Large-Scale Balancing with Norwegian Hydro Power in the Future European Electricity Market

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Abstract

In this study insights are gained on the impact of a future expansion of Norwegian hydro power on market prices, trade flows, and production in Norway and neighboring countries. The main differences between two scenario's that are analyzed is that in Big Storage scenario Norway has a strong ambition to participate in the EU power markets while in Niche Storage Norway's ambition is moderate. This is also represented by the high hydro- and transmission capacities in Norway in Big Storage. Our results show that developments of the EU grid and hydro capacity in Norway, as well as the level of coordination in the markets, *and how these interact*, are important determinants concerning the role of Norwegian hydro and its utilisation. While hydro conventional units benefit from high electricity prices, Hydro Pumped Storage (PS) capacity benefits from high price *volatility* since it is both a consumer and producer of electricity. In today's situation the price volatility in Norway is expected to increase with transmission capacity expansion. However, our results show that when assuming a strong EU grid a threshold exists after which additional transmission capacity on Norwegian borders actually reduces price volatility in Norway. This is because price volatility of surrounding countries is reducing compared to today's situation. More specifically, a further expansion of the grid beyond the level in Niche storage does not improve the business case for Hydro PS units due to reduced price volatility. Hence, from the perspective of a hydro PS operator Niche Storage scenario is most preferred, and Big Storage is most preferred from the perspective of a hydro conventional operator due to higher electricity prices. However, if investments in the EU grid would stagnate or increase moderately, price volatility would be higher throughout EU, and additional transmission capacity as in Big Storage could increase price volatility in Norway and benefit Hydro PS units as well.

[1] http://www.cedren.no/english/Projects/HydroBalance

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Summary

With Europe's strong ambitions to increase the share of renewable generation, high shares of variable renewable generation from wind and sun pose a significant challenge to the grid operators to balance demand and supply at all times. By increasing the system's flexibility, e.g. by energy storage, extreme situations can be better accommodated. Norway, with its high shares in hydro storage capacity, is often considered as an interesting partner that could act as a large 'green' battery. Within the the HydroBalance WP2 project, the focus is to investigate the feasibility of large-scale developments of balancing and storage from Norwegian hydropower in the future European electricity market. Four scenarios were developed for the future role of Norwegian hydro in the integrated EU electricity market by the year 2050. ECN contributes to the HydroBalance project by utilizing ECN's electricity market model COMPETES to analyze two of four scenarios at the intermediate step of 2030; one where Norway's ambition to participate in the EU markets is strong (**Big Storage**) and another where Norway's ambition is moderate (**Niche Storage**). Norway's ambition in Big Storage is also reflected by high transmission capacities connecting Norway to the rest of Europe and high Hydro capacities. In Niche storage, the transmission- and hydro capacities are moderate and there is only a limited coordination in the intraday market resulting in a lower potential to trade electricity in times of a surplus or a shortage. In addition, two climate years (2012 and 2013) are analyzed to increase the robustness of the results taking into account different profiles of demand, wind and whether it is a dry or wet year for hydro conventional storage. For solar only a single profile is considered.

Since electricity is traded at various time scales, the forecast errors of wind are reduced closer to real time dispatch. In COMPETES, the two most relevant markets – i.e. **Day-ahead (DA)** and **intraday market (ID)** - are simulated taking into account wind forecasts and realized wind profiles, respectively. In this study, the demand for flexibility is then defined as:

- **Demand for flexibility due to volatility of V-RES generation and due to volatility in the demand for electricity**; the demand for flexibility due to volatility is equal to the change in the residual demand (i.e. demand minus forecasted V-RES generation) between two consecutive hours. These fluctuations can be accommodated either by increasing or decreasing

generation from flexible units, or by adapting net imports or net consumption of hydro PS units from one hour to the next. As a final option, demand or wind production could be curtailed.

- **Demand for flexibility due to forecast errors of wind;** in the DA market (non) spinning capacity is allocated to accommodate forecast errors in the ID market. In the ID market not only generation schedules are adapted, but also consumption schedules of hydro PS can be adapted to accommodate forecast errors.

From the analysis, the following observations are made:

Compared to today's situation, price volatility in future is expected to increase in Norway*;* in today's situation, electricity prices in Norway are relatively stable due to a high share of (controllable) hydro capacity, limited v-RES shares and relatively limited transmission capacities. In future this is expected to change due to increased shares of v-RES not only in neighbouring countries, but also in Norway itself. This, in combination with a strengthened grid increases trade interactions between Norway and its neighbours and thereby volatility on the markets. Therefore in our scenarios, price volatility in Norway is expected to increase w.r.t. current levels.

When assuming a strong future EU grid a threshold is expected after which a further increase in transmission capacity on Norwegian borders does not lead to an increase in price volatility*:*

- *Not only expansion and strengthening of the transmission capacity on Norwegian borders are an important factor for the future role of Norwegian hydro, but also the grid investments throughout EU;* in Norway, the impact of increasing the cross-border transmission capacity on prices also depends on transmission investments across Europe. In our analysis, the EU grid is assumed to be strengthened such that price volatility on EU mainland is in general decreasing w.r.t. today's situation. Therefore, in this situation an increase of transmission capacity on the Norwegian borders will reduce price volatility in Norway instead of increasing price volatility.
- *In 2030, a further increase of transmission- and Hydro PS capacity beyond levels assumed in Niche storage increases average prices but decreases price volatility and hence is beneficial to business case of hydro conventional units but non-beneficial to the business case of hydro PS units;* An important observation in this study is that high transmission capacities connecting Norway to the rest of Europe reduces price volatility and increases average electricity prices in Norway. Hydro conventional capacity, benefits from the increased prices, especially when Hydro conventional capacity is high and storages can be utilized in a flexible way to accommodate fluctuations in Norway and abroad. Hydro PS units on the other hand are both producers and consumers of electricity. Increased prices are only beneficial if prices are volatile and Hydro PS units can consume electricity to charge in low priced hours. Since high transmission capacities within EU in Big Storage scenario reduce price volatility, Hydro PS units in Norway cannot earn significant profits by arbitraging between low and high priced hours to charge and discharge, respectively. As a consequence, even though Hydro PS capacity is higher in Big storage scenario, its utilization is lower which suggests an overcapacity of Hydro PS in Big Storage scenario. Therefore, it is important to have an optimal

strategy in investments for hydro PS and the cross-border transmission capacities. The optimal strategy in Big storage scenario for an improved business case of Hydro PS could be less investments in Hydro PS when a strong future EU grid is anticipated.

Due to higher scarcity for flexible capacity resulting in higher peak prices on ID market compared to DA market, there is a payoff to reserve hydro conventional capacity for ID market depending on the level of market coordination**;** the larger the area of coordination in the ID market, the better the wind forecast errors can be accommodated via cross-border trade. With full coordination as in Big Storage, the ID market results are more in line with the DA market than with limited coordination as is the case in Niche Storage. Hence, since prices between DA and ID in Big Storage do not differ, there is no additional benefit to reserving hydro conventional capacity for the ID market. Due to limited coordination in Niche Market that increases the difference between prices on DA market and ID market, there is however a payoff to reserve hydro conventional capacity.

Increasing V-RES generation in EU results in more significant flows between Norway and the rest of Europe compared to today's situation; with increasing V-RES generation in EU and also in Norway, the residual demand is in general becoming more volatile. This has a significant impact on the trade flows, increasing the demand for cross-border trade between Norway and the neighbouring countries to accommodate fluctuations. With strong interconnections, the increased volatility in residual demand compared to today's situation results in more significant trade flows between Norway and the rest of Europe. In particular, Norway, having high amounts of competitive hydro power generation and storage capacities is an interesting electricity trade partner to balance demand and supply throughout Europe.

Impact of model assumptions and limitations on the results:
Storage technologies like Hydro PS are arbitrage technologies whose business cases depend on volatility in prices earning revenues from arbitraging between high and low priced periods. In this study the following important developments and assumptions, and their uncertainty, are distinguished as to play a crucial role in determining the price volatility in Norway and EU in future:

- *Transmission capacity expansion across Europe*: in our analysis we assume a strong and highly integrated EU electricity market such that price volatility in Europe is actually reduced. As a consequence, further strengthening the grid between Norway and neighbouring countries is non-beneficial to the business case of Hydro PS because it reduces price volatility in Norway. Thus, in our study, fluctuations in supply and demand throughout Europe is already being accommodated via cross-border transmission to a significant extent which reduces the potential for Norwegian Hydro PS units to provide this flexibility. If a low or moderately integrated and strengthened EU grid was assumed, the business case of Norwegian Hydro PS would likely improve from increased transmission capacity between Norway and neighbouring countries. For example, in the National Energy Outlook (NEO) of 2017 that can be considered as a business-as-usual scenario (Schoots et al., 2017), the price volatility in 2030 in Norway is significantly lower compared to the Netherlands and

Germany, which suggests that additional transmission capacity on Norwegian borders increases price volatility in Norway.

- *(Variable) renewable capacity in Europe and Norway*: Hydro PS units in Norway could significantly benefit by charging in hours with high shares of (variable) RES in the EU in case the surplus could not be (fully) distributed across Europe and hourly electricity prices would reflect the low marginal costs of RES. Therefore, the RES share - in combination with the transmission capacity - in the EU is an important determinant for the business case of Hydro PS in Norway. Furthermore, in our scenario assumptions, Norway is assumed to have a relative high wind capacity (11 GW). At the time of the model analyses, Vision 4 of ENTSO-E (2014a) was the most recent version, assuming 11 GW of wind. The most recent version of ENTSO-E Vision 4 that is now available assumes 2,4 GW of wind in Norway. Hence, the wind capacity assumption in Norway in this study seems on the high end which is likely to result in an overestimation of price volatility in Norway.
- *Modelling the dispatch of hydro conventional*: In our approach, hydro production is exogenously determined in a pre-stage procedure and dispatched depending on residual demand in Norway, and to some extent to the residual demand in neighbouring countries. This might overestimate price volatility within Norway. In case hydro conventional was optimally dispatched, i.e. endogenously determined in the model, price volatility in Norway would likely to be lower.

The business case of conventional hydro is less vulnerable to these developments since conventional hydro is competitive back up capacity compared to conventional technologies and its operation is not depending on volatility in prices.

Other developments could also have a positive impact, e.g. significant electrification without Demand-Side-Response (DSR) to accommodate fluctuations, or a negative impact, e.g. DSR or other forms of energy storage, on the business case of Hydro PS. These developments are not taken into account in our analysis. From the perspective of a Norwegian Hydro PS operator, especially the developments regarding the transmission expansion in Europe are identified as important since a strong and integrated EU grid can significantly reduce the potential for Hydro PS to operate as is shown by this study.

1

The need for power system flexibility

Europe's ambitions

Europe has strong ambitions to reduce GHG emissions, increase the energy efficiency and develop a more sustainable energy system by increasing the share of renewables in final energy consumption. Europe aims at a renewable share in the final energy consumption of 20% in 2020 and of 27% in 2030 (EC, 2015a). For 2020, the renewable target differs per country depending on the potentials to exploit certain renewable technologies. Currently, hydro power is the largest contributor to the renewable production in Europe whereas wind power is the second largest contributor and solar power the third largest contributor (EC, 2015a). In contrast to hydro power that is either must-run (i.e. run-of-river) or highly controllable (i.e. hydro storage), wind and solar power are *variable* and relatively *unpredictable* by nature. Consequently, with increasing shares of variable renewables (V-RES) that are needed in order to meet EU's target, it becomes more challenging for Transmission System Operators (TSOs) to balance demand and supply in the electricity system and therefore these characteristics hamper the integration of high shares of V-RES.

