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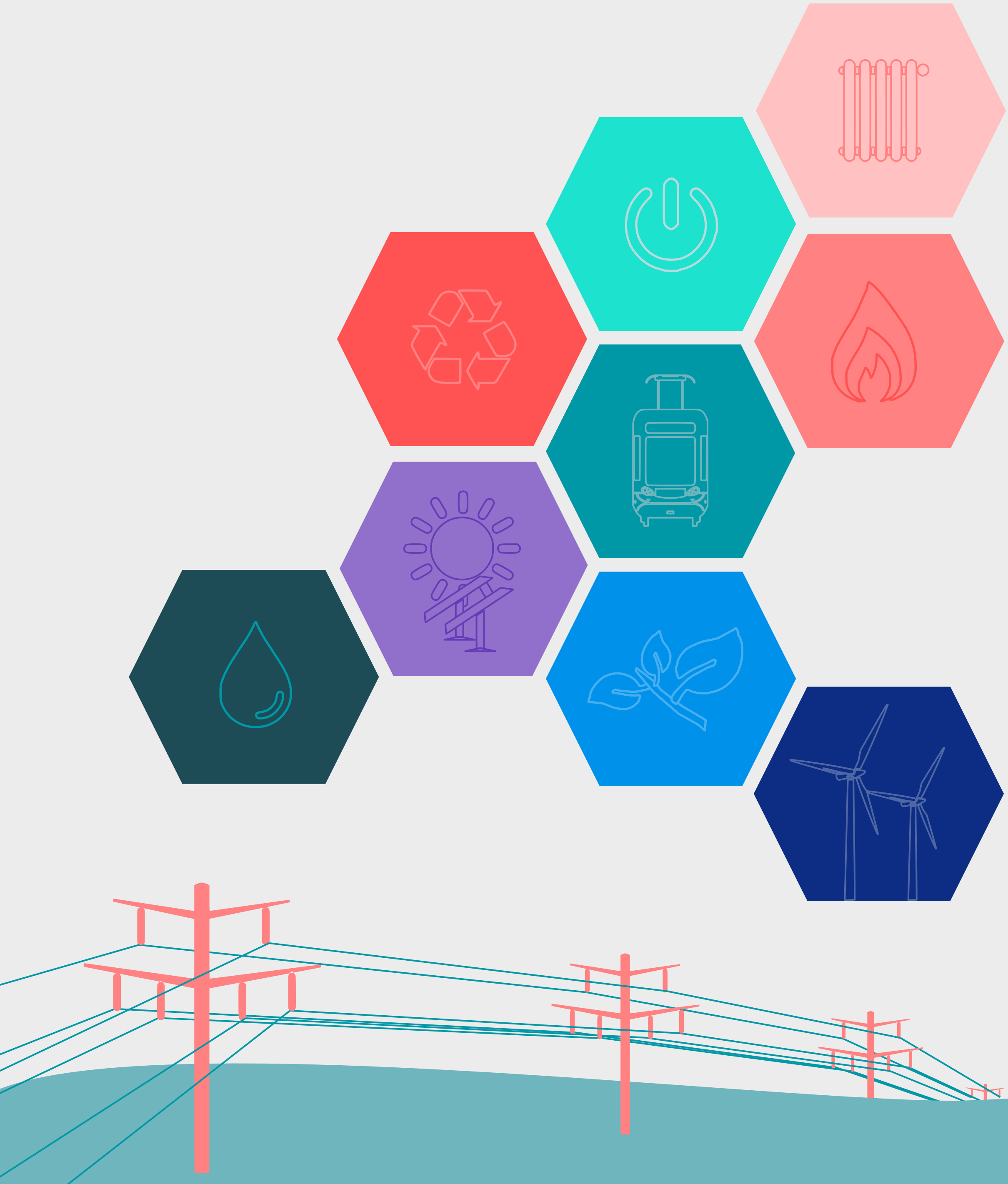

POWER AND GAS SECTOR OUTLOOK FOR INFRASTRUCTURE PLANNING 2018

Power and Gas Sector Outlook for Infrastructure Planning

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Contents

Abbreviations

BID	"Better Investment Decisions" (model applied by Energinet.dk to simulate the total northern European electricity system)
GDP	Gross domestic product
BSMMG	Baltic Sea Market Modelling Group
GVA	Gross value added is the gross domestic product (GDP) less net expenses. This means that GVA expresses the value of production at the factory (i.e. before taxes etc.)
CHP	Combined Heat and Power
CIF	Cost, Insurance and Freight (import price)
CCS	Carbon Capture and Storage
DEA	Danish Energy Agency
DECO17	Denmark's Energy and Climate Outlook 2017 (last year's baseline projection)
DECO18	Denmark's Energy and Climate Outlook 2018
DK1	Electricity price area 'western Denmark'
DK2	Electricity price area 'eastern Denmark'
DTU	Technical University of Denmark
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
EPT	Energy production statistics
ESCO	Energy saving company
FLH	Full-load hours
GJ	Giga Joule = 10^9 joule (J), unit of energy
GW	Giga Watt = 10^9 watt (W), unit of power
GWh	Giga Watt hours = 10^9 watt hours (Wh), unit of power
HSDC	Hyper-Scale Data Centre
IEA	International Energy Agency
LTM	National Transport Model (Technical University of Denmark)
MAF	Mid-term Adequacy Forecast - ENTSO-E
MW	Giga Watt = 10^6 watt (W), unit of power
MWp	Mega Watt peak, solar PV capacity stated in panel capacity (direct current)
NCG	NetConnectGermany GmbH Co. KG, German gas TSO and gas market area
PGSO-IP17	Power and Gas Sector Outlook for Infrastructure Planning 2017 (last year's power and gas sector outlook published by Energinet)
PGSO-IP18	Power and Gas Sector Outlook for Infrastructure Planning 2018
PJ	Peta Joule = 10^{15} Joule (J), unit of energy
P2X	Power-to-X
PPA	Power Purchasing Agreement
PSO	Public Service Obligations
PV	PhotoVoltaic
RUS plan	Plan for reinvestment, development and restoration
TSO	Transmission System Operator (electricity and gas system)
TYNDP	10-year Network Development Plan - ENTSO-E
TWh	Tera Watt hours = 10^{12} Watt hours, unit of energy
RE	Renewable energy

1 Introduction and summary

1.1 Danish Energy and Climate Outlooks

The Danish Energy Agency (DEA), Department for System Analysis currently produces three long term energy (and climate) outlooks:

1. Denmark's Energy and Climate Outlook (DECO) - Baseline Scenario Projection Towards 2030 With Existing Measures (Frozen Policy)
2. Power and Gas Sector Outlook for Infrastructure Planning (PGSO-IP) - Best Guess Scenario Towards 2040 With Additional Measures
3. National Energy and Climate Plan (NECP) – Outlook towards 2030 and 2040 under the EU Energy Union with Existing and Planned Measures

Denmark's Energy and Climate Outlook is Denmark's baseline scenario projection towards 2030 and represents a technical assessment of how Danish energy demand and energy production, as well as Danish greenhouse gas emissions, will evolve over the period to 2030 based on existing measures (frozen policy). The purpose of the DECO is to describe where Denmark stands and what challenges Denmark faces with regard to meeting its energy and climate obligations and policy targets. The DECO is therefore an important planning tool in setting Danish energy and climate policy, as well as an important reference for assessing the impacts of new policy initiatives. The DECO is made every year. The latest version (DECO18) was published in April 2018.

Denmark's Power and Gas Sector Outlook for Infrastructure Planning is prepared annually for use by Energinet (the Danish Power and Gas Transmission System Operator) as a basis for Energinet's planning of the Danish energy system power and gas infrastructure. The PGSO-IP describes developments in the Danish energy system up to 2040. The PGSO-IP is based on a best and - as far as possible - robust guess at developments in the energy system so as to safeguard against systematic under- as well as over-investment in the transmission grid, both of which would cost society more compared with an appropriate development. The PGSO-IP describes how a long-term green transition might unfold, so it encompasses any additional measures needed for this development to happen, but the outlook does not suggest which specific further initiatives (in addition to the initiatives covered by the 2018 Energy Agreement) would be necessary.

Finally, according to the new governance rules of the EU Energy Union, EU countries are required to develop **Integrated National Energy and Climate Plans** (NECPs) that cover the five dimensions of the Energy Union (decarbonisation; energy efficiency; energy security; internal energy market; and research, innovation and competitiveness) for the period 2021 to 2030 (and every subsequent ten year period) based on a common template. Denmark submitted its first draft NECP in December 2018 and the final NECP will be submitted before the end of 2019. After the first submission of plans they must be up-dated every 4-5 years, and progress reports on implementation of NECPs shall be submitted on a biennial basis from 2023, and reporting on GHG policies and measures and projections every two years from 2021. The NECP provides an outlook to 2030 and in many cases to 2040 on the basis of existing policies and measures, while also providing impact assessments of planned policies and measures.

This remaining part of this report is a direct translation from Danish to English of the Power and Gas Sector Outlook for Infrastructure Planning for 2018.

1.2 Background and objective

A power and gas sector outlook for Infrastructure Planning (PGSO-IP) is prepared annually for use by Energinet in work to develop the electricity and gas infrastructure of the Danish energy system. The PGSO-IP is a description of developments in the Danish energy system up to 2040. This report describes the assumptions and data in the PGSO-IP that Energinet uses from the time of the report's publication in 2018 and up to the publication of next year's power and gas sector outlook.

Energinet was previously responsible for preparing this outlook. In the Finance Act for 2017, the government decided to transfer this responsibility to the Danish Energy Agency. The aim was to ensure earlier involvement of the authorities in the decision-making process and to ensure greater legitimacy of Energinet's investment decisions through a segregation of responsibilities.

The power and gas sector outlook for infrastructure planning (in short: power and gas sector outlook) is published once a year and normally during the first half-year. However, due to work during the spring of 2018 to prepare the proposal for a new political energy agreement, and due to the date of the establishment of the final energy agreement on 29 June 2018 (Danish government, 2018), publication of this year's report was postponed until autumn, so that the adopted Energy Agreement could be included in the outlook.

The power and gas sector outlook constitutes the basis for analyses of future, long-term net investments. Furthermore, the outlook is also used as the basis for a large number of analyses and annual reports from Energinet, including Energinet's so-called RUS plans (plan for reinvestment, development and restoration), environmental reports, security of supply reports, reporting to the European TSO networks ENTSO-E and ENTSO-G, investment project business cases, etc.

1.3 Scope and reservations

Energinet's infrastructure investments are very long-term. Therefore, the PGSO-IP extends up to 2040. The PGSO-IP is based on a best and - as far as possible - robust guess at developments in the energy system so as to safeguard against systematic under- as well as over-investment in the transmission grid, both of which would cost society more compared with an appropriate development.

In contrast to Denmark's Energy and Climate Outlook (DECO), which is based on a frozen-policy approach (i.e. on the assumption of no new initiatives in the area of climate and energy), the purpose of the PGSO-IP is to determine a number of detailed and comprehensive set of assumptions about how the Danish energy system could develop in the future. These assumptions are based on a best possible guess at the expected future developments in the energy system and not only the developments likely to unfold with current regulation. It should be noted, however, that due to time pressure it has not been possible to include the effect of the government's objective for a stop to the sale of petrol and diesel cars by 2030 in the "best guess" scenario.

The PGSO-IP describes how a long-term green transition might unfold, but the outlook does not suggest which specific further initiatives (in addition to the initiatives covered by the 2018 Energy Agreement) could be necessary to ensure the development described.

Due to the long time horizon, the PGSO-IP is not a best guess at a concrete future energy policy, because the time horizon for the concrete initiatives decided will be considerably shorter. The PGSO-IP is the Danish Energy Agency's best guess at a technical development for the energy system in a scenario that assumes a continued green transition of the Danish energy system and on the basis of which Energinet can carry out its grid and network planning effort taking into account cost-effectiveness and long-term policy demands.

