Summary of Danish experiences enabling maximum wind power integration

FINAL REPORT

15-07-2016

Published by:

Ea Energy Analyses
Frederiksholms Kanal 4, 3. th.
1220 Copenhagen K
Denmark
T: +45 88 70 70 83
F: +45 33 32 16 61
Email: info@eaea.dk
Web: www.eaea.dk

Contents

1 Foreword

As part of the project *Research on Hami Emery Base Coordinated Operating Mechanism* Ea Energy Analyses and Energinet.dk are tasked with summarising Danish experiences that have enabled a high degree of wind penetration. This report aims to describe the most important elements related to wind integration in Denmark, as well as indicate how some of these facets can be applied to the Hami Energy Base.

The contents of the report draw from knowledge acquired through various projects and experiences, as well as previous reports prepared by Energinet.dk and Ea Energy Analyses.

2 Introduction

2.1 Danish targets and current situation

The Danish Government has set a target that more than half of the traditional electricity consumption[1] should be supplied by wind power in 2020. In the longer term, this wind expansion can be expected to increase even further as part of the Government's objective to be free of fossil fuels by 2050.

As a result, the Danish electricity system has in recent years distinguished itself internationally due to its ability to successfully integrate a growing percentage of wind power production. In 2015, wind power accounted for 42% of national electricity demand, and in numerous hours, a much higher percentage than this. Concrete examples of this are often showcased, such as the situation from November of 2013 depicted below, in which total Danish wind power production was greater than total Danish electricity demand.

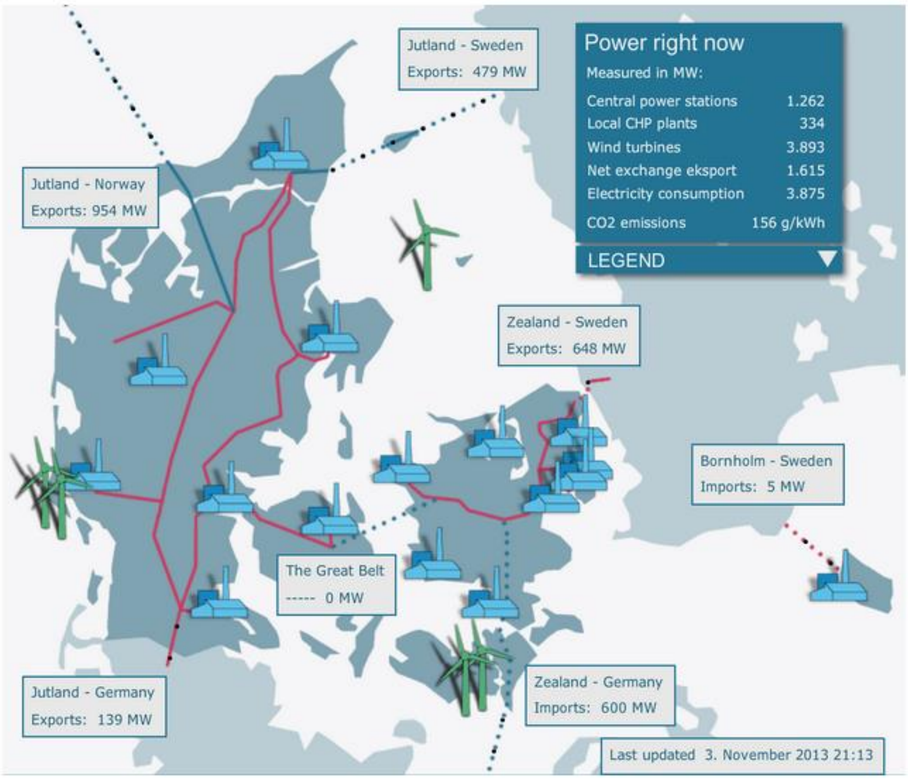


Figure 1: Screenshot of the Danish power system from November 3rd, 2013 (Energinet.dk, 2013)

[1] The traditional electricity consumption encompasses the kinds of electricity consumption that exist today, such as electricity use for lighting and household appliances. Non-traditional electricity consumption is the anticipated electricity consumption for heat pumps and electric vehicles, which will cause the total electricity demand to rise.

Wind production greater than electricity demand, an increasingly more common event.

While not yet an everyday event, the above situation is by no means a circumstance that only occurs once or twice a year. In 2015 for example, there were over 400 hours (ca. 4.6% of the time) during which Danish electricity production from wind was greater than total electricity demand. This is highlighted in the duration curve below which plots Danish wind production as a share of total Danish electricity demand for each hour of 2015. A stated goal of the current project is to highlight experiences from countries and/or regions that have a wind power proportion in the power system up to 80%. For Denmark as a whole, in 2015 this occurred in more than 13.5% of hours.

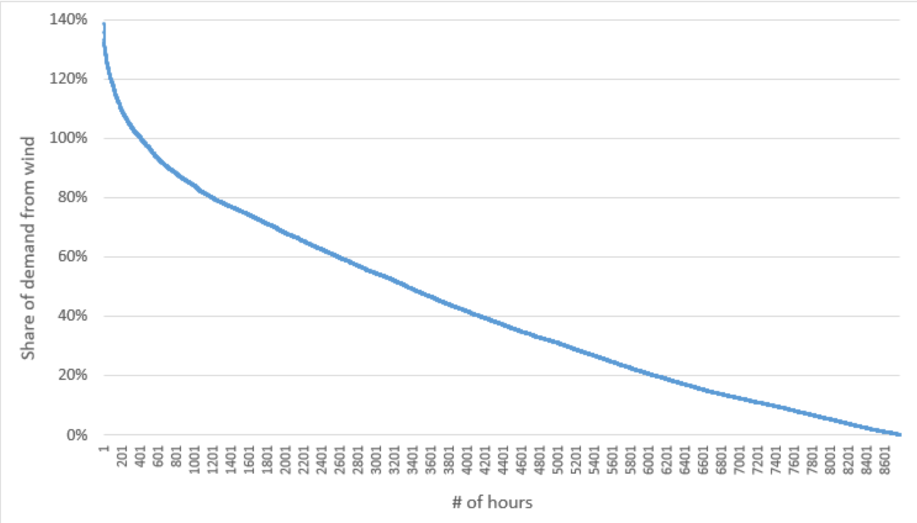


Figure 2: Hourly duration curve for 2015 Danish wind production as a share of total electricity demand.

It is precisely the situation reflected in the figure above that makes Denmark a relevant case study for how to handle and dispatch high levels of wind penetration.

The high wind penetration levels in Demark are the result of a number of aspects working in combination. The primary goal of this report is therefore to describe these aspects, and to discuss how Danish experiences can be applied to the Hami Energy Base project.

2.2 From overarching policy to day-to-day operations

During the Chinese delegation's visit to Denmark, there was interest in understating how Denmark goes from its overall long-term policy goals and targets to the day-to-day operations. The report will endeavour to cover a number of the aspects of this process throughout. Generally speaking though, the central government determines the long-term goals and targets, often with input from leading experts from academia and industry representatives.

When these targets and/or policy goals have been established the government must then determine what incentives, infrastructure, and legal and/or regulatory frameworks must be place in order for the targets to be met. If we for example take a target of 50% wind in 2020, some of the overall aspects the government had to undertake included:

- Establishing subsidies for onshore wind in order to encourage private investors to invest in wind production.
- Develop bidding rounds for areas designated for offshore wind farms
- Ensure that Energinet.dk undertook analysis and potential investments in both the domestic transmission grid and interconnectors to neighbouring countries.

2.3 Report structure

In summarising Danish experiences for the maximisation of wind power production, this report will therefore:

- Briefly outline the structure of the Danish power system and its key stakeholders
- Describe the incentives for wind production in Denmark
- Describe the Danish market structure within which all electricity producers operate in.
- Detail how system operation utilizing wind forecasting allows for dispatch of high wind penetration levels
- Describe how the above aspects in combination affect each of the power production groups (i.e. wind power producers, central power plants, etc.).
- Discuss the most important aspects from the Danish experiences that can be applied to the Hami Energy Base project.

2.4 Analysis detail level

It is our understanding that the CREEI and NEA decision makers are aware of the general situation in Denmark, and therefore the analysis will go into greater detail and involve:

- Analysis of specific cases, including examples such as that depicted in Figure 1
- Description and analysis of concrete dispatch examples
- Detailed description and analysis of pricing and market structures

3 Challenges related to integration of wind

Three main challenges

Generally speaking, due to the fluctuating and intermittent nature of wind, there are three main challenges associated with integrating wind power:

1. To ensure the value of wind when it is very windy (In a Chinese context, this would relate to reducing curtailment).
2. To ensure sufficient production capacity when there is no wind. Wind power expansion results in it being less attractive to build base load plants.
3. To balance wind power production, i.e. managing wind's fluctuating and partly unpredictable production patterns.

3.1 Ensuring the value of wind when it is very windy

If a large part of the produced wind power electricity is sold at low or negative prices it damages the wind turbine's economy and thereby reduces the incentive to invest in new wind turbines. For this reason, it is crucial to ensure the value of wind, both to maintain its socioeconomic value, and in order to preserve the economic foundation for continued wind power development. The solutions are to reduce production at other power production units, export to neighbouring countries, or to increase electricity consumption where this is economically attractive. Existing and new electricity consumption (electricity for heat generation, electric vehicles, etc.) can also assist by not using electricity during periods of the day when the electricity system is most hard-pressed.

When these options have been exhausted it would be possible to curtail production from some of the wind turbines, both for shorter periods consisting of a few minutes, or for longer periods extending several hours. This is possible for all modern wind turbines. Excess electricity is therefore not a technical problem but rather an economic one, which can be minimised when the rest of the energy system is dynamic. In a future with a large share of wind power, it will likely be economically beneficial to stop some wind turbines every now and then.

3.2 Ensuring sufficient production capacity when it is not windy

The challenge of ensuring sufficient production capacity can be dealt with in several ways: establishing peak generation capacity such as gas turbines, or via a closer integration of grid with neighbouring countries. Flexible electricity consumption and the activation of emergency power generators are also interesting possibilities that are, to a certain extent, already in use. The value of the various alternatives depends in particular upon the length of the duration that the strategy can be used. While certain types of flexible electricity consumption can only provide a solution for a number of hours with lacking capacity, other possibilities such as peak load plants or international grid connections can be used over longer periods of time with no wind power production, which potentially could last for a number of weeks.

3.3 Balancing wind power

There is a need for balancing if e.g. the production from wind power falls unpredictably, either as a result of altered wind conditions, or due to production issues caused by technical problems or damage to the turbines. The latter also applies for fallouts from other production units or transmission connections. Balancing can be achieved either by power plants or by consumers being prepared to change their production/consumption patterns with relatively short notice (see the text box below). Gas turbines can be well suited to meet this need, but also coal-fired power plants and other productions units, electric boilers, or electrical heat pumps, and other consumption units can provide balancing services. Increased integration with neighbouring countries' energy systems can also provide access to more sources capable of providing balancing.

4 Danish power system development

The integration of wind power has involved changes at all levels of the energy system, involving both technical measures and adaptions of energy markets support schemes, taxes, procurement of system services as well integration with the heat sectors. The following chapter will briefly describe the development of Danish electricity production, as well as the evolution in physical infrastructure that has aided in integrating growing proportions of wind production.

4.1 Development and current status

Over the last 15 years, the annual Danish electricity consumption (including network losses) has been quite steady, at roughly 35 TWh per year, with the load varying between 2,100 MW and 6,200 MW. While demand may have remained largely unchanged, the power system in Denmark has however evolved from one consisting almost solely of large-scale thermal power plants, to a system comprised of a mix of large-scale units, small-scale units, auto-producers, and wind turbines (see figure below).

Wind capacity portion continues to grow

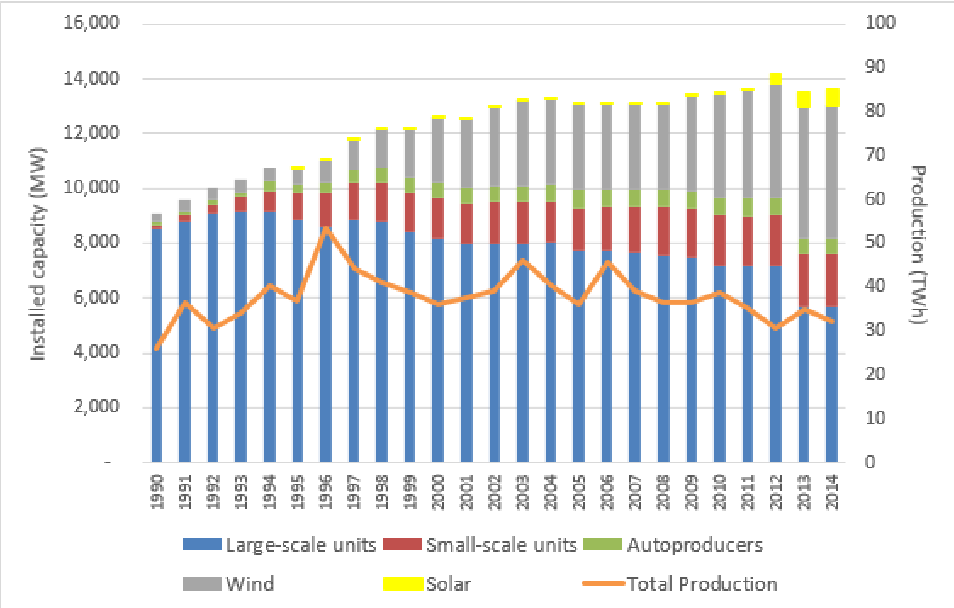


Figure 3: Development in installed power capacity in Denmark (left axis), and total production (right axis), 1990-2014 (Danish Energy Agency, 2015a)

Figure 3 illustrates how the growth of wind capacity in Denmark over the last 25 years has partly come to replace capacity at large-scale power plants. In Denmark, all small-scale, and the overwhelming majority of large-scale, units are combined heat and power (CHP) plants. In terms of production, Figure 4 below highlights the fact that the last 6 years have seen wind greatly increase its share of Danish electricity production, largely at the expense of large centralised plants. 2014 was the first year in which production from wind was greater than that from centralised plants, and this trend continued into 2015 as the gap continues to grow. Figure 4 also clearly illustrates that in years with large electricity exports, such as 2003 and 2006, it is the large central power plants that provide this additional production.

