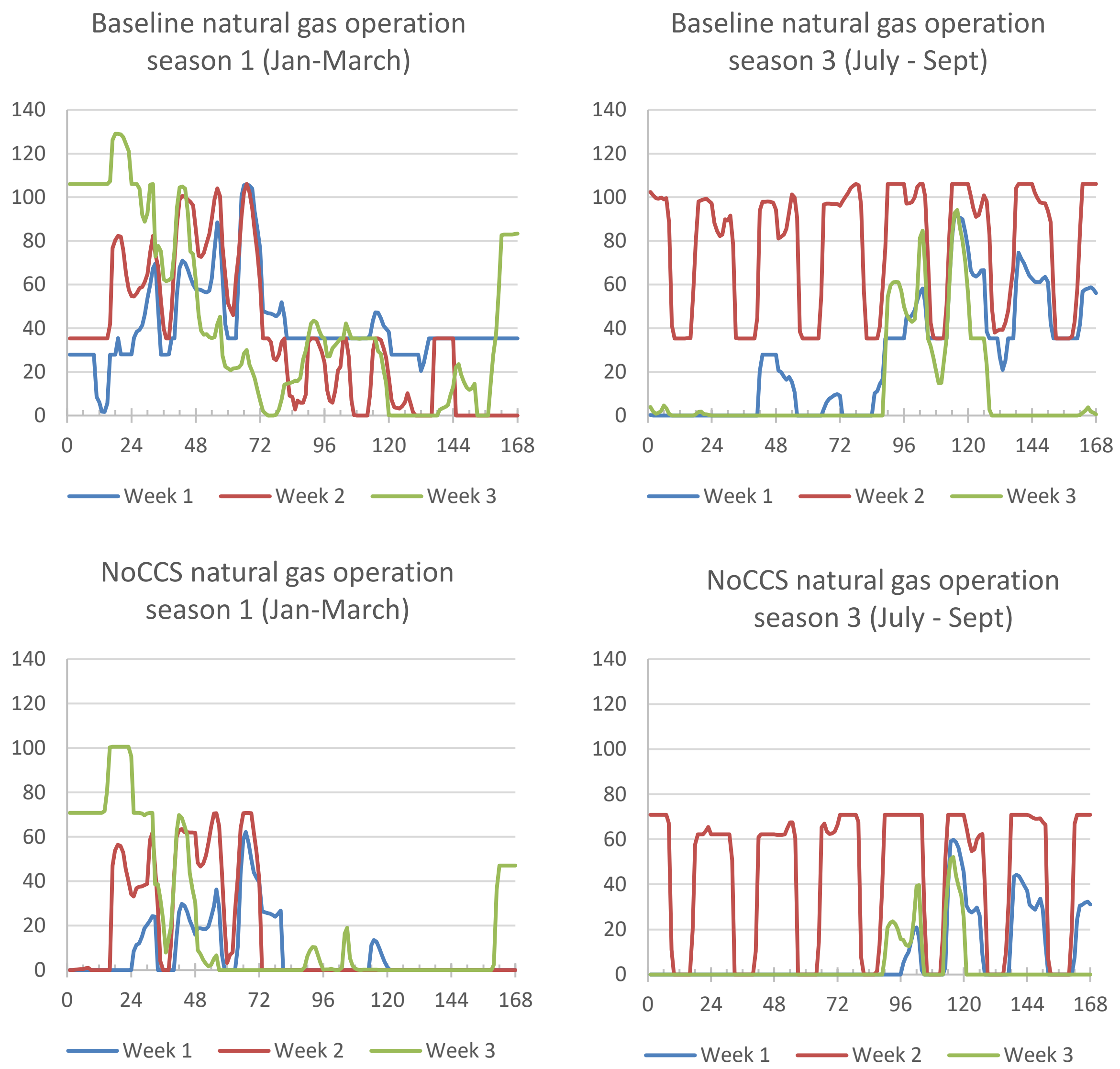


Figure 28: The electricity production from natural gas in the four countries where Norway has an export pipeline (UK, Germany, France and Belgium). The graphs show the variation in production (GWh/h) over 168 hours for three different typical weeks within the season from January to March and July to September in 2050.

7.3 Balancing in the short-term - provision of system services and regulation services using flexible hydropower

This section provides a perspective on the operational benefits and challenges of exchanging balancing services in the short time horizon of seconds to minutes at short notice. The background to the content of this section is the results from the BM-MPM project and two further PhD studies (Jaehnert, 2012; Farahmand, 2012; Aigner, 2013; Gebrekiros, 2015).

7.3.1 Integration of regulating power markets in Northern Europe

There are potential operational benefits and challenges relating to the exchange of balancing services among the Nordic countries and continental European countries for regulation and reserve purposes in the short time horizons. In 2007, SINTEF Energy Research initiated the project 'Balance Management in Multinational Power Markets'[5] (BM-MPM) in order to study the cross-border exchange of balancing services between different countries and the development of multinational balancing markets. The analyses highlight the potential of Nordic hydropower production flexibility, the benefits of cross-border cooperation and the necessary transmission capacity to reduce the challenges related to variability and uncertainty of power generation from renewable energy sources in Northern Europe.