It is important to stress that the power and gas sector outlook has been prepared specifically for Energinet to provide Energinet with the best possible basis for grid planning, investment decisions, security of supply analyses, etc. This circumstance should therefore be noted if the outlook is used for other purposes. For example, it will not be possible to calculate the total Danish greenhouse gas emissions on the basis of the PGSO-IP, as it looks only at the sectors relevant to the electricity and gas transmission grids and therefore not at emissions from for example agriculture or the share of biofuels in petrol consumption.

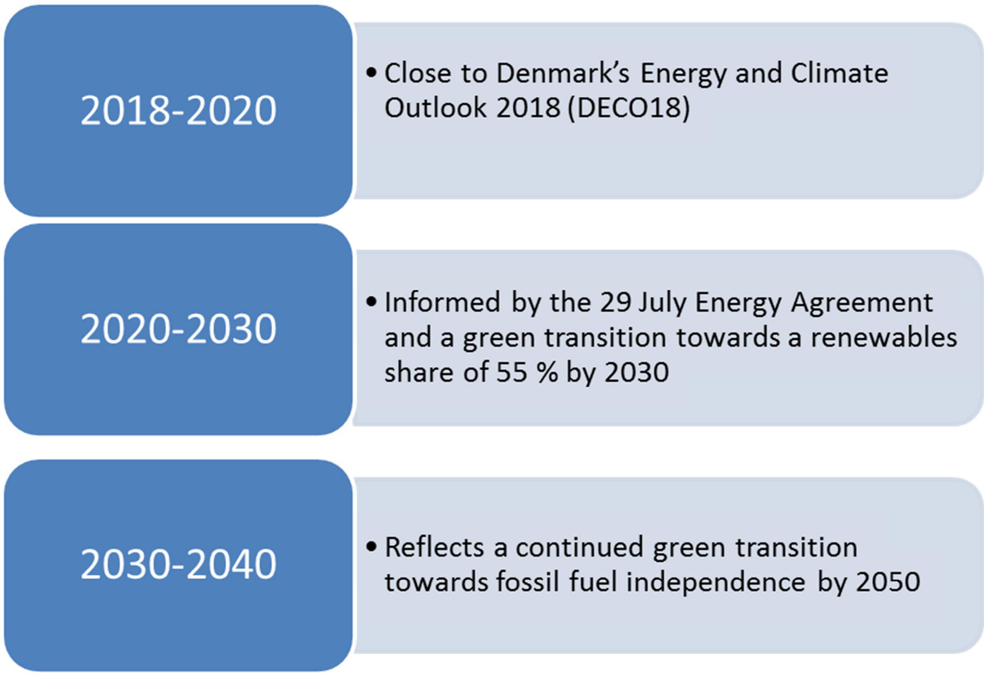
Projecting what the energy system will look like in more than 20 years from now is, of course, associated with great uncertainty. The Danish Energy Agency therefore uses a range of potential developments and, for most sectors, an uncertainty margin, i.e. a range of outcomes, will be described. These ranges can be used by Energinet but are not necessarily comprehensive enough for the sensitivity analyses that Energinet will prepare at a later stage, e.g. in connection with its grid planning. The Danish Energy Agency intends to further develop this aspect in its future power and gas sector outlooks.

1.4 The underlying approach

As mentioned above, the purpose of the power and gas sector outlook is to provide Energinet with a plausible and robust guess at developments in the future Danish energy system, so that Energinet can make socio-economically appropriate grid and system development plans and investment decisions. Energinet will supplement the PGSO-IP with sensitivity analyses to reveal the resilience of various possible paths and trends.

In its preparation of the PGSO-IP, the Danish Energy Agency has endeavoured to describe a development trajectory for the energy system that takes account of expected technological developments and a continued green transition, as well as of long-term political objectives. The 2018 Energy Agreement has set aside funds to help achieve a renewables share of around 55% by 2030. The projections incorporate the main effects of the Energy Agreement from 29 June 2018, and the political goal of a 55% renewables share in energy consumption by 2030, as well as the goal of a zero-emissions society by 2050, which for the energy sector has been approximated to a continued green transition towards fossil fuel independence by 2050. Figure 1 illustrates the approach and indicators used by the Danish Energy Agency in its work to prepare the PGSO-IP 2018.

Figure 1: The Danish Energy Agency's approach to work with PGSO-IP18



In the short term (the period 2018-2020), only a limited methodological difference is expected between PGSO-IP18 and DECO18. DECO18 is based on a frozen-policy approach.

Up to 2030, the PGSO-IP18 differs from DECO18, and provides an example of a transition towards a higher renewables share by 2030 based on the policy instruments and objectives included in the 2018 Energy Agreement. This means that, as opposed to DECO18, the PGSO-IP18 incorporates the concrete initiatives in the 2018 Energy Agreement. As the 2018 Energy Agreement does not include concrete initiatives all the way up to 2030, a series of assumptions have been made to ensure the ultimate achievement of a 55% renewables share by 2030. This applies in particular for the period 2025-2030.

Projections for the period 2030-2040 are based on expected technological developments and an economically efficient green transition. These projections outline a further trajectory towards fossil fuel independence by 2050. 'Best guess' for the period 2030-2050 assumes a linear development towards fossil fuel independence in total energy consumption for all sectors together, except for the transport sector. The transport sector is assumed to adapt to fossil fuel independence at a slower pace than the remaining sectors. The PGSO-IP also provides a guess at how renewable energy gas and renewable energy electricity will be gradually incorporated into the transport sector, while developments in the use of liquid biofuels have not been examined.

1.5 Model platform

The Danish Energy Agency has based its work on this power and gas sector outlook on the integrated model platform for projections and impact analyses in the energy and climate area. This makes for transparency and comparability with Denmark's Energy and Climate Outlook (DECO).

The model platform integrates the following of the Danish Energy Agency's sub models (see Danish Energy Agency, 2018a for a more detailed description):

- RAMSES models electricity and district heating supply
- IntERACT models energy consumption by the corporate sector and households
- The Transport Model models energy consumption in the transport sector
- The PSO model is used to calculate expected future expenditure on subsidies for electricity production
- Technology Deployment Models, for example for solar PV and onshore wind, which model the profitability of technology investments in terms of corporate profitability and investors' returns requirements. Thus, the models estimate the probable capacity deployment scenario against the current investment and operating conditions

This approach is not substantially different from Energinet's previous practice of preparing the power and gas sector outlook. The Danish Energy Agency, however, applies its own models, which have been adapted to ensure comparability with other projections by the Agency, while at the same time remaining useful to Energinet.

1.6 Content of the power and gas sector outlook

This power and gas sector outlook mainly addresses electricity generation capacities and electricity and gas consumption, as these aspects are vital for Energinet. The following therefore does not focus on total energy production, and thus e.g. on the renewables share, instead focus is on expectations for new renewables electricity capacity, including the size and phase-in of potential new offshore wind farms, the development in power plant capacity and expected developments in electricity demand by sector.

PGSO-IP18 follows the same structure as in previous years and includes developments with regard to the following topics:

1. Economic indicators
2. Fuel and carbon prices
3. Electricity demand
4. Power load in the system
5. District heating
6. Electricity production capacities
    a. Power plant capacities
    b. Solar PV
    c. Wind turbines
7. Foreign data and interconnectors, electricity
8. Gas data
9. Gas network

In contrast to previous years' power and gas sector outlook, PGSO-IP18 does not include projections of the electricity price, as the electricity price is a (model) output and therefore not an input assumption for Energinet's analyses. Below is a summary of expected developments for a number of key parameters in PGSO-IP18.

1.7 Summary of key assumptions

Table 1 shows the most important assumptions within a number of selected topics. The table is followed by a brief description. More detailed descriptions are given in the subsequent sections.

Table 1: Table of important assumptions, PGSO-IP18

Topic:	2030	2040
Economic indicators, fuel prices and carbon prices	As in DECO18, however the carbon price has been adjusted	Same methodology as in DECO18 projected to 2040 with the carbon price adjusted
Traditional electricity demand	Electricity demand by the corporate sector and households is expected to increase slightly	This development continues up to 2040
Electricity demand, large Data centres	Linear growth as in DECO18	Continued linear growth
Electricity demand for transport[1)]	Same development as in DECO18 up to 2024. From 2025-2039 expected to increase somewhat more than in DECO18, corresponding to a 25% sales share for electric and plug-in hybrid cars in 2030, as opposed to a 22% share in DECO18	After 2030, sales of electric and plug-in hybrid cars are expected to increase more steeply, so that by 2040 they will make up 100% of new car sales. The share of purely electric cars (i.e. not hybrid) is expected to increase from around 60% in 2030 to 80% in 2040.
Power plant capacities	A greater decrease in capacity than in DECO18	In overall terms, power plant capacity is expected to be reduced by around 35% by 2040 compared with today
Onshore wind	Energy Agreement up to 2024[2)] plus a continued gross deployment of 200-230 MW/year[3)]. Best guess at realisable capacity assumed to be 5 GW	Continued gross deployment of around 160 MW annually, corresponding to a continued total capacity of 5 GW taking into account decommissioning of old turbines
Offshore wind	2400 MW, with 1600 MW in western Denmark and 800 MW in eastern Denmark (the final location will depend on a more detailed screening)	An additional deployment of what corresponds to an average of 300-350 MW annually in the period 2030-2040 - includes expected replacement of decommissioned offshore wind turbines (around 1100 MW in the period)
Solar PV	Energy Agreement up to 2024[2)] plus continued ground-mounted solar farm deployment of 100-200 MW annually. The deployment of household and commercial units is limited due to reductions in electricity taxation and transition to instant settlement	Accelerated deployment towards a maximum solar PV capacity of 15% of total electricity demand due to price pressure
Gas consumption	It is expected that natural gas consumption will have fallen by around 40% in 2030 compared with today, while biogas consumption is expected to double during the same period.	Natural gas consumption is expected to fall by an additional around 20% by 2040, while a slight increase in consumption of biogas is assumed in the period 2030-2040

[1)] The stop on sales of petrol and diesel cars proposed by the government in its Climate and Air Policy Proposal has not been included in the best guess scenario but is covered by the upper range of outcomes for electricity demand for light road transport. [2)] Includes a rough assumption about the split of awards of technology-neutral tenders between onshore wind and solar PV. [3)] This is expected to reflect that the number of turbines is reduced to the level indicated in the 2018 Energy Agreement, because it is expected that, during the period, a large number of old end-of-life turbines will be dismantled and because the new turbines built in their place are expected to be considerably larger.

1.7.1 Economic indicators, fuel prices and carbon prices
Projections of economic indicators and fuel prices follow the same procedure as in DECO18 and are identical to DECO18 up to 2030. The carbon price, however, has been adjusted to reflect the reform of the EU emissions trading system (EU ETS) and the associated increases in carbon prices in 2018.

1.7.2 Electricity demand by the corporate sector and households
Electricity demand by households and the corporate sector has been modelled in the Danish Energy Agency's IntERACT model, which describes the interaction between economic/financial aspects, energy-system development and political initiatives. Projections in PGSO-IP18 are based on DECO18 but also include the tax-related elements from the 2018 Energy Agreement (a reduction in the electricity tax and in the electric heating tax, as well as removal of the general electricity tax for certain liberal professions) and a measure to promote energy-efficiency improvements, which is assumed to be continued up to 2040.

In overall terms, electricity demand by households and the corporate sector (excluding heat pumps and data centres) is expected to increase slightly up to 2040. Electricity demand is expected to be around 30 TWh in 2030 and around 31 TWh in 2040. The slight increase reflects conflicting effects of energy savings on the one hand, and on the other hand, tax relief, economic growth and increased use of heat pumps.

Electricity demand for individual heat pumps is expected to increase because the associated technology is expected to be able to compete with both natural gas boilers and wood pellet boilers. At the same time, the reduction in the tax on electricity for heating will occasion a higher consumption of electricity for heat pumps.

1.7.3 Hyper-scale data centres
On the basis of a separate analysis on hyper scale data centres (HSDC) prepared by COWI for the Danish Energy Agency (COWI, 2018), it has been assumed that, by 2030, there will be around six large data centres with an average electricity output for ICT equipment of 150 MW each. This is an average figure, which means there may be both more and smaller, or fewer and larger data centres. The number of average-size HSDCs is expected to increase to nine by 2040, if the linear growth in data volumes continues. In this scenario, total electricity demand from HSDCs will grow to around 7 TWh in 2030 and to more than 11 TWh in 2040, corresponding to a share of total electricity demand in 2030 and 2040 of about 16% and 22%, respectively.