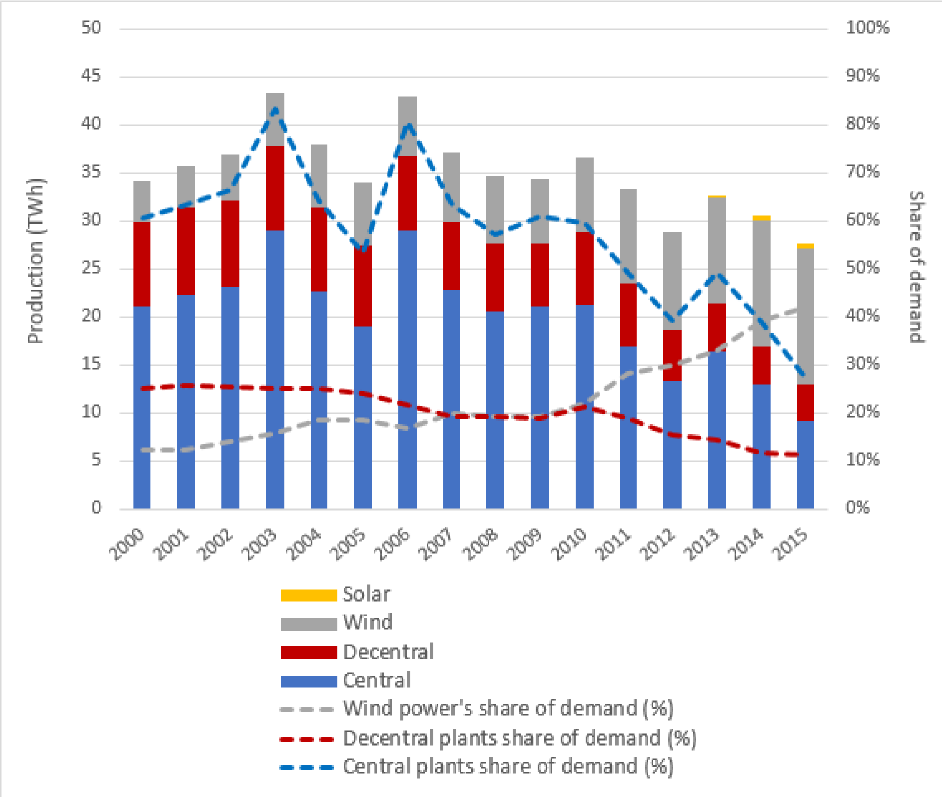


Figure 4: Danish annual electricity production according to production type (left axis), and share of annual demand (right axis). (Energinet.dk, 2016a)

In Denmark, there is a political target that by 2020, wind power should cover 50% of the domestic electricity demand. As illustrated in the above figure, in 2015, wind power accounted for 42% of national electricity demand, and if the recent trend continues, then this goal will likely be achieved well before 2020.

A larger portion of the wind power is located in the Western part of Denmark, where the share of wind power relative to electricity demand reached 55% in 2015 compared to 23% in Eastern Denmark.

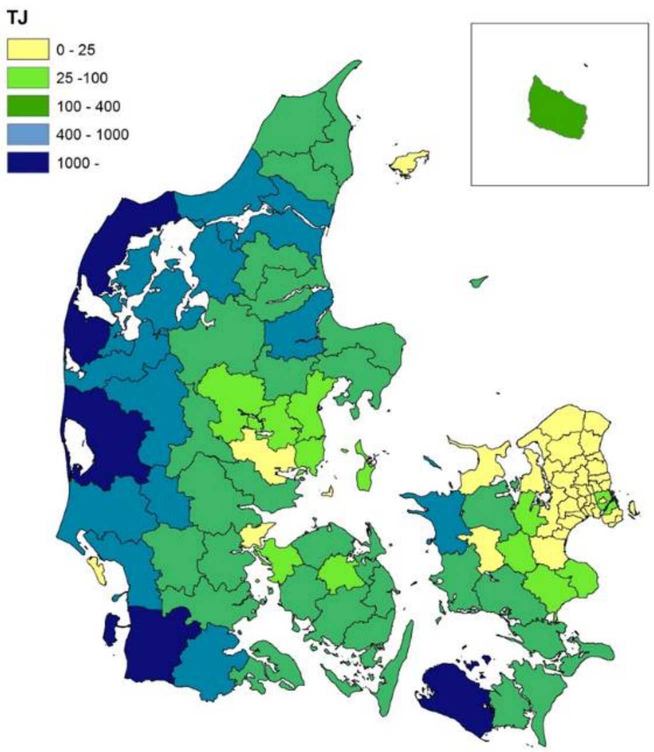


Figure 5: Distribution of onshore wind turbine generation within Denmark (generation in TJ in 2013 per municipality). (Danish Energy Agency, 2014)

In a number of occasions in 2015 with high wind speeds and/or relatively low electricity demand, the wind share production exceeded 100% of electricity demand in Western Denmark. In total, there were over 1,400 of these hours in 2015 in Western Denmark. A duration curve displaying 2015 wind production as a share of total electricity demand for Western Denmark alone is displayed below.

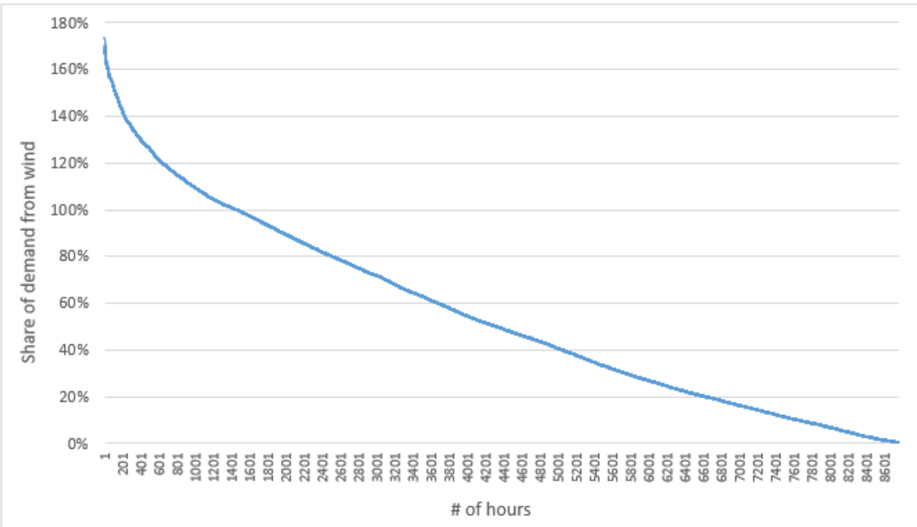


Figure 6: Hourly duration curve for 2015 wind production as a share of total electricity demand in Western Denmark.

4.2 Utilisation of interconnectors

Interconnectors to Germany, and particularly to Norway and Sweden, are very efficient means of integrating wind power. In practice, the availability of interconnectors (primarily to Germany) can be limited to due to congestions in internal grids in Denmark's neighbouring countries. Figure 7 displays a snapshot of the current power system in Denmark for a day in June of 2015, including the use of interconnectors with Norway, Sweden and Germany.

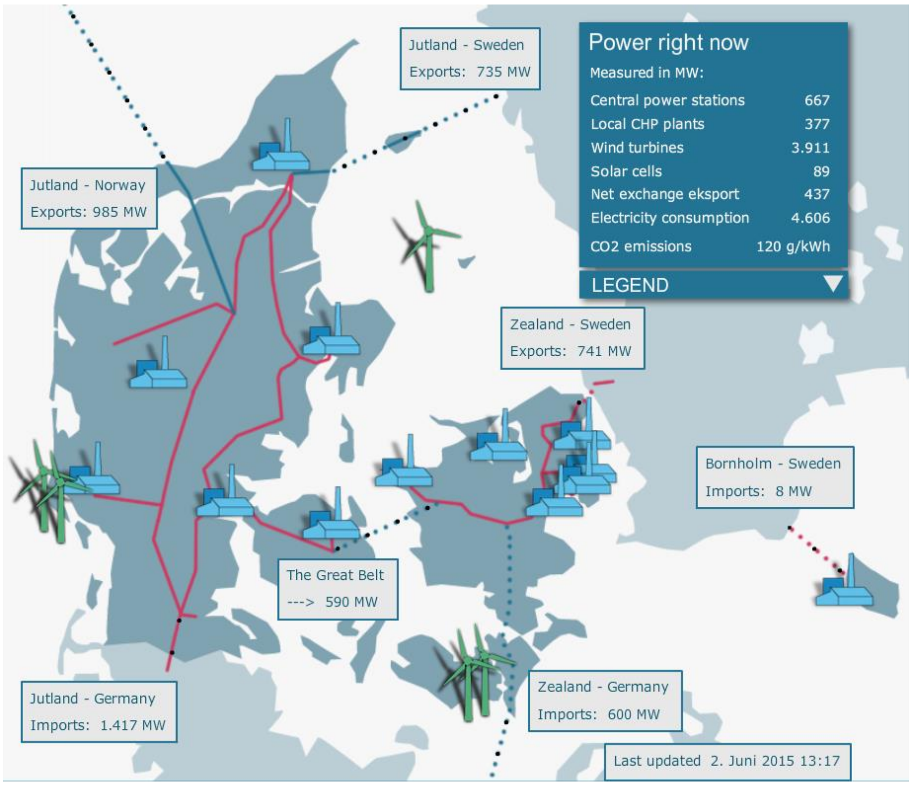


Figure 7: Snapshot of the Danish power system June 2nd 2015 at 13:17. The blue buildings represent central power stations, while wind turbines signify offshore wind farms. Red lines indicate an AC transmission line and blue lines indicate a DC transmission line. (Energinet.dk, 2015a)

Currently, the total technical import/export capacity to Norway and Sweden are respectively 1,650/1,700 MW and 1,980/2,440 MW while the figures for Germany are 2,100/2,380 MW. Moreover, Eastern and Western Denmark are connected via a 600 MW DC connection.

In addition, interconnectors are planned to the Netherlands (700 MW by 2019) and to the UK (1,400 MW by 2022). In addition, Energinet.dk and the German TSO TenneT have agree up upgrade the interconnection between Western Denmark and Germany to 2,500 MW in both directions. Lastly, by 2022 Eastern Denmark and Germany will add 400 MW of indirect connected capacity via the Kriegers Flak project, which involves the establishment of two offshore wind parks, and an offshore grid connecting the two parks to one another and to Denmark and Germany.

4.3 System stability tools

In hours where electricity production from wind is greater than electricity demand, it is not enough to merely have sufficient transmission capacity to export the excess electricity production to Denmark's neighbours, but the security of the system must also be maintained. Energinet.dk recently experienced a day when none of the central power plants were producing electricity, but because Energinet.dk now has 7 synchronous condensers totalling roughly 2,100 MVar throughout the system at its disposal, the system security was maintained.

4.4 Curtailment levels

The continuing increase in both wind production, and its share of electricity demand, has not resulted in increased curtailment from the TSO. In fact, the last time that Energinet.dk directly ordered curtailment was on Jan 1st, 2009, when they curtailed an offshore park. A partial reason for the lack of curtailment has been the continued development in additional interconnector capacity, but as will be outlined in the following chapters, market elements and flexibility from heat and power generators have also played significant and connected roles.

5 Danish market structure and incentives

Having looked at the physical characterises of the Danish system, the following chapter will describe the Danish market structure within which all electricity producers operate in. It will aim to illustrate how electricity prices are generated, describe the incentives in place for wind production in Denmark, and lastly, reflect on how do these markets and incentive schemes achieve in terms of wind integration.

5.1 Reshaping electricity markets

Traditionally, the Danish energy sector was organised with consumer or municipality ownership and non-profit regulation. Throughout the 1990s, there was a growing pressure in the Nordic Countries and from the EU to increase efficiency and trade through liberalisation. With the liberalisation of electricity markets in the Nordic countries from the mid-1990s, the electricity sector had to work under completely new conditions.

Today, as in all other EU countries, electricity production and trade is a commercial activity governed by free competition, while the transmission and distribution networks are governed as regulated monopolies. In the present electricity market, the price is being formed every hour of the year based on the balance between demand and supply.

5.2 Price generation

Denmark is part of the Nordic power market, NordPool. In this market, there is an hourly market price of electricity (spot price) that reflects the marginal costs of generating electricity in the system. The market model is auction based; all electricity producers in an area receive the same price for their product at a certain time. Due to the auction principle, the producer has an incentive to bid into the market with prices based on their short-range marginal cost (SRMC). If the market is clearing at a price-level higher than his SRMC, it will still be advantageous for it to keep producing electricity. However, its earnings might not necessarily be sufficient to cover fixed costs.

Wind turbines would typically bid in at the lowest cost on the electricity market. This is due to the fact that wind power production does not involve any fuels costs. When the turbines are producing, they force the expensive power plants out of the electricity market, which thereby lowers the market price of electricity. In this way, wind power has a price lowering effect on the electricity market during periods of high wind levels. Large amounts of wind power production can also lead to hydroelectric plants withholding their production until a later time when electricity price levels are higher. This means that wind power can indirectly exert a price deflating effect even during periods when wind power production is low. As such, the amount of wind power generation today is just as important (or more important) for the price formation as the level of demand.

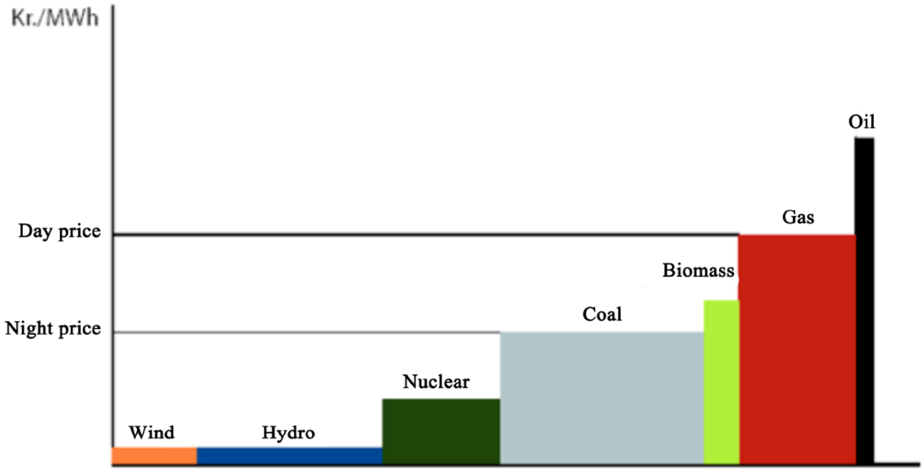


Figure 8: Stylised demand/supply curve for the Scandinavian and German electricity market. Wind power farms would most likely bid in at the lowest costs in the electricity market, as they don't have any fuel costs to cover. The same applies in principal to hydroelectricity – however hydroelectric plants with a storage capacity have the possibility of holding back production and thereby optimising their production in accordance with the expected market prices for electricity. Hereafter follows nuclear energy, coal and biomass plants, which are more expensive than hydro and wind, but also have relatively low fuel costs, and finally gas and oil fired plants.

In a market-based system, the value of wind power will be expressed as the value that the market ascribes the production, directly expressed through the price of electricity. The price that the wind turbine can sell its production for in the market can be regarded as the socioeconomic value of wind turbine power production.[2]

5.3 Successive markets allow for increased flexibility

The previous section introduced the general concept for how the market price affects the incentive for generation and consumption in the power system. In actuality, the market is organised through successive markets, in which power is bought and sold, perhaps several times as the time of operation approaches. The figure below shows the general procedure for the physical markets for electricity.

[2] In a cost-benefit analysis the value of the sold production must be compared to the costs involved in erecting and maintaining the wind turbine.