Case studies of a 2010 and a 2020 scenario (Jaehnert & Doorman, 2014) investigated the large-scale wind power integration in the power system using two interacting models: a short-term balancing market model and a spot-market model, EMPS. The published studies include detailed data of the Northern European power system. The analyses show that there are considerable changes in the operation of the power system when moving from the 2010 to the 2020 scenario. With a significant increase in interconnection capacity, the exchange between the Nordic system and continental Europe is nearly doubled. The impact of variable inflow to the Nordic hydropower system is reduced, but due to the wind power production a higher short-term volatility of the system dispatch and consequently of electricity prices is observed.

[5] http://www.sintef.no/Projectweb/Balance-Management/

Additionally, the results indicate higher system imbalances and hence costs in the balancing power market. However, an integration of national balancing markets in Northern Europe provides a good possibility to counteract this cost increase, while the system security is enhanced at the same time. To assess the balancing market outcome, a dedicated mathematical model was developed to address explicitly the exchange of balancing services between the Nordic and continental European power system.

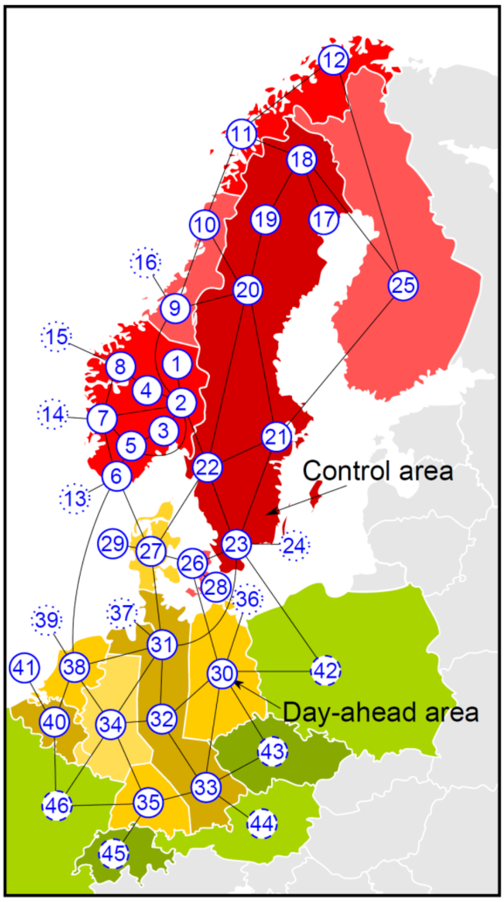


Figure 29: Geographical area of analysis: north-west Europe.

The case study of the integration of Northern European balancing markets shows significant economic benefits (Jaehnert, 2012). When exchange of reserve capacity is made possible, on average 20% of the reserve capacity required in the continental area will be procured in the Nordic countries. This will result in annual savings of about EUR 40 million. Furthermore, the activation of balancing reserves can be reduced by 40% due to system-wide netting of imbalances[6], resulting in additional savings of about EUR 100 million. In reality, the savings could be even higher, due to the assumptions in the model. The market design in the model assumes an integrated clearing of the day-ahead spot market and the procurement of reserves, which results in a more efficient dispatch than achieved by current practices in reality. Hence, there are already lower costs for the procurement of reserves before the market integration.

Table 11: Results of balancing market integration in the 2010 scenario

		No integration	Full integration
Reserve requirements	MW	7945	7945
Average reserve capacity exchange	MW	0	981
Annual reserve procurement cost	M€	153	113
Annual activated balancing energy	MWh	11816	8586
Annual balancing energy exchange	MWh	0	4609
Annual system balancing cost	M€	191	97
Total annual regulating power market costs	M€	350	210

[6] The term ‘netting of imbalances’ is used to describe a balancing market design in which the resulting deviation is calculated as the net deviation in several control areas (countries). If one area has a negative deviation and another has a positive deviation, the net effect will be zero and there will be no need to perform control actions.

7.3.2 System impacts from large-scale wind power

Aigner (2013) evaluated further system impacts of large-scale wind power and proposed measures for a cost-efficient and secure integration in the power system. The focus was on the development of a high-resolution wind power production model, a joint grid expansion model and the development of market models to simulate an integrated intra-day and balancing market in Northern Europe to illustrate the role of Nordic hydropower in order to even out the wind power variations in the continental system. Detailed time series of wind data were used as input to a mathematical model that simulated an integrated Northern European intra-day and balancing power market. Furthermore, a joint model was established simulating a cost-optimal grid expansion under the influence of large-scale wind power and its effects on a common European day-ahead market. The influence of wind power production on the power system and the power markets was analysed by scenarios for the years 2010, 2020 and 2030. Installed wind capacity in the area is assumed to increase from an actual value of 97 GW to 270 GW in 2020 and 397 GW in 2030. The share of offshore installations in the North Sea and Baltic Sea will respectively account for 16% (45 GW) in 2020 and 25% (100 GW) in 2030 (Figure 30). Although the geographical separation of production facilities will further increase in future scenarios, the overall production pattern will remain highly variable.