However, there is considerable uncertainty concerning future developments. Among other things, this is because data operators have yet to decide on any further data centres in Denmark and because they can decide to relocate existing data centres to other countries at relative short notice, if this is more appropriate. We are currently aware of six HSDC projects in Denmark.

1.7.4 Electricity and gas for transport
The power and gas sector outlook includes electricity and gas consumption for light and heavy road transport, rail transport and sea transport. Electricity is considered a relevant fuel in all transport areas, while gas is only assessed to be relevant for heavy road transport and international sea transport.

The best guess at the development in electricity demand for light road transport assumes that the development will follow DECO18 in the period 2020-2024, after which electricity demand will start to increase more steeply. Electrification of the transport sector is therefore expected to start off relatively slowly but then increase at a higher rate up to 2040. 'Best guess' projections are based on expectations about technology and price developments for electric cars and on the ambition of fossil fuel independence by 2050. In overall terms, electric and hybrid cars are expected to account for 100% of new car sales in 2040. The share of purely electric cars (non-hybrid) is expected to increase from around 60% in 2030 to 80% in 2040. This does not take account of a scenario in which hydrogen cars account for a smaller share of the green transition in light road transport.

It should be noted that it has not been possible to include the effect of the government's climate proposal for a stop to the sale of petrol and diesel cars by 2030 in the best guess scenario. However, it is likely that the proposal will only have a minor effect on the transmission grid, although a separate analysis has been launched to examine this in more detail. The results of this analysis will be included in next year's power and gas sector outlook. Furthermore, the ambition that all new cars be low-emission cars by 2030 and zero-emission cars by 2035 has been reflected in the range of outcomes for electricity demand for passenger cars and vans. The projection of electricity demand for light road transport will be reviewed in connection with PGSO-IP19 and in light of the results of the political negotiations on the government's 2018 Climate and Air Proposal.

It is expected that electricity will play a minor role in heavy road transport. However, the Danish Energy Agency has not performed a more detailed analysis of this. Therefore, it is assumed - as a rough estimate - that electricity demand by heavy road transport will correspond to around 10% of electricity demand by light road transport throughout the period up to 2040.

Furthermore, for gas consumption by heavy road transport, it is assumed that the use of gas will be gradually phased in after 2025 and up to 2040 when gas consumption will make up 10% of total energy consumption by heavy road transport.

The expected trend in electricity demand by regional rail transport and the Fehmarnbelt Fixed Link corresponds to PGSO-IP17 and is based on assessments of the development in power load by Banedanmark (the Danish railway track governmental body) and Energinet. The projections also include the expected electricity demand for suburban light railways, electrified railways (S-tog) and underground railways (metro) that was included in the traditional electricity demand figure in PGSO-IP17. This consumption is the same as in DECO18 and is kept at a constant level after 2030.

The projection of energy consumption by sea transport is based on DECO18. Sea transport is only expected to make up a very small proportion of total electricity and gas consumption for transport in 2040.

1.7.5 Power plants

Compared with DECO18, the long-term trend has been adjusted to take account of the ambition in the 2018 Energy Agreement for a 55% renewables share by 2030, coal-free energy supply by 2030 and fossil fuel independent energy supply by 2050. At the same time, the political call for increased deregulation of the district heating sector and for lower electricity taxes has been taken into account.

The district heating system is expected to see a fall in the natural-gas-fired CHP capacity and an increase in heat pumps in the district heating system during the 2020s and 2030s compared with a frozen-policy scenario. DEAs best guess at the total operational power plant capacity is that it will be reduced by around one-third by 2040, compared with today's level. Note that this is a guess at the total installed (i.e. available) capacity, which means that all of the total capacity available is not necessarily used but can increasingly serve as back-up capacity during shortages of renewables-based electricity in the system. Note also that there is great uncertainty about the development in power plant capacity and that the power plant capacity could be reduced at a faster pace than expected in PGSO-IP18, especially in the current situation with major changes to framework conditions. Therefore, a lower range of outcomes has been incorporated for large-scale power plants. However, also small-scale power plant capacity could fall at a slower pace than expected. The analysis of collective heat supply that will be performed as follow-up to the 2018 Energy Agreement will examine this in more detail.

1.7.6 Large heat pumps and electric boilers

The development in the capacity of heat pumps and electric boilers up to 2020 is the same as in DECO18 and is based on energy production statistics for 2016, as well as on knowledge about concrete projects.

The development in the period 2020-2040 is based on estimates about individual district heating areas where heat production from CHP plants and natural gas boilers that are discontinued will be partially replaced by new heat pumps. Also here, the underlying assumptions are associated with considerable uncertainty, and this topic - along with the topic of small-scale power plant capacity - will be examined in more detail in future years.

Furthermore, it is assumed that there will be some deployment of electric boilers, adding to the existing capacity of 661 MW.

1.7.7 Onshore wind

It is predicted that there will be a possible gross deployment of around 2 GW from 2020 to 2030. This means that the current onshore-wind capacity of 4.2 GW (beginning 2018) is expected to increase by around 1 GW, reaching around 5 GW in 2030. Existing rules e.g. on distance requirements, historical practice, local opposition, the 2018 Energy Agreement, etc. will set a limit to what can realistically be expected in terms of capacity deployment. A substantial number of old turbines are expected to be dismantled during the period. These are expected to be replaced by fewer but larger turbines. This is assessed to be in line with the decision in the 2018 Energy Agreement to reduce the number wind turbines from 4,300 to no more than 1,850 by 2030. However, PGSO-IP18 does not include assumptions about the number of turbines; only about the installed capacity. Once there is a concrete plan for the reduction of turbines as follow-up to the Energy Agreement, a more detailed analysis will assess the rate at which old turbines are expected to be dismantled.

It is assumed that, after 2030, the new gross onshore capacity will correspond to the capacity that is dismantled, so that a total capacity level of 5 GW is maintained. This corresponds to annual installation of around 160 MW new gross onshore wind capacity after 2030. This will lead to an additional fall in the number of onshore wind turbines from 2030 to 2040, as it is assumed that the new turbines will have a larger capacity than the old turbines dismantled.

1.7.8 Offshore wind

The 2018 Energy Agreement includes establishment of three new offshore wind farms, each of at least 800 MW before 2030: One offshore wind farm of 800 MW with grid connection in 2024-2027 and a decision that two farms of at least 800 MW each are to be put out for tender in 2021 and 2023, respectively. The first farm is expected to be located in DK1 off the west coast of Jutland. However, the location is still uncertain and is awaiting the result of various screenings already launched.

Given the relatively high biomass prices compared with gas, more wind is required to reach the long-term goal of net-zero emissions approximated through fossil fuel independence in the energy sector. An additional offshore wind deployment of 300-350 MW annually is assumed for the period 2030-2040, primarily in DK1. This includes prolonging the operational life of turbines, dismantling old turbines and replacing them with new, and re-powering existing offshore wind farms.

1.7.9 Solar PV

To a larger degree than for wind, it is expected there will be an upper limit for deployment of solar PV capacity. This limit is determined by economic aspects due to the relatively low number of full-load hours in a year. The more photovoltaic solar modules installed, the greater is the pressure on the electricity price during hours when the sun is shining and the modules produce at their highest, and the less attractive it is to invest in solar PV. On the basis of analyses of the solar PV potential, it has been assessed that electricity production from solar PV will amount to a maximum of around 15% of total electricity demand. This assessment has been decisive for the long-term projection of solar PV capacity in Denmark.

PGSO-IP18 assumes that solar PV capacity will increase gradually until it peaks at a maximum capacity of around 7,000 MWp in 2040.

1.7.10 Interconnectors

Assumptions about interconnectors have not been adjusted compared with PGSO-IP17. This is because interconnectors are planned precisely on the basis of the power and gas sector outlook, and therefore the projections of electricity transmission lines and gas lines are inherently 'frozen policy' projections. Note, however, that commissioning of the Viking Link and the associated expansion of the connection to Germany has been postponed by one year to 2024.

1.7.11 Consumption and production of gas in Denmark

Danish natural gas consumption has been assessed to fall considerably - from overall consumption of around 100PJ in 2018 to around 60 PJ in 2040. The corporate sector is responsible for the greatest share of Danish gas consumption and the sector's consumption is expected to stay roughly the same throughout the period. Households as well as gas for electricity and district heating production today account for a significant part of consumption, but up to 2040 consumption is expected to fall and most pronounced for gas for electricity and district heating production. Gas for transport has been assessed to increase during the period, albeit from a low starting point, and gas consumption for transport is not expected to be higher than 5 PJ in 2040.

The short-term projection of biogas production takes account of anticipated construction projects, while the long-term projection takes account of the biogas production potential and subsidies for production of biogas. The most recent projections (which also form the basis for DECO18) cover the period 2018-2023. The baseline projection assumes that production of biogas will be constant after 2023. DECO18 includes only biogas upgraded for use in the gas grid. Compared with DECO18, the years 2021 to 2023 have had extra production volume added due to the expected result of the DKK-240-million biogas pool set aside annually over 20 years in the 2018 Energy Agreement. After this, biogas production for the gas grid is kept at a fixed level up to 2030, followed by a slight increase up to 2040.

Assumptions about gas interconnectors have not been adjusted compared with PGSO-IP17. The total balance for gas flows has been calculated on the basis of the Danish Energy Agency's oil and gas projection, an expected falling trend in Sweden's gas consumption in line with Danish gas demand, and on assessments about future gas flows to the Netherlands from the North Sea and to/from Germany. These assessments are associated with great uncertainty.

2 Economic indicators and prices

2.1 Economic indicators

The economic indicators are used as input when calculating fuel prices and when projecting consumption. Furthermore, Energinet uses the indicators in their annual budget calculations.

DEA has used data from the ADAM (Annual Danish Aggregate Model) model in connection with the 2018 Finance Bill (Danish Ministry of Finance, 2017a) as the basis for all economic indicators (real GDP, GVA deflator, interest rate on 10-year government bonds, net price index, dollar rate, euro rate and index of consumer prices). The same basis was used for DECO18.

Expectations for average real growth in gross domestic product (GDP), inflation measured as the percentage change in the net price index, and the interest rate level in the final year of Danish 10-year government bonds are described in table 2.

Table 2: Trends in real GDP, inflation and interest rates on 10-year government bonds

	2018	2019	2020	2025	2030	2040
	Annual change in %					
Real GDP (5-year average)	1.7	1.7	1.7	1.5	1.2	1.0
Net price index	1.6	1.8	2.0	2.1	2.1	2.0
	%					
Interest rate on 10-year government bonds[1)]	0.8	1.6	2.2	4.4	4.5	4.5

1) The government interest rate is the nominal, effective interest rate, i.e. not adjusted for inflation.

When assessing investment projects in which the feasibility analysis is based on socio-economic calculations, Energinet follows the guidance set out in DEA's and the Danish Ministry of Finance's guidelines (Danish Energy Agency, 2018b) and (Danish Ministry of Finance, 2017b). In the assessment of investment alternatives, a socio-economic discount rate is used which to begin with is 4% but is then gradually reduced for long-term projects as shown in table 3. The socio-economic discount rate is a real interest rate, i.e. adjusted for inflation.

Table 3: Real socio-economic discount rate in %

	0 – 35 years	36 – 70 years	More than 70 years
Applied interest rate	4%	3%	2%

Currency conversions in connection with projections of fuel prices and carbon prices use the exchange rates from the Danish Ministry of Finance's 2018 Finance Bill, see table 4.

Table 4: Dollar and euro exchange rates (Danish Ministry of Finance, 2017b)

	2018	2019	2020	2025	2030	2040
DKK/USD	6.89	6.80	6.70	6.25	6.25	6.25
DKK/EUR	7.44	7.44	7.44	7.44	7.44	7.44

2.2 Fuel prices and carbon prices

Fuel prices (of fossil as well as biomass fuels) and carbon prices are used as input for most of the intended applications of the power and gas sector outlook. The prices are included in market calculations to determine the marginal costs of using the fuels and they therefore have direct influence on the calculated electricity price. The prices are included in all analyses in which the use of the fuels is included in the variable costs.