System flexibility

In recent years, the importance and need for a *flexible* energy system in an energy-only market[2] is addressed more frequently. With a flexible system, security of supply and the balance of the system could be better maintained also under high shares of V-RES generation. System flexibility entails a wide range of options to provide flexibility both on the demand side (e.g. Demand Side Response, DSR) and the supply side (e.g. energy storage, interconnection- and flexible generation capacity). Norway - with its high share of hydropower - is often considered as a country that could act as a "*green battery*" to provide carbon neutral generation to Continental EU in times of low V-RES generation. Oppositely, in times of high V-RES generation, Norway could import cheap electricity and pump water into the higher reservoir in hydro Pumped Storage (PS) units. In this way, extreme situations due to the volatile V-RES production can be better accommodated. Currently, these trade dynamics already take place to some extent, although the dominant flow direction is from Norway to the rest of Europe (TenneT, 2014 and TenneT, 2015a). This might change when V-RES capacity is increasing in

[2] In an energy-only market, e-prices are set by the marginal costs of the final unit that is producing in a certain period. With increasing shares of competitive V-RES generation, V-RES could determine the e-price in a higher share of the time. Consequently, e-prices are reduced and also become more volatile, irrespective of transmission capacity. This results in lower margins or even negative margins ('missing money' problem) for the most expensive conventional units – often flexible gas capacity - leading to lower investments in back-up capacity. The introduction of a capacity market is one of the options to accommodate this issue (see Özdemir et al., 2013).

Continental Europe as well as in Norway, resulting in more volatile trade also during the day. The trade dynamics between Norway and Continental EU also depend on the climate year; in case of a relative wet year, it is more likely that there is more potential for electricity production in Norway.

This study is performed within the HydroBalance project that focuses on the *role of Norwegian hydropower in the future European energy market with a particular emphasis on Northwest Europe. More specifically, the study focusses on how existing and potential future expansions in hydropower flexibility could contribute as a part of the European transition towards a more sustainable low-carbon energy system.* Within the HydroBalance project, four different future scenarios are considered with regard to 1) the degree of integration of Norway with the power markets and grid of Europe 2) the expected volume of balancing provided by Norwegian hydropower to European power markets and 3) the type of balancing in terms of the time horizon (Sauterleute et al., 2015 and CEDREN, 2015).

One of the interesting research questions regarding the role of hydropower as a flexibility option in the future is to identify its impact on electricity trade and prices in the future electricity markets and to assess the resulting economic opportunities for investors on various markets; i.e., day-ahead, intraday, reserve markets, etc. In this study two of the four storylines - that are characterized by a relative high demand for flexibility due to high shares of V-RES in EU- are simulated to analyse the operation and the marginal revenues of hydro power in Norway. To this aim, ECN's European electricity market model COMPETES is utilized to come up with hourly electricity production and hourly market prices in Norway as well as the trade between Norway and the neighbouring countries for the year 2030. While the focus of the HydroBalance project is in general on 2050, 2030 is considered an important intermediate year towards a carbon neutral European power sector that is the aim for 2050. The model takes into account the interaction between day-ahead (DA) and intraday (ID) markets and calculates the resulting DA and ID prices. The resulting market prices can be used as an input for studying profitability for Norwegian hydropower investments similar to e.g. Wolfgang et al. (2016).

COMPETES is a relaxed unit commitment model[3] (Hobbs et al., 2015) that is well able to capture system flexibility by i.a. including transmission capacities, constraints for ramping, minimum up and down times, and the lumpiness in generator start-up decisions. Furthermore, the model has an hourly resolution in order to capture hourly V-RES generation and demand. The total yearly conventional hydro production, the hourly profile for V-RES generation and demand of *2012* and *2013* are used to represent two climate years. The methodology and assumptions regarding the COMPETES model are more thoroughly described in Appendix BAppendix A. Chapter 2 discusses the scenarios that are analysed and the corresponding assumptions such as the production- and transmission capacity, demand, and energy prices. Chapter 3 discusses the model results with a focus on the electricity prices and accompanying revenues for Norwegian hydropower operators, while Chapter 4 elaborates on the most important findings and conclusions.

[3] COMPETES is formulated as a full unit commitment model for the Netherlands and a relaxed unit commitment model for the other countries.

2

Storylines and scenario assumptions

2.1 Storylines in HydroBalance project

In this study two of the four storylines that are defined for the HydroBalance project are analysed, namely ***Big Storage*** and ***Niche Storage*** (Sauterleute et al., 2015). Both storylines are characterized by a relative high demand for flexibility due to high shares of V-RES in total installed EU capacity and generation (see section 2.3.1). In both Big Storage and Niche Storage, the EU markets are strongly interconnected to support the exchange of power across Europe. The two storylines mainly differ with respect to the transmission capacity interconnecting Norway to the rest of Europe, the total hydro capacity in Norway, and the level of integration of Norway in EU's power markets.

In Big Storage, Norway has a strong ambition to participate in the European power markets on both the long and short time horizons. The hydro storage capacity is highest in Norway and the level of competition from energy storage abroad to provide flexibility is relatively low, i.e. no other energy storage types such as Power to Gas (P2G) or Compressed Air Energy Storage (CAES) are available. High interconnection capacities between Norway and surrounding countries allow Norway to provide the flexibility on the power markets in Europe.

In Niche storage, the installed hydro power capacities in Norway are lower and hydro pumped storage capacities abroad are higher resulting in more significant competition from abroad to provide flexibility. In addition, the degree of integration of Norwegian hydro in the European markets is moderate which is also reflected by lower transmission capacities connecting Norway to surrounding countries. In the next section, two of the most relevant markets (DA and ID market) are discussed, and more in particular on how the markets are modelled by COMPETES.

2.2 Day-ahead and intraday power markets

Types of power markets

In the electricity market, trade takes place on several time scales from long term markets (i.e. forward markets) to medium and short term markets (i.e. *day-ahead* *markets* (**DA**), *intraday markets* (**ID**) and *balancing markets*). The DA and ID markets are organized by power exchange where demand and supply come together and the market is cleared at a price (e.g. APX, EEX). The DA market closes one day prior to the actual delivery of electricity while the market is cleared at the market price for each hour of the next day. The ID market closes one hour to 5 minutes prior to the actual delivery. After the closing of the ID market the real time balancing is done by the TSO on the balancing market where the TSO activates earlier contracted reserves to secure system stability. Initially, the reserve market was organized nationally and reserve capacity was mainly depending on the probability of *power plant outages* (contingency events) and *load prediction errors.* With the increasing levels of V-RES generation, forecast errors of wind and solar generation has resulted in higher demands for reserve capacity. By accommodating the forecast errors of V-RES as much as possible on the short term power markets (e.g., increasing liquidity in ID market by trading over larger areas; reducing the lead time of wind forecasts through ID markets; introducing balancing responsibility for all producers including RES as in the Netherlands), the demand for reserves could be reduced. For example, from 2009 onwards, the German TSOs started to use the ID market to accommodate forecast errors of V-RES generation (Borggrefe & Neuhoff, 2011).

There are various definitions for reserve capacity depending on certain properties such as response rates, where i.e. Frequency Containment Reserves (FCR) have response rates of less than 30 seconds, Frequency Restoration Reserves (FRR) can respond within 5 minutes and Replacement Reserves (RR) within 15 minutes to one hour (EC, 2015b).[6]

Box 1

Status quo of European electricity market coupling

In order to be able to integrate high levels of V-RES in the electricity system and to accommodate imbalances from V-RES generation, the coupling of EU electricity markets is important. In recent years significant efforts are made by EU TSOs and power exchange markets to couple DA markets by auctioning transmission capacity. Market coupling implies an optimal allocation of available cross-border transmission capacity to increase the *efficiency of the markets, stimulate price convergence* and thereby *increase social welfare*. An important step towards an Integrated European Market was taken on the 4th of February in 2014 when the North West EU (NWE) DA market coupling went live.[4] This enabled full coordination on the DA markets of 10 countries in Northwest EU. In May 2015, the process of optimally allocating transmission capacity was improved for the Central West European (CWE) region. A process that is referred to as *Flow-Based Market Coupling*. With Flow-Based Market Coupling, available transmission capacity is not determined beforehand but assigned on a variable basis to the highest valued trade transactions from a social welfare perspective.

A next important step towards a single Integrated European Market is to couple the ID markets. The European Cross-Border Solution (XBID Solution) project investigates the feasibility of coupling European Intraday electricity markets starting with Northwest EU. Currently, cross-border trade on the intraday market already takes place to some extent in ELBAS-4[5]– a power exchange platform owned by Nordpoolspot. The ELBAS-4 algorithm facilitates trading with the Nordic area as well as with both the Baltic area and western part of Continental EU. Although it must be noted that the traded amounts on the intraday markets are currently significantly lower than on the day-ahead markets (ACER/CEER, 2014; pages 127-128).

Modelling of DA and ID market in COMPETES

Step 1, modelling of DA Market: Unit-Commitment (UC) simulation is performed to estimate operational costs of the residual system resulting from the load factor

[4] http://www.epexspot.com/en/market-coupling

[5] http://www.nordpoolspot.com/TAS/Intraday-market-Elbas/elbas-4/

[6] Old terminology: primary, secondary and tertiary reserves, respectively (Borggrefe & Neuhoff, 2011).

reduction of the conventional generation, flexibility constraints and the increased frequency of start-ups of the generation units, and the curtailment of I-RES generation. The unit commitment problem is the problem of deciding which power generating units must be committed/decommitted over a planning horizon. COMPETES UC model finds such a solution that minimizes the total variable, minimum-load, and start-up costs of generation and the costs of load-shedding within a year in all the countries. COMPETES UC model is performed for the simulations of the day-ahead market in Europe by using *predictions* of wind and solar generation at an hourly resolution for each day of the year.

Furthermore, since contingency events, load forecast errors and forecast errors for solar power are not considered, wind forecast errors are the *main driver* for trade in the ID market and also the main determinant for allocating capacity to ID market. The allocation of capacity is determined in the DA market based on a certain share of the production of wind scheduled in DA market. The idea behind this is that the higher the production of wind scheduled in the DA market, the larger the impact in the ID market in case of forecast errors and therefore more capacity is needed to accommodate these errors and increase total revenues earned on the DA and ID market combined.[7] Furthermore, only capacity that is withheld due to down-ramps from wind generation are considered because it is assumed that a surplus of wind generation could be curtailed if the system was unable to accommodate it.

Since COMPETES has an hourly resolution and results of ID market are assumed equal to the balancing market and because contingency events are not considered, Frequency Containments Reserves (FCR) and Frequency Replacement Reserves (FRR) cannot be distinguished. Instead, the allocation of (part of) a units' capacity to the ID market is *market driven* and either *spinning* or *non-spinning*. Spinning capacity is provided by online units that are already committed and therefore have fast response rates of less than 15 minutes (e.g. online coal fired units). Non-spinning capacity refers to offline units that are uncommitted but that have response rates of more than 15 minutes but less than an hour (e.g. offline gas turbines).

Step 2, modelling of ID Market: We again use COMPETES UC model but this time with *actual* wind power generation so that we can calculate the balancing costs as a result of the wind forecast error. Also, the allocated capacity to ID market as determined in the first step is available to accommodate fluctuations. The ID market simulation results in upward/downward adjustment of domestic generation units and the balancing operation costs and prices as well as adjustment of cross-border trade within the coordinated area. The market price in the balancing market will be equal to the market price in the ID market since contingency events are not considered.

Regarding different levels of coordination between countries, i.e. allowing cross-border trade to take place, COMPETES has the option to simulate no coordination, full coordination including all countries, or including a selection of interconnected countries that participate in the ID market (see also Box 1). Both in Niche Storage and Big Storage it is assumed that Norway is able to participate in all European DA markets, while only in Big Storage it is also assumed that all ID markets in the EU are fully coordinated or

[7] In COMPETES, the market is assumed to be perfectly competitive implying that the market players are price-takers.

coupled. In Niche storage, in the ID market Norway's participation is limited to trading with Sweden, Finland, Baltics, Germany, Denmark, the Netherlands, and Belgium, as is in line with ELBAS-4 under the assumption that trade can take place on all borders.

2.3 Installed capacity and hourly profiles of generation and demand

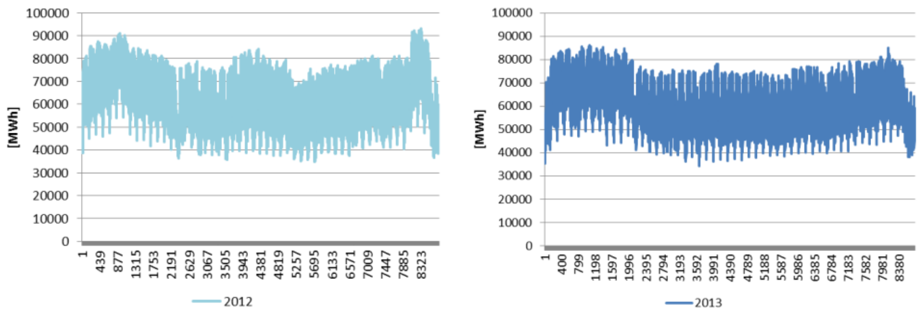
2.3.1 Installed capacities and demand assumptions

Vision 4 of the Scenario Outlook and Adequacy Forecast (SO&AF) – also referred to as the "Green Revolution" scenario – is used to represent the storylines of Big Storage and Niche Storage for the whole of Europe (ENTSO-E, 2014a). Vision 4 provides installed capacities per technology and per country and demand projections for the year 2030. In Vision 4, investments in renewable capacity are significant and the generation mix is on track towards a carbon neutral EU power sector in 2050.