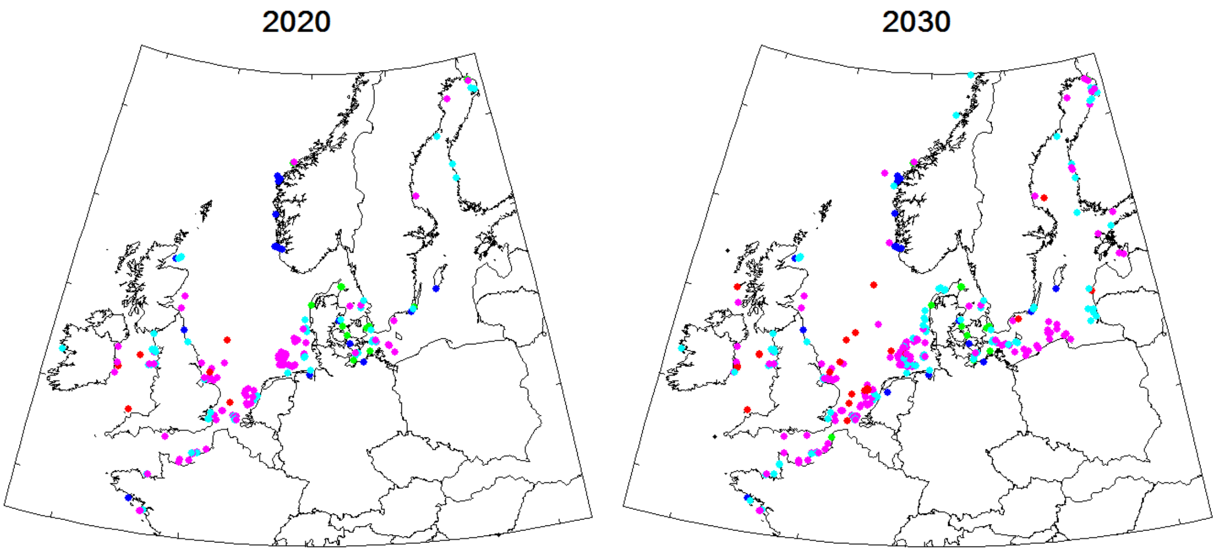


Figure 30. Offshore installations included in the data set in Aigner (2013).

The European wind power production varies between 2.2% and 61% of installed generation capacity in 2020 and between 2.5% and 62% in 2030. Considering only offshore installations in the North Sea and Baltic Sea, the production variability becomes almost intermittent, ranging from 1.4% to 86.7% in 2020 and 1.5% to 92.1% in 2030. The increased variability results from clustering offshore facilities in small areas and thus reduces the effect of geographical smoothing. Until 2030, the hour-to-hour variations will drastically increase up to 19 GW/h in Europe and 11 GW/h in the North Sea and the Baltic Sea. Although offshore installations only correspond to about 20–25% of the total installed capacity in Europe, they are responsible for 40–60% of the overall hourly fluctuations.

However, although the hourly wind power production variability will increase significantly, its effects on the European net load[7] variability will remain limited. In 2020, almost no increase in net load variations can be detected on a European level. The variability will only increase by about 3 GW/h in 2030. This appears to be rather modest, assuming maximum hourly load variations of up to 70 GW/h on a European level.

Gross system imbalances and balancing energy are almost doubled in the 2020 scenario compared with the 2010 scenario without balancing market integration. With an overall amount of EUR 343 million, the reserve procurement costs are more than twice as high as those in the results for 2010. The system balancing costs are estimated at EUR 154 million in 2020, and to increase by about 25% in comparison with the costs in 2010.

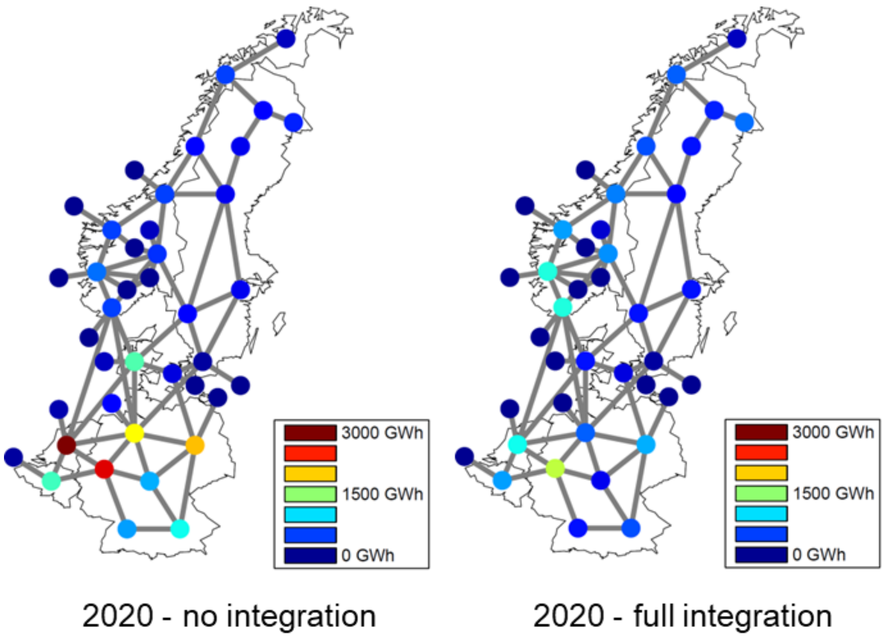


Figure 31: Balancing energy activation under different integration schemes.