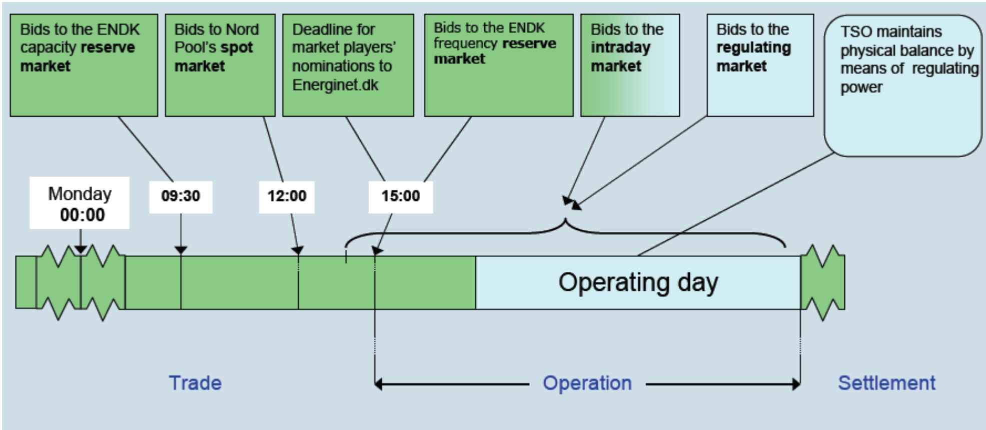


Figure 9: Successive markets for electricity in a Danish context (Source: Energinet.dk)

Forward markets

Though not represented in the figure above, the first markets that electricity can be purchased/sold on, are the forward or 'financial' markets. These commercial markets allow participants to buy or sell electricity to be delivered at a future time, and thereby lock in future prices today. These markets are referred to as financial markets as they do not require the participant to physically produce or utilise the electricity purchased/sold. Financial contracts manage risks and are essential for the market participants in the absence of long-term physical contractual markets. The figure below displays a screen shot of one these markets, the Nasdaq commodity market, where the market selected is 'Nordic electricity', the type is 'Year', and product is 'Futures', with the values being displayed in nominal euro per MWh/h.

PRODUCT SERIES	BID	ASK	LAST	+/-	%	HIGH	LOW	ON*	OFF*	VOL*	DAILY FIX	OI	SIZE**
ENOYR-17	19.21	19.25	19.20	-0.05	-0.26	19.35	19.20	81	81.0	162	19.20	9673	8760
ENOYR-18	18.90	18.95	18.95	0.05	0.26	19.10	18.90	53	33.0	86	18.95	4770	8760
ENOYR-19	18.55	18.65	18.55		0.00	18.66	18.55	11	31.0	42	18.55	2548	8760
ENOYR-20	20.12	20.20	20.10	0.09	0.45	20.10	20.10	2	2.0	4	20.10	964	8784

Figure 10: Screen shot from the Nasdaq commodity market, where the market selected is 'Nordic electricity', the type is 'Year', and product is 'Futures', with the values being displayed in nominal euro per MWh/h. (Nasdaq, 2016)

The red circle in the figure indicates the latest price that each of the 4 products was sold at, in this case end of year average electricity prices for 2017, 2018, 2019, and 2020. If we take 2020 as an example, at the time the screenshot was taken, it would be possible to purchase or sell 1 MWh of electricity for each hour during that year for an average price between 20.12-20.20 €/MWh/h, with the last trade occurring at a price of 20.10 €/MWh/h.

Reserve market

Moving to what are often referred to as the physical markets, and starting from the left in Figure 9, the TSO will accept bids on the reserve markets. Invitation for these bids are based on the TSO's expectation that it might require the ability to regulate within the hour of operation in the following day. Based on the TSO's anticipated potential demand for regulating power the following day, and the received bids, the TSO is in practice holding an auction for reserve capacity. This ensures that the market participants (generators and consumers) do not enter into market positions after the auction, whereby they are unable to participate in the spot market and the intraday market as described below. No energy is sold in the capacity reserve market, only the obligation to bid a certain amount of capacity into the regulating power market the following day, and therefore participants winning the bids in the reserve market, must consider this obligation when bidding into the subsequent markets.

Day-Ahead Market

The day-ahead market was introduced briefly in the previous section, as the central Nordic energy market is the spot market (Nord Pool Spot) where a daily competitive auction establishes a price for each hour of the next day. The trading horizon is 12 - 36 hours ahead and is done in the context of the next day's 24 hour period. The system price and the area prices are calculated after all participants' bids have been received before gate closure at 12:00. Participants' bids consist of price and an hourly volume in a certain bidding area. Retailers bid in with expected consumption while the generators bid in with their production capacity and their associated production costs. Different types of bids exist, e.g. a bid for a specific hour or in block bids, which exist in several variations.

Determining the Spot Price

The price is determined as the intersection between the aggregated curves for demand and supply for each hour – taking the restriction imposed by transmission lines into account. Figure 11 illustrates the formation of the system price on the spot market as a price intersection between the purchase and sale of electricity.

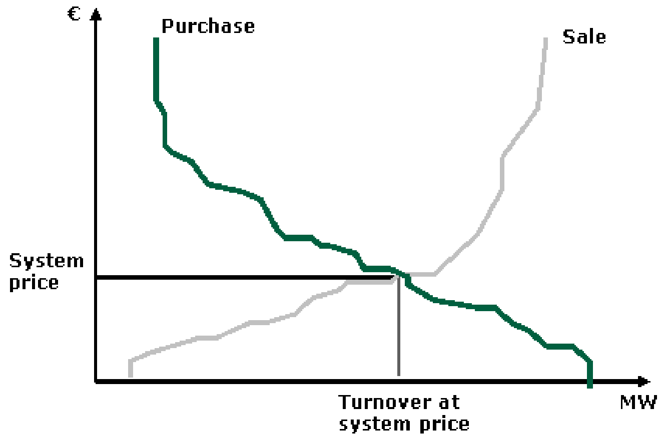


Figure 11: The formation of the system price for electricity on the Nord Pool Spot market. (www.Nord Poolspot.com)

In common parlance, when one talks about the electricity price, one is referencing the day-ahead price, as this the price at which the vast majority of electricity is bought and sold at. In addition, the day-ahead price is also the reference price for the indexed financial contracts (as opposed to physical) used for hedging the power price longer term (as was discussed in the forward markets section above).

Sales bids could from generation companies who own power generation facilities from conventional power stations, CHP-units, hydropower, wind farms, etc. Each generation company has its own view and knowledge of its short-run generation costs and therefore at which price it will be able to make a positive gain (or short-run operating profit). All generators (and consumers) receive (pay) the same price within the price area regardless of the bid price they have submitted. The power auction guarantees that you will not be asked to generate (consume) if the price is lower (higher) than the price you have bid. Therefore, each generator (and consumer) has the incentive to submit his true generation costs (willingness-to-pay) to the market, which means that the market ends up dispatching the generation with the lowest short-run costs and consumption with the highest value for consumers.

The deadline for bids to the day-ahead market is 12:00 CET for hourly bids for the 24 hours of the next day. This means that market participants are forced to make the best possible estimates concerning the costs and availability of their generation capacity for the next day. This is of course a challenge for wind power generators, which have to submit bids based on forecasts. If the forecasted wind does not appear at the time of operation, the wind generator will have sold power that he is not able to produce and will be in imbalance. Similarly, CHPs availability may be based on forecasted heat demand, and even conventional units may experience forced outages between the market clearing and the scheduled generation the next day. Retailers representing the consumers also have to bid based on the forecasted demand.

Generators and consumers that are not in balance with their positions (how much they have bought or sold) in the day-ahead market face an imbalance cost. This cost is based on what it costs for the TSO to bring the system into balance in the regulating power market. To prevent this unfavourable imbalance cost, they may choose to engage in the intraday market.

The responsibility for maintaining the balance between what has been bought/sold and what is consumed/generated is held by the balance responsible parties (see text box).

Balance Responsible Parties (BRP) – There are roughly 40 registered BRPs in Denmark, and they can be divided into Load Balance Responsibles (LBR), and Production Balance Responsibles (PBR).

- PBRs are by and large a power generation company, or several power generators joined together, but can also be aggregators that pool a number of smaller production units together. PBRs bid in on the various markets on behalf of their electricity producer(s).
- LBRs are typically electricity trading companies that through the pooling of consumers bid in on the various electricity markets. The main task of a LBR is to make a plan for the consumption the upcoming day. The load balance responsible must also document how the electricity has been purchased.

In case of imbalances (deviations from the plan), the balance responsible must buy or sell this difference from the TSO, Energinet.dk.

The Intraday Market (Elbas)

Given that the time from fixing of the price and the plans for demand and generation in the spot market to the actual delivery hours is up to 36 hours, deviations do occur. Deviations can come from e.g. unforeseen changes in demand, tripping of generation or transmission lines, or from inaccurate prognoses for wind power generation. Such deviations can be mitigated during the operational day via entering into hourly contracts in the Elbas market, where electricity can be traded from the time the spot market closes up until 45 minutes before the operating hour.

Elbas is a continuous market, where the prices are set on a first-come-first-served basis, matching the highest priced purchase bid with the lowest priced supply bid. Balance responsible parties can use this market to rebalance their positions before the hour of operation. Smaller volumes are traded on Elbas than on the day-ahead market as the producers and consumers are only trading their expected deviations from what they have sold or bought. However, as the hour of operation approaches, market participants will get more knowledge of their physical positions, e.g. through newer forecasts and known forced outages. Through the continuous bilateral trading between the market participants, the are afforded the opportunity to rebalance their positions prior to the hour of operation.

Reserves

Electricity production and consumption always has to be in balance, and after the close of the Elbas market 45 minutes before the operating hour, the task of balancing the two is left to Energinet.dk. In the hour of operation, Energinet.dk utilises several types of reserves to ensure the stability of the system. The reserves can be grouped into automatic and manual reserves.

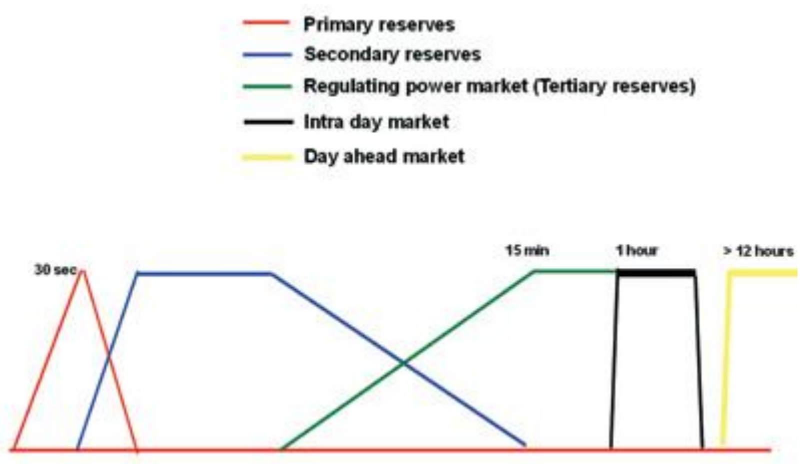


Figure 12: Timeframes and ramp rates for the various reserve types.

Automatic reserves

When there is an imbalance between the supply and demand in any power system, the frequency will move away from the desired operational frequency level (50 Hz). Automatically, frequency controlled primary reserves will adjust to compensate for the supply-demand imbalance. These reserves are purchased in the market and depending on the type, can receive both a reserve payment, and an energy payment if activated. As the name would indicate, they are activated automatically in accordance with frequency deviations, but are expensive and have limited capacity. Once these have been activated, they are quickly replaced by secondary and subsequently tertiary reserves, which are organised through the regulating power market.

Regulating Power Market

To anticipate excessive use of automatic reserves and in order to re-establish their availability, regulating power is utilised. The tertiary reserves thereby allow for the other reserves to return from their maxed out state to be prepared for the next disturbance/imbalance which may occur. Regulating power is a manual reserve. It is defined as increased or decreased generation that can be fully activated within 15 minutes. Regulating power can also be demand that is increased or decreased. Activation can start at any time and the duration can vary.

NOIS-list

In the Nordic countries there is a common regulating power market managed by the TSOs with a common merit order bidding list known as the NOIS-list (Nordic Operation Information List). The balance responsibles (for load or production) make bids consisting of amount (MW) and price (DKK/MWh). All bids for delivering regulating power are collected in the common NOIS list and are sorted by increasing prices for up-regulation (above spot price), and decreasing prices for down-regulation (below spot price). These bids can be submitted, adjusted, or removed until 45 minutes before the operation hour. In Denmark, the minimum bid size is 10MW, and the maximum is 50 MW. The Elspot price meanwhile represents the minimum price for up regulating power bids and the maximum price for down regulating power bids. An example of the NOIS-list is displayed below in Figure 13.

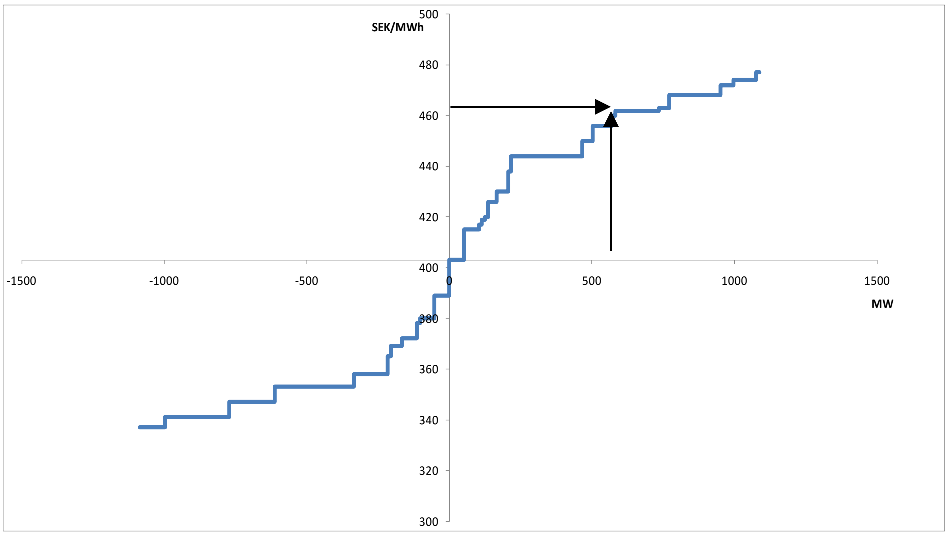


Figure 13: Example of the NOIS list, from 17.6.2009, CET 07-08. 583 MW of up regulating power was activated, corresponding to a price of 460 SEK/MWh (Data provided by SvK).

The bids are selected by the TSO based primarily on the price, but other things may be taken into consideration, such as the precise grid location of the regulating asset and any potential transmission congestions. The price for regulating power delivered within one hour is based on the highest accepted bid by the TSO within that hour for up regulation reserves (more generation), and the lowest accepted bid in that hour for down regulation reserves. As in the day-ahead market, this provides the incentive for market participants to bid their true short-run costs or willingness to consume, as they will receive the price established through competition.

The technologies participating in the regulating power market, include both power generation and consumption technologies. Once a bid is activated by the TSO, the supplier must be able to fully adjust his generation or consumption within 15 minutes to the level dispatched by the TSO. This means that while the market is smaller than the day-ahead market in terms of the volumes transacted, the additional constraints preclude market participation by non-flexible technologies. Also, since the demand is driven by the imbalance, the price attained is usually more favourable than the spot market price, as can be seen from Figure 14.