Demand

To analyze hourly profiles of demand, historical hourly demand profiles of two climate years (2012 and 2013) are used to distribute total demand for electricity based on Vision 4 over the hours of 2030. The hourly historical profiles are taken from ENTSO-E (2015a). Vision 4 is characterized by a relative *high* future demand for electricity, implying an increase from approximately 3.3 PWh at the current level to about 3.9 PWh in 2030 in EU28 plus Norway, Switzerland and Balkan countries together. **Figure 1** shows an example of the hourly profiles of 2012 and 2013 in Germany.

Figure 1: Example of hourly electricity demand profile (hourly demand profile in 2012 and 2013 in Germany). Source: ENTSO-E (2015a)



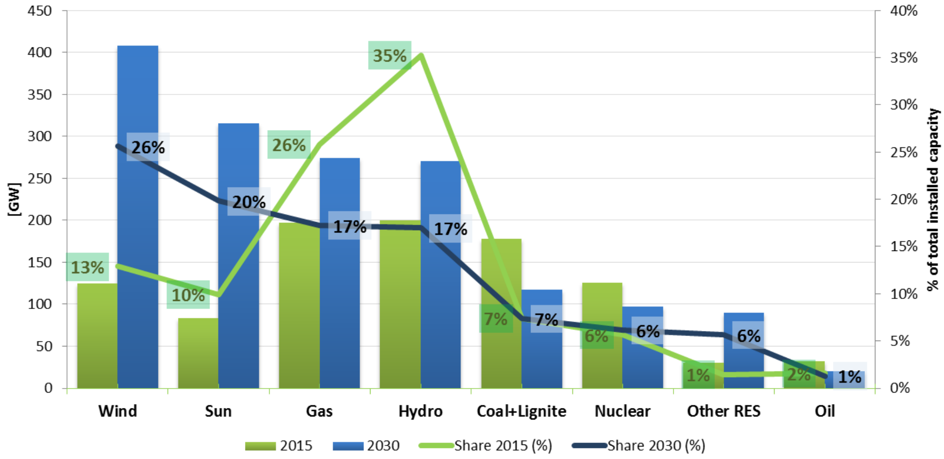
Installed generation capacities

Besides a relative high demand for electricity, Vision 4 is characterized by relative high shares of (V-)RES capacity in total installed EU generation capacity (**Figure 2**) (ENTSO-E, 2014a).[8] In order to compare deviations in installed capacity over time, current installed capacities of 2015 are also shown in **Figure 2**. The capacity of the technologies that are

[8] At the time of the model analyses, Vision 4 of ENTSO-E (2014a) was the most recent version. In this scenario Norway has a relative high capacity of wind (5 GW of onshore and 6 GW of offshore). Compared to the most recent version of ENTSO-E Vision 4 that is now available, this seems to be an overestimation because it mentions 1 GW of onshore and 1,4 GW of offshore wind.

most polluting are decreasing (i.e coal, lignite, and oil), while back-up capacity is mostly provided by relative clean and flexible gas fired units of which the capacity actually increases compared to 2015. The installed hydro capacities in Norway are based on values specified for the HydroBalance project (see section 2.3.2)

Figure 2: Total installed capacity in EU per technology. Source: ENTSO-E (2014a) and Sauterleute et al. (2015).

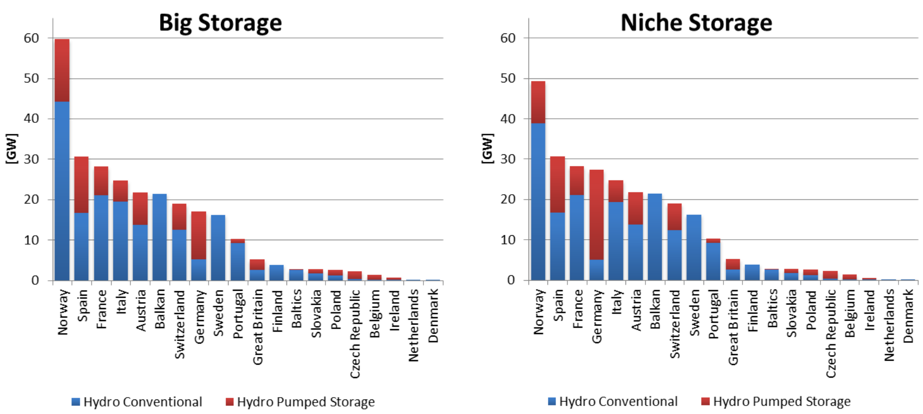


2.3.2 Hydro generation

Hydro power technologies and capacities

Hydro production is the sum of power generation from conventional hydro (run-of-river and reservoir storage) and hydro PS. In **Figure 3** the installed Hydro capacities are given for Big Storage and Niche Storage. In order to take into account higher competition of European hydro production with Norwegian hydro in Niche Storage, the difference in total hydro capacity of Norway in Big storage and Niche storage is assumed as additional Hydro PS capacity in Germany in Niche storage.

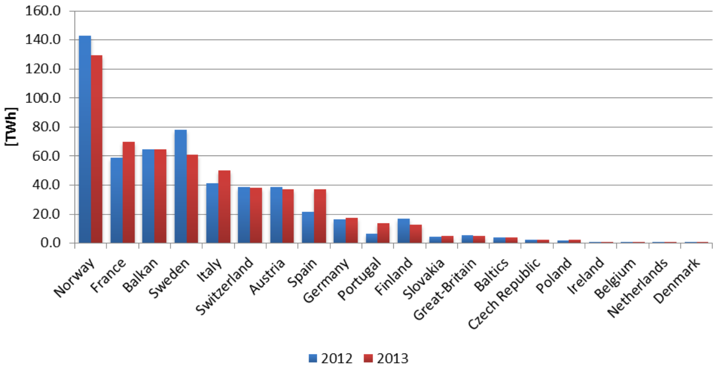
Figure 3: Installed hydro conventional capacity per country in Big Storage and Niche Storage in 2030 [GW]. Sources: ENTSO-E (2014a) and Sauterleute et al. (2015).



Hydro conventional

Hourly hydro conventional generation is calculated prior to the actual runs with the COMPETES model and assumed as an input to the model. Hourly Run-of-River (RoR) generation is determined by using data on annual hydro generation, the share of RoR per country, and monthly data on the RoR production. In order to calculate hourly hydro storage production, RoR is assumed to be must-run or inflexible generation, and the dispatch of flexible generation from hydro storage is assumed to depend on the residual demand hours (demand minus V-RES generation). Since the highest prices are expected in the high residual demand hours, hydro storage is assumed to produce in the highest residual demand hours in a certain year. The underlying idea for this approach is that there is a positive correlation between residual demand and prices. The generation from hydro storage is distributed over the year in such a way that the sum of the hourly generation is equal to the assumed annual hydro production for that year. The annual hydro conventional production is based on historical values of the climate year under consideration (2012 and 2013). 2012 is characterized as a record-breaking year for hydro power generation in Norway, and also in the rest of Scandinavia. In 2013, the production from hydro power in Norway was approximately 10 percent lower (**Figure 4**). For Continental Europe – and especially the south of Europe - it is more or less the other way around. For example, in Spain, 2012 was actually a very dry year while 2013 can be considered as a relative wet year (RED, 2015).

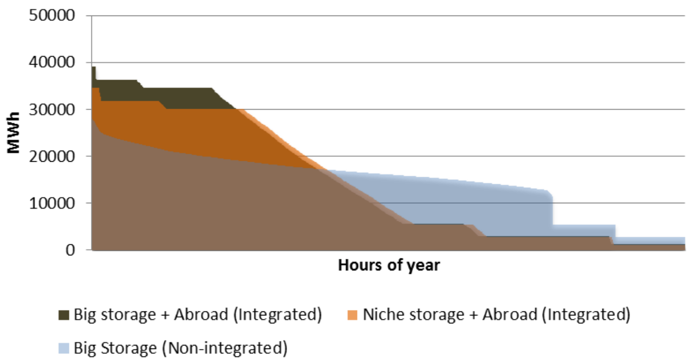
Figure 4: Total hydro conventional hydro production in 2012 and 2013. Source: ENTSO-E (2015b).



In order to take into account that Norway can provide flexibility to neighbouring countries by means of hydro conventional generation, the residual load (minus local hydro generation) in the neighbouring countries is added to the hourly residual load of Norway. An example of the impact is shown in **Figure 5** where "non-integrated" shows the distribution of hydro production over the hours of a year based on the residual load of Norway only. In Big Storage, higher hydro conventional capacities and additional transmission capacities lead to increased flexible usage of hydro conventional units in Norway. Thus, the distribution of total hydro production over the year differs between Big Storage and Niche Storage. One of the main limitations of this approach is that total yearly hydro production is a given depending on a certain climate year, and hydro generation is not optimized taking into account the transmission constraints and the effects of trade between countries on the prices. This could lead to the overestimation of hydro production in Norway during hours with high total residual demand in neighbouring countries, as well as the overestimation of price volatility in Norway.

Furthermore, test runs suggested that there is also a minor benefit in allocating hydro conventional production for the ID market in Niche Storage due to more significant differences in e-prices between ID and DA. As a consequence, 3 percent of the production is assumed to be allocated to the ID market and distributed over the hours based on residual demand in ID market (i.e., taking into account realized wind profiles). Assuming that 3% is allocated to the ID market is scenario specific and is a threshold for Niche storage where allocating more production for ID market leads to an undermining of benefits for hydro conventional units due to lower e-prices. In Big Storage, even without reserved hydro production, the differences in prices in DA and ID were considered too small.

Figure 5: Hourly distribution of Norwegian hydro conventional generation (RoR and storage) ordered from high to low based on forecasts of wind (climate year = 2013).



Hydro Pumped Storage

Hydro PS units are optimized endogenously by the model to operate such that they maximize their revenues by charging and discharging electrical energy within a day. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for generation-demand balancing. The amount of the power consumed and produced in the charge and discharge processes and the duration of these processes depend on the characteristics of the storage technology such as efficiency losses and power and energy ratings which are an input to the model. In this study an efficiency of 70 percent is considered. Finally, in both scenarios 90 percent of the total production capacity of Hydro PS is assumed to be allocated for the DA market. The hourly charge and discharge levels are adjusted for providing flexibility in the ID market for which the remaining 10 percent is assumed to be allocated to the ID market only.

2.3.3 V-RES generation

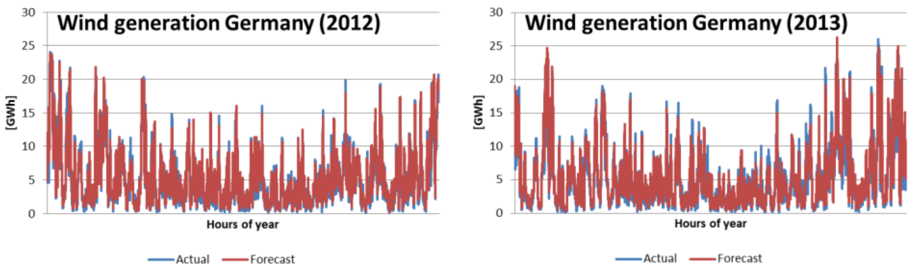
The maximum hourly power generation from solar and wind depends on the hourly load factors and the installed capacities of these technologies that are inputs to the model. The hourly load factors - representing the variability of wind and solar - are calculated based on the historical hourly generation data of the climate years under consideration provided by the TSOs of different countries.[9] Especially for Northwest

[9] Wind times series from 2006-2014 for a few EU countries are given by Bach (2015) and of 2012 for the Netherlands by ECN (2014). Also Energinet (2015); Nordpoolspot (2015); Terna (2015); 50Hertz (2015); Amprion (2015); TenneT (2015b); and TransnetBW (2015); and Eirgrid (2015) provide hourly wind data.