The prices of the fuels used are broken down between representative places of use, i.e. for large-scale plants or large-scale CHP plants (at large-scale plants) and for small-scale CHP plants, district-heating plants and industrial plants (at small-scale plants). The fuel prices are factor prices, which means they have been calculated without taxes, subsidies and VAT.

The basis for the coal, oil and natural-gas prices is the most recent projections from the International Energy Agency (IEA, 2017). The IEA calculates long-run equilibrium prices for fossil fuels under conditions set up in a series of interrelated scenarios for developments in global energy markets, and these are updated in the IEA annual *World Energy Outlook* publication.

The prices in this power and gas sector outlook are based on the development in the central "New Policies Scenario" in *World Energy Outlook 2017* (IEA, 2017). Furthermore, forward prices of fuels are used over the short term, and these subsequently partially converge with the IEA prices over the long term. This methodology has been described in more detail in a memorandum on assumptions for *Denmark's Energy and Climate Outlook 2018* (Danish Energy Agency, 2018c) and in the background report for Denmark's Energy and Climate Outlook 2017 (Danish Energy Agency, 2017a).

The fuel prices are identical with the prices that were used in DECO18, but the carbon price has been written up to reflect the significant changes in the price during 2018.

2.2.1 Projection of prices of coal, oil and natural gas

DEA uses forward prices of oil from the Danish Ministry of Finance and the Ministry for Economic Affairs and the Interior, while it obtains its own forward prices of coal and natural gas. The origins of forward prices are stated in table 5.

Table 5: Sources of forward prices used in the Danish Energy Agency (used for DECO18, PGSO-IP18 and for the 2018 assumptions for socio-economic analyses)

Coal	ICE Rotterdam Coal Futures
Crude oil	CME Group Brent Last Day Financial Futures Quotes
Natural gas	EEX NCG Natural Gas Year Futures

The forward prices are market prices on 30 November 2017.

Convergence method: Weighting between forward prices and EIA long-run equilibrium prices

DEA uses the following formula to calculate developments in fuel prices and partial convergence towards the IEA's long-run equilibrium prices up to 2025:

$$fuelprice_{\,t} = \; w_t \times IEAprice_{\,t} + (1 - w_t) \times forwardprice_{\,t}$$

where w_t is 0 in 2018 and 2019 and 0.5 in the period 2020 to 2025. After 2025 the prices have been projected using the growth rates from the IEA's "New Policies Scenario" in *World Energy Outlook 2017*.

From international prices to Danish CIF prices (import prices)

Danish import prices have been estimated by adding to the international price the average difference between Danish historical prices (calculated on the basis of the following energy account tables from Statistics Denmark: ENE2HA and ENE4HA) and IEA prices (from the IEA's *Energy Prices and Taxes* and previous versions of *World Energy Outlook*). The difference has been calculated for each fuel as an average for the period 2001-2015, see table 6. As can be seen from the table, Danish coal and crude oil prices have historically been at a higher level than the IEA prices. However, Danish natural-gas prices have been considerably lower.

The historical price difference between Danish and IEA prices for coal and crude oil is assumed to remain constant in fixed prices for the entire projection period, while for natural gas it is expected that Denmark will gradually change from being a net exporter of natural gas (and therefore often a price setter) to being a price-taker as natural gas production in the North Sea subsides. The Danish CIF price for 2036 has been calculated as the IEA price plus the average historical difference between the IEA natural-gas prices and the German natural gas spot price from NCG, corresponding to DKK -5.9/GJ (2018 prices). Prices for the period 2018-2035 have been interpolated from these two price differences. For the period 2036-2040 the price difference is assumed to remain constant and equal to the 2036 price in fixed 2018 prices.

Table 6: Average historical difference between Danish prices and IEA prices for coal, crude oil and natural gas in the period 2001-2015

DKK/GJ (2018 prices)	Price difference relative to the IEA	Price difference relative to the IEA (from 2036)
Coal	0.4	
Crude oil	4.4	
Natural gas	-14.0	-5.9

The methodology applied is the same as in DECO18 and is based on the 2018 assumptions for socio-economic analyses (Danish Energy Agency, 2018d).

Prices at place of use in Denmark

For conversion of the Danish import price to the actual price paid by Danish market players for the fuel products, a number of estimated additional charges (price supplements) for costs of refining and costs of transport, storage and markup have been applied. The price supplements applied are shown in table 7. All supplements have been kept unchanged in fixed prices for the entire projection period.

Table 7: Costs of refining and costs of transport, storage and markup for fossil fuels

DKK/GJ (2018 prices)	At large-scale plants	At small-scale plants
Coal	1.3	-
Fuel oil	-13.6	-
Gas oil	21.6	33.7
Natural gas*	1.2	5.7

*The natural-gas price includes sunk costs and covers both already incurred investments as well as ongoing costs that are independent of the 'size' of the demand. The stated price is a market price, which is used for corporate-economic calculations and is included in Energinet's market model. Note, however, that, in socio-economic analyses, a supplement has to be added to the natural-gas price reflecting the quantities of renewable energy gas in the grid. Source: (Danish Energy Agency, 2018d).

The end prices of the relevant fossil fuels at large-scale plants and at small-scale plants, respectively, are shown in figures 2 and 3.

Figure 2: Projections of prices of fossil fuels at large-scale plants for the period 2018-2040

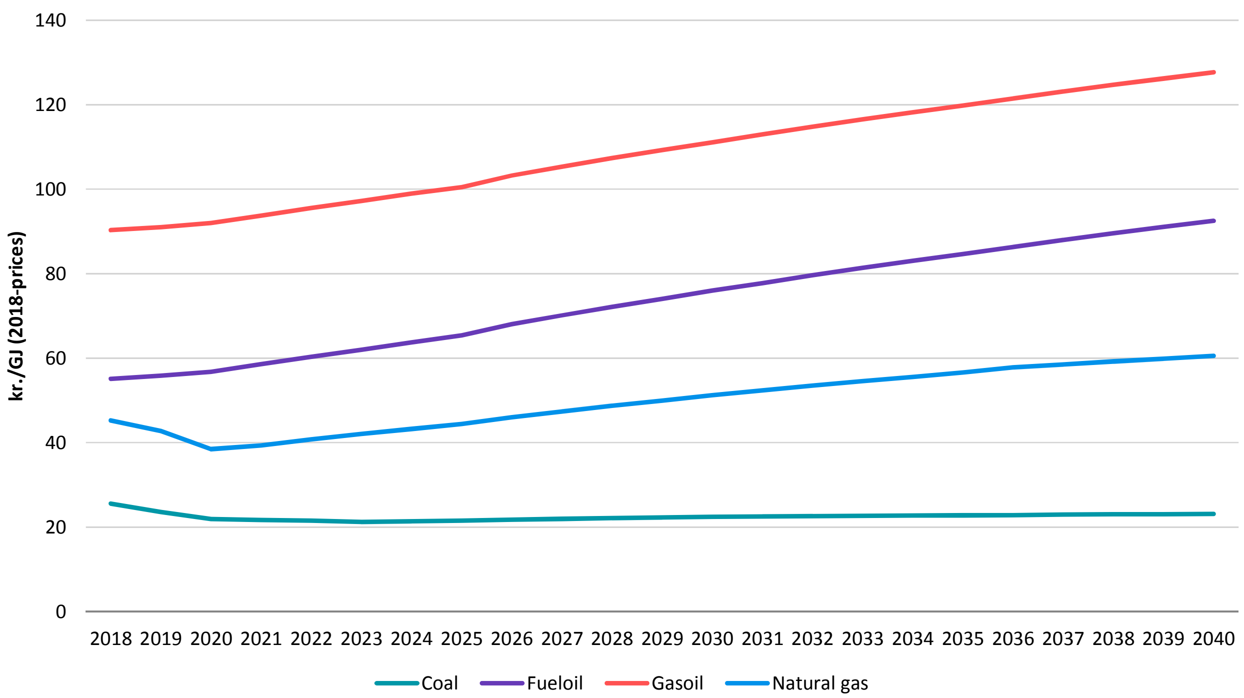
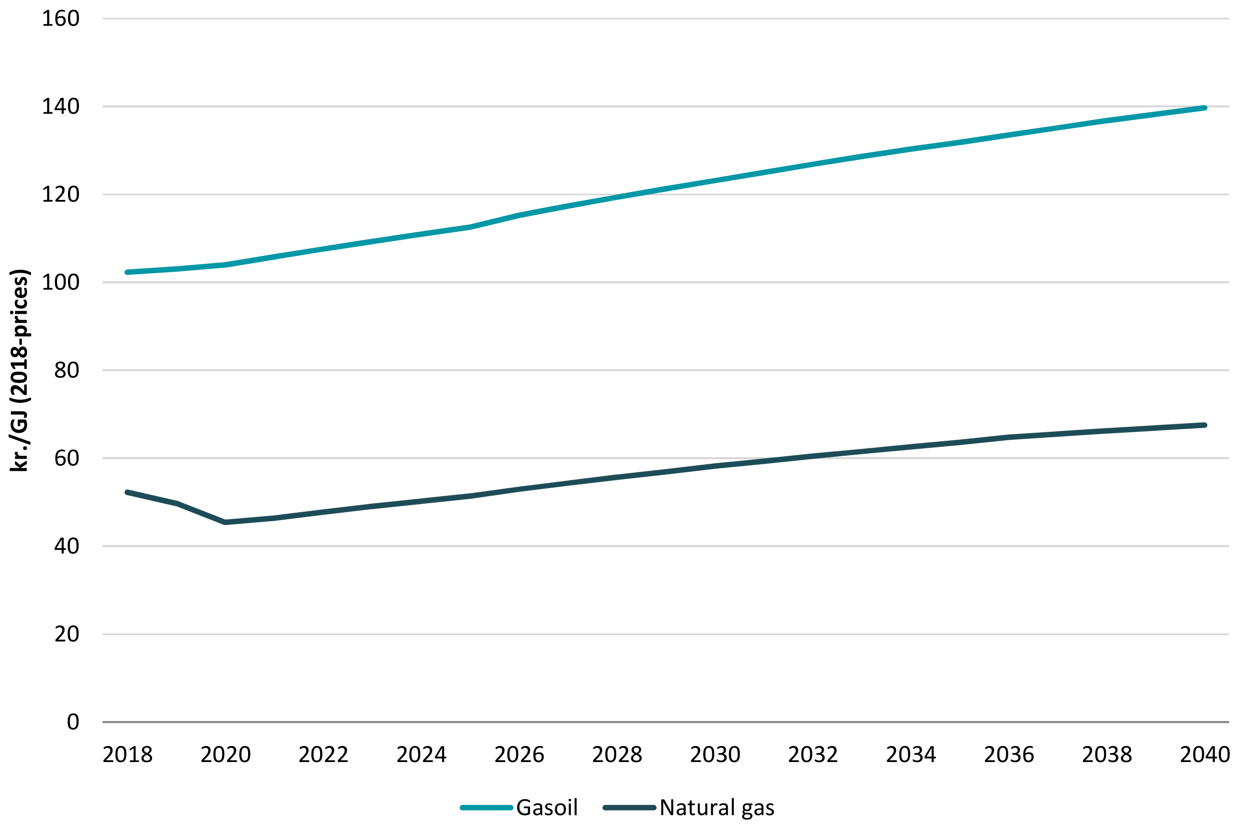


Figure 3: Projections of prices of fossil fuels at small-scale plants for the period 2018-2040



2.2.2 Projection of prices of straw, wood chips and wood pellets

The IEA does not prepare regularly updated projections of prices of solid biomass (straw, wood chips and wood pellets). Therefore, Ea Energianalyse has prepared an analysis of the long-term Danish import prices of solid biomass (EA, 2013) for DEA, and has developed a methodology for converting these import prices to prices at place of use in Denmark (EA, 2014).

The assumptions for socio-economic analyses were updated in 2016. The update entailed a number of improvements to the original methodology, including the addition of a convergence scenario between forward prices and long-run equilibrium prices, also for wood pellets, based on the assessment that the markets for wood pellets had become well-functioning enough to ensure reliable forward prices.