Using the possibilities of a fully integrated market with its system-wide reserve procurement and exchange possibilities, the 2010 procurement costs can be cut by 40%, while in the 2020 scenarios the costs are reduced by about 30%. Almost the same conclusion can be drawn for the balancing costs, which are reduced by 30% in the 2010 scenario and 50% the 2020 scenarios by utilizing the flexibility of the Nordic hydropower. As most of the cheap balancing resources are situated in the Nordic region, the exchange of balancing reserves will increase and become more and more important in future scenarios, while the activation of reserves in Continental Europe will decrease.

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[7] Net load describes the remaining demand for dispatchable power plants (i.e. demand minus production from intermittent renewable energy sources).

7.3.3 Integrated power system balancing in Northern Europe

A study by Farahmand (2012) includes a two-step model for the optimal procurement of reserve capacity and activation of balancing services, taking into account transmission constraints in the case of exchange between two synchronous areas. The two steps in the model represent a simultaneous clearing of the day-ahead and reserve capacity markets, and of the real-time balancing market. Farahmand considers the multinational exchange of balancing services in a pool comprising Norway, Germany, and the Netherlands. The model was applied to state of the Northern European power system in 2010 and a future system in 2030, with increased wind penetration and rising transmission capacity between the Nordic and continental power system. In addition, a future system with a complex offshore grid configuration involving a high share of variable generation has been studied in the context of implementing the proposed balancing market integration.

In contrast to the above-discussed analyses of the integration of Northern European balancing markets, the model explicitly addresses the transmission grid constraints through power flow equations (DC-power flow). Available transmission capacity is allocated implicitly to the balancing services exchange, based on the trade-off between day-ahead energy and balancing capacity exchange. The investigated scenarios address this issue under the framework of a joint market for energy and reserve capacity, which leads to better utilization of the interconnections by avoiding socio-economic losses in the day-ahead market imposed by a fixed reservation of the corridors for reserve exchange.

Quantifying the potential benefits (i.e. socio-economic cost reduction) for the simulated year of 2010 indicates that through the integration of balancing markets in Northern Europe, there is a potential for operational cost savings of EUR 400 million per year. The results include the optimal distribution of balancing resources in each control area, together with the optimal exchange of balancing services. It is shown that through system-wide reserve procurement, an average of 0.9 GW of upward regulating reserve for the continent is procured in the Nordic system, representing approximately 30% of the required reserves in Germany and the Netherlands. However, the activated reserves are reduced by 31% through the effect of imbalance netting. The methodology has been implemented for the full integration of balancing market arrangement. The analysis shows in detail how the dispatch of generating units and the exchange between areas varies for different levels.

For 2030, the expected large-scale integration of wind power into the Northern European power system poses significant challenges for system planning and operation. The annual expected operational cost saving is EUR 512 million, which is 30% of the system balancing cost. Norway provides the main share of upward balancing reserves exported from the Nordic system to the Central European system, which is almost 76% of the total exported values. In addition, it the activated reserve is reduced by 24% due to the effect of imbalance netting.

7.3.4 Balancing market design with a sequential market clearing

The modelling of an integrated balancing market in a setting similar to the current sequential market clearance order in Europe has been done by Gebrekiros (2015). It is used to analyse the impact of balancing market integration in the current European electricity market settings and to allow for comparison of different market designs. Accordingly, optimization models addressing cross-border reserve procurement and balancing energy market integration were developed. These models are composed of three interdependent blocks: reserve bidding price determination, reserve procurement, and day-ahead market clearance. In addition, a methodology for optimal cross-border transmission capacity allocation was developed.

The analysis results show that unit-based upward and downward bidding prices for reserve capacity provision are a function of the difference between the spot price forecasts and a unit's marginal cost. Furthermore, the total reserve procurement cost decreases with an increased share of reserved net transfer capacity (NTC) because of the possibility of procuring cheaper cross-border reserves. However, the day-ahead cost generally increases with increase in reserved capacity. For small shares of reserved transmission capacity, procuring reserves from another system reduces the need to keep reserves in the expensive system, thus increasing the flexibility and likewise reducing the day-ahead cost.