Europe this dataset is more or less complete for 2012 and 2013. For countries for which the hourly data is not available, correlations from the TradeWind (2009) data set of the year 2004 are used to indicate which country-specific time series were applicable to represent the wind time series of neighboring countries.[10] For solar, only a full dataset of 2005 was available to represent hourly solar production (SODA, 2011).[11] Since there is a seasonal correlation between wind and solar – e.g. summer is relatively more sunny and less windy - but not necessarily an hourly correlation, it is acceptable to use wind and solar profiles of two different years to represent a future year. Forecast errors for solar power are not considered in this study.

In this study, wind forecast errors are the main driver for trade in the ID market (section 2.2). Hourly wind forecast errors are calculated by taking the difference between actual wind and forecasted wind usually expressed as a percentage of total installed wind capacity. For Germany, Ireland, Italy, Baltics, Denmark and the Netherlands, historical data both on forecasts of wind and realized wind are available and used as a direct input to the model (e.g. see **Figure 6**). The Normalized Root Mean Square Error (NRMSE) gives an indication for how well or bad the wind in a certain area is forecasted. For Germany as a whole, 2012 was slightly better forecasted than 2013 as shown by an NRMSE of 3% and 3.2%, respectively (Fraunhofer IWES report, 2015). Due to smoothing effects, the overall NRMSE for Germany is lower than for the four control areas in Germany (i.e. TenneT, Amprion, 50Hertz and TransnetBW). This data was used as an input to the Wind Forecast Error Auto Regression (AR) model[12] to estimate a set of forecast errors for countries where only the data on realized wind was available. For the ID market runs, a single set of forecast errors is assumed.

Figure 6: Example of hourly wind forecasts and realized wind generation (data of Germany in 2012 and 2013). Sources: TenneT (2015b), TransnetBW (2015), Amprion (2015), 50Hertz (2015).



[10] In case there is a strong positive correlation between two countries, it indicates that the countries generally show the same wind patterns. For example, data for Spain was available but not for Portugal. Since TradeWind data shows a strong correlation between Portugal and Spain (±80%), the wind profile of Portugal in 2012 and 2013 is represented by the profile of Spain. In case there was a weak correlation, the wind patterns of the two countries are generally not alike. Then, TradeWind data of the year 2004 was used.

[11] Solar hourly load factors were calculated on the basis of the sunsets time, sunrise time, their evolution throughout the year and solar irradiation values in 118 nodes distributed in Europe (SODA, 2011).

[12] In this model, a first-order autoregression (AR(1)) is used, which generates time series of forecast errors based on the statistical characteristics of the historical data (Stock and Watson (2007)). For the countries where full data set is not available, the forecast error time series are simulated by using the average statistical characteristics of the neighboring countries.

2.3.4 Demand for flexibility

The hydro conventional and PS capacity installed in Norway provides a flexibility option to accommodate fluctuations in the demand for electricity and V-RES generation and to accommodate forecast errors of hourly V-RES generation throughout Europe. In this study, the demand for flexibility is distinguished in two ways:

Demand for flexibility due to volatility of V-RES generation and due to volatility in the demand for electricity; the demand for flexibility due to volatility is either the demand to ramp up in case the change in the residual demand (i.e. demand minus forecasted V-RES generation) between two consecutive hours is positive or a demand to ramp down in case the change in residual demand in between two consecutive hours is negative. The demand for flexibility due to volatility to ramp up can be accommodated by increasing the generation from flexible units, reducing the net consumption from hydro PS units, or by increasing the net import. As a final option, demand could be curtailed under Value of Lost Load (VOLL) pricing that is assumed to be 3000 €/MWh. The demand for flexibility due to volatility to ramp down can be accommodated by decreasing the generation from flexible units or net exports, increasing the net consumption from hydro PS units, or by curtailment of wind.

Demand for flexibility due to forecast errors of wind; the demand for flexibility due to forecast errors of wind is equal to the forecast error that can either be negative in case of less wind production resulting in a demand to ramp up, or positive in case of more wind production resulting in a demand to ramp down.

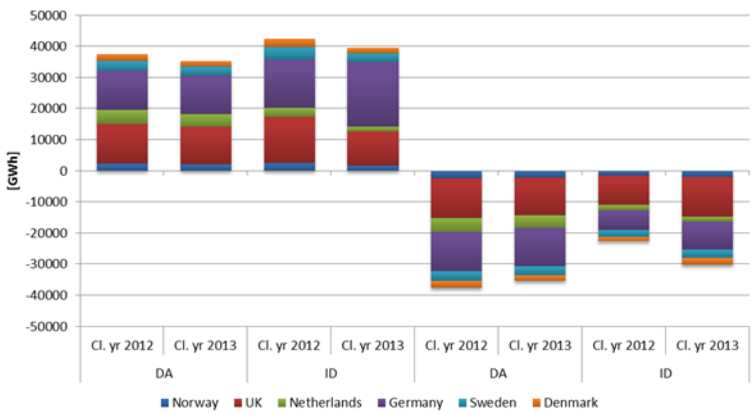
Both the hourly V-RES profiles and hourly demand profiles are an input to the model. Therefore, demand for flexibility in line with the above definitions can be calculated prior to the model runs. **Figure 7** shows the total yearly demand for flexibility to ramp up and down in Norway and neighbouring countries. The total demand for flexibility due to volatility of residual demand is represented by the total demand in the DA market where wind profiles are based on forecasts. The total demand for flexibility due to forecast errors is represented by the total demand in the ID market where market outcomes are based on realized wind. From **Figure 7** it can be seen that the demand to ramp up due to forecast errors is higher than the demand to ramp down due to forecast errors. This is because the yearly realized wind production that is used as input to the Wind AR model of the countries for which the data is available is in general lower than the yearly forecasted wind production. Obviously, since a single set of forecast errors is determined, demand for flexibility could be different when considering another set of forecast errors derived from the wind AR model. Furthermore, while volatility in residual demand is higher in climate year 2012 in Norway and its direct neighbours, the forecast errors that drive trade on the ID market are not necessarily larger. In Germany, the climate year 2012 was better forecasted than 2013. For UK it is the other way around.[13]

Finally, note that total demand for flexibility does not differ between Big Storage and Niche Storage due to equal profiles for V-RES generation and demand. The main

[13] In Niche Storage, it is assumed that Norway only participates on the DA UK market.

difference is with regard to the supply of flexibility, i.e. transmission capacities and hydro capacities in Norway and abroad.

Figure 7: Total demand for flexibility to ramp up and down in 2030 in Norway and its direct neighbours.



2.4 Cross-border transmission capacities

The cross-border transmission capacities in Europe are represented by so called Net Transfer Capacities (NTC). The SO&AF Vision 4 scenario is in line with the transmission capacities given in ENTSO-E Ten Year Network Development Plan (TYNDP) of 2014 with *all* transmission expansion projects considered to enable a fully integrated EU market (see also **Figure 21** in Appendix B).[14] In the Niche Storage scenario and the Big Storage scenario we will assume an additional transmission capacity of 10 GW and 15 GW, respectively, as is suggested by SINTEF. The total capacity per cross-border is assumed to be distributed *in proportion to* the wind shares in the neighbouring countries.

In test runs it is found that there is generally no congestion from Norway to Sweden and from Norway to Denmark, while transmission lines from Norway to UK, the Netherlands and to Germany are congested in a relative high share of the time. Hence, additional transmission capacity was added to the interconnection capacity linking Norway with UK, Netherlands and Germany in proportion to the share of V-RES capacity in total capacity (**Table 1**).

Table 1: NTC values interconnecting Norway and neighbouring countries [GW]

From Norway to:	TYNDP 2014	TYNDP 2014 + Big Storage	TYNDP 2014 + Niche Storage
United Kingdom	2.8	6.8	5.4
Netherlands	0.7	6.2	4.4
Germany	1.4	7.0	5.1
Denmark	1.7	1.7	1.7

[14] This also includes the projects with the status “under consideration” and in case a range of NTC increase is given; the higher value is chosen.

Sweden	3.7	3.7	3.7

2.5 Fuel- and CO_2 prices

Since Vision 4 assumes that energy policy and energy prices are in favour of a sustainable generation mix, the 450 scenario of the World Energy Outlook - that strongly supports clean technologies - is taken as the corresponding energy price scenario (WEO, 2014). In the 450 scenario, CO_2 prices are sufficiently high so that relative clean gas fired units are able to compete with coal fired units (ENTSO-E, 2014a) (**Table 2**).

Table 2: Fuel- and CO_2 prices (in USD/euro of 2013). Source: WEO, 2014 (“450” scenario).

Fuel	Price	Unit	Price	Unit[15]
Coal	78	USD/Tonne	2.3	Euro/GJ
Natural gas	10	USD/MBtu	7.2	Euro/GJ
Oil	102	USD/Barrel	12.6	Euro/GJ
CO2	100	USD/Tonne	75.3	Euro/Tonne

[15] Exchange rate: 1 USD = 0.753 euro. Conversions: 26 GJ/ton coal; 1.05 GJ/MBtu; 6.1 GJ/Barrel. Prices in WEO 2015 are comparable to WEO 2014.

3

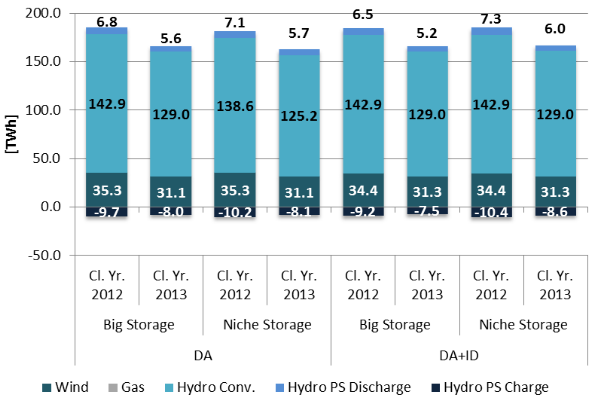
The role of Norwegian hydro power in 2030

3.1 Production-mix in Norway

Since the production of hydro *conventional* storage is a given in our approach, total production mainly differs due to consideration of two climate years

As illustrated in **Figure 8**, 2012 was a relatively wet year and hence the production of hydro conventional is significantly higher compared to 2013 levels that was considered a relatively dry year. Furthermore, since the e-prices in DA and ID – that are discussed in section 3.3 - are not so different in Big Storage, none of the hydro conventional generation is allocated to the ID market. Only in Niche storage, the e-prices in the ID market were considered to be sufficiently high to allocate part of the total hydro conventional generation to the ID market to increase the revenues.

Figure 8: Production in Norway per technology, and production (discharge) and consumption (charge) of Hydro PS in TWh.[16]



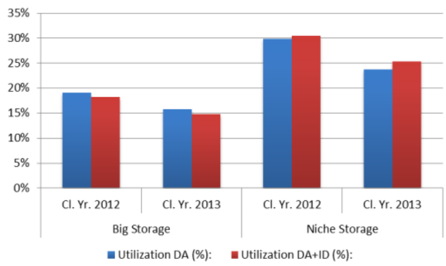
[16] Gas units produce about 0.3-0.5 TWh annually.

Although Hydro PS capacity in Norway is lower and competition is more significant in Niche Storage, the utilization of Hydro PS capacity is higher compared to Big Storage

The share of wind in total generation in Norway and in Continental Europe increases significantly. [17] This results in higher volatility of residual demand, i.e. demand minus variable RES production, on the Norwegian market and other European electricity markets (recall section 2.3.4). In the future EU market, there are various flexibility options to accommodate this such as transmission capacities and energy storage. Via the interactions with the markets abroad, Hydro PS units in Norway could accommodate fluctuations on the DA market by consuming or producing electricity. In the ID market, Norwegian Hydro PS units could provide flexibility by adapting the DA schedules for consumption and production. For instance, it is seen that fluctuations in Big Storage due to forecast errors are mostly accommodated by decreasing consumption of Hydro PS in ID market whereas fluctuations in Niche Storage are mostly accommodated by increasing production of Hydro PS in the ID market. Both are options in case there is a demand to ramp up which is generally larger than the demand to ramp down (recall **Figure 7**). Which option is more optimal i.a. depends on whether in a certain hour Norway is a net importer of electricity – importing relative cheap generation from abroad - or a net exporter.