PGSO-IP18 uses the most recent prices for solid biomass projected by Ea Energianalyse in 2016 for the Danish Energy Agency (EA, 2016). The projections are based on long-run equilibrium prices up to 2050 for wood chips, wood pellets and straw. For imported wood chips and wood pellets, the prices represent import prices at delivery at a Danish port, and for straw and domestically produced wood chips, at the place of use. The long-run equilibrium prices can be converted to prices at place of use (small-/large-scale plants) by estimating the relevant price supplements, see table 8. This methodology has been described in more detail in a memorandum on assumptions for Denmark's Energy and Climate Outlook 2018 (Danish Energy Agency, 2018c).

Table 8: Costs of transport, storage and markup for solid biomass

DKK/GJ (2018 prices)	At large-scale plants	At small-scale plants
Wood chips	2.5-8	1.4-7
Wood pellets	2.2	6.7

Source: (Danish Energy Agency, 2018d).

The end prices for the relevant biomass fuels at large-scale plants are shown in figure 4, while the corresponding prices at small-scale plants are shown in figure 5.

Figure 4: Projections of prices of biomass fuels at large-scale plants for the period 2018-2040

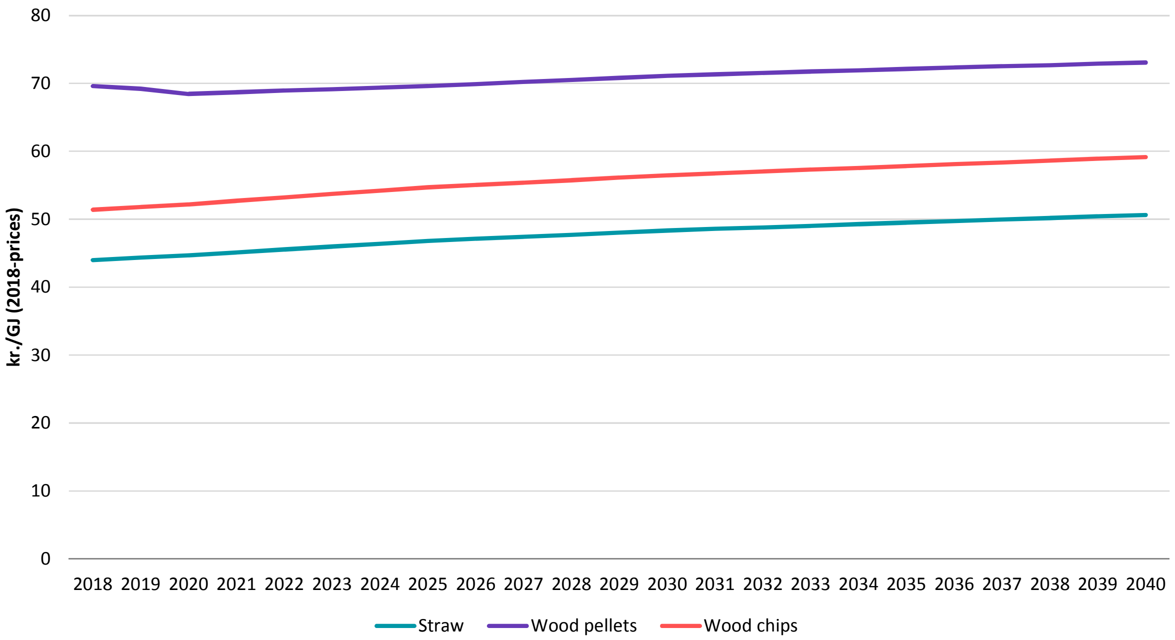
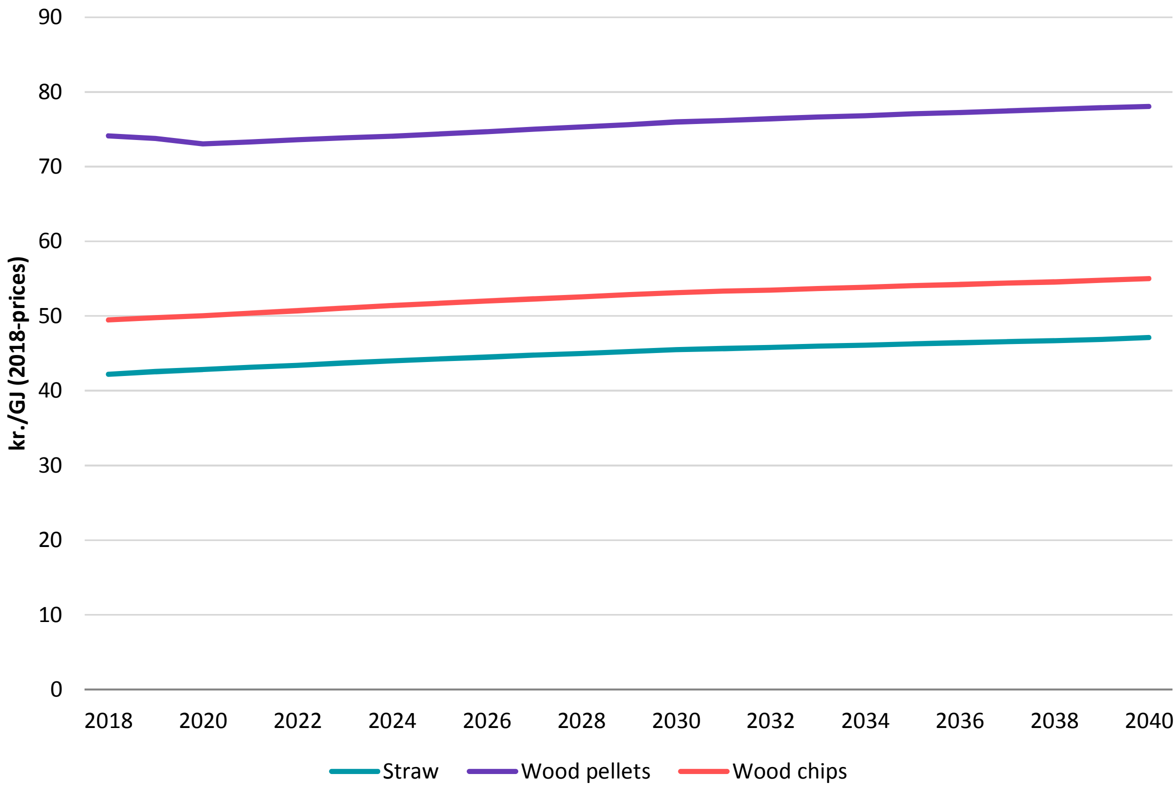


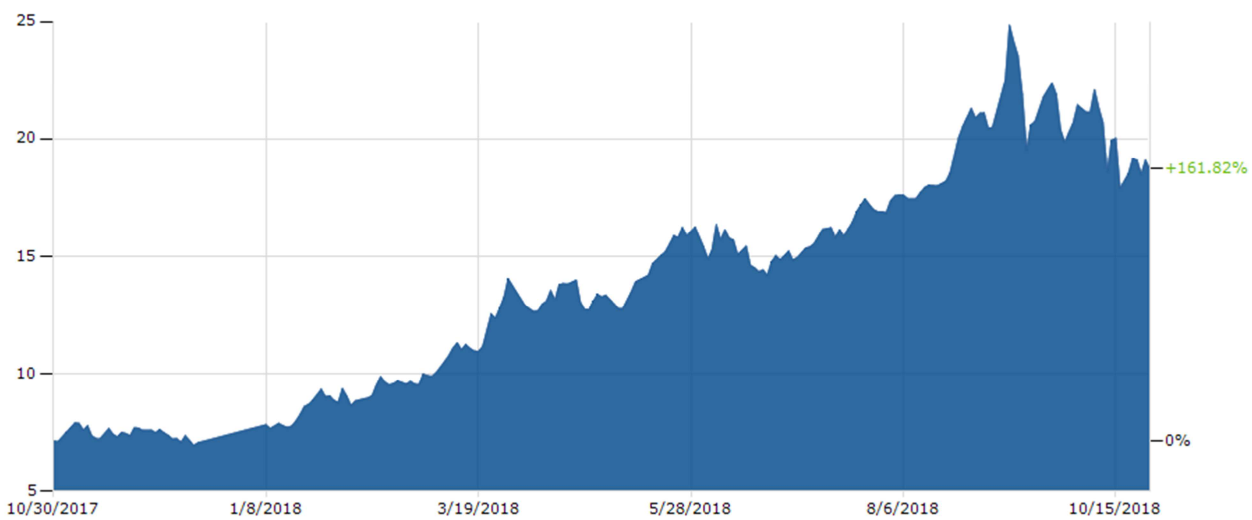
Figure 5: Projections of prices of biomass fuels at small-scale plants for the period 2018-2040



2.3 Carbon prices

In the EU, the carbon emission allowance price is a market-driven price, and emission allowances are traded both on spot markets and on secondary markets. In 2018 the market prices of carbon emission allowances increased significantly, e.g. because the European Commission tightened the framework for the ETS market, see figure 6.

Figure 6: Trends in the EU emission allowance price from October 2017 to October 2018

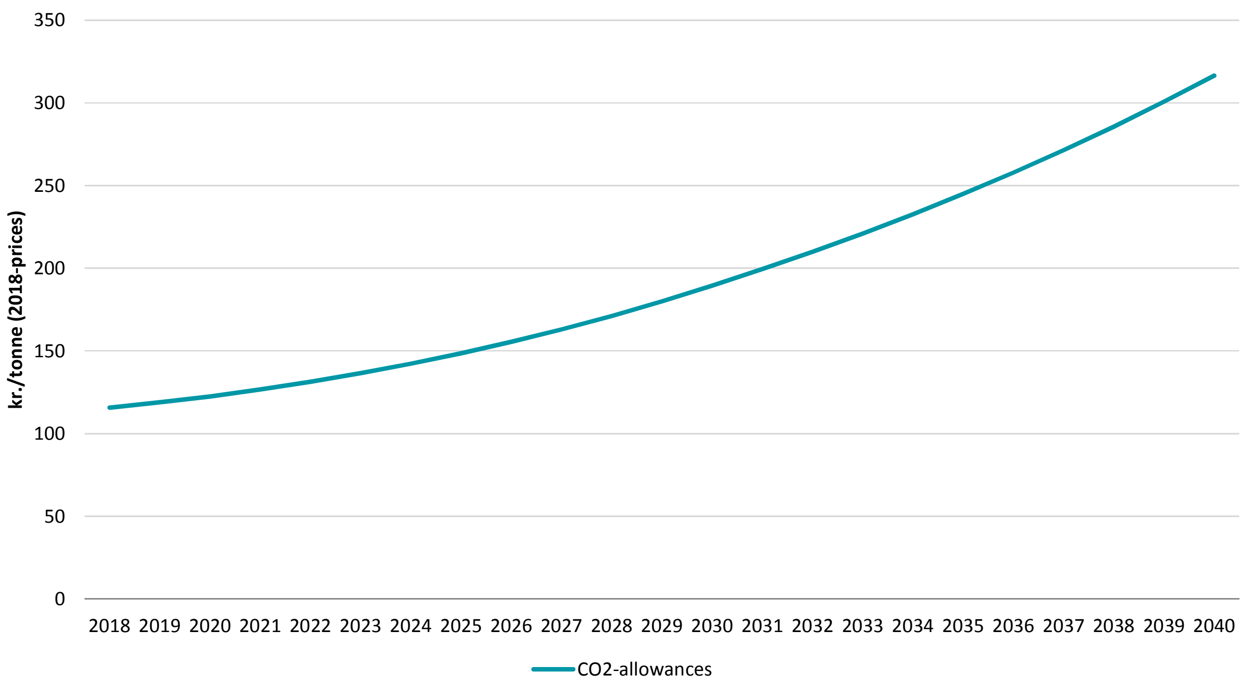


Source: https://markets.businessinsider.com/commodities/co2-emissionsrechte, 15 October 2018

The Danish Energy Agency has used the Danish Ministry of Finance's methodology for projection of carbon prices. On the basis of the reform of the EU ETS and the increase in carbon prices during 2018, the Danish Ministry of Finance revised its methodology in autumn 2018. PGSO-IP18's projection of carbon prices is based on this revised methodology. The revised methodology calculates the estimated implications of the ETS reform, which are reflected in a higher carbon price. Consequently, the projected carbon prices are substantially higher than the prices included in DECO18. Calculation of the carbon prices in DECO18 was based on an annual carbon price of DKK 46/tonne, i.e. the average carbon price in 2017.