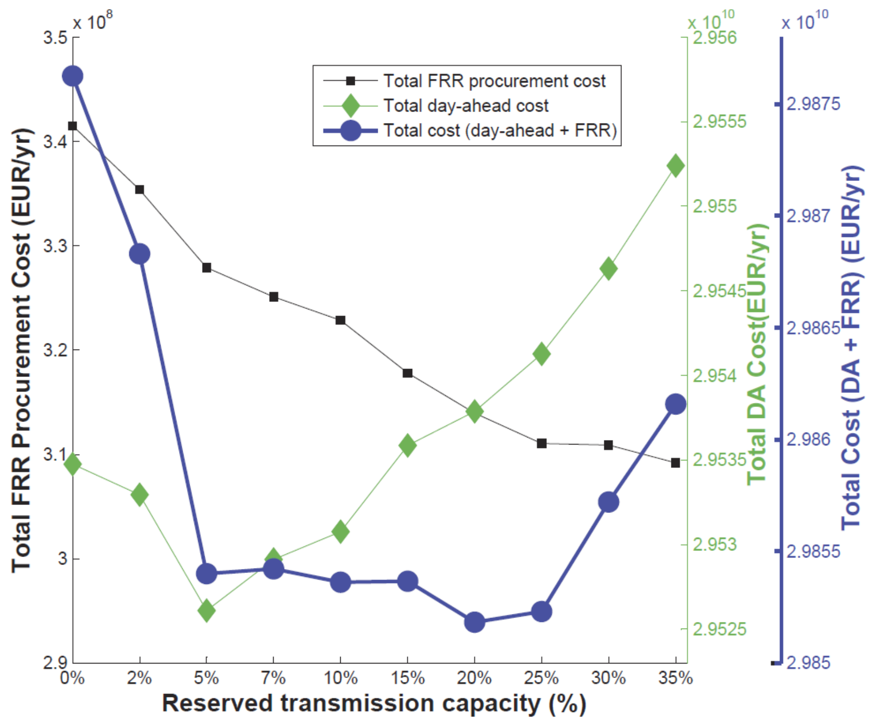

Figure 32: Annual procurement cost versus transmission capacity reservation for reserve capacity exchange.

By using an NTC-based methodology to allocate optimally transmission capacity for reserve capacity exchange for a planning period of 24 hours, a reduction of EUR 26 million (≈ 8%) in reserve procurement and EUR 53 million in total costs is obtained compared with the base case of no reservation. This result shows that optimal reservation of NTC for reserve capacity exchange can reduce both reserve procurement costs and day-ahead costs simultaneously (see Figure 32). Furthermore, sensitivity analyses using a 12-hour reservation period showed very significant cost reductions, which emphasizes the importance of short reservation periods for reserve procurement.

The possibility of cross-border balancing energy exchange gives cost reduction benefits in comparison with local balancing. The decrease in balancing costs is due to the netting of imbalances and the use of cheaper balancing energy from neighbouring zones. Further, due to the general improvement in market efficiency, and considering the IEEE 30-bus test system, the integrated flow-based balancing energy market clearing results in a 20% lower balancing cost compared with the NTC-based approach.

7.4 Use of Norwegian hydropower for medium-term balancing and energy storage

As shown by the EMPIRE analysis, there is a potential for using Norwegian hydropower for flexible energy exchange at the hourly scale within days. With regard to the longer periods of balancing demand and supply (when intermittent generation is low for weeks), there are very few alternatives to hydropower with large reservoirs if CO_2 emissions are to be avoided.

7.4.1 Medium-term flexibility provision and storage

A CEDREN study (Harby et al., 2013) is currently focusing on the potential contribution from Norwegian hydropower to the European energy system. In the study, it is assumed that there is a need for large-scale flexibility provision and energy storage due to the integration of wind and solar power with a focus on the situation in 2030. Results have been used from the Tradewind project (Tande et al., 2008), which assumes a total of 94,611 MW of wind power in the North Sea Area is installed both onshore and offshore. Additionally, we assume there are sufficient interconnectors between the Nordic grid and the European grid to exchange the amount of power installed for large-scale balancing power and energy storage.

Many European countries have few natural lakes and no available existing reservoirs for pumped hydro storage. Norway has large reservoirs and/or lakes used for traditional hydropower production, and it might be possible to increase the capacity by using existing reservoirs. The case study from CEDREN investigates the development of storage hydropower and pumped storage in Norway with storage volumes that could serve to provide flexible power and storage with durations up to several weeks.

The CEDREN study focuses on reservoir pairs in south-west Norway as potential sites for large-scale flexibility provision in the medium term. The study has been followed by a more detailed analysis of three cases, aiming at analysing implications for the operational schemes of the affected reservoirs in addition to current operation, when balancing wind power from the North Sea area.

A simulated wind power time series for the North Sea area from the Tradewind project was used to determine the daily required amount of flexible power used to balance the variations in wind.

A list of power plants was selected to be studied for potential increased installed capacity for power plants with outlet directly to the sea or to a fjord. The study also looked at pairs of reservoirs where it would be possible to install pumped hydropower between the reservoirs, including both pairs of reservoirs where there is an existing power plant today as well as potential new sites. The first results showed many potential new power plants and pumped power plants. The technical and economically best solutions were selected for further studies of the installations listed in Table 12.

Table 12: New power generation and pump installations (Source: Solvang et al., 2012).