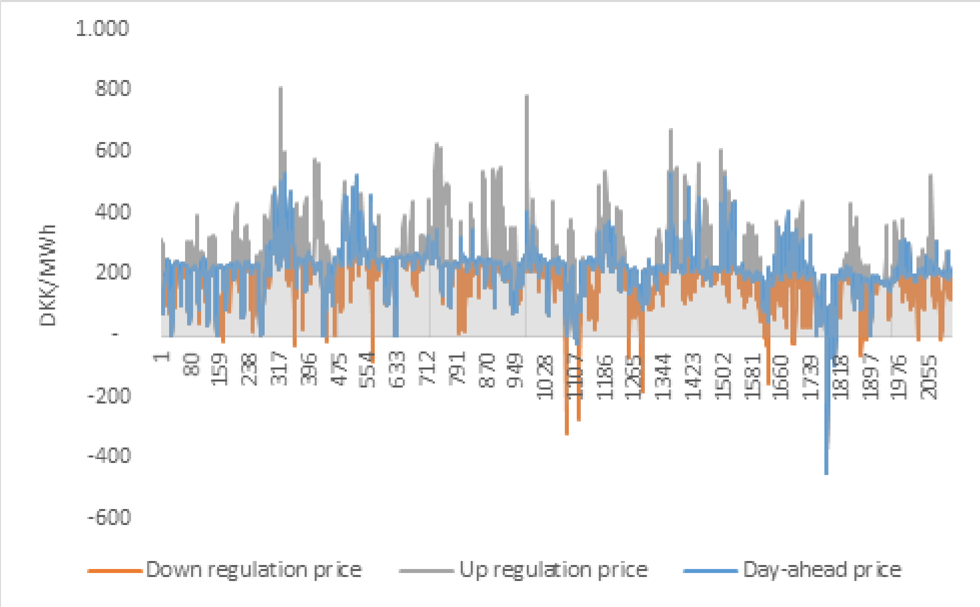


Figure 14: Power prices in Western Denmark in 2014 (until 30-09-2014) ((Energinet.dk, 2014)

Usually the generation units activated for up regulation have a higher short-run cost than the spot market price, or they would have been committed in the day-ahead market. For generators, down regulation provides an opportunity to for units that have sold power in the day-ahead market, to avoid having to generate this power if the market imbalance is in surplus.

Thereby the market participant can sell power at one price and buy that same power back at different price while earning a profit. This aspect rewards generators for providing flexibility to the system.

The converse holds for consuming technologies. If their consumption bid was not selected in the spot market, they may be activated in the down regulation market. Note that for consuming technologies, down regulation means increasing consumption. As these prices are more favourable for the purchaser of electricity as evidenced by Figure 14 , there is an additional incentive here to be flexible and participate in reducing the system imbalances. Consuming technologies may also have been selected in the spot market, but then submit up regulation prices at which they are willing to decrease consumption in relation to their day-ahead position. Thereby they effectively sell back power to the market and make a profit of the difference between the spot market and the up regulation price.

"Self curtailment" via the regulating power market – As was shown in Figure 14, the down regulating price can sometimes be quite low, and even negative, thus indicating a large oversupply of electricity relative to the planned demand/supply balance. This will most likely occur in situations with a large amount of electricity production from wind. In these occurrences, producers that have planned to generate electricity can offer to reduce part or of all their production in the regulating power market. In essence, the producers are offering to 'buy' power by reducing their production. Plants with high stop/start costs would require a very low price for doing so, and therefore would require a large negative price in order to reduce their production. Wind farms on the other hand have very low start/stop costs, and they can therefore bid into the regulating power market with down regulation bids just below 0. I.e. they could offer to reduce their production by 10 MW for -10 DKK/MWh/h, and this 'bought' electricity which reduces the over supply, 'costs' the wind plant -100 DKK/MWh/h, resulting in the wind park receiving a payment for reducing its production. In 2015, this self regulation, or 'self curtailment' via the regulating power market, equated to roughly 2-3% of total wind production on an annual basis (Energinet.dk, 2016b).

Naturally, some of the plants which are most capable of taking advantage of these market opportunities are plants which have a high degree of flexibility, both in terms of ability to regulation generation and consumption. Perhaps more importantly, they have the flexibility shift their energy supply needs between different technologies and the timing of energy supply. District heating plants are in Denmark especially well suited towards providing this flexibility, and this will be detailed in the following chapter.

5.4 Support schemes to wind power in Denmark

The Danish wind power support scheme has also undergone changes in recent years, driven by, among other things, a wish to promote the deployment of system friendly wind turbines.

Historically, wind power was supported through investment grants and net metering schemes. During the last 30 years, onshore wind power has been subsidised, first through fixed feed-in tariffs, and later via a market premium on top of the electricity market price.

2008-2014 scheme rewarded turbines with high capacity

According to the wind-power project support scheme introduced by the renewable energy law as of 2008, all new land-based wind-power projects[3] were to receive a nominal feed-in premium (FIP) of 0.25 DKK/kWh (€0.034/kWh) above and beyond the spot market price for the first 22,000 full-load hours[4]. After the equivalent of 22,000 full-load hours had been generated, the project had to rely on market price for power as its revenue source (Danish Energy Agency, 2015b).

As an example, 2 MW wind turbine would receive subsidies for 44,000 MWh of generated power, whereas a 3 MW wind turbine would receive subsidies for 66,000 MWh of generation. The system gave incentives for developers to install turbines with a high rated capacity in order to maximize support. Industry sources would attribute the very high average capacity rating of wind turbines installed in Denmark (e.g. averaging 3 MW in 2012) to the land-based wind power support scheme in effect until 2014.

The previous support system involved three potential drawbacks. First of all, there was a risk that the wind turbines were not designed in the most cost-efficient manner, secondly subsidies risk being too high, and thirdly – and perhaps most importantly – it gives favour to wind turbines that are not very attractive from a system perspective. A 2 and 3 MW turbine may have the same size and design apart from the generator size. Whereas the 2 MW turbine will reach its peak generation at wind speeds around 10 m/s, the 3 MW turbine will reach maximum generation at approx. 12 m/s. From a system perspective, however, the value of the additional generation of the 3 MW turbines is likely to be more limited, because the generation takes place at

[3] As well as so-called 'open door' offshore projects, i.e. off-shore project not put out for tender.
[4] Also, a subsidy of DKK 0.0237/kWh (€0.0032/kWh) was awarded for the technical lifetime of the wind power project to cover balancing costs (Energinet.dk, 2015b).

times when the wind power generation is already high and market prices in general are lowest (see Figure 15).

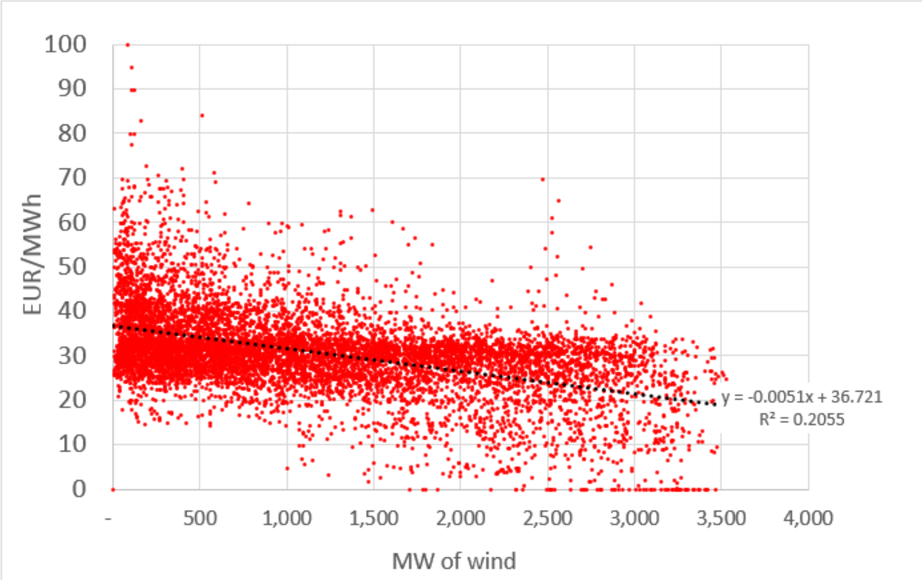


Figure 15: Correlation between wind power production in West Denmark and the market price of electricity in Euro per MW for 2014. Please note that the axis has been capped at 0 and 100 €/MWh, thus omitting those few hours from 2014 with values above 100 and below 0.

Land-based wind power support scheme reform in 2014

As of 2014, the legislation was changed in an attempt to address the abovementioned challenges. The power production eligible for the feed-in-premium is now dependent on both the turbine generator size and the rotor size, and it is calculated using the following formula:

$$\text{Power production eligible for FIP} = 30\% \times \mathit{Turbine\ rated\ power}\ (MW) \times 22{,}000\ \mathit{Full\ load\ hours} + 70\% \times 8{,}000\ kWh/m^2 \times \mathit{Rotor\ swept\ area}\ (m^2) =$$

$$= \mathit{Turbine\ rated\ power}\ (MW) \times 6{,}600\ \mathit{Full\ load\ hours} + \mathit{Rotor\ swept\ area}\ (m^2) \times 5.6\ MWh/m^2$$

The technological choice of turbines is driven by a number of factors, e.g. land availability, regulations, site conditions etc., yet, ceteris paribus, the support regime reform in Denmark in 2014 provides less incentive for installing turbines with high capacity ratings alone, whilst rewarding turbines with higher yield (lower specific power).

The deployment of offshore wind power has mainly taken place through tenders of large-scale project in the order of 200 to 600 MW. The applicants compete for the lowest fixed feed-in-tariffs. In the most recent tenders, developers are not offered a feed-in-tariff when electricity market prices are negative.

5.5 Market structure and incentive schemes– What does this mean for wind integration?

The successive markets described above, and to a lesser extent the redesigned incentive schemes for wind, aim to promote flexibility in the power system as they reward all generators that are flexible. Meanwhile those that continue to produce at times with a lot of wind are ‘punished’, as they receive low and/or even negative prices for their electricity at these times.

Value of wind power – An indicator of successful integration

One indicator of the ability to integrate wind power is the price that wind power receives in the spot market. As was highlighted in Figure 15, the greater the wind production, the lower the average spot price. As was discussed previously (and illustrated in Figure 8), this is due to the fact that wind crowds out more expensive generation in the day ahead markets with its lower bids. It is therefore interesting to see exactly how much lower a price wind electricity receives relative to the average electricity price. This is displayed in Figure 16 which plots the historic differences in the average electricity price wind producers in Western Denmark received relative to the average electricity price (red line), and wind power as a % of electricity consumption in Western Denmark (grey bars).

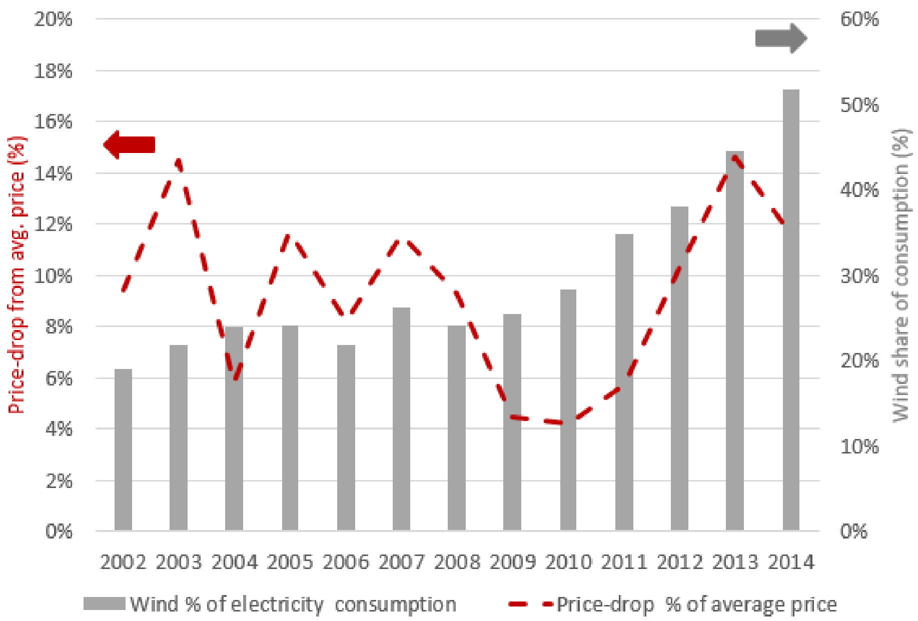


Figure 16: Historic differences in the average electricity price wind producers received relative to the average electricity price (red line), and wind power as a % of electricity consumption (grey bars). All data is for Western Denmark. Source data from Energinet.dk (Energinet.dk, 2015c).

In looking at Figure 16, it is apparent that from 2002 to 2010 there was an overall trend that saw the price difference (received by wind producers relative to the average) fall, despite the fact that wind's share in total consumption increased from 19% to 28%. This trend can partly be explained by new interconnectors, which allow for the export of electricity when prices are low, however this cannot be the sole reason. It would therefore appear to indicate that producers are 'learning' to become more flexible, as result of the incentives put in place by the market structure.

From 2010 to 2013 the proportion of wind power increased substantially in Western Denmark, from 28 to 14%, and thus it is perhaps not surprising that the gap in the electricity price received by wind parks increased as well (from 4% to 10%). However, despite wind proportion being twice as high in 2013 as 2003 (44% vs 22%), the price gap was not higher in 2013. In fact, by 2014, the gap began to fall again, despite the proportion of wind increasing to over 52%, thus once again indicating that producers are still adapting and becoming more flexible. Exactly how non-wind producers are becoming more flexible is described in the following chapter.

6 Power plant flexibility & District heating

6.1 Flexible power plants

As was outlined above, the high share of wind power that has developed in Denmark over the last 25 years has provided an early incentive for increasing the flexibility of thermal power plants. From the power plants' perspective, the high fluctuation of residual load resulting from the high share of variable wind power generation leads to steep load gradients. It also requires fast start-ups at low cost, and as low minimum stable generation as possible.

Motivation and prerequisites for increasing the flexibility of thermal power plants

Figure 17 illustrates the challenge for thermal power plants resulting from increased fluctuations of residual load. In the case of a renewable power shortage (load exceeds RES-E generation), there is an increasing demand for steep positive load gradients on running plants, as well as a need for fast start-ups of hot, warm or cold thermal plants. Vice versa, steep negative load gradients on running plants and as low minimum stable generation as possible are required in case of a renewable power surplus. In between these two cases, rapid fluctuations of residual load require large positive/negative load gradients.

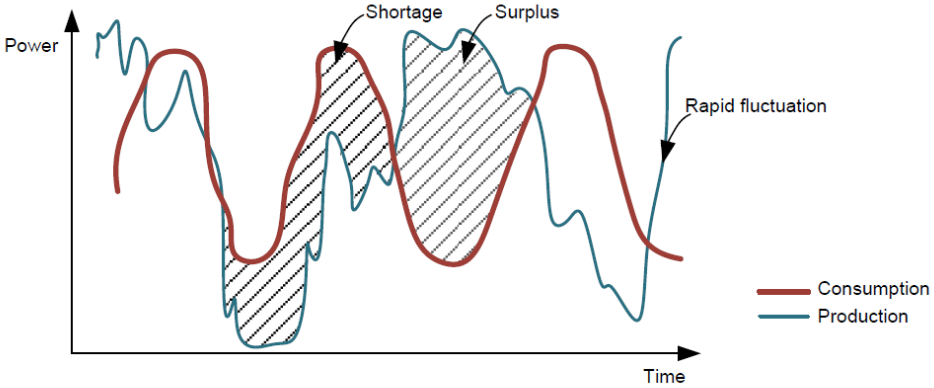


Figure 17: The flexibility challenge for thermal power plants as a result of fluctuating consumption and VRES-E production. (Blum & Christiansen, 2013)

As a result, Danish coal power plants that had originally been designed as base load units have been transformed into some of the most flexible power plants in Europe. Already today, load gradients of 4%P_N/min for coal-fired units (9%P_N/min for gas turbines) are considered the Danish standard. The minimum load could be decreased down to 10%P_N and a fast start is possible within less than 1 hour.