Using the new methodology, an average carbon price for 2018 of DKK 116/tonne is expected, corresponding to around EUR 15/tonne, see figure 7. The price is expected to increase steadily to a level of around DKK 190/tonne by 2030 and to a level exceeding DKK 300/tonne in 2040. Note that, historically, carbon prices have varied greatly and that future price developments are associated with considerable uncertainty.

Figure 7: Projections of carbon prices for the period 2018-2040

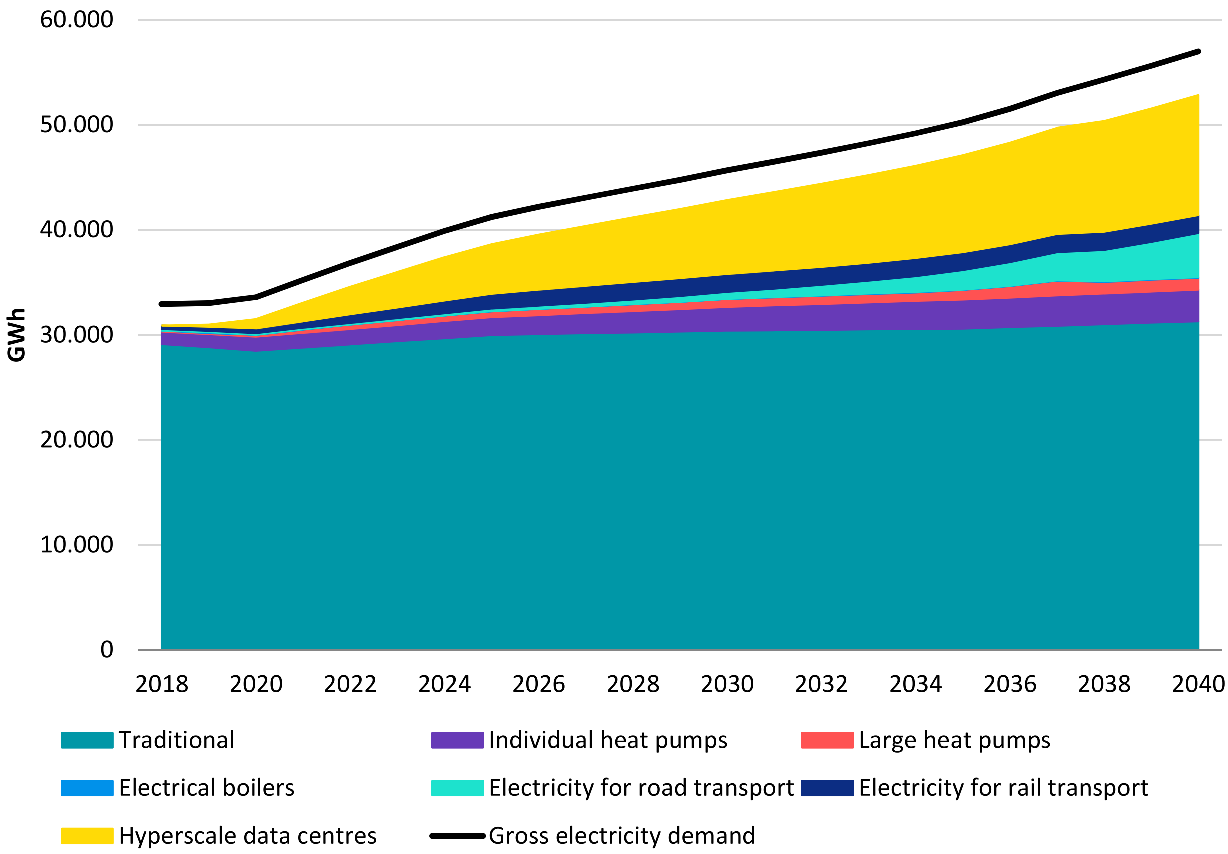


3 Electricity demand

Total electricity demand is broken down by electricity demand by households and the corporate sector excluding individual heat pumps (this is termed “traditional” electricity demand); electricity demand following from electrification of the heating sector (consumption by individual and large heat pumps and electric boilers) and the transport sector; as well as electricity demand by the large data centres expected to be established in Denmark.

The expected trends in Denmark's gross electricity demand and net electricity demand by sectors are illustrated in figure 8. The difference between gross and net electricity demand is due to losses in the electricity grid.

Figure 8: Expected trend in total Danish electricity demand during the projection period



Traditional electricity demand accounts for the major part of total electricity demand, and only a slight increase is expected over the projection period. This increase is attributable to, on the one hand, opposing effects of tax reliefs and general economic growth and, on the other hand, energy-efficiency improvements. The demand for electricity by data centres is expected to follow a steep upward trend, increasing total electricity demand by 22% in 2040. Electricity demand by heat pumps (individual heat pumps in households and the corporate sector as well as large heat pumps in district heating areas) is expected to increase, primarily due to the government's tax reliefs and technological advancements. Electrification of the transport sector is expected to gain momentum during the second half of the period, primarily driven by technological advancements.

The projections are associated with considerable uncertainty, especially with regard to relatively new technologies with large potentials but about which there is relatively limited experience with regard to projecting future developments. A number of sensitivity analyses have therefore been performed. These are described for each sector in more detail below.

3.1 Traditional electricity demand

The projection of electricity demand by households and the corporate sector is based on DECO18 with adjustments for tax changes and other measures in line with the 2018 Energy Agreement.

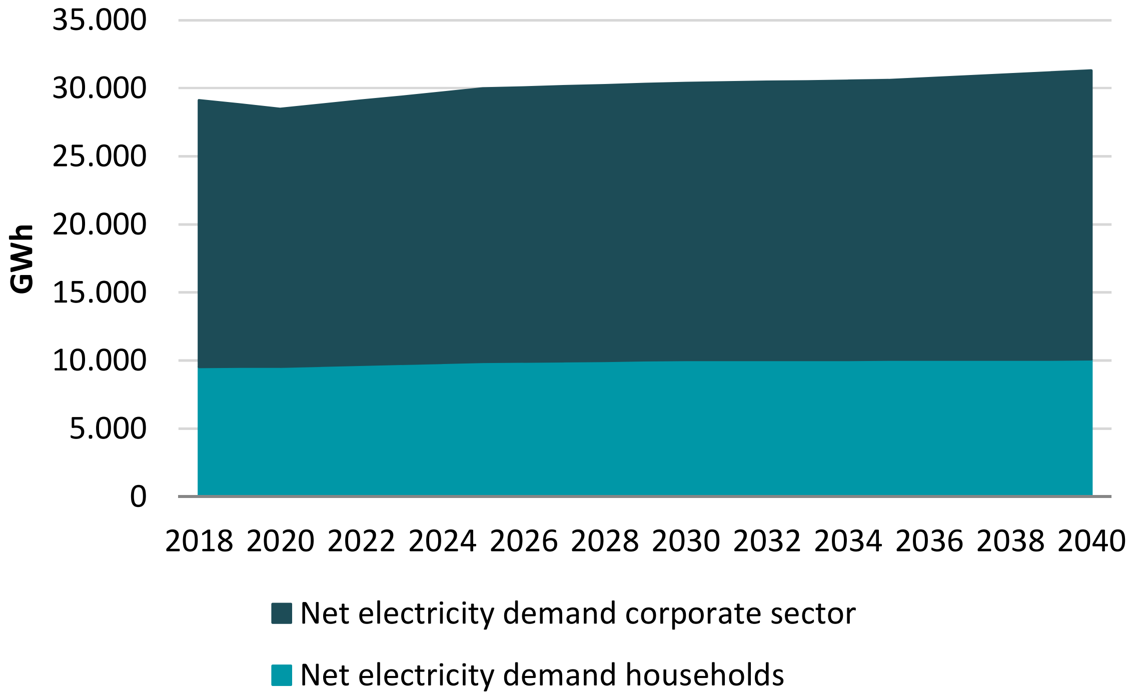
For households, an efficiency improvement effort has been incorporated reducing the net space heating demand for existing buildings by around 4 PJ by 2040 compared with a scenario which includes only the efficiency improvements that are expected to occur naturally in connection with renovations.

For the corporate sector, the energy-efficiency improvement effort is maintained all the way up to 2040, corresponding to the level set out in the 2018 Energy Agreement, which includes decisions on initiatives with expected annual energy savings of around 1.5 PJ. There are many savings to be gained from improving electric motors, lighting and from electrifying processes.

Finally, relaxation of the common electricity tax has been included. The relaxation will be phased in gradually up to 2025, as set out in the 2018 Energy Agreement.

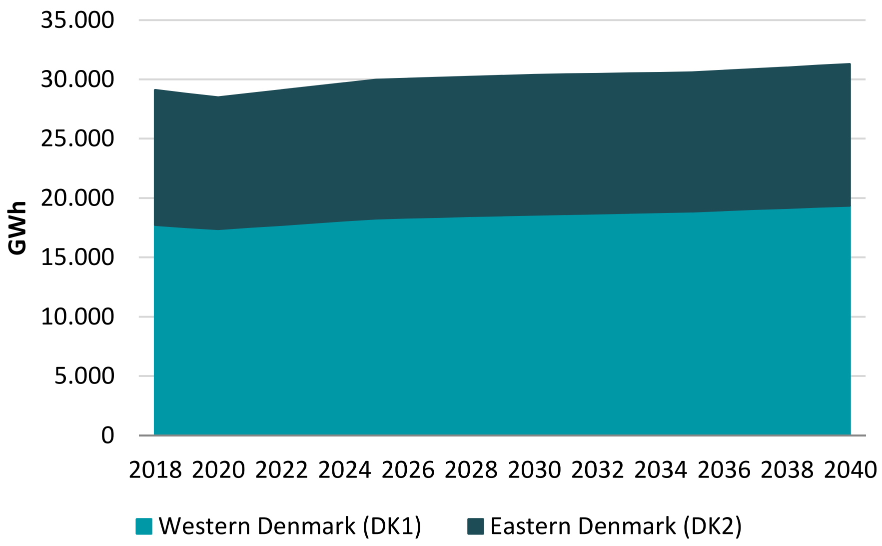
The effects of these initiatives pull the best guess scenario in opposing directions, but together with the expected general economic growth, electricity demand by households and the corporate sector (excluding heat pumps and data centres) is expected to increase slightly up to 2040, see figure 9.

Figure 9: Expected trend in electricity demand broken down by households and the corporate sector



The split between western and eastern Denmark is shown in figure 10.