Case	Power station	Output (MW)	Upper reservoir[1]	Lower reservoir[2]
A2	Tonstad pumped-storage power station	1400	Nesjen (14 cm/h)	Sirdalsvatn (3 cm/h)
B3	Holen pumped-storage power station	1000	Urarvatn (10 cm/h)	Bossvatn (12 cm/h)
B6b	Kvilldal pumped-storage power station	2400	Blåsjø (11 cm/h)	Suldalsvatn (6 cm/h)
B7b	Jøsenfjorden hydro storage power station	2400	Blåsjø (11 cm/h)	Jøsenfjorden (sea)
C2	Tinnsjø pumped-storage power station	2000	Møsvatn (3 cm/h)	Tinnsjø (4 cm/h)
C3	Tinnsjø pumped-storage power station	2400	Kallhovd (7 cm/h)	Tinnsjø (4 cm/h)
D1	Lysebotn hydro storage power station	1800	Lyngsvatn (12 cm/h)	Lysefjorden (sea)
E1	Mauranger hydro storage power station	400	Juklavatn (14 cm/h)	Hardangerfjorden (sea)
E2	Oksla hydro storage power station	700	Ringedalsvatn (12 cm/h)	Hardangerfjorden (sea)
E3	Tysso pumped-storage power station	1000	Langevatn (13 cm/h)	Ringedalsvatn (11 cm/h)
F1	Sy-Sima hydro storage power station	1000	Sysenvatn (11 cm/h)	Hardangerfjorden (sea)
G1	Aurland hydro storage power station	700	Viddalsvatn(12 cm/h)	Aurlandsfjorden (sea)
G2	Tyin hydro storage power station	1000	Tyin (2 cm/h)	Årdalsvatnet[3]
	Total new power generation capacity	18,200		

Notes: [1] Water level decrease shown in parentheses; [2] Water level increase show in parentheses; [3] Insufficient data to calculate water level increase in Årdalsvatnet

Based on time series of stage and live storage volume of the reservoirs, the balancing power on daily basis was simulated on top of the current operation for the Norwegian power system. This was assumed to be realized by installing reversible turbines in addition to the existing power stations, without constructing any new dams or reservoirs. The CEDREN study concluded that it is feasible to install about 20,000 MW in new capacity in Norwegian hydropower without large environmental impacts, because water-level fluctuations would be moderate even though more than 5 TWh storage capacity might be used at any time. (For additional information on the use of pumped hydropower, see Graabak et al., 2017).

8 Flexibility in the Norwegian energy system

In this section we summarize the challenges and opportunities related to the European need for flexibility, balancing services and storage in the future energy system. Flexible Norwegian energy can play a role in the future energy system in Europe. We provide a short summary of the different types of flexibilities discussed in the Introduction. However, the two EMPIRE scenarios show that there is substantial uncertainty with respect to installed generation capacity from different energy sources and the geographical distribution of the production.

8.1 Opportunities

Exchange of energy is the trading of electricity between two geographical markets. Value for society is created by importing from markets at lower prices and exporting to markets at higher prices. With a massive expansion of the Norwegian renewable generation but without a similar increase in load, as described in the two EMPIRE scenarios (with CCS and NoCCS), Norway will be a net exporter of energy. An added value from this export would come from flexibility in the hydropower system. This would create opportunities for the future Norwegian energy system in its interaction with the rest of Europe.

Short-term flexibility: load or generation can be adjusted in time periods ranging from minutes to hours. In the two EMPIRE scenarios, it is clear from Figure 26 and Figure 27 that the flexibility in the Norwegian hydropower system is used actively.

The hydropower system makes it possible to optimize the daily export and import profile in order to export more when the prices are high and export less or import when prices are low. Flexible hydropower is also important to increase the value of other renewable resources in Norway, because the net export can be managed flexibly.

Medium-term flexibility: to provide a backup for periods of up to weeks, often needed in systems with high wind penetration. This requires access to alternative generation capacity with flexibility to generate for several weeks and also to store energy, for example hydropower plants with reservoirs or natural gas power plants.

Our studies show that the flexibility of hydropower is unrivalled when it comes to providing this type of flexibility when CCS is not a commercial technology. If CCS is a commercial technology, natural gas with CCS can provide such flexibility, due to the flexibility in natural gas pipelines.

Seasonal flexibility: utilizes patterns in generation and load between winter, spring, summer and autumn. Hydropower systems with reservoirs, natural gas in reservoirs and some thermal heat storage systems are ways to store energy between seasons in order to smooth out seasonal differences in price, creating value in similar ways as exchange between different price regions.

The EMPIRE analysis shows that there are clear seasonal differences in the export and import patterns in cables and in the power generation (both hydropower and natural gas). The same differences are observed for pipelines. Both the natural gas and hydropower system are flexible enough to handle these seasonal differences.

Balancing services including reserve capacity and balancing energy are system services with a short response time, short duration, and potentially high peak power, and are essential to ensure a continuous balance of supply and demand in the system for stable operation.