According to involved engineers[5], the transformation process has been subject to a number of prerequisites that had to be fulfilled in order to achieve the projected flexibilisation. These include precise knowledge of the existing limits combined with the willingness to take risks during the implementation phase, adaption to local conditions, as well as full acceptance throughout the organisation.

As a result, a number of suggestions can be derived as best practice to adapt the Danish experience to other power systems. The organisational integration of the optimisation procedure is illustrated in Figure 18. As a first step, long-term scenario studies (10-20 years) are required in order to assess the expectable magnitude of increasing load fluctuations. Next, the economic value of all available flexibility measures have to be estimated, followed by a ranking of different options for prioritisation. The power plant portfolio can then be optimised in a top-down approach through development of adequate software. Finally, the individual optimisation of each power plant can be conducted in an iterative, step-wise approach after determining flexibilisation bottlenecks through data analyses and operator interviews and defining achievable flexibility levels. This procedure applies for improving load gradients as well as decreasing minimum load, start-up time and start-up costs.

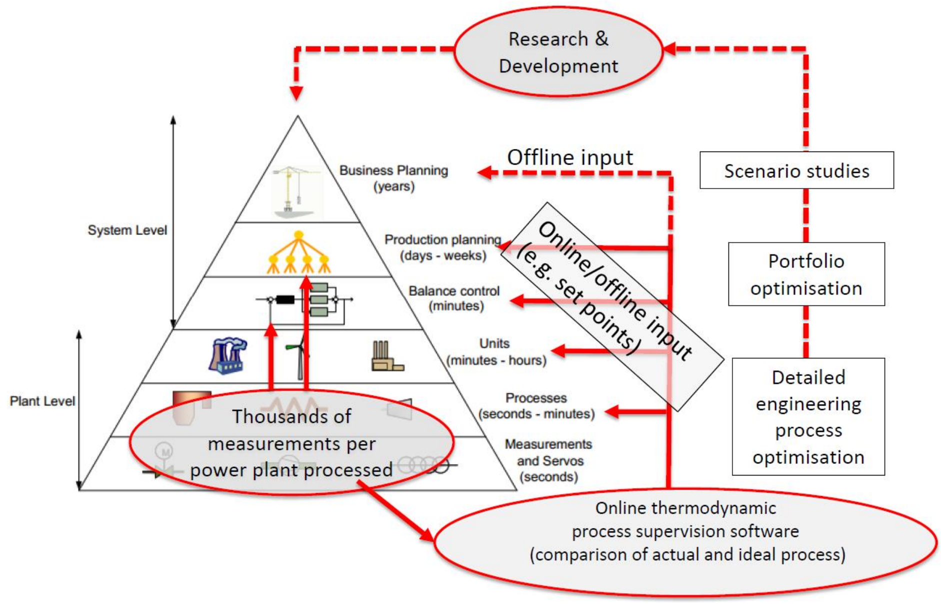


Figure 18: Optimisation of power plant flexibility at different organisational levels. (Blum & Christiansen, 2013)

[5] The content of this section is based primarily on a presentation by Rudolph Blum, former R&D director for power plant development at ELSAM/DONG Energy and Torkild Christensen, former engineer for design, optimisation and flexibilisation of thermal power plants at ELSAM/DONG Energy

Flexibility of German and Danish power plants

Denmark and Germany have a number of electricity transmission interconnectors, share a border, and have access to the same power plant technology. As such, it is interesting to compare the flexibility parameters of Danish and German power plants.

Table 1 displays an overview over flexibility parameters of Danish and German power plants comprised from different sources. It reflects the generally higher flexibility of gas-fired power plants as compared to coal-fired power plants. Open cycle gas turbines (OCGT) and gas-fired steam turbines (ST) are superior to combined-cycle gas turbines (CCGT) in terms of flexibility. However, the overall efficiency of CCGT power plants is higher, which is not reflected in the table. Overall, Danish power plants are more flexible than their German counterparts in all regarded categories.

Fuel and plant type	Country	Status	Positive load gradients (% P_N/min)	Min. stable generation (% P_N)
Coal ST	DK	prevailing[1]	3-4	10-20
	DE	prevailing[1]	2-3	45-55
	DE	prevailing[2]	1,5	40
	DE	state of the art[2]	4	25
	DE	optimisation[2]	6	20
Nat. gas ST	DK	prevailing[1]	8-10	<20
Nat. gas OCGT	DE	prevailing[2]	8	50
	DE	state of the art[2]	12	40
	DE	optimisation[2]	15	20*
Nat. gas CCGT	DK	prevailing[1]	3	50-52
	DE	prevailing[2]	2	50
	DE	state of the art[2]	4	40
	DE	optimisation[2]	8	30*

*Table 1: Typical prevailing and possible flexibility parameters for thermal power plants in Denmark (DK) and Germany (DE). ST = steam turbine, OCGT = open cycle gas turbine, CCGT = combined cycle gas turbine. *The lower limit of minimum generation of gas turbines is constrained by emission threshold values for nitrous oxide and carbon monoxide. Sources: [1] (Blum & Christiansen, 2013) (values for 2011); [2] (Feldmüller, 2013)*

The prevailing load gradients of existing Danish coal power plants (3-4% P_N/min) already achieve what is labelled as possible state of the art of German technology. Average German coal power plants fall behind with only 1.5% P_N/min. The minimum stable generation of Danish power plants at 10-20% P_N is even smaller or equal than the optimisation potential stated for the German plants (20% P_N). German coal power plants are still subject to minimum generation of 40% P_N on average.

Danish natural gas-fired steam power plants achieve load gradients of up to 10% P_N. German data on gas-fired steam power plants are not available for direct comparison, but the available data reveals that Danish gas-fired steam power plants already exceed German open cycle gas turbines, which is regarded as the most flexible power plant technology in Germany.

The load gradients of Danish CCGT power plants are slightly higher than the those of their German counterparts, while minimum generation is on the same level. For power plants based on gas turbines (OCGT as well as CCGT), the minimum generation achievable through optimisation is limited by threshold values for maximum permissible emissions of nitrous oxides and carbon monoxide. Natural gas-fired steam turbines are not subject to this limitation, because of the different combustion process.

According to Feldmüller (Feldmüller, 2013), thermal power plants in Germany are not utilising their full technical flexibility potential. As a reason for falling back behind state of the art, the source identifies lack of incentives. For example, the required load gradients for primary balancing power in Germany are at 2% P_N/30sec as compared to a stricter 10% P_N/10sec in the UK (status 2013). This lack of regulatory incentive is accompanied by a lack of financial incentive to invest in more flexible solutions.

Concrete steps

In order to address the growing challenge of fluctuating load, efforts have been undertaken over the past 15-20 years to enable increased load flexibility, reduce minimum load, and steepen ramp rates. A number of prerequisites had to be fulfilled for this purpose. In the exemplary case of DONG Energy and its predecessors, all improvements were based on own expertise, which required technical knowledge of the relevant engineering disciplines. All involved engineers were provided with access to reliable power plant process data with high resolution over many years of operation. It was ensured that control room operators underwent thorough theoretical and practical education. Thereby, control room staff could be directly involved in optimising the power plant's operation. They were instructed to continuously seek further improvements of flexibility and develop suggestions for respective modification of design and control. The implementation of optimisations was carried out in close dialog between operators and engineers.

Stepwise approach for optimising power plant flexibility

A stepwise approach has been applied for achieving considerable flexibility improvements in Denmark. The approach is illustrated in Figure 19 for the case of minimum load reduction. It is equivalently applied for increasing ramp rates and optimise start-up.

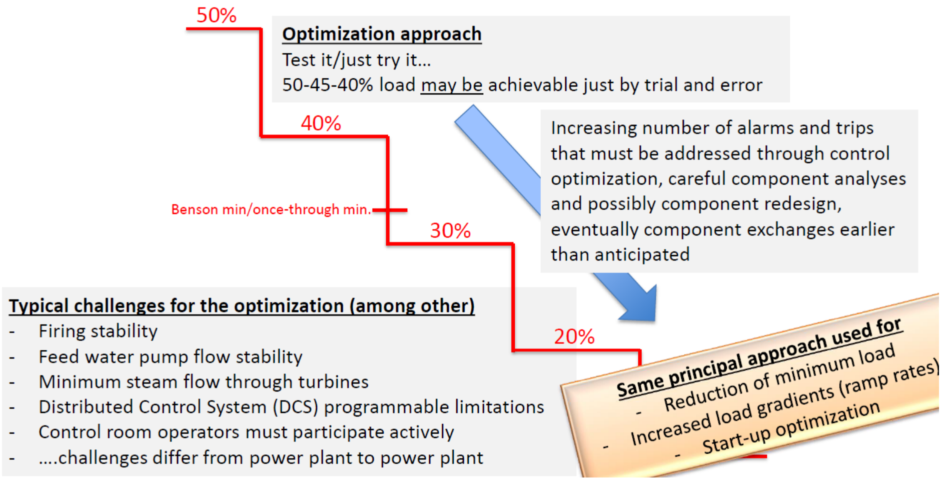


Figure 19: Stepwise approach for increasing power plant flexibility. (Blum & Christiansen, 2013)

Firstly, load is carefully reduced until the first bottle-neck appears. Subsequently, the observed problem is analysed with the goal to find an adequate solution. Finally, the load can be further reduced until a new limitation appears. With an increasing amount of iterations, the amount of failures and alarms increases. Therefore, it is essential that the unit is thoroughly protected by alarms and warnings and all required measurements must be continuously calibrated and maintained.

The typical solutions to flexibility problems are often achieved by control optimisation and possibly component redesign based on careful component analyses. In some cases, the new process parameters will exceed design limitations, which requires an exchange of components earlier than originally anticipated. The optimal trade-off can be determined by means of respective cost-benefit analyses. The optimisation challenges vary from plant to plant. Based on the Danish experience they typically comprise firing stability, feed water pump flow stability, minimum steam flow through turbines and program limitations of the Distributed Control System (DCS).

Examples for flexibilisation of Danish plants

Two examples shall illustrate the Danish approach and achievements of power plant flexibilisation. Firstly, an exemplary optimisation routine shows how start-up time can be reduced. Secondly, the daily cyclic operation of a Danish power plant demonstrates the realisation of low minimum load and steep ramp rates.

Start-up optimisation of a coal fired power plant

The optimisation of a coal power plant commissioned in 1998 shall serve as an example for the reduction of start-up time. The suggested measures are expected to yield a reduction by 28%, from 131 to 94 minutes. The procedure of the power plant start-up with and without optimisation is shown in Figure 20. The most relevant improvements are to be achieved within the early phase of the start-up by keeping vital components at a higher temperature. This decreases the time required for providing superheated steam to the turbines. As a result, grid synchronisation is possible within 60 instead of 90 minutes.

In the next optimisation step, the ramp up time from the point of grid synchronisation to full generation capacity is reduced by 7 minutes. This is achieved by replacing the old rigid, non-reprogrammable control software with a new one that allows for flexible adaption of start-up criteria.

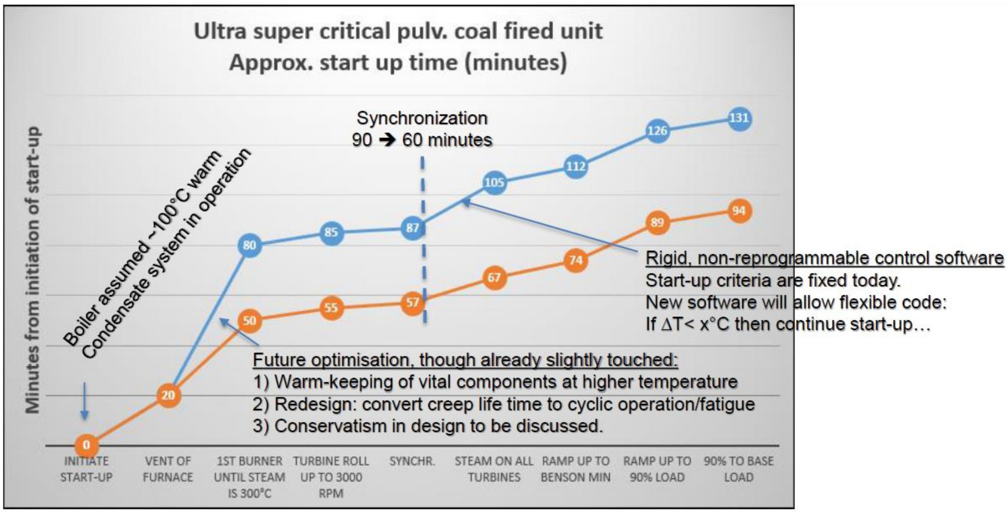


Figure 20: Start-up optimisation of a coal power plant. (Blum & Christiansen, 2013)

Low minimum load and steep ramp rates

Figure 21 displays the daily cyclic operation of a Danish natural gas-fired steam power plant for a selected day. It provides an example for low minimum load and steep ramp rates.

During the night, the power plant operates below the so-called Benson minimum. The Benson minimum represents the boiler load above which the evaporator feedwater can circulate autonomously. Below this limit, forced circulation is required to maintain sufficient flow rates. The graph indicates that the Benson limit is passed several times per day, which deviates from original design criteria. This leads to increased stress on the components, which can cause early fatigue. Therefore, a component redesign may be required. Alternatively, the replacement intervals can be shortened for affected components. In the regarded case, assessments concluded that the components would endure the more flexible mode of operation without compromising their lifetime.

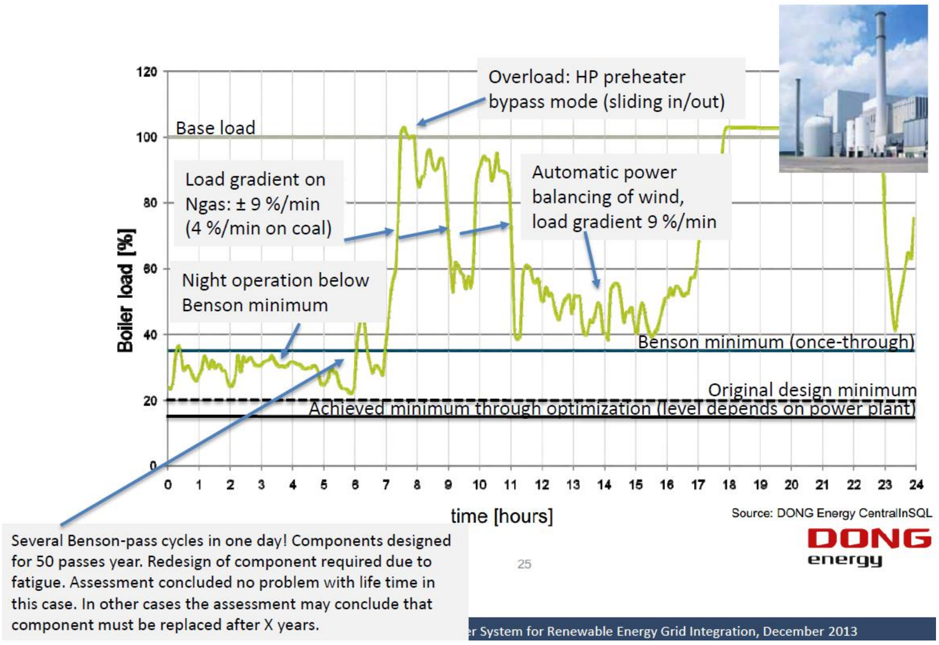


Figure 21: Daily cyclic operation of a gas fired Ultra Super Critical steam power plant. Source: Blum and Christensen 2013

The figure also illustrates steep ramp rates, which correspond to a maximum of 9%P_N/min for the example gas-fired steam power plant. For Danish coal power plants, 4% P_N /min are standard. The achievable ramp rates help the power plant to adapt to steep load gradients and enable automatic balancing at a high variability of load.