Figure 10: Expected trend in electricity demand by households and the corporate sector, in western and eastern Denmark (excluding consumption by heat pumps and data centres)

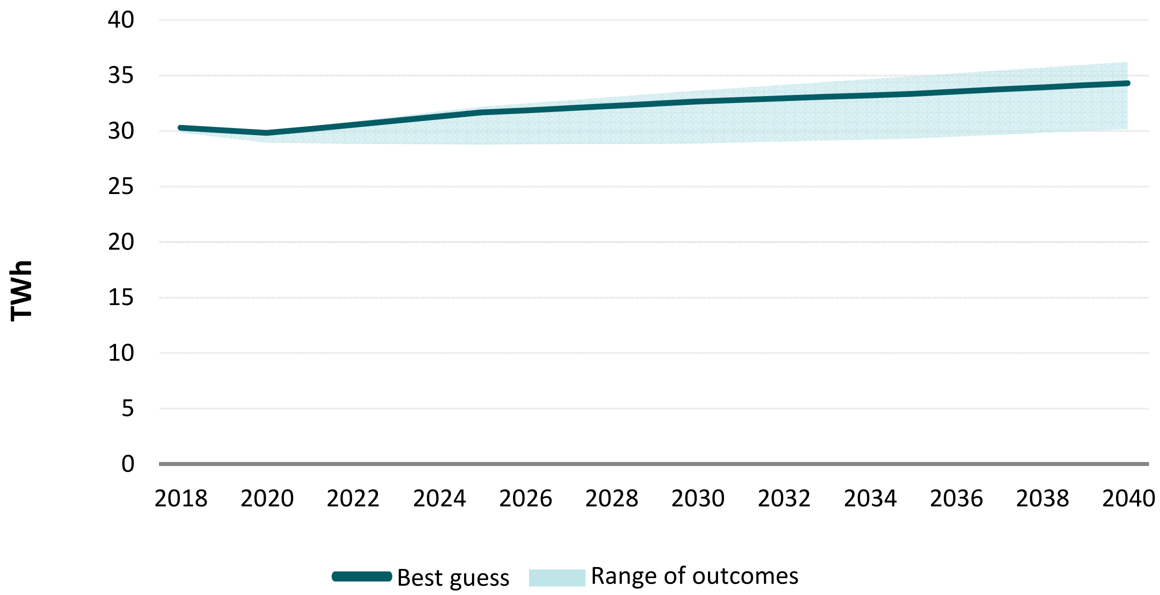


3.1.1 Sensitivities

Apart from political initiatives, the projection of electricity demand by households and the corporate sector is mainly driven by trends in electricity prices, taxes and fuel prices, as well as by technology costs. Figure 11 shows a possible range of outcomes for trends in traditional electricity demand. The range of outcomes for traditional electricity demand trends is relatively narrow because outcomes are affected by several opposing effects. The range of outcomes reflects a number of converging events (see below) but could be widened if the factors described are changed additionally.

Electricity demand will be lower in the event of higher electricity prices, lower gas prices, higher costs of investing in electricity technologies, and lower costs of investing in district heating technologies and gas technologies - and vice versa. At the same time, greater supply of energy-efficiency improvements in the corporate sector will give rise to lower electricity demand, while electricity demand will be higher if fewer energy-efficiency improvements are implemented.

Figure 11: Range of outcomes for traditional electricity demand



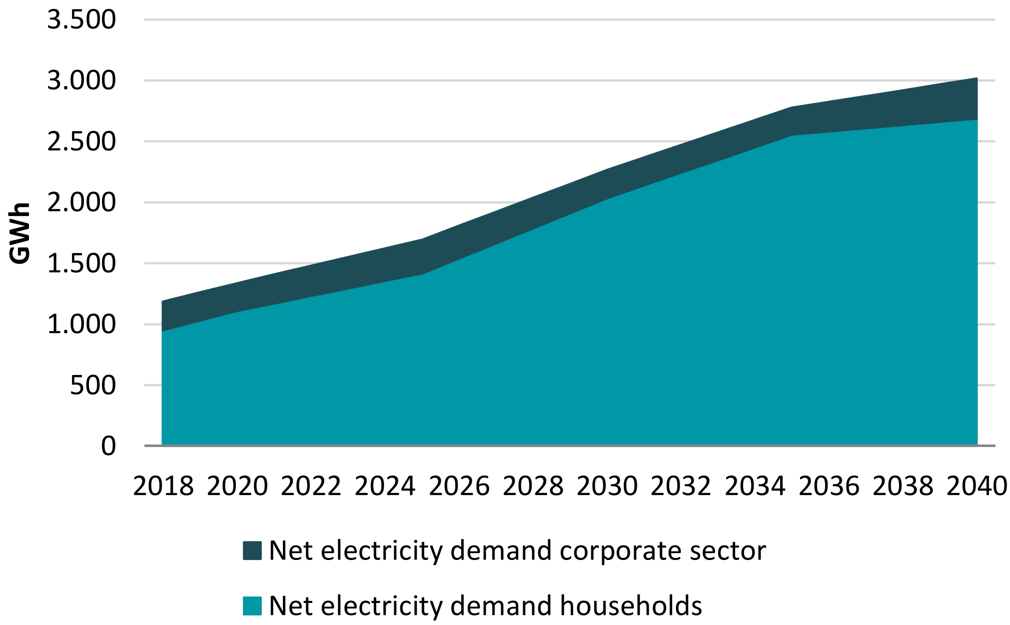
3.2 Heat pumps

Electrification of the energy sector is an important building block in the green transition and for greater use of renewable energy in the heating sector in particular. A reduction in the tax on electric heating following from the 2018 Energy Agreement will encourage a shift to heat pumps. However, the trend in electricity demand by heat pumps is characterised by uncertainty and depends extensively on technological advancements, the level of energy-efficiency improvements and the price of electricity and fuels.

3.2.1 Individual heat pumps

The trend in electricity demand by heat pumps in households and the corporate sector has been modelled in IntERACT together with traditional electricity demand. Electricity demand for heat pumps is expected to increase because the associated technology is close to maturation and to being able to compete with both natural gas boilers and wood pellet boilers. The reduction in the tax on electricity for heating will improve the competitiveness of heat pump technologies and will occasion an increase in installed capacity and thus also a higher consumption of electricity for heat pumps. The expected electricity demand for heat pumps by households and the corporate sector is shown in figure 12.

Figure 12: Expected trend in electricity demand by heat pumps in households and in the corporate sector

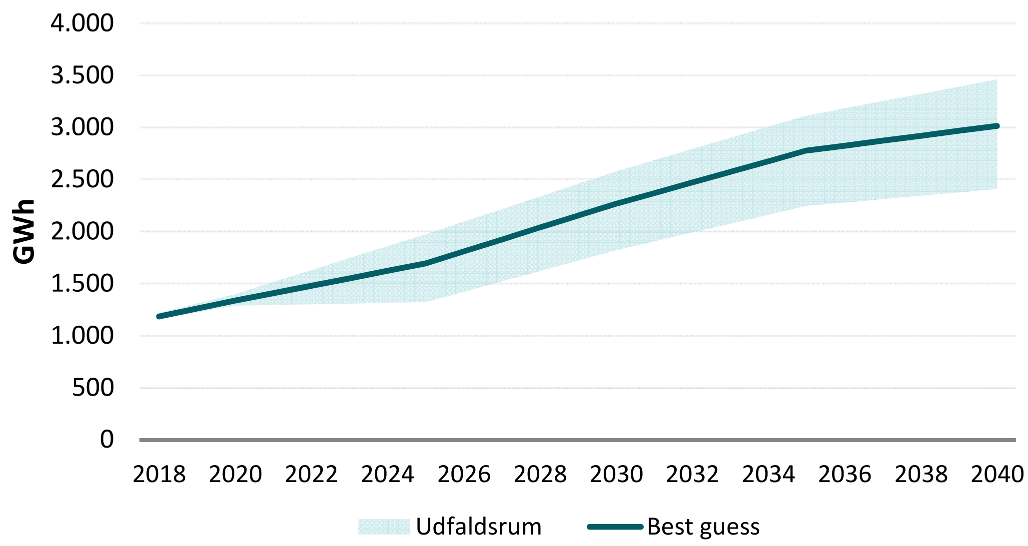


Although the corporate sector demand for electricity remains fairly constant it does not mean that the number of heat pumps remains constant. Rather, it reflects a scenario in which heat pumps become more efficient, leading to an increase in numbers and with it an increase in the consumption of ambient heat and in the space heating delivered to end-users. With regard to technological advancements, the analysis of the trend in electricity demand is based on the Technology Catalogue. However, a number of new technologies such as P2X (Power-2-X), CCS and industrial process heat pumps have not yet been included in the Danish Energy Agency's models. These will be included in future PGSO-IP reports. Furthermore, the Technology Catalogue is updated on a regular basis whenever new knowledge is available. For example, this year work is underway to include the most promising and well-documented new electricity storage technologies.

Sensitivity

The uncertainty in projections of consumption of electricity for individual heat pumps is mainly driven by the price level of competing fuels (fuels for district heating in particular) and by whether households and the corporate sector carry out energy-efficiency improvements. All else being equal, more energy-efficiency improvements in households and the corporate sector will lead to lower consumption of electricity for heat pumps. The same applies if the district heating price, in particular, is lower than assumed. A larger reduction in the tax on electric heating, lower costs of heat pumps due to technological advancements, and information campaigns and/or ESCO schemes will give rise to a higher consumption of electricity for heat pumps. A possible range of outcomes for developments is shown in figure 13. Also here the range of outcomes is affected by a combination of different factors that pull electricity demand in opposite directions. The lack of symmetry can be explained by mutual dependencies between these factors.

Figure 13: Possible range of outcomes for developments in the use of electricity for individual heat pumps



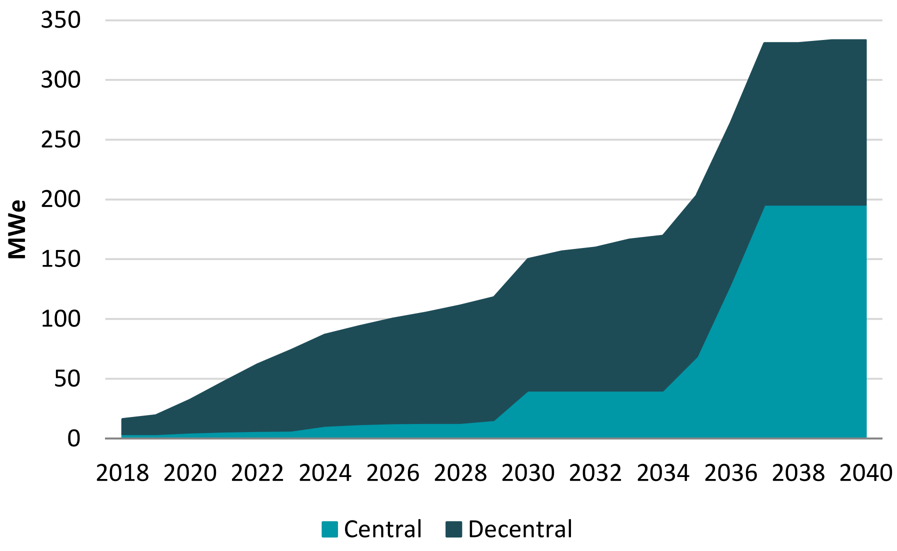
3.2.2 Large heat pumps

The development in large heat pump capacity up to 2020 is the same as in DECO18. After 2020, this capacity will increase as a consequence of the likely effect of the tax reliefs set out in the 2018 Energy Agreement. At the same time heat pumps based on surplus heat from data centres have been projected separately. The projection is based on the expected deployment level of data centres and on an appraisal of the potential for exploiting surplus heat prepared by COWI on behalf of the Danish Energy Agency (COWI, 2018).

The development from 2030-2040 is based on estimates about individual district heating areas where the heat production from discontinued CHP plants and natural gas boilers will be replaced by new heat pumps and other heat production.

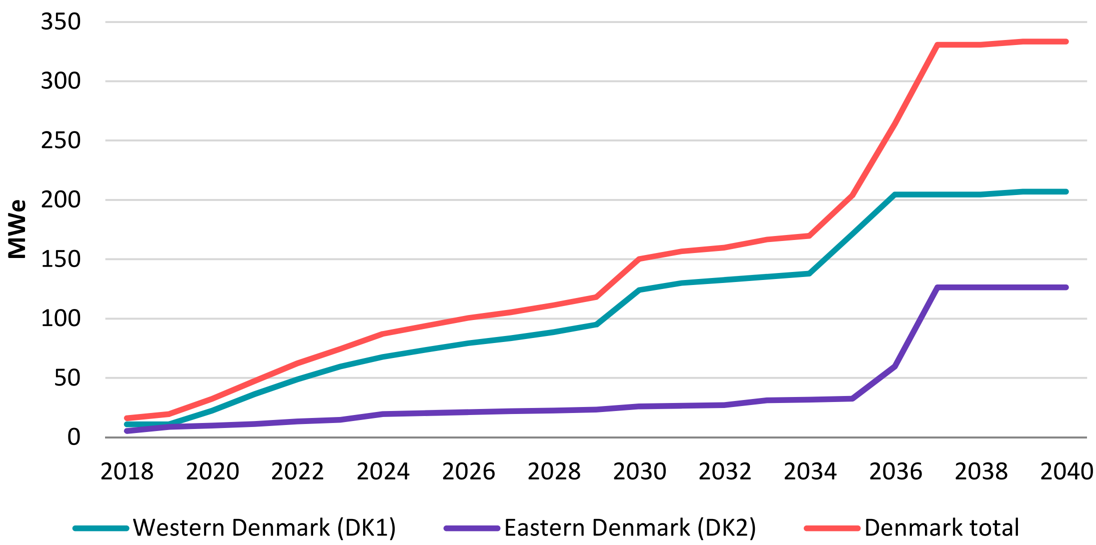
Figure 14 shows the expected capacity development for large heat pumps in the district heating sector broken down by heat pumps in large-scale and small-scale district heating areas, respectively. In the RAMSES model, large heat pumps have a relatively high utilisation time because large heat pumps are not expected to be competitive due to their high investment costs, unless they have a high utilisation time. This is a (model) output, and capacity is the only input assumption.