Studies of balancing markets show that with an integration of European balancing markets, a significant number of system imbalances can be avoided. In addition, such an integration can allow for a foreign participation in these markets, where Norwegian hydropower has good opportunities to deliver reserve capacity and balancing energy to Continental Europe.

8.2 Challenges for the hydropower system

The potential to use Norwegian hydropower both to provide flexible energy and for balancing services is based on the use of existing reservoirs to avoid large environmental impacts by creating additional hydro storage capacity. Due to the need for seasonal storage, Norway has a large hydro reservoir capacity and there is never a lack of free capacity in the reservoirs as long as they are used for short-term storage and balancing.

When considering the volumes suggested by the EMPIRE analysis in the 2050 system, net exchange rates range from 30GWh/h exports in the Baseline scenario (and twice that amount in the NoCCS scenario) to net imports within the same day. This will require massive investments in cable.

Challenge: While the analysis suggests these are profitable for Europe, it is the market design and the pricing of this flexibility that will determine whether they are also profitable for Norway.

The EMPIRE model does not consider whether this flexibility is feasible from an environmental perspective. Such studies have been made by the HydroBalance project (Graabak et al., 2017), the results of which suggest that to make Norwegian hydropower this flexible without any environmental impact, it will most likely be necessary to increase the generation capacity, use existing reservoirs and install pumping capacity. Pumping and new tunnels allow the use of existing reservoirs within current concession limits of highest and lowest water levels, as shown by CEDREN (Charmasson et al., 2017).

Challenge: More research is needed to investigate under which conditions in terms of investment costs and market design such investments in generation and pump capacity would be profitable.

Building capacity to provide the flexible energy and balancing services will not be riskless. The European Union's Third Energy Package proposed in 2007 addressed the issue of how to stimulate market competition but did not address the issue of whether the market offered the necessary incentives to invest in generation, distribution, and transmission and storage capacity in a system with greater shares of renewables. How the EU is addressing these concerns is important for Norway's opportunities as a provider of flexible energy in the hourly, weekly and seasonal horizon.

The cable capacity necessary to support import and export is highly scenario-dependent. If CCS technology were not available, the EMPIRE studies suggest that power exports from Norway would almost double, mainly due to increased utilization of offshore wind resources. Under such demand, technology and policy uncertainty, long-term agreements between private parties or between countries would be necessary. The need for this capacity, as well as flexibility in energy provision and for balancing services must be seen in relation to how the national generation and transmission systems are built in European countries. While we see more and more market integration in energy-only markets, and even balancing markets, countries still seem to invest in their national systems driven by self-interest. We do not believe that market participants alone will have the strength to secure the needed development for new generation and for capacity in cables from Norway to the rest of Europe unless policy uncertainty is reduced.

Challenge: It is doubtful whether investments of this size would happen under today's policy uncertainty. Long-term agreements should therefore address the division of costs, revenues and risk between the participants in the relevant value chains and between the relevant countries.

The installation of new cables between countries, as well as the provision of balancing services, flexible energy and capacity services must be priced. It would be natural for the buyer of the services to pay for the cost as a minimum. However, the benefit from the services may be far higher than the cost of providing them, in which case the profit sharing would be negotiable. For example, new cables can provide value simultaneously to different stakeholders such as generation companies, system operators, grid owners and customers in both the originating country and the importing country, but this is not always the case when building a new cable between two countries. Hence, there are challenges in terms of distributing costs, revenues and risks of investments. There are considerable investment costs for large-scale upgrades of the electricity transportation systems. When it comes to reserves and capacity markets, the costs are often high compared with the energy volumes involved.

Challenge: It will be necessary to decide on tariffs for direct transmission of power between countries, for cross-border transit, and for cable reserved for balancing or capacity services. This necessity is directly linked to the above-mentioned division of costs, revenues and risk.

For the reserve capacities and balancing services in the short term, these considerations are crucial as they depend on additional capacity that is not needed for Norwegian energy export and import or generation. Hence, it requires that someone else needs the capacity. The energy volumes involved are small, while the cost of reserving capacity is potentially high. Typically, this will be extra power installed on the generation side and extra cable capacity. Uncertainty is somewhat reduced by the fact that the extra power and cable can be used both for balancing services and for hourly or weekly energy exchange.

Challenge: We need to understand better how to allocate capacity in the cables and how to price that capacity if the volume of cables should be investable.

This can also be seen in relation to current efforts to promote national capacity mechanisms and/or markets, often referred to as capacity remuneration mechanisms (CRMs). If introduced nationally and uncoordinated, CRMs would pose a risk to the progress of cross-border market integration and competition in Europe.

Challenge: This is a major governance challenge that must be addressed actively by Norwegian stakeholders concerned with the provision of flexible energy services to Europe.

Traditionally, Norwegian consumers have borne the cost of grid investment. It can be argued that this is fair as it has been to the benefit of the consumers through increased security of supply and more stable prices.

Challenge: The more focused the cable system is on net export or service provision, the more difficult it is to argue that Norwegian consumers should pay for the cost.