Lastly, the figure shows that the rated capacity can be exceeded at times of high load. This overloading is achieved by bypassing the high pressure preheater in the steam cycle.

6.2 District heating as a system integrator

A very large portion of Danish electricity production is connected to the district heating system. With the exception of a few plants, all power plants in Denmark have the possibility of co-generating electricity and district heat. This results in restrictions with respect to the ability to integrate wind, as options for electricity production are to some extent limited by the requirement to supply the heat demand. However, integration of the power and district heating sector also provides opportunities for enhanced integration of variable renewable energy.

In other situations it can be necessary to stop cogeneration of electricity and heat all together. The production of cogenerated heat is environmentally and economically sensible as long as the alternative is letting the heat produced go to waste. However, in order to fully utilise the electricity produced by wind, it will become increasingly environmentally and socioeconomically attractive to decouple this link between heat and electricity production.

Combined heat and power extraction plants

Most central plants are CHP plants, which can switch between producing only electricity (referred to as condensation mode), and producing both district heat and electricity. In combined heat and power mode, the low-pressure turbine can be bypassed, ensuring heat production at sufficient temperature. When extra power production is needed, the low pressure turbine will be used fully, and district heat generation will be omitted (see Figure 22). This flexibility offers the opportunity to increase power generation within a very short time horizon, e.g. for balancing fluctuations in the power system. Today, this ability is used by Danish power plants to optimise operation according to the power prices (day-ahead or intraday) and to provide ancillary services.

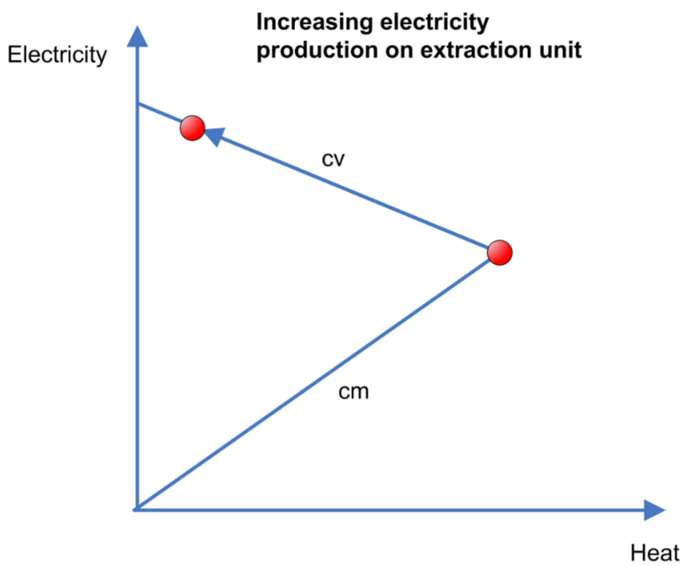


Figure 22: Illustration of operation points with different electricity to heat ratios for a combined heat and power extraction plant.

Smaller decentralised power plants are mainly so-called ‘backpressure steam plants’, which produce electricity and heat at a particular ratio. They can normally only produce electricity when they also have the possibility of supplying heat to the district heating system. However, it is possible to retrofit these backpressure power plants with cooling options. For smaller decentralised plants this would be air cooled condensers. In Denmark today, this option is mainly used at biogas-fired CHP-plants, which want to use the available biogas production during summer time, when district heat demand is low.

Turbine bypass

Some larger power plants have the option to let the steam bypass the turbines and use it directly to produce heat if they have installed a 'steam bypass' system.[6] As such, when CHPs use steam bypass they effectively function like a boiler. This enables power plants to avoid electricity generation at times with low electricity prices (e.g. due to high wind penetration), while avoiding a complete shutdown of the plant and continuing heat generation. Steam bypass systems can be installed relatively inexpensively (approximately 0.1 million DKK per MW.[7]

Heat storage

Heat stores have been established in conjunction with the majority of the Danish CHP plants. These heat accumulators are usually designed to store roughly 8 hours worth of heat production from the main CHP plants in the district heating system. Heat storages increase the flexibility of the electricity system as the CHPs can reduce or stop production of heat and electricity during windy periods, and instead supply their heating customers with heat from the heat accumulators. Likewise, CHPs can supply electricity during times with low wind generation and store the heat production. Larger heat storages are one option for improving the flexibility of a system characterised by both a large share of wind power, and a large share of cogenerated heat and power.

Electricity to heat

A way to ensure the value of variable electricity generation is to introduce new electricity consumption at times with high electricity generation. One option is to use electricity to produce heat, for example through the use of centralised electric boilers or high efficiency heat pumps connected to the district heating system. In terms of energy input/output, heat pump systems can supply up to 4 times as much heat compared to the electricity they use, and can thereby contribute to a highly efficient overall energy usage. On the

[6] Steam bypass is most relevant for steam turbine cogeneration plants (there is a total of 5 GW installed capacity in Denmark).

[7] There is a significant difference between the extra investments necessary to establish a steam bypass in new plants and the investments involved in adapting existing plants. The investment necessary is also dependent on the power plant in question, but it is estimated to cost roughly 25 million DKK to establish a steam turbine bypass on a medium sized centralised CHP with a potential decrease in electricity production of approximately 250 MW. This corresponds to a cost of 0.1 million DKK per MW (Source: Ea, 2009b: Placing increasing amounts of renewable energy into the electricity system, Report part 2: Catalogue of solutions)

other hand, heat pump systems involve significant investments. An alternative to heat pumps with a substantially lower investment cost is electric boilers. However, they are also much less efficient, as *one* unit of electricity is converted to *one* unit of heat. Heat pumps are therefore well suited for applications with many operating hours, whereas electric boilers are more cost-effective for applications involving fewer operating hours.

With respect to using the heating system to ensure the value of wind it is relevant to note that the cooling of the housing stock, thereby resulting in increased thermal requirements, increase in proportion with the wind speed, which correlates positively with increased wind energy production.

Adapting district heating production to variable power prices

The optimal operation of the integrated power and district heating system depends on the power price. Low power prices will often indicate high generation from variable renewable energy, while high prices indicate a need for additional power generation. Figure 23 displays a comparison of the heat production price from different units, depending on the electricity price.

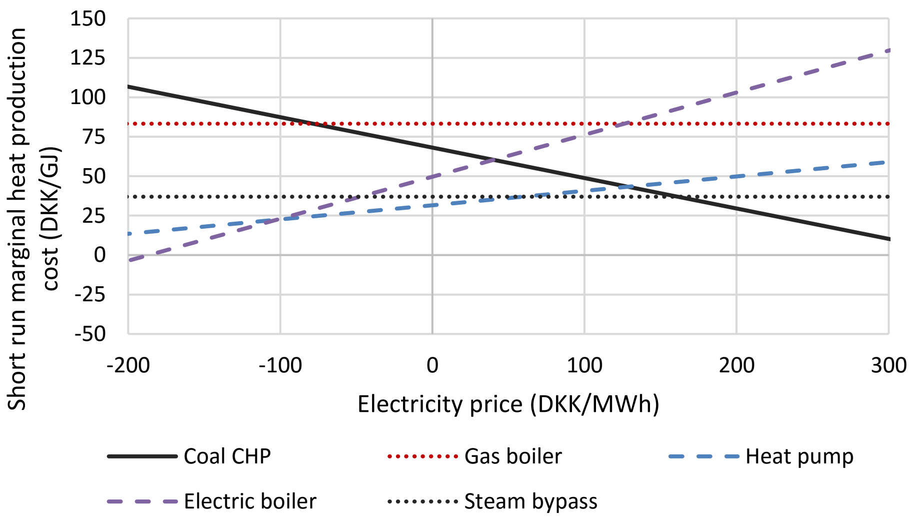


Figure 23: Short run marginal heat production price for different units depending on the electricity price. Illustrative example. Actual prices will depend on fuel prices, emission prices and taxes and subsidies.

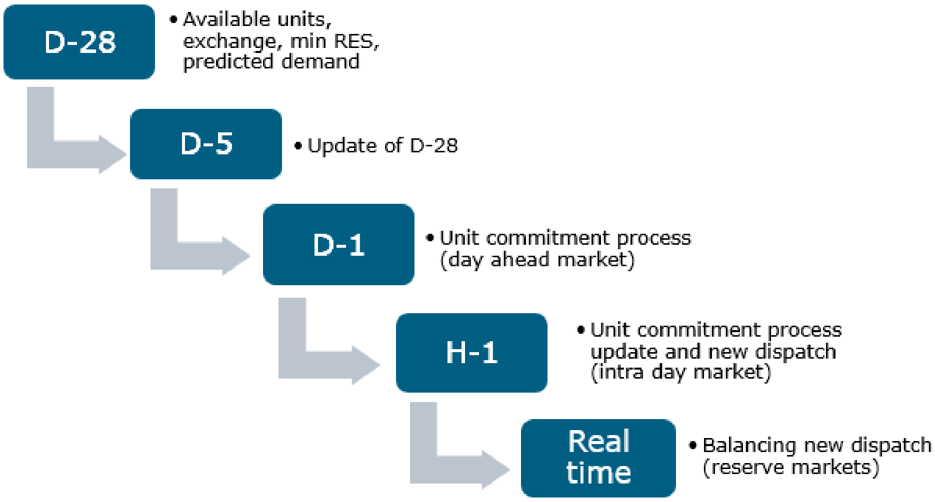
At very low (negative) electricity prices, electric boilers offer the cheapest price, since the boiler can earn money by consuming electricity. As electricity prices rise, it can be cheaper to use first the more efficient heat pump, and then the turbine bypass on the CHP-plant. At prices above approximately 180 DKK/MWh, CHP-production is beneficial. If the CHP-plant is an extraction unit, with very high electricity prices, opportunity costs will occur, since the plant could choose to produce more electricity when omitting heat production thereby increasing income. As a result, at very high electricity prices, the gas boiler will therefor provide the cheapest option.

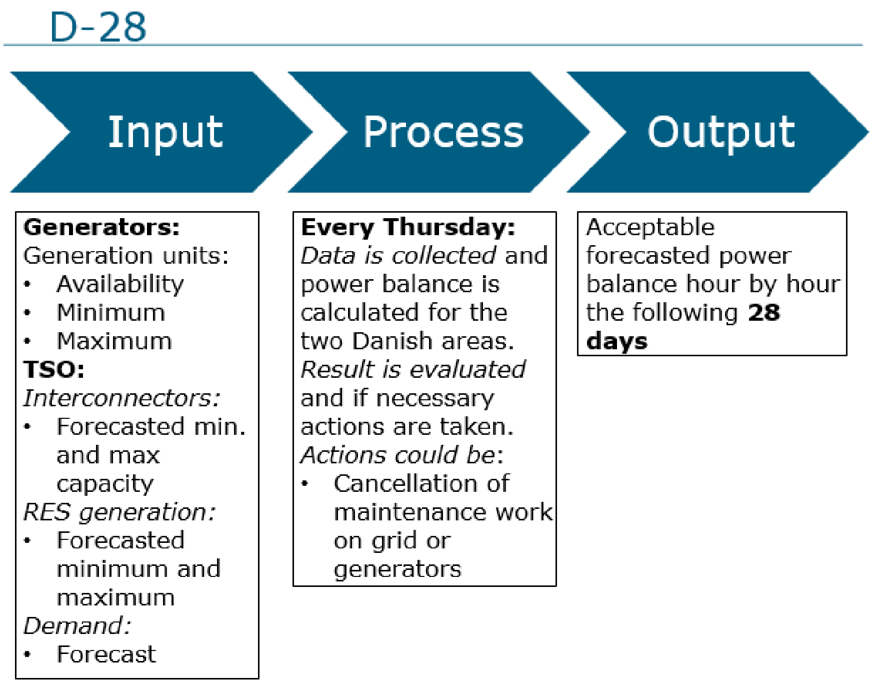
7 Danish system operation and dispatch

The preceding chapters have described the Danish power system, energy markets, incentives, and technical capabilities of the respective generators. This chapter will attempt to illustrate how all of the above play into the power balance as seen from the perspective of the Danish TSO, Energinet.dk.

7.1 Decision tree for power balance

Starting 4 weeks before the hour of operation, the decision tree for the power balance from Energinet.dk's perspective is depicted in the series of figures below, starting with 28 days before, and moving towards real time.





D-7

Input

Generators:
Generation units:
- Availability
- Minimum
- Maximum

TSO:
Interconnectors:
- Forecasted min. and max capacity

RES generation:
- Forecasted minimum and maximum

Demand:
- Forecast

Process

Every Thursday:
Data is collected and power balance is calculated for the two Danish areas. *Result is evaluated* and if necessary actions are taken. *Actions could be*:
- Cancellation of maintenance work on grid or generators

Output

Acceptable forecasted power balance hour by hour the following **week**

D-1, morning before 9 AM

Input

Generators:
Generation units:
- Availability
- Minimum
- Maximum

TSO:
Interconnectors:
- Firm capacity

RES generation:
- Forecasted production based on meteorological data

Demand:
- Forecast

Process

Every day:
Data is collected and power balance is calculated for the two Danish areas. *Result is evaluated* and if necessary actions are taken. *Actions could be*:
- Cancellation of maintenance work on grid or generators
- Forced availability of generators

Output

Acceptable forecasted power balance hour by hour the following **day**

D-1 approx. 5 PM

Input

Generators:
Generation units:
- Scheduled production every 5 minute
- Min. and Max.

TSO:
Interconnectors:
- Scheduled exchange every 5 minute

RES generation:
- Forecasted generation every 5 minute

Demand:
- Forecast every 5 minute

Process

For every time-step:
Power balance is calculated for the two Danish areas.

Result is evaluated and if necessary actions are taken.
Actions could be:
- Trade with neighbor's
- Cancellation of maintenance work on grid or generators
- Forced production

Output

Acceptable forecasted power balance every **5 minutes.**

H-1

Input

Generators:
Generation units:
- Updated Scheduled production every 5 minute
- Min. and Max.

TSO:
Interconnectors:
- Scheduled exchange every 5 minute

RES generation:
- Updated forecasted generation every 5 minute

Demand:
- Updated Forecast every 5 minute

Process

For every time-step:
Power balance is calculated for the two Danish areas.