Even though the Norwegian hydro PS capacity in Niche Storage is 5 GW lower compared to Big Storage and there is more competition from abroad, the total utilization of Hydro PS in Niche Storage within the DA market and within DA+ID market is higher, which seems a remarkable result (**Figure 9**). The explanation lies within the price volatility. Since hydro PS units charge when prices are low and discharge when prices are high, price volatility is a requirement for Hydro PS units to have a good business case; i.e. the larger the differences between high and low priced hours, the more revenues Hydro PS units can generate and the higher its utilization. Due to the assumption of a strong EU grid, fully coordinated markets, higher transmission capacity on Norwegian borders and additional Hydro PS capacity, price volatility in Norway is reduced in Big Storage compared to Niche storage. This results in less potential for hydro PS capacity to make optimal use of price differences between hours. This suggest that in our analysis there is an overcapacity of Hydro PS installed in Big Storage. Section 3.3 and 3.4, that focus on price volatility and (marginal) revenues of hydro units respectively, provide a further elaboration on this important finding. In addition, in Niche storage in ID market there is more scarcity leading to more volatile prices since there is only limited coordination. As a consequence, only in Niche storage the utilization of Hydro PS increases in ID market.

Figure 9: Utilization of hydro PS units (= average daily charge (MWh)/total daily storage capacity (MWh)

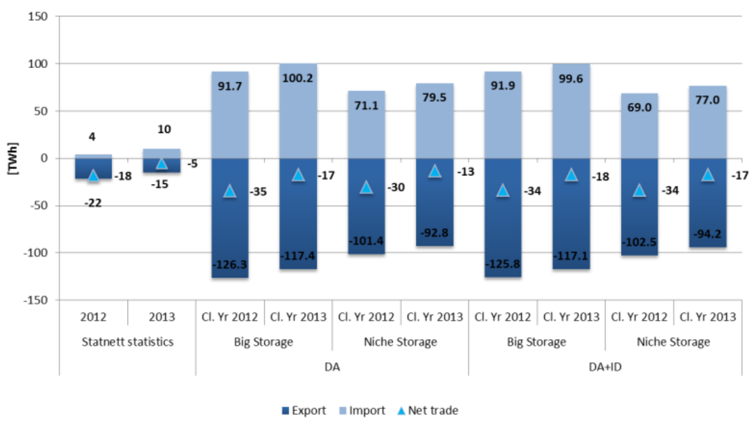


[17] From about 2 percent in 2014 (ENTSO-E, 2015b) to approximately 20 percent in 2030 in Norway, and in the whole of EU from about 7 percent in 2014 to about 20 percent in 2030

3.2 Exports, imports and net flows of electricity in Norway

The increase in generation volatility on the European electricity markets has a significant impact on the trade flows, since it increases the demand for cross-border trade between Norway and the neighbouring countries to accommodate fluctuations. As shown in **Figure 10**, the 2030 trade flows – supported by high transmission capacities - are much more significant compared to the trade flow statistics of 2012 and 2013 (Statnett, 2015). Furthermore, the main difference between the two climate years is the total hydro production in Norway since 2012 is characterized as a relative wet year and 2013 as a relative dry year, while for the rest of EU it is generally vice versa. Also, 2012 is assumed to be a bit more windy than 2013. As a consequence, the total imports are higher in climate year 2013 while the total exports are lower. With regard to the differences between Niche and Big Storage, the main reason why the (net) export is higher in Big Storage is because of higher transmission capacity.

Figure 10: Exports, imports and net trade flows in Norway in DA and DA+ID

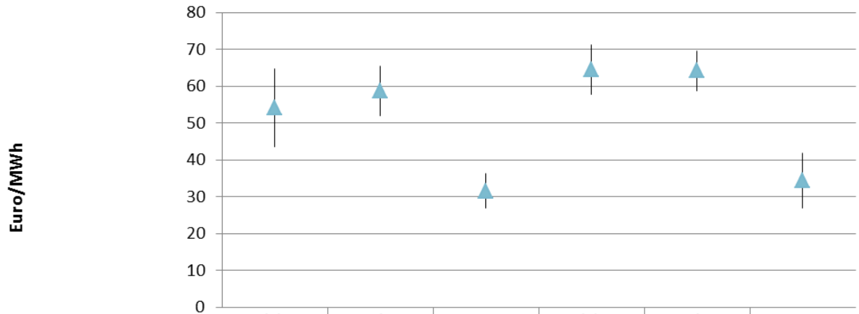


3.3 Price volatility in the (future) electricity market

Compared to today, it is expected that the price volatility is increasing in Norway in 2030

Currently, electricity prices in Norway are relatively stable due to high shares of (controllable) conventional hydro and limited transmission capacity. In future, when residual demand is becoming more volatile from increased V-RES shares in Europe and in Norway, and the network is expanded[18] and strengthened, the electricity prices in Norway are becoming more volatile compared to the current situation (**Figure 11**). However, a threshold exists for increased price volatility in combination with significant network investments since cross-border trade also accommodates extremes and thus mitigates price volatility. In particular, price volatility on the EU mainland is in general expected to decrease in Big Storage and Niche Storage compared to today's situation as is shown in **Figure 11** for the Netherlands. The reason why average electricity prices are expected to be higher compared to today, is mainly due to assuming increasing fuel- and CO_2 prices.

Figure 11: Price volatility in NO and NL representing today's situation (i.e. current) compared to Big Storage and Niche Storage DA market result for climate year 2012. Source: COMPETES model and APX (2016).



	Norway			Netherlands		
	Niche Storage	Big Storage	Current	Niche Storage	Big Storage	Current
Price volatility up	65	65	36	71	69	42
Price volatility down	44	52	27	58	59	27
▲ Average	54	59	32	65	64	34
Delta Price volatility up-down	21	13	9	13	11	15

In 2030, assuming a strong EU grid, a further increase of transmission- and Hydro PS capacity beyond levels assumed in Niche storage decreases price volatility

Considering that prices on the EU mainland are expected to become less volatile compared to today's situation based on our assumptions, it implies that further strengthening the grid does not increase price volatility, as is shown by higher price volatility in Niche storage compared to Big Storage in **Figure 12**. Additionally, it holds that the higher the Hydro PS capacities, the less remaining potential for new Hydro PS capacity to make optimal use of price differences. In Big Storage scenario this threshold seems to be reached. Since in Big Storage scenario both high transmission capacities and high hydro PS capacities are assumed, price volatility is significantly lower than in Niche Storage. In order to support these findings and distinguish the impact of higher transmission capacities from higher Hydro PS capacities and different hourly dispatch of hydro conventional, two sensitivity runs are analysed. The Niche Storage scenario (DA, 2012) is run with higher Hydro PS capacities equal to Big Storage [Sensit_1], and with higher transmission- and Hydro PS capacities equal to Big Storage [Sensit_2] (see Appendix A). In the latter, the only difference with Big Storage is then the hourly

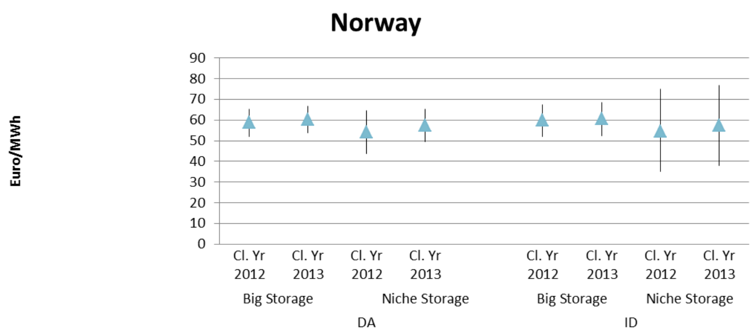
[18] For example, currently Norway is not directly connected to the UK where prices are relatively high. In 2021, Norway and UK will become interconnected via the North Sea Network (NSN) cable of 1400 MW. This investment is expected to increase volatility in prices in Norway and reduce price volatility in UK.

dispatch of hydro conventional that is equal to Niche Storage and based on the residual demand of Norway only. From the analyses it is shown that both additional hydro PS capacity and transmission capacity on Norwegian borders reduce price volatility, and that transmission capacity expansion beyond the level in Niche Storage does not improve the business case for Hydro PS when assuming a strong and integrated EU grid.

In Big Storage scenario, average prices are higher than in Niche Storage
Via the high transmission capacity in Big Storage, Norway could provide low cost generation to the rest of Europe as well as import electricity for charging in Hydro PS units in times of a surplus of low cost supply from Continental Europe and the UK. In general, the generation mix in Norway has lower costs compared to the generation mix abroad. Hence, by more extensive electricity trade (**Figure 10**), prices in Norway in Big Storage are determined to a more significant extent by marginal (price setting) units abroad resulting in higher prices in Norway compared to Niche Storage (**Figure 12**). Oppositely, prices in neighbouring countries are in general lower in Big Storage as is shown in **Figure 13** where the impact on average prices and their volatility is shown for the Netherlands.

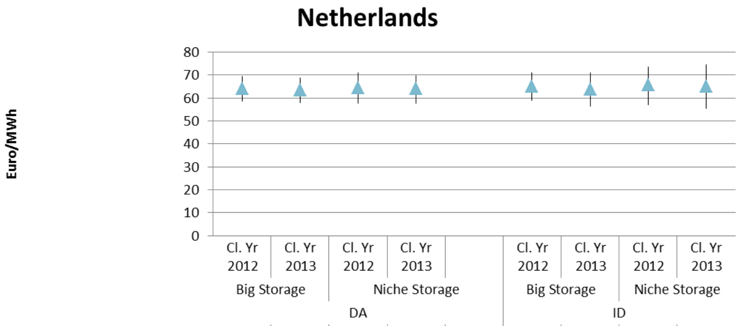
In Niche storage, the market integration is limited due to the limited coordination in ID markets and lower transmission capacities between Norway and Continental Europe. Norway is only able to provide (and demand) flexibility in ID markets within nine countries instead of thirty-two other countries. This results in more volatile prices in ID markets of Niche Storage. Furthermore, since both the DA and ID markets are fully coordinated in Big Storage, the e-prices in these markets do not differ much; the e-price is on average 1 euro/MWh higher while prices are only slightly more volatile in ID market.

Figure 12: Price volatility in Norway in euro2010/MWh. Source: COMPETES model.



	DA Big Storage Cl. Yr 2012	DA Big Storage Cl. Yr 2013	DA Niche Storage Cl. Yr 2012	DA Niche Storage Cl. Yr 2013	ID Big Storage Cl. Yr 2012	ID Big Storage Cl. Yr 2013	ID Niche Storage Cl. Yr 2012	ID Niche Storage Cl. Yr 2013
Price volatility up	65	67	65	65	68	68	75	77
Price volatility down	52	54	44	49	52	53	35	38
▲ Average	59	60	54	57	60	61	54	57
Delta Price volatility up-down	13	13	21	16	16	16	40	39

Figure 13: Price volatility in the Netherlands in euro2010/MWh. Source: COMPETES model.



	DA Big Storage Cl. Yr 2012	DA Big Storage Cl. Yr 2013	DA Niche Storage Cl. Yr 2012	DA Niche Storage Cl. Yr 2013	ID Big Storage Cl. Yr 2012	ID Big Storage Cl. Yr 2013	ID Niche Storage Cl. Yr 2012	ID Niche Storage Cl. Yr 2013
Price volatility up	69	69	71	70	71	71	74	75
Price volatility down	59	58	58	58	59	57	57	55
Average	64	64	65	64	65	64	66	65
Delta Price volatility up-down	11	11	13	12	12	15	17	19

3.4 (Marginal) revenues for Norwegian hydro power

This section elaborates on the findings with regard to the (marginal) revenues of hydro units. From the analysis it becomes clear that one needs to make a distinction between hydro conventional and hydro PS since hydro PS units not only produce electricity but also consume electricity. As a consequence, whereas hydro conventional units need high electricity prices, hydro PS units need volatile prices instead.