8.3 Challenges for the natural gas system

The variation in the consumption patterns shown in Figure 28 illustrates how natural gas from the Norwegian pipeline system can be an important flexibility provider for the European power market. Our analysis of variation in this report shows that the capacity of the linepack storage in the pipelines will be able to handle this challenge.

Challenge: The projected use pattern for natural gas in 2050 is highly dynamic and will require the commercial development of flexible services for pipeline storage and the prioritizing of ramping capabilities for natural gas power plants with and without CCS when developing new technology. The central issue will be flexible natural gas value chains.

Another interesting observation in the EMPIRE study is that with CCS technology in place, the demand for natural gas in the power sector in 2050 will be almost double in the Baseline scenario compared with the NoCCS scenario. With CCS technologies, natural gas will also be used as baseload in some seasons.

9 Recommendations

Our analysis shows that Norway can contribute to the European flexibility and storage needs with both hydropower and natural gas at many different time horizons. Hydropower can be used for providing flexibility in most time horizons, ranging from seconds to seasons.

Renewable energy:
If Norway wants to take a larger role as a provider of flexibility, more investments in HVDC[8] cables to Europe are needed. To fully utilize the Norwegian resources, European cooperation on investments in the energy system needs to be increased. Through the Energy Union, cooperation on market integration in intraday and spot markets, and to some degree short-term balancing markets, is increasing, but investment decisions by individual countries still tend to be based on national interests related to welfare, jobs or security of supply. For countries such as Norway, which would invest to provide energy or services for other countries, that situation creates policy uncertainty related to the demand for the products. The policy uncertainty could prevent full utilization of the Norwegian resources, as potential investors face uncertainty on the demand side coming from political choices rather than from the markets.

We recommend entering into EU-wide collaboration agreements or multilateral agreements between countries in order to reduce uncertainty by addressing the division of costs, revenues and risk between the participants in the relevant time horizons.
Capacity markets[9] for generation can be used to promote coordinated investments. **We recommend** that Norway should take an active role to ensure that these markets are coordinated and not introduced nationally. This is a major governance challenge and must be addressed.
In order to provide balancing services in the very short term, capacity must be reserved in cables and in generation. The trade-off related to using the capacity for energy exchange instead must be considered in pricing of such services, reflecting that the energy volumes are small but their value high:

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[8] HVDC: High-voltage, direct current (*høyspent likestrømsoverføring*)
[9] In a capacity market, suppliers are required to have enough resources to meet their customers' demand plus a reserve amount.

- If capacity is going to be built to provide more of this short-term flexibility, **we recommend** cross-border markets for such services to be further developed and secured in the long run.
- **We recommend** decisions on tariffs to be used both for direct transmission of energy between countries and for cross-border transit, as well as for system services mainly established to provide flexibility in the very short term. There is a policy risk involved in this respect because the tariffs are linked to risk, revenue and cost sharing.

The full utilization of Norwegian renewable resources requires more cables for import and export, and a strengthening of the Norwegian grid. Traditionally, Norwegian consumers have borne the cost of grid investment. It can be argued that this is fair for parts of the infrastructure investments needed for domestic offering of balancing services and reducing security of supply issues. Parts of this new capacity will most likely benefit the consumers through increased security of supply and more stable prices.

However, with regard to the net export of energy, capacity services and balancing services provided to other countries, it is more difficult to argue that Norwegian consumers should cover the cost. **We recommend** the development of a new regime for cost distribution related to the building of new cables for this purpose if the Norwegian renewable potential is to be fully utilized.

Natural gas in the power system:
Our studies show that without CCS, natural gas may still play a major role in the power sector in 2030 and 2040, but in 2050, the volume of natural gas used by the power sector in the NoCCS scenario will only be half the volume suggested if CCS is successful as a commercial technology.

Natural gas with CCS somewhat reduces the share of renewables in the generation mix, but provides system benefits:

- The availability of CCS reduces the need for overinvestment in renewables, which tend to cause substantial amounts of curtailed generation, even when inexpensive energy storage and demand response measures are available as investment options.
- The need for transmission investments is reduced, saving system costs and thus reducing consumer prices.
- Controllable generation capacity in the system will increase security of supply.

We recommend further support of the commercialization of CCS value chains in order to secure the use of Norwegian natural gas as a flexibility source for the European power system.

Natural gas complements hydropower with the capability of pipelines to provide substantial flexibility in the horizon ranging from hours to a few weeks and between seasons, using the storage capacity of pipelines as well as the seasonal storage capabilities in reservoirs. Natural gas power production in a system dominated by fluctuating renewable generation will vary greatly, with steep ramps and significant differences between production peaks and valleys. This will require a flexible and secure fuel supply and generation capacity.

We recommend that more research is directed towards developing flexible power generation technologies for natural gas with CCS.

For natural gas, new services, business models, commercial terms and legislation are needed to promote flexibility services in the pipeline system. Today, the gas storage capacity in the pipelines is reserved for security of supply purposes. It may require a change in legislation to offer part of this capacity as a commercial service. **We recommend** that Norway should take an active stance in identifying viable pathways for further development in Europe.

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