Figure 14: Expected capacity development for large heat pumps, central and decentral district heating areas



The split between western and eastern Denmark is shown in figure 15. Considerably more heat pumps are expected to be deployed in western Denmark than in eastern Denmark. This is because of better opportunities to exploit surplus heat, e.g. from large data centres, and because a greater number of small-scale CHP plants are likely to be decommissioned in western Denmark.

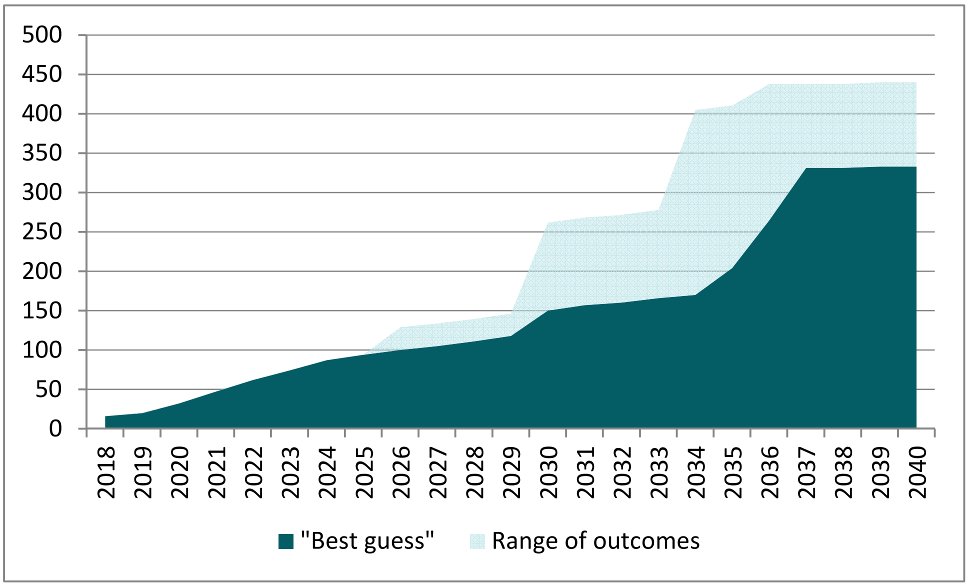
Figure 15: Expected electricity capacity development for large heat pumps, eastern and western Denmark



Sensitivity

Capacity developments for large heat pumps are associated with great uncertainty and this uncertainty is closely linked to uncertainty about capacity developments for power plants. If the pace at which power plants close down is faster than expected in the 'best guess' scenario, demand for heating will have to be met by other sources, e.g. heat pumps. The figure below shows a possible range of outcomes with more large heat pumps offsetting lower power plant capacity. This is shown as a range of outcomes in the section on power plant capacities. The upper range of outcomes is likely to include a large-heat-pump capacity of around 440 MWe in 2040, as opposed to 330 MWe in the best guess scenario. Note, however, that the expected number of heat pumps may be even greater if the pace at which large-scale plants close down is also faster than assumed in the 'best guess' scenario.

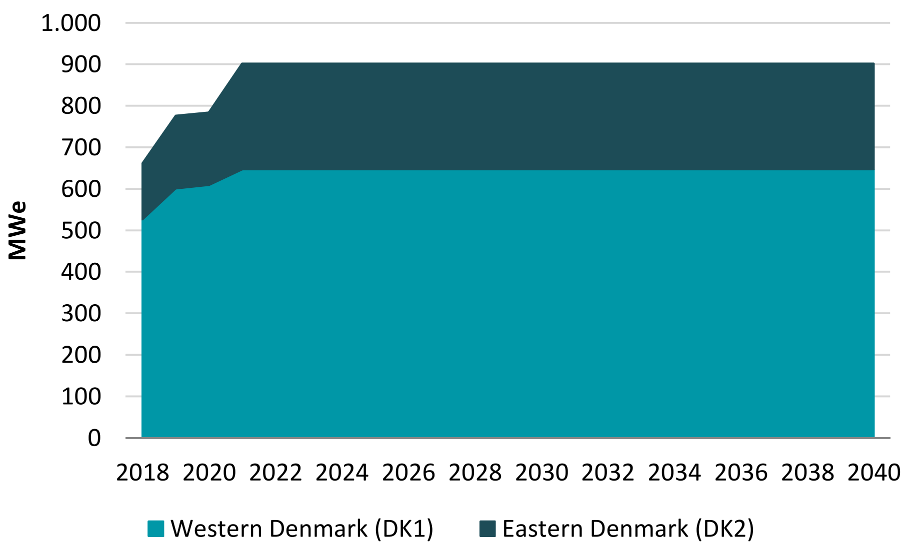
Figure 16: Possible range of outcomes for developments in large heat pumps



3.3 Electric boilers

The development in electric boiler capacity is based on energy production statistics, as well as on knowledge about concrete projects. Deployment of electric boilers is expected up to 2021 leading to a capacity of around 900 MW, up from the existing 661 MW. Capacity is subsequently expected to remain at the same level for the rest of the period, see figure 17.

Figure 17: Expected electricity capacity development for electric boilers, eastern and western Denmark



Several district-heating companies have launched projects to establish electric boilers. There may be a number of reasons for this. Among other things, investment costs are low and electric boilers can therefore serve as cheap reserve capacity in the heat supply system, and this, in turn, means that larger investments can be postponed. Another reason could be that the electricity spot prices are expected to continue to fluctuate considerably, with negative prices during some periods. However, similar to in earlier PGSO-IP publications by Energinet, DEA has chosen to keep the capacity at the same level from 2021 and onwards for the remainder of the projection period due to the considerable uncertainty about numbers and location, in particular. Furthermore, in the RAMSES model, electric boilers have very few operating hours and, thus, low electricity consumption. Note that this is a (model) output. In Energinet's use of PGSO-IP18, the capacity is the only input assumption.

3.4 Transport

The transport sector is divided into rail, sea and road transport.

Electrification of the transport sector has not yet gained momentum in Denmark but is expected to as a consequence of technological advancements and greater political focus. The pace of such electrification is difficult to predict, and the projection of the associated electricity demand is therefore associated with great uncertainty.

3.4.1 Trends in electricity demand by rail transport

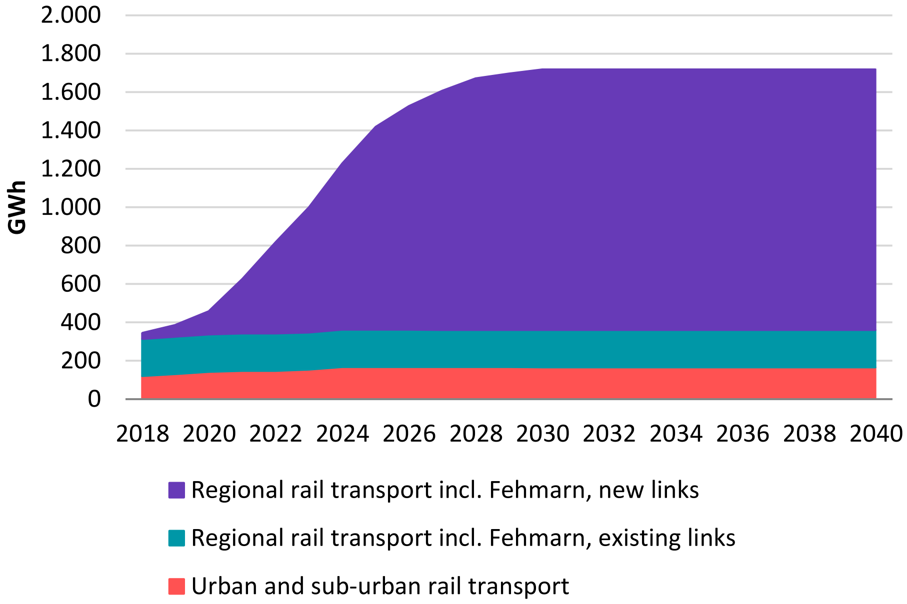
Rail transport includes regional rail transport and the Fehmarnbelt Fixed Link, as well as electrified urban railways (S-tog), underground railways (metro) and suburban light railways.

The expected trend in electricity demand for regional rail transport and the Fehmarnbelt Fixed Link is the result of concerted efforts between Banedanmark (the Danish railway track governmental body) and Energinet. Based on an electrification plan following from the 2012 political agreement on electrification of regional rail transport, and on timetables for expected train services up to 2030, Banedanmark has simulated the load on the system from regional rail transport. Energinet has subsequently converted the load to expected electricity demand, which from 2030 has been kept at a constant level up to 2040. The consumption figure includes the expected effects of the establishment of the Fehmarnbelt Fixed Link between Denmark and Germany. The Danish Energy Agency has not at this stage adjusted these figures but has let them remain the same as in PGSO-IP17.

The expected development in electricity demand for electrified railways (S-tog), underground railways (metro) and suburban light railways follows DECO18 up to 2030, after which consumption has been kept at a constant level. The consumption figure is based on data from the Transport, Construction and Housing Authority. In previous power and gas sector outlooks from Energinet, electricity demand for urban and sub-urban rail transport was included in traditional electricity demand.

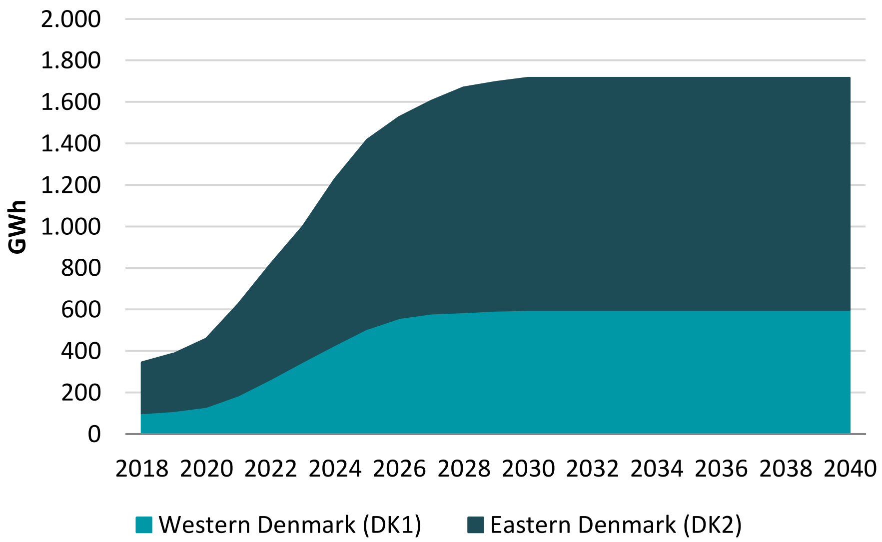
The expected electricity demand for rail transport is shown in figure 18. The figure clearly shows how electrification of regional rail transport accounts for the major part of electricity demand, not least after completion of the Fehmarnbelt Fixed Link.

Figure 18: Expected trend in electricity demand for railways



The split between western and eastern Denmark is shown in figure 19. Up to 2030, electricity demand in eastern Denmark will increase significantly with the planned completion of the Fehmarnbelt Fixed Link in 2028. The increase in electricity demand in western Denmark is expected to be lower because south-going traffic is expected to be relocated from the Great Belt Fixed Link to the Fehmarnbelt Fixed Link.

Figure 19: Expected trend in electricity demand for rail transport, western and eastern Denmark