Big Storage scenario is most preferable from the perspective of a hydro conventional unit operator since high transmission capacities in combination with high Hydro PS capacities increases prices, and thus revenues, compared to Niche storage
Hydro conventional capacity is dispatched such that it produces when prices are highest. In Big Storage the average prices are the highest and from **Figure 14** it is shown that hydro conventional units also benefit the most in Big Storage. Even though total production is lower in climate year of 2013, the loss in revenues is partly recovered due to somewhat higher electricity prices leading to higher revenues per MWh (**Figure 15**).

Figure 14: Total revenues from conventional hydro production in Norway in 2030 in Million Euro

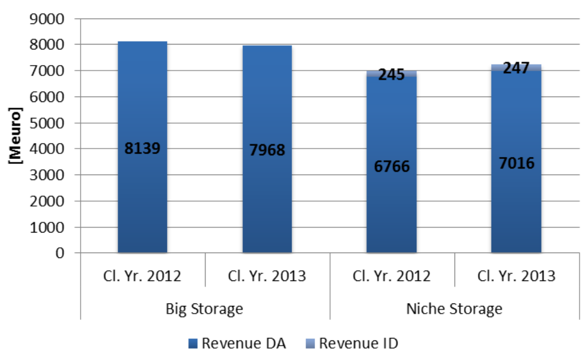
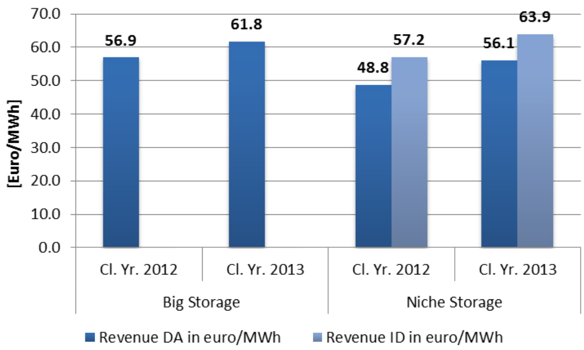


Figure 15: Revenues from conventional hydro production in Norway in 2030 in €/MWh produced



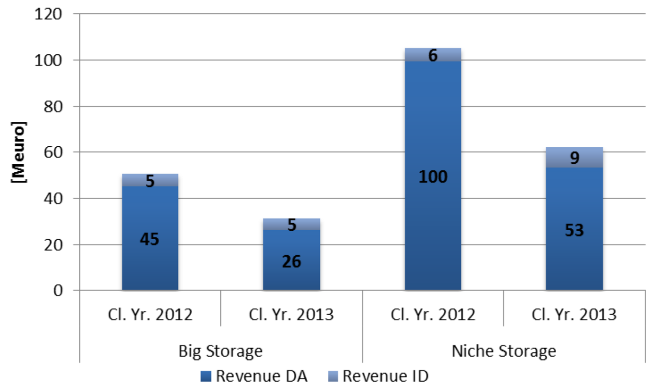
In Niche Storage, e-prices in DA market are lower resulting in lower yearly revenues. However, since the ID markets in Niche storage are not fully coordinated, there is more scarcity leading to higher prices in the peak (**Figure 12**). It therefore pays off to reserve some hydro conventional generation (i.e., 3% of total production) for the ID market as is shown by the revenues per MWh in **Figure 15**. Although the average price of the ID market is higher than DA market, allocating more production for the ID market results in a lower ID market price undermining the marginal revenues.

From the sensitivity analyses presented in Appendix A it is shown that high Hydro PS capacities increases average prices and therefore revenues earned by conventional hydro. However, especially the high transmission capacities, as assumed in Big Storage, seem an important factor to increase prices in Norway and thus revenues for conventional hydro.

Overall, the Big Storage scenario is most desirable from the perspective of a hydro conventional unit due to higher average prices and the higher transmission- and hydro conventional capacities allowing hydro conventional owners to operate their units more flexibly while total yearly hydro conventional production is the same in Niche Storage and Big Storage.

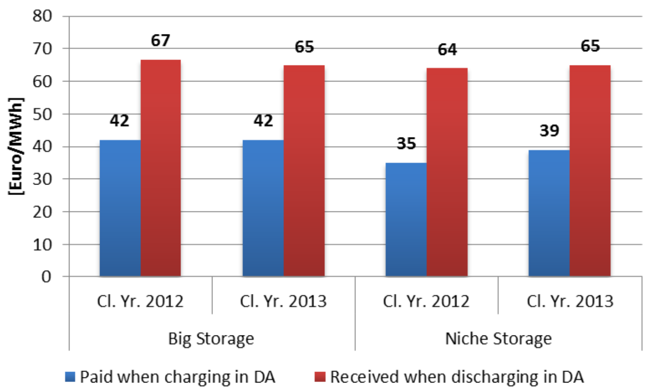
High transmission capacities in combination with a strong EU grid and high hydro PS capacities as in Big Storage scenario, does not strengthen the business case for hydro PS since price volatility is reduced compared to Niche Storage
The revenues of hydro PS in DA market as shown in **Figure 16** refer to the net revenues from consuming electricity when charging – and therefore paying the electricity price – and producing when discharging – and therefore receiving the electricity price for the production. Hydro PS units benefit from volatile prices since these units optimize their revenues by charging when prices are low and discharge when prices are high. The more volatile prices are, the more revenues these units are able to generate. This is also shown in **Figure 16** where revenues are higher in Niche storage due to more volatile prices (section 3.3).

Figure 16: (Net) revenues from Hydro PS in Norway in 2030



The difference between the average DA market price received when discharging and paid when charging are largest in Niche Storage in climate year 2012 (29 euro/MWh), and smallest in Big Storage in climate year 2013 (23 euro/MWh) (**Figure 18**). This in addition to the higher utilization of Hydro PS units in Niche Storage (**Figure 9**), results in the highest revenue for Hydro PS in Niche Storage in climate year 2012 (**Figure 16**). **Figure 9** also shows that utilization in Niche Storage 2012 is also significantly higher compared to Niche Storage 2013, which is a result from a higher demand for flexibility in DA (**Figure 7**) and higher volatility in 2012 leading to more opportunities for Hydro PS to generate revenues. Thus, the combination of high utilization, and high price volatility leading to diverging payments for charging and earnings for discharging, are both in favour to generating higher revenues which are almost twice as high compared to Niche Storage 2013.

Figure 17: Average prices paid when charging and average prices received when discharging in DA market (weighted average derived from hourly (dis)charge and hourly electricity prices)



Considering that forecast errors of wind are the main driver for trade in the ID market, the revenues of Hydro PS in the ID market from adapting the production and consumption of Hydro PS units to supply flexibility for wind forecast errors, are calculated based on the following assumptions :

In times of a demand to ramp up due to lower realized wind generation compared to the forecasts (i.e. negative forecast errors), hydro PS units can:

- Supply flexibility by decreasing the amounts charged in a certain hour. In this case, Hydro PS pays the DA price for the consumption in the DA market. If they reduce their consumption, they will be willing to be compensated at least the DA price for decreasing their consumption in the ID market. If the ID market price is higher than the DA market price then they receive the ID market price for decreasing their consumption.
- Supply flexibility by increasing the discharge in a certain hour. In this case, Hydro PS units produce more than in DA and they get ID price for the additional production. Thus, the product of the change in discharge and the ID market price are their (additional) revenues

In times of a demand to ramp down due to higher realized wind generation compared to the forecasts (i.e. positive forecast errors), hydro PS units can:

- Supply flexibility by increasing the amounts charged in a certain hour. In this case, Hydro PS units charge more than in DA and they pay the ID price for the additional consumption. Thus, the difference in total charge in DA market compared to ID market times the ID price are the (additional) costs they have to incur.
- Supply flexibility by decreasing the discharge in a certain hour. Hydro PS units earn the DA price for producing in the DA market. If they reduce their production in the ID market while still receiving a revenue on DA, they need to compensate this by buying power equal to the reduced amount in ID market. For this amount they would be willing to pay at most the DA price. If the price in the DA market is higher than the price in ID market, then they pay the ID market price. If the price in the ID market is higher than in DA market, they pay the DA price for the reduced amounts. By reducing their discharge, Hydro PS units can use the stored amounts at other times when prices on ID are higher (i.e. opportunity benefits).

Even though there is a pay-off to participate in both markets than only participating in a single market, it can be seen that the revenues earned on the ID market are significantly smaller than on the DA market. **Figure 18** and **Figure 19** illustrate the reason behind it. Hydro PS units can generate revenues by providing *positive control power*, i.e. by increasing discharge or by decreasing charge compared to DA market. While the average price received when increasing discharge are high - since otherwise Hydro PS units would not increase their discharge – the average price earned when decreasing charge is relatively low (**Figure 19**), thereby limiting the total revenues earned in ID. This is because in some hours, units decrease their charge but still charge in that particular hour with relative low prices.

For providing *negative control power* by decreasing discharge or increasing charge, it is the other way around; average prices paid when increasing charge are relatively low resulting in relatively low payments, but the average prices paid when decreasing discharge are relatively high. This is because if Hydro PS units decrease their discharge while still discharging in that particular hour, the prices are relatively high. **Figure 18** shows that the provision of positive and negative control power by hydro PS units is more or less in balance resulting in a small positive net revenue in the ID market (**Figure 16**).

From **Figure 18** and **Figure 19** it also becomes clear why net revenues in Niche Storage are somewhat higher than in Big Storage, where the colours of the ways Hydro PS can provide flexibility in **Figure 18** are in line with the colours of the average price Hydro PS units earn or pay in **Figure 19**.

In the ID market, Hydro PS units earn the most when increasing the discharge and will pay the most when decreasing discharge, since in both situations high prices are expected (**Figure 19**). Even though more flexibility is supplied by Hydro PS in the ID market in Big Storage, the net revenues are relatively low. This is due to high shares in supplying positive power control by decreasing charge - with relative low earnings per MWh - in combination with high shares in supplying negative control power by decreasing charge - with relative high payments per MWh. In Niche Storage the opposite holds, and especially for climate year 2013. As a consequence, highest net revenues are gained in Niche Storage 2013 (**Figure 16**).

Figure 18: Flexibility supplied by Hydro PS in terms of **positive control power** (i.e. increasing discharge or decreasing charge) and **negative control power** (i.e. decreasing discharge or increasing charge) in the ID market in Norway in 2030.

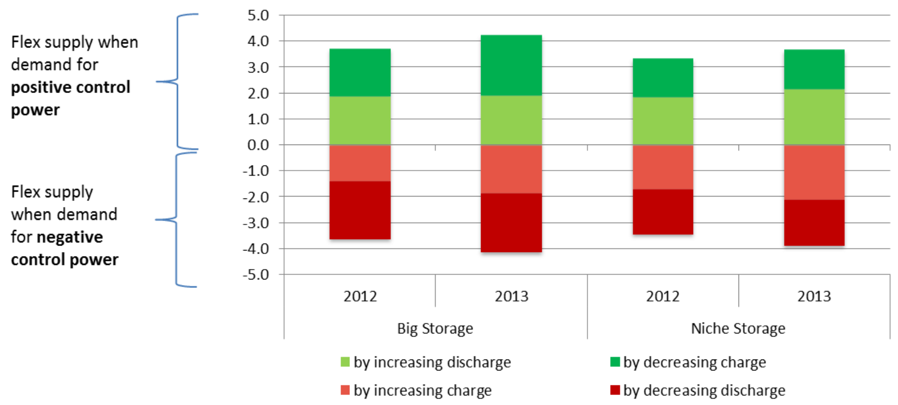
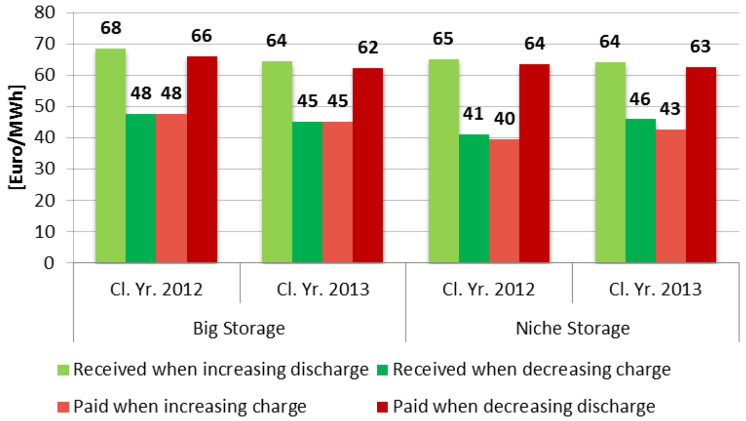


Figure 19: Average prices **received** when reducing charge in ID market or when increasing discharge in ID market; and average prices **paid** when reducing discharge in ID market or when increasing charge in ID market in Norway



4

Strong EU grid: most supportive to conventional hydro, competitor to pumped hydro

This study serves to analyze and identify important aspects that influence and determine the role of Norwegian hydro power in the future integrated European electricity market (e.g. transmission capacities and impact of the level of coordination in the electricity markets). Since Norwegian hydro units are analyzed in an aggregated fashion, this study focusses less on the technical feasibility that might have an impact on the role of Norwegian hydro to provide flexibility. By aggregating Norwegian hydro capacity, other restrictions such as cascading effects and conflicting activities due to recreational or agricultural use of storages are not considered.