Result is evaluated and if necessary actions are taken.
Actions could be:
- Trade with neighbor's
- Cancellation of maintenance work on grid or generators
- Forced production

Output

Acceptable forecasted power balance every **5 minutes.**

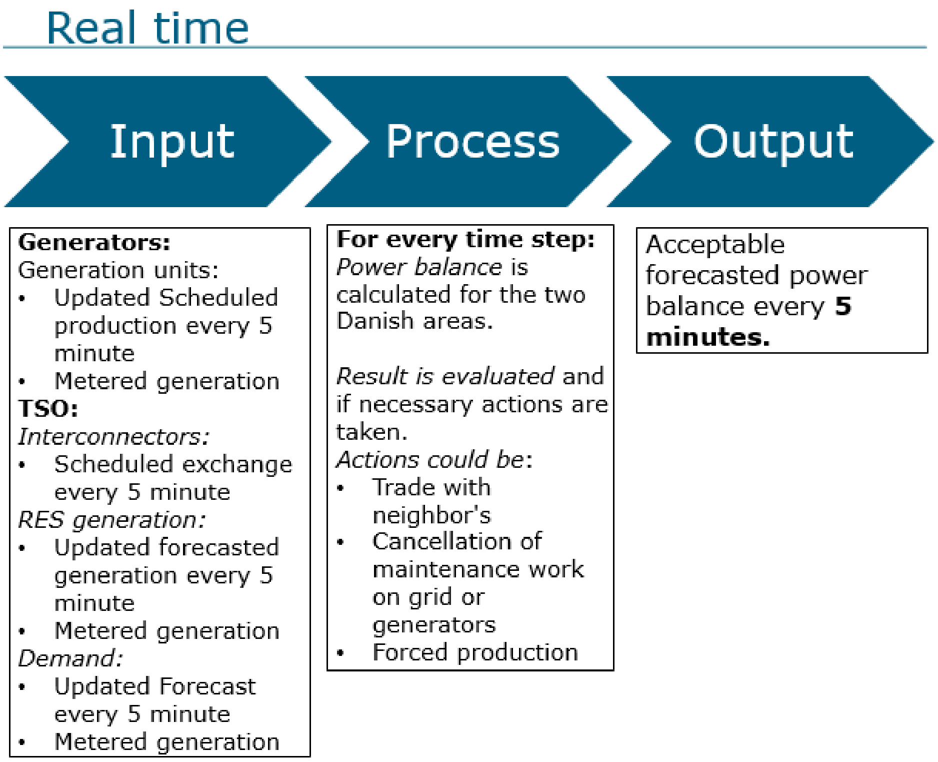


Figure 24: Decision tree for power balance

7.2 Utilisation of wind forecasts in dispatch and system operation

As was indicated in Figure 24 above, updated forecasts play a significant role in the ongoing power system balance, and for Energinet.dk, forecasting wind power is a key consideration.

Handling wind power predictability

The predictability of wind power is highly dependent on the time horizon. For the day-ahead market, the horizon is 12 hours for the first hour of the operating day, and 36 hours to the last hour. With this horizon, the mean average percentage error (MAPE) for individual wind parks is 19% (2014 data). However, as was detailed in the previous chapters, generators can make adjustments to the day-ahead plan, e.g. by use of the intra-day market Elbas. This is possible until one hour before the operating hour, at which time wind power has a high degree of predictability.

Energinet.dk's own forecasts

In the hour of operation, Energinet.dk bears the responsibility of maintaining the system balance, and does so by utilising the various automatic and manual reserves described previously. However, the significant amount of wind development in Denmark introduces challenges for the TSO, particularly related to the forecasted wind speeds and resulting electricity production. The figure below highlights this challenge as it displays the amount of electricity production from wind (as a % of the installed capacity) depending on the wind speed.

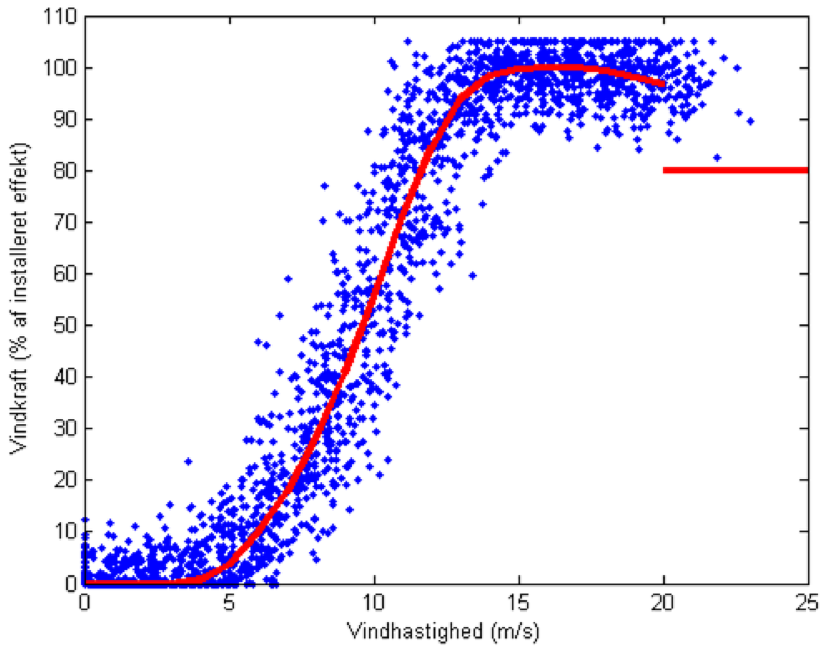


Figure 25: Electricity production from wind (as a % of the installed capacity) depending on the wind speed.

The figure illustrates that with forecasted wind speeds that are very low, or very high, changes in the actual wind speed do not result in realised production that is significantly different from forecasted production. However, with forecasted wind speeds between roughly 6 and 10 m/s, a realised change of just 1 m/s will bring about large changes in the actual production. According to Energinet.dk, with about 5 GW of installed wind power capacity in the system, a change of 1 m/s in wind speed can result in a change of more than 650 MW generation (Energinet.dk, 2016b).

Due to the large potential fluctuations in wind production, Energinet.dk also undertakes its own forecasts for each of the two Danish areas: DK1 and DK2, utilising two forecasting tools, one external and one internal. The meteorological forecasts rarely agree on the same wind speed, and as such, forecasts are based on a combination of meteorological prognoses. The external forecast is a combined forecast based on 4 meteorological prognoses, which starts 48 hours before the hour of operation, and are updated hourly. The internal forecast is a combined forecast based on 3 meteorological prognoses, and provides day ahead (12-36 hour) and short term (0-6 hour) forecasts, with several updates per hour.

In the Mean Absolute Error figures displayed below, Energinet.dk compares the difference in the settlement data from forecasted production, relative to installed wind capacity. Thus with 5,000 MW, and a MAE of 3% one hour before the operation hour, this corresponds to 150 MW.

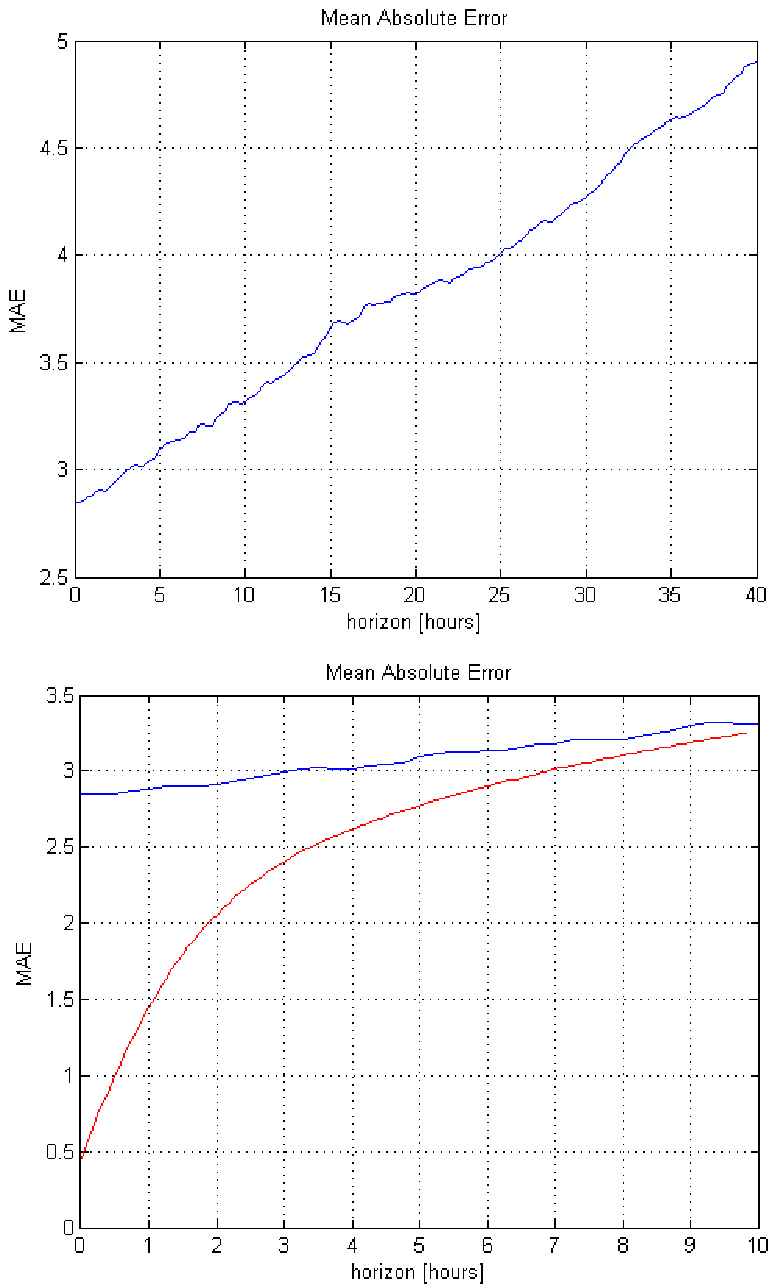


Figure 26: Mean absolute error for Energinet.dk's Danish wind power forecasts relative to total installed capacity (blue lines). The red line incorporates online measurements into the forecasts. The top figure is over a 40-hour time horizon, and the lower figure zooms in on the last 10 hours. (Energinet.dk, 2016b).

From the lower part of Figure 26 it is apparent that one hour before the hour of operation, the average forecasting error is around 1.5%. This amounts to 75 MW, and with a maximum MAE at this time of roughly 4-5%, the maximum forecast errors are in the level of 200-300 MW, which is much less than the reserve requirements for N-1 situations (700 MW, due to largest interconnector).

Balance is held on the system level

In reviewing Figure 26 it is important to note that Energinet.dk balances each physical system as one. Thus while individual wind park forecasts may have a large variance from their actual production, for each of DK1 and DK2, Energninet.dk undertakes their own forecasts for the whole systems, and this will have a lower forecast error as some of the individual errors will be in opposite directions.

Use of forecasting tools and online measurements in practice

The success of balancing renewable energy production is highly dependent on the availability of accurate forecasting and scheduling systems. A good day-ahead forecast can help the owners of the production units to make the right bids on the spot market, and a good short term forecasting model can help the TSO to proactively order slower reserves, rather than depending on fast and expensive reserves, once the imbalance has arrived.

Energinet.dk has forecasting models for wind production, solar production and load. The models are autoregressive and they use input from different meteorological services as described in the previous section.

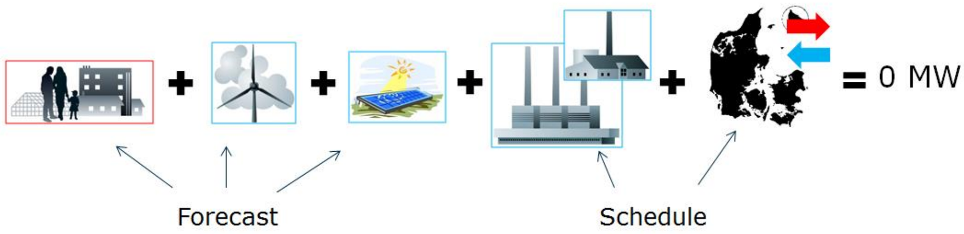


Figure 27: Overview of Energinet.dk's forecasting and measurement tools

The results from the forecasting models go into a scheduling handling system where they, together with schedules from all production units and schedules for interconnectors, are used to calculate the total power balance for the next 24 hours. The tool also gives the dispatcher access to a bidding list for up and down regulation during the day.

Two screen shots of this operational tool are displayed below.

The first screen shot illustrates the result of the continuous updating process for the wind power forecast. The latest updated prediction (Actual prediction) comes much closer to the actual wind power generation (Scada measurement and up-scaling).

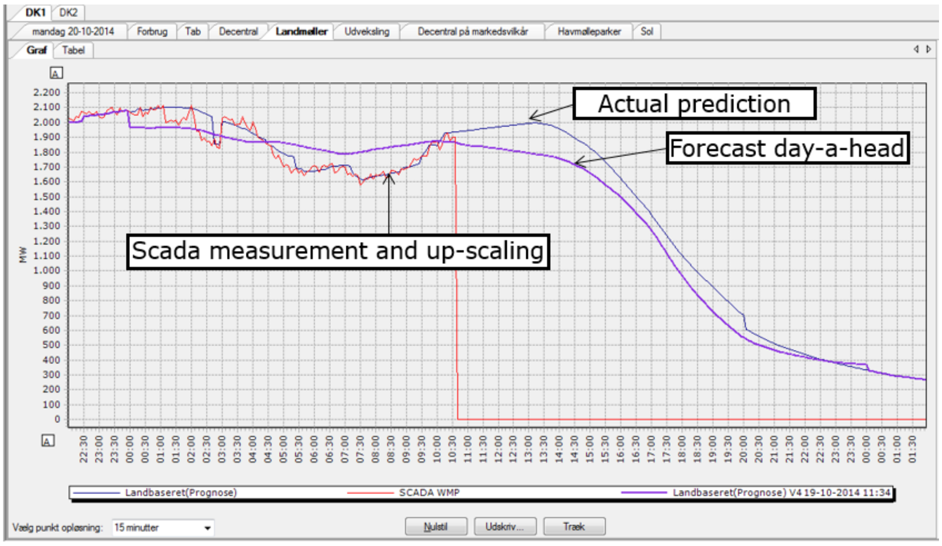


Figure 28: Screenshot from Energinet.dk's operational planning tool for Western Denmark (Energinet.dk, 2016b)

The second screen shot illustrates the predicted system balance for the coming hours. The predicted system balance is the net result of all the forecasts and schedules shown in the first figure in this section.

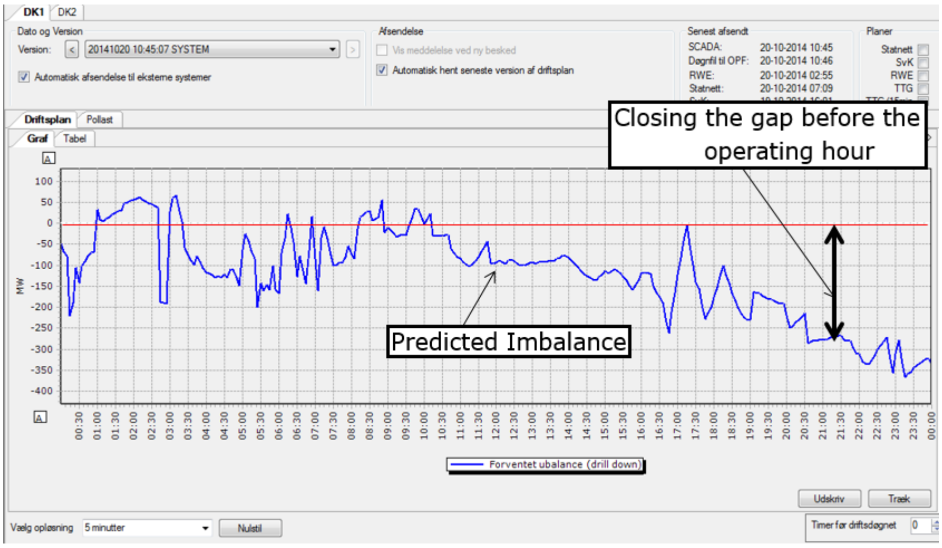


Figure 29: Screenshot from Energinet.dk's operational planning tool for Western Denmark (Energinet.dk, 2016b)

Since all forecasts and schedules are continuously updated, the predicted system balance is always based on latest available data and gives the operator the best possible basis for anticipatory handling of imbalances to ensure system security and minimise balancing costs.