The main conclusions are the following;

Compared to today's situation, price volatility in future is expected to increase in Norway*;* in today's situation, electricity prices in Norway are relatively stable due to a high share of (controllable) hydro capacity, limited v-RES shares and relatively limited transmission capacities. In future this is expected to change due to increased shares of v-RES not only in neighbouring countries, but also in Norway itself. This, in combination with a strengthened grid increases trade interactions between Norway and its neighbours and thereby volatility on the markets. Therefore in our scenarios, price volatility in Norway is expected to increase w.r.t. current levels.

When assuming a strong future EU grid a threshold is expected after which a further increase in transmission capacity on Norwegian borders does not lead to an increase in price volatility*:*

- *Not only expansion and strengthening of the transmission capacity on Norwegian borders are an important factor for the future role of Norwegian hydro, but also the grid investments throughout EU;* in Norway, the impact of increasing the cross-border transmission capacity on prices also depends on transmission investments across Europe. In our analysis, the EU grid is assumed to be strengthened such that price volatility on EU mainland is in general decreasing w.r.t. today's situation. Therefore, in this situation an increase of transmission capacity on the Norwegian borders will reduce price volatility in Norway instead of increasing price volatility.

- *In 2030, a further increase of transmission- and Hydro PS capacity beyond levels assumed in Niche storage increases average prices but decreases price volatility and hence is beneficial to business case of hydro conventional units but non-beneficial to the business case of hydro PS units;* An important observation in this study is that high transmission capacities connecting Norway to the rest of Europe reduces price volatility and increases average electricity prices in Norway. Hydro conventional capacity benefits from the increased prices, especially when Hydro conventional capacity is high and storages can be utilized in a flexible way to accommodate fluctuations in Norway and abroad. Hydro PS units on the other hand are both producers and consumers of electricity. Increased prices are only beneficial if prices are volatile and Hydro PS units can consume electricity to charge in low priced hours. Since high transmission capacities within EU in Big Storage scenario reduce price volatility, Hydro PS units in Norway cannot earn significant profits by arbitraging between low and high priced hours to charge and discharge, respectively. As a consequence, even though Hydro PS capacity is higher in Big storage scenario, its utilization is lower which suggests an overcapacity of Hydro PS in Big Storage scenario. Therefore, it is important to have an optimal strategy in investments for hydro PS and the cross-border transmission capacities. The optimal strategy in Big storage scenario for an improved business case of Hydro PS could be less investments in Hydro PS when a strong future EU grid is anticipated.

***Due to higher scarcity for flexible capacity resulting in higher peak prices on ID market compared to DA market, there is a payoff to reserve hydro conventional capacity for ID market depending on the level of market coordination*;** the larger the area of coordination in the ID market, the better the wind forecast errors can be accommodated via cross-border trade. With full coordination as in Big Storage, the ID market results are more in line with the DA market than with limited coordination as is the case in Niche Storage. Hence, since prices between DA and ID in Big Storage do not differ, there is no additional benefit to reserving hydro conventional capacity for the ID market. Due to limited coordination in Niche Market that increases the difference between prices on DA market and ID market, there is however a payoff to reserve hydro conventional capacity.

Increasing V-RES generation in EU results in more significant flows between Norway and the rest of Europe compared to today's situation; with increasing V-RES generation in EU and also in Norway, the residual demand is in general becoming more volatile. This has a significant impact on the trade flows, increasing the demand for cross-border trade between Norway and the neighbouring countries to accommodate fluctuations. With strong interconnections, the increased volatility in residual demand compared to today's situation results in more significant trade flows between Norway and the rest of Europe. In particular, Norway, having high amounts of competitive hydro power generation and storage capacities is an interesting electricity trade partner to balance demand and supply throughout Europe.

<u>Impact of model assumptions and limitations on the results:</u>
Storage technologies like Hydro PS are arbitrage technologies whose business cases depend on price volatility, earning revenues from arbitraging between high and low

priced periods. In this study the following important developments and assumptions, and their uncertainty, are distinguished as to play a crucial role in determining the price volatility in Norway and EU in future:

- *Transmission capacity expansion across Europe*: in our analysis we assume a strong and highly integrated EU electricity market such that price volatility in EU is actually reduced. As a consequence, further strengthening the grid on Norwegian borders is non-beneficial to the business case of Hydro PS because it reduces price volatility in Norway. Thus, in our study, fluctuations in supply and demand throughout EU is already being accommodated via cross-border transmission to a significant extent which reduces the potential for Norwegian Hydro PS units to provide this flexibility. If a low or moderately strengthened EU grid was assumed, the business case of Norwegian Hydro PS would likely improve from increased transmission capacity between Norway and neighbouring countries. For example, in the National Energy Outlook (NEO) of 2017 that can be considered as a business-as-usual scenario (Schoots et al., 2017), the price volatility in 2030 in Norway is significantly lower compared to the Netherlands and Germany, which suggests that additional transmission capacity increases price volatility in Norway.
- *(Variable) RES capacity in Europe and Norway*: Hydro PS units in Norway could benefit by charging in hours with high shares of (variable) RES in the EU in case the surplus could not be (fully) distributed across Europe and hourly electricity prices would reflect the low marginal costs of RES. Therefore, the RES share - in combination with the transmission capacity - in the EU is an important determinant for the business case of Hydro PS in Norway. Furthermore, in our scenario assumptions, Norway is assumed to have a relative high wind capacity. At the time of the model analyses, Vision 4 of ENTSO-E (2014a) was the most recent version, assuming 11 GW of wind. The most recent version of ENTSO-E Vision 4 that is now available assumes 2,4 GW of wind. Hence, the wind capacity assumption in Norway in this study seems on the high end which is likely to result in an overestimation of price volatility in Norway.
- *Modelling the dispatch of hydro conventional*: In our approach, hydro production is exogenously determined in a pre-stage procedure and dispatched depending on residual demand in Norway, and to some extent to the residual demand in neighbouring countries. This might overestimate price volatility within Norway. In case hydro conventional was optimally dispatched, i.e. endogenously determined in the model, price volatility in Norway would likely to be lower.

The business case of conventional hydro is less vulnerable to these developments since conventional hydro is competitive back up capacity compared to conventional technologies and its operation is not depending on volatility in prices.

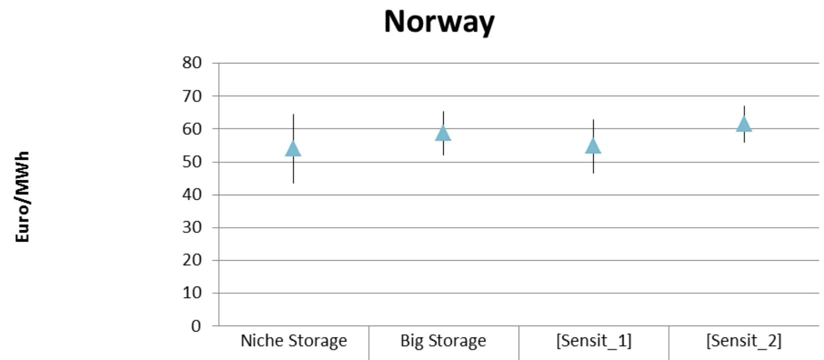
Other developments could also have a positive impact, e.g. significant electrification without Demand-Side-Response (DSR) to accommodate fluctuations, or a negative impact, e.g. DSR or other forms of energy storage, on the business case of Hydro PS. These developments are not taken into account in our analysis. From the perspective of a Norwegian Hydro PS operator, especially the developments regarding the transmission expansion in Europe are identified as important since a strong and integrated EU grid can significantly reduce the potential for Hydro PS to operate as is shown by this study.

Appendix A. Sensitivity analyses

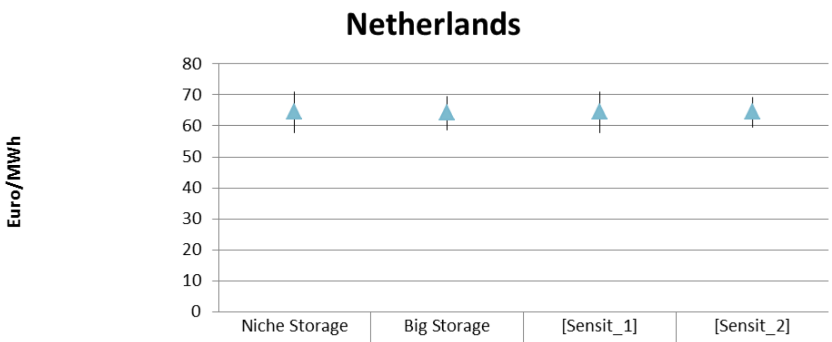
One of the main conclusions that can be drawn from this study is that in the future EU network - assuming an expanded and strengthened EU network and higher Hydro PS capacities in Norway- a further expansion of the transmission capacity on the Norwegian borders might not increase price volatility as is the case today. In order to support this conclusion and to discern the impact of higher transmission capacities from higher Hydro PS capacities and different profiles for hydro conventional production, the Niche storage scenario is run with higher Hydro PS capacities in Norway and abroad ([Sensit_1]) and with both higher Hydro PS capacities and transmission ([Sensit_2]). Hence, the differences of [Sensit_1] with Big Storage is the hourly dispatch of conventional hydro and the transmission capacity on Norwegian borders, and the difference between [Sensit_2] and Big Storage is then only the hourly dispatch of conventional hydro.

Figure 20 shows that the scenario with lowest transmission capacities and Hydro PS capacities (i.e. Niche Storage) results in the highest volatility in prices. Then, by only increasing the Hydro PS capacity as is the case in [Sensit_1], the price volatility reduces because of optimal allocation of consumption and production from the additional Hydro PS capacity in low and high priced hours. In [Sensit_2] the additional transmission capacity further reduces price volatility, especially due to increased prices in low priced hours, i.e. marginal units abroad determine the prices in Norway to a more significant extent than in Niche Storage due to less congestion and higher exchange. Furthermore, in our approach hydro conventional production is determined in a pre-stage to the model run, where in Big Storage Norwegian conventional hydro is also (partly) accommodating residual demand abroad. From **Figure 20** it is seen that this actually results in an increase in the price volatility compared to [Sensit_1] and [Sensit_2], which might be an artefact of modelling it in a pre-stage since congestion is not considered. Hence, with regard to the pre-stage calculation of hydro conventional, the price volatility in Big Storage is likely overestimated.

Figure 20: Sensitivity of price volatility in various future scenario's representing 2030 for DA market of climate year 2012 (COMPETES).



	Niche Storage	Big Storage	[Sensit_1]	[Sensit_2]
Price volatility up	65	65	63	67
Price volatility down	44	52	47	56
▲ Average	54	59	55	61
Delta Price volatility up-down	21	13	16	11



	Niche Storage	Big Storage	[Sensit_1]	[Sensit_2]
Price volatility up	71	69	71	69
Price volatility down	58	59	58	60
▲ Average	65	64	65	65
Delta Price volatility up-down	13	11	13	10

From **Table 3** it is shown that both total production and consumption of hydro PS units and their utilization are lower in Big Storage compared to Niche Storage even though the capacity is higher (result of DA, climate year 2012). In [Sensit_1], the utilization is reduced to *24%* instead of 30*%* as in Niche Storage. This is still higher than the *19%* utilization in Big Storage but it indicates that by adding another marginal Hydro PS unit[19], the potential to maximize profits from price volatility is lower than that of the previous marginal Hydro PS unit. In [Sensit_2] the high Hydro PS capacity is further suppressed in its operation and utilization since the additional transmission capacity reduces price volatility so that (dis)charge levels are even lower than in Niche Storage. Therefore, from the perspective of a Hydro PS operator, Niche storage scenario is the preferred scenario.

[19] Marginal in this case refers to increasing capacity with e.g. 1 MWe

Table 3: Comparison two sensitivity scenarios to the main scenarios, Niche Storage and Big Storage (DA market run of climate year 2012).

		Niche Storage	Big Storage	[Sensit_1]	[Sensit_2]
Totals (TWh)	Hydro PS, Charge	10.2	9.7	11.9	6.7
	Hydro PS, Discharge	7.1	6.8	8.3	4.7
Utilization (%)	Hydro PS	30%	19%	24%	13%
Total revenues (Million euro)	Hydro PS	100	45	63	17
	Hydro Conv.	6766	8139	6989	8707
Exports (TWh)		101	126	101	125
Imports (TWh)		71	92	72	94
Net trade (TWh)		-30	-35	-30	-31

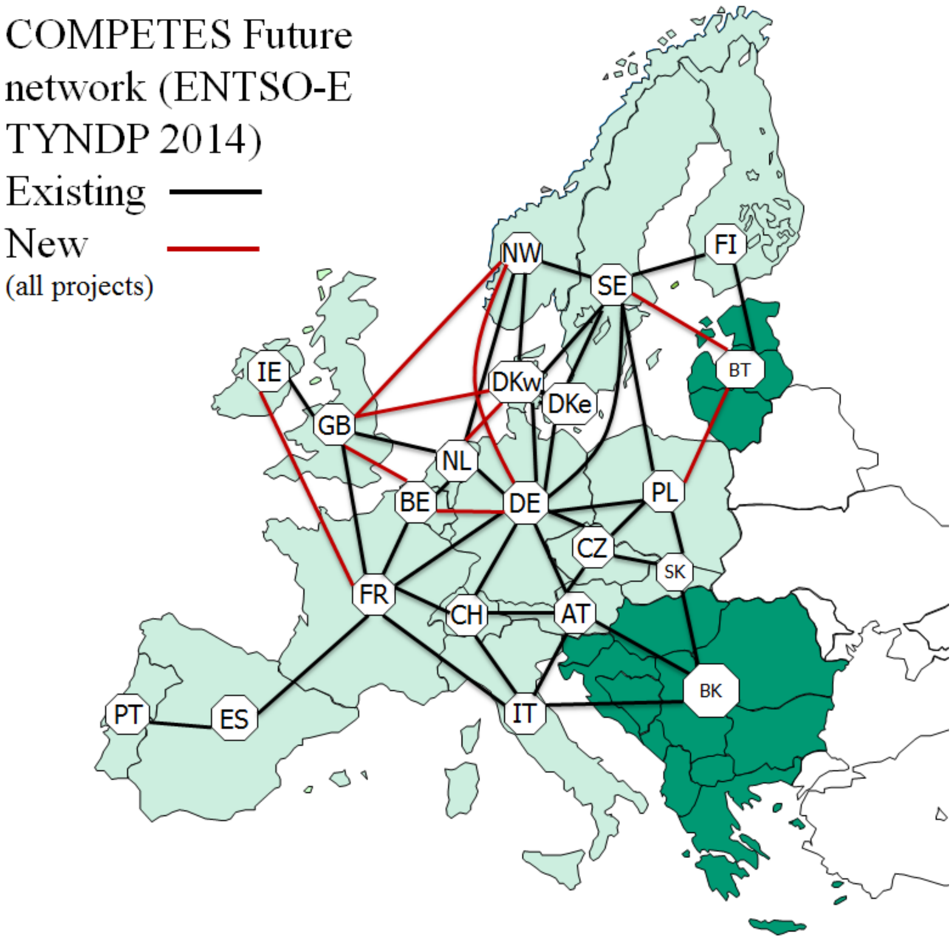
Appendix B. The COMPETES model

Introduction
COMPETES[20] UC is a unit-commitment model of the transmission-constrained European power market. The model covers 28 EU member states and some non-EU countries (i.e., Norway, Switzerland, and the Balkan countries) including a representation of the cross-border transmission limitations interconnecting these European countries.
Every country is represented by one node, except Luxembourg which is aggregated to Germany, and the Balkan area and Baltic countries are aggregated in one node. Furthermore, Denmark is split in two nodes due to its participation in two non-synchronous networks (See Figure 21). The model assumes an integrated EU market where the trade flows between countries are constrained by Net Transfer Capacities (NTC) reflecting the ten year network development plan of ENTSO-E (ENTSO-E TYNDP, 2014b).

COMPETES UC model aims to find an optimal generation schedule for the problem of deciding which power generating units must be (un)committed over a planning horizon at minimum cost, satisfying the forecasted system load as well as a set of technological constraints. These constraints include the flexibility capabilities of different generation technologies as well as the lumpiness in generator start-up decisions; a feature not considered in most continent-wide electricity market models. The model also includes hourly profiles of wind and solar generation that are intermittent by nature.

[20] COMPETES UC is an extension of COMPETES Model (Hobbs and Rijkers, 2004) which has been developed in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University, as a scientific advisor of ECN.

Figure 21: Geographical coverage in COMPETES UC and the representation of the cross-border transmission links in 2030 in line with ENTSO-E TYNDP (2014b) (all projects).



Unit Commitment Problems are considered to be difficult to solve for large systems due to their complexity of finding integer solutions. While the exact formulation of a Mixed Integer Linear Program (MILP) is used for the separate units in the Netherlands, an approximation of MILP is formulated for the other countries/regions where technologies are aggregated in order to overcome this complexity. The corresponding approximating problem proposed by Kasina et al. (2013) aims to solve large scale systems within a reasonable time while capturing most of the characteristics of a unit commitment problem. To summarize, the unit commitment formulation of COMPETES minimizes total variable, minimum-load and start-up costs of generation and the costs of load-shedding in all countries subject to the following electricity market constraints:

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.
- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant. Furthermore, hourly reserve capacities (spinning and non-spinning) can be optionally determined in the day-ahead market via a deterministic approach. In COMPETES, wind forecast errors are the main drivers for trade in the intraday market. The higher the wind generation in a certain hour in the day-ahead market, the more significant the impact on the intraday market in

case of forecast errors. Hence, hourly reserve capacities are determined based on a certain percentage of the wind production in a country or node.

- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.
- *Ramping up and Down constraints:* These limit the maximum increase/decrease in generation of a unit between two consecutive hours
- *Minimum Load Constraints:* These constraints set the minimum generation level of a unit when it is committed. For the Netherlands, every unit is modelled with minimum generation levels and the corresponding costs. For other countries, this constraint is approximated by a relaxed formulation since the generation capacities and the minimum generation levels represent the aggregated levels of the units having the same characteristics (e.g., technology, age, efficiency etc.).
- *Minimum up and down times (Only for the units in the Netherlands):* These constraints set the minimum number of hours that a unit should be up or down after being started-up or shut-down.

The incorporation of start-up costs, ramping rates, and minimum load levels allows a better representation of the system flexibility to accommodate the variability and forecast errors of wind. In addition, the model also includes the flexibility decisions related to the operation of storage. The long-term planning decisions in the form of adequate generation capacity and cross-border import capacity is part of the scenario and thus exogenous to the model.

Model input and assumptions

The input data of COMPETES UC involves a wide-range of generation technologies (see Table 4). The generation type, capacity, and the location of existing generation technologies are regularly updated based on WEPPS database UDI (2012). COMPETES database is in particular detailed out with unit by unit generation in the Netherlands. For the other countries, the units with the same technology and similar characteristics (i.e., age, efficiency, technical constraints) are aggregated.

Table 4: The categorization of electricity generation technologies in COMPETES

Fuel	Technology	Description
Conventional technologies		
Gas	GT	Gas Turbine
	CCGT	Combined Cycle
	CHP	Co-generation
	CCS	Carbon Capture & Storage
Derived gas	IC	Internal Combustion
	CHP	Co-generation
Coal	PC	Pulverized hard coal
	Co-firing	Pulverized hard coal with co-firing of biomass
	IGCC	Integrated Gasification Combined Cycle
	CCS	Carbon Capture & Storage
Lignite	PC	Pulverized brown coal
	CHP	Co-generation
Oil	-	-

Nuclear	-	-
Renewable technologies		
Biomass	Standalone	-
Waste	Standalone	-
Geo	-	Geothermal
Solar	PV	Photovoltaic
	CSP	Concentrated Solar Power
Wind	Onshore	-
	Offshore	-
Hydro	CONV	Conventional hydro (run of river and storage)
	PS	Pumped Storage
RES	Other	Other renewables (e.g. tidal & waves)

The main inputs for electricity supply can be summarized as:

- Operational and flexibility characteristics per technology and per country
  - Efficiencies
  - Installed power capacities
  - Availabilities (seasonal/hourly)
  - Minimum load of generation and min-load costs
  - Start-up/shutdown costs
  - Maximum ramp-up and down rates
  - Minimum up and down times (only for the units in the Netherlands)
- Emission factors per fuel/technology
- Fuel prices per country, CO_2 ETS, national coal tax (NL)
- Hourly time series of intermittent RES (wind, solar) and demand
- RoR (run of river) shares of hydro in each country
- External imports from Africa (optional)

The flexibility assumptions for conventional units are assumed to differ with the type and the age of the technology as summarized in **Table 5**. The part-load efficiencies for min-load levels given in **Figure 22** are taken into account for calculation of the min-load costs incurred when units with these technologies are committed.

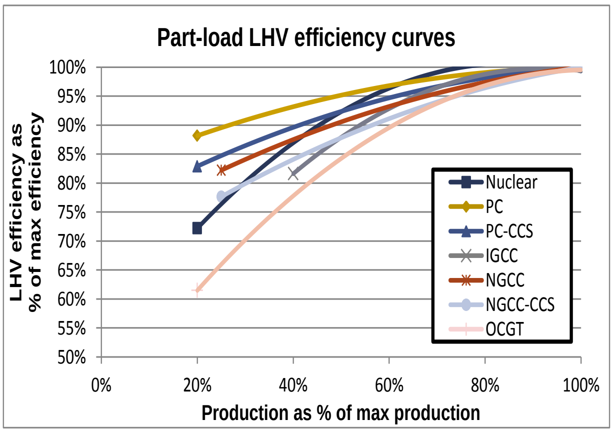
Table 5: Flexibility options for conventional technologies in COMPETES

Technology	Commissioning period	Minimum load (% of max. capacity)	Ramp rate (% of max. capacity/ hour)	Start-up cost[21] (€/MW installed per start)	Minimum up time (hour)	Minimum down time (hour)
Nuclear	<2010	50	20	46 ±14	8	4
	2010	50	20	46 ±14	8	4
	>2010	50	20	46 ±14	8	4
Hard coal and lignite	<2010	40	40	46 ±14	8	4
	2010	35	50	46 ±14	8	4
	>2010	30	50	46 ±14	8	4
IGCC	<2010	45	30	46 ±14	8	4

[21] Warm start-up costs are assumed for all technologies but OCGT. For OCGT, a cold start is assumed.

	2010	40	40	46 ±14	8	4
	>2010	35	40	46 ±14	8	4
NGCC	<2010	40	50	39 ±20	1	3
	2010	30	60	39 ±20	1	3
	>2010	30	80	39 ±20	1	3
OCGT	<2010	10	100	16 ±8	1	1
	2010	10	100	16 ±8	1	1
	>2010	10	100	16 ±8	1	1
CHP	<2010	10	90	16 ±8	1	1
	2010	10	90	16 ±8	1	1
	>2010	10	90	16 ±8	1	1
Sources[22]:		[1-9]	[1-8, 10]	[11]	[11]	[11]

Figure 22: Part-load efficiency curves for different technologies. Source: Brouwer et al., 2013.



[22] [1] (Jeschke et al., 2012); [2] (Dijkema et al., 2009); [3] (OECD/IEA, 2010); [4] (IEAGHG, 2012a); [5] (Klobasa et al., 2009); [6] (Balling, 2010); [7] (Hundt et al., 2010); [8] (Isles, 2012); [9] (Stevens et al., 2011); [10] (NETL, 2012b); [11] (Lew et al., 2012).

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