The intraday market closes 1 hour before operation, but in practice Energinet.dk does not start activating manual reserves to reduce coming imbalances until about 30 minutes before the operational hour. As described previously, the manual reserves are activated as regulating power according to the Nordic regulating power NOIS list. Should it be necessary to regulate the power in the Nordic countries, the cheapest bid placed on the common list will be activated, though, giving due consideration to possible restrictions in the interconnections between the countries.

By consistently updating forecasts, monitoring online production, and utilising the NOIS list to activate the cheapest available regulating power when necessary, balancing and operational costs are held as low as possible, all while ensuring that the large amounts of RE are integrated into the electricity system.

After the operational hour

After the operational hour, Energinet.dk will calculate the costs of activating/acquiring the necessary reserves in each of DK1 and DK2, and these costs will be passed on to the balance responsible parties according to their contribution to the net imbalance.

Energinet.dk is the balance responsible party for older turbines while commercial players (balance responsible parties) handle the majority of newer wind turbines. For the market actors, the costs of balancing wind power varies depending on the wind conditions and the price of balancing energy, and can also vary between the balance responsible parties. The average cost of balancing of wind energy is rather modest – about 2 Euros per MWh produced by wind turbines in 2013, which is in line with previous years. As of 2018, commercial players will also take over balance responsible for the older wind turbines (Energinet.dk, 2015c).

7.3 Flexibility in the electricity system - an example

A good example of both how flexible the Danish power system has become, and how the various elements described in this report contribute to it, can be deemed from the example below, which displays the hourly dispatch for the week of August 31st to September 6th, 2015.

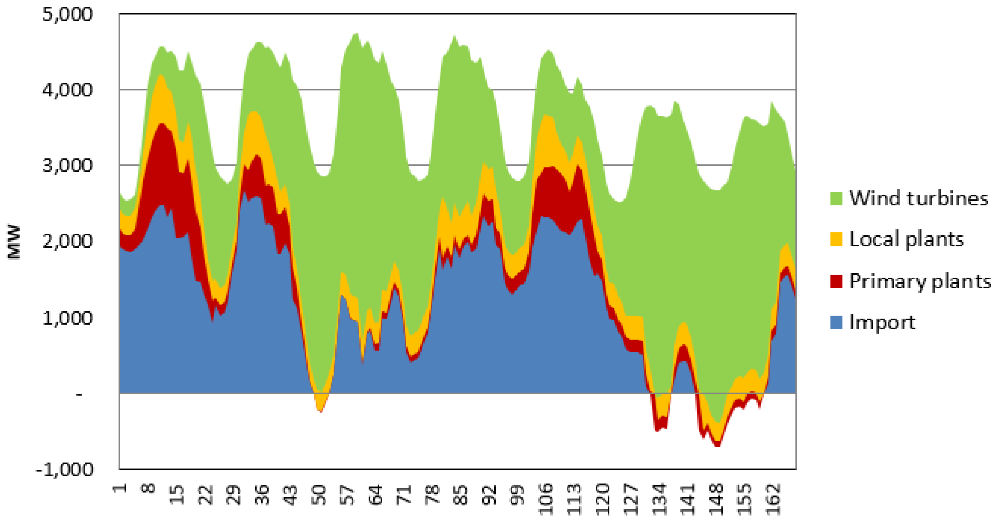


Figure 30: Hourly dispatch for the week of August 31st to September 6th, 2015.

During the week depicted in the figure, we see that large amounts of electricity were imported via the international connections when wind production was low (blue portion). In addition, production from the large primary plants (red) and smaller local plants (yellow) were also higher during these periods. Meanwhile, when wind production was very high, interconnectors were used to export (particularly when demand was also low in the weekend). In addition, both the large primary and smaller local plants also greatly reduced and/or shut down production during times with large amounts of wind.

As the figure below indicates, the reason that the individual primary and local plants behave as they do, is due to the market prices for electricity. When prices are very high, the plants produce as much as possible, and when prices are very low, they reduce their production as much as possible. The same holds for Denmark's neighbours, when the market price is high in Denmark, its neighbours are motivated to export as much electricity to Denmark as possible (blue), and the opposite holds true when prices are low, as they now are interested in purchasing Denmark's cheap electricity.

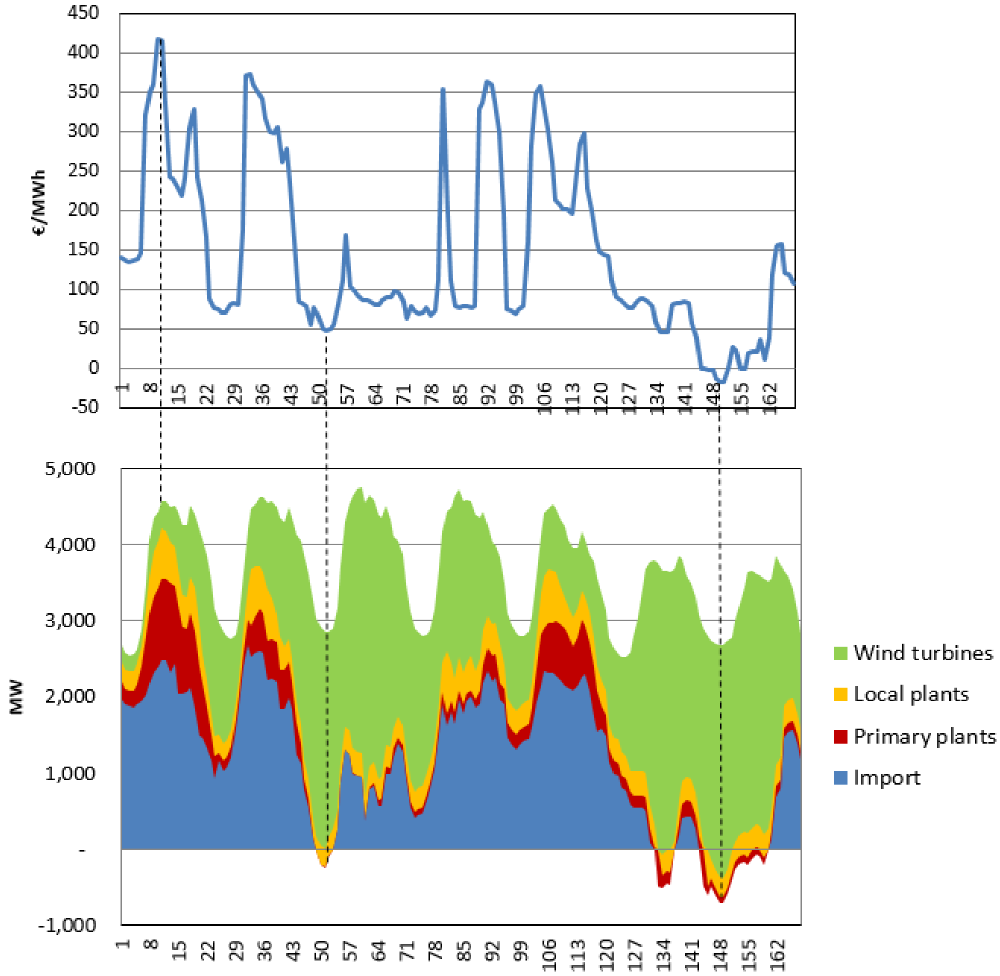


Figure 31: Linkage between spot prices and dispatch

8 Application of Danish experiences to the Hami Energy Base

While there are a number of differences between the physical and regulatory conditions in Hami and Denmark, there are still a number of takeaways from the Danish experiences that can be applied to the Hami Energy Base, which can enable higher wind integration rates.

Grid planning, coordination and operation

The Danish wind integration experience highlights the importance of interconnectors that can be utilised both in periods of high RE production, but also in periods when RE production is low. This is an issue that is apparently quite relevant for the Hami power base, as a number of grid congestions result in large amounts of renewable energy being curtailed. The Danish experience thus illustrates the importance of coordinating local and regional grid planning with the development of large amounts of new generation capacity.

The transmission system in Denmark and the neighbouring countries is also a major measure for integrating renewable energy on a daily basis. As Denmark is part of the Nord Pool Spot market, which is coupled to the other European power markets, integration of renewable energy does not happen in Denmark alone, but is in fact coordinated with neighbouring countries. For the Hami Energy Base, improved coordination of transmission grid usage especially between provinces (e.g. Gansu and Henan at the receiving end of the UHVDC line) could improve integration of renewable energy. This would require to strive more flexible and dynamic planning of the transmission flow according to continuously updated forecasts, as opposed to trying to fulfil fixed transmission schedules planned day-ahead or earlier. Furthermore, coordination of unit commitment and dispatch of the Hami Energy Base units with the provincial dispatch procedures could improve RE integration.

Proper incentive structures

Via the market structure that is in place in Denmark, there are very strong monetary incentives (i.e. low electricity prices) for power plant producers to avoid producing electricity when RE production is high and/or electricity demand is low. On the flip side, when electricity prices are high (generally when RE production is very low), power plant producers are rewarded for their production. While fully recognising that Hami does not have a power market in place similar to that of Denmark, it is very important to note that having a series of complex power markets in place is not the only way of encouraging traditional power plants to plan generation in accordance with the system needs.

A number of simple first steps could be undertaken to promote traditional generation at the ‘proper’ time, including adjusting the current fixed rate tariff for coal, so that when forecasts for wind production are high, coal production will receive a lower tariff, while when forecasts are low, they receive a higher tariff. Another rather simple first step could be the introduction of production trading rights, thus allowing for wind parks that might otherwise be curtailed to produce instead of coal plants that now ramp down their production. Coal plants would do so due to receiving a payment from the wind farm, while at the same time also realising savings related to fuel costs. Given the rather large difference in the current tariffs for wind and coal production, the introduction of a win-win situation of this type should be quite viable. Lastly, it is worth noting that in order to encourage decision makers to bring about changes allowing for this win-win situation, it may be useful to develop the system in a fashion that results in them also receiving a piece of the larger pie.

While not a win/win proposal, an important observation is the necessity to reduce and eventually remove the concept of guaranteed full load hours, particularly for coal plants as this current practice greatly hampers RE integration efforts. Also guaranteed number of full load hours for RE include a number of disadvantages, including lacking incentive to integrate more RE than guaranteed, and lacking incentives to plan future RE investments in the most beneficial way, e.g. expansion of wind power where full load hours are high and grid congestions low.

Flexibility of power plants

The introduction of proper incentives for coal generators to produce at the correct time discussed above, would also lead to coal plants having an incentive to becoming more flexible. Danish experiences have shown that the market incentives have played a role in plant operators utilising a systematic almost ‘trial and error’ approach to consistently improve their flexibility. While the incentive to be more flexible was market driven, it was largely left up to the plants to determine how about to bring about these flexibility improvements, and by involving all levels of plant operation and maintenance into this process, significant results have been achieved. In China, it is our understanding that new plants must simply meet stated technical minimums when being designed and constructed, and therefore there is no incentive to take a ‘trial and error’ approach to test and improve on these limitations. The

Hami power base, with its 8-10 identical new coal units could provide a perfect ‘laboratory’ for the implementation of a program that attempts to improve the flexibility of the coal units. Given their uniform nature, an optimist could envision a situation where different aspects were tested out at different units, or the various units ‘competed’ to become the most flexible.

Utilisation of forecasts

The focus on constant improvement of forecasting data and equipment has proved to be beneficial for the Danish TSO, as more accurate, and in particular the use of the most recent available forecasts, greatly reduces the forecast error, which thereby reduces the amount of reserves that are required, which in turn reduces the overall system costs.

Seen from a Hami perspective, a reduction in the forecast error would allow for a greater portion of the forecasted RE production to be taken into consideration in the unit commitment planning, thus reducing the minimum coal production in some hours. In addition, the use of continually updated forecasts would also allow for the national and provincial dispatch centres to inform the coal production units to decrease their production in order to reduce curtailment levels. In Denmark, forecasts are not only calculated and used by wind farm owners in order to minimise cost in the balancing markets, but also independently by the TSO. In addition to incentives for the wind power owners in Hami to develop improved forecasts, a TSO-driven forecast system could also be beneficial for system operation.

9 References

Blum, R., & Christiansen, T. (2013). High Flexibility Power Plants – 25 Years of Danish Experience. *ENS-China workshop meeting on Future Flexible Power System for Renewable Energy Grid Integration.* Beijing.

Danish Energy Agency. (2014). *Energy Statistics 2013.* Copenhagen: Danish Energy Agency.

Danish Energy Agency. (2015a). *Energy in Denmark 2013.* Copenhagen: Danish Energy Agency.

Danish Energy Agency. (2015b, February 25). *Energistyrelsen*. Retrieved from Procedures and permits for offshore wind parks: http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks

Energinet.dk. (2013, November 3). *Power Right Now.* Retrieved from Energinet.dk: http://energinet.dk/EN/El/Sider/Elsystemet-lige-nu.aspx

Energinet.dk. (2014, October 5). *Download of market data.* Retrieved from Energinet.dk: http://www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx

Energinet.dk. (2015a, June 2). *Power right now.* Retrieved from Energinet.dk: http://energinet.dk/EN/El/Sider/Elsystemet-lige-nu.aspx

Energinet.dk. (2015b, February 25). *Energinet.dk*. Retrieved from Afregning: http://www.energinet.dk/DA/El/Vindmoeller/Afregning/Sider/Afregning.aspx

Energinet.dk. (2015c). *Download of Market Data.* Retrieved from Energinet.dk: http://www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx

Energinet.dk. (2015c, May 13). *Energinet.dk udliciterer balanceansvar for vindmøller og små kraftvarmeværker*. Retrieved from Energinet.dk: http://energinet.dk/DA/El/Nyheder/Sider/Energinet-dk-udliciterer-balanceansvar-for-vindmoller-og-smaa-kraftvarmevaerker.aspx

Energinet.dk. (2016a, April 14). *Udtræk af markedsdata*. Retrieved from Energinet.dk: http://energinet.dk/DA/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx

Energinet.dk. (2016b, April 5). Energinet.dk and the Danish Energy System - Hami project. Fredericia.

Feldmüller, A. (2013). *Wie flexibel ist der heutige konventionelle Kraftwerkspark aus Herstellersicht?* Retrieved from Siemens AG (Siemens Energy, ServiceFossil): http://www.ef-fizienteenergiesysteme.de/fileadmin/user_upload/PDF-Dokumente/Veranstaltungen/Workshop_Retrofit/3_SIEMENS_Feldmueller.pdf

Nasdaq. (2016, April 19). *Market prices*. Retrieved from Nasdaq commodities: http://www.nasdaqomx.com/commodities/market-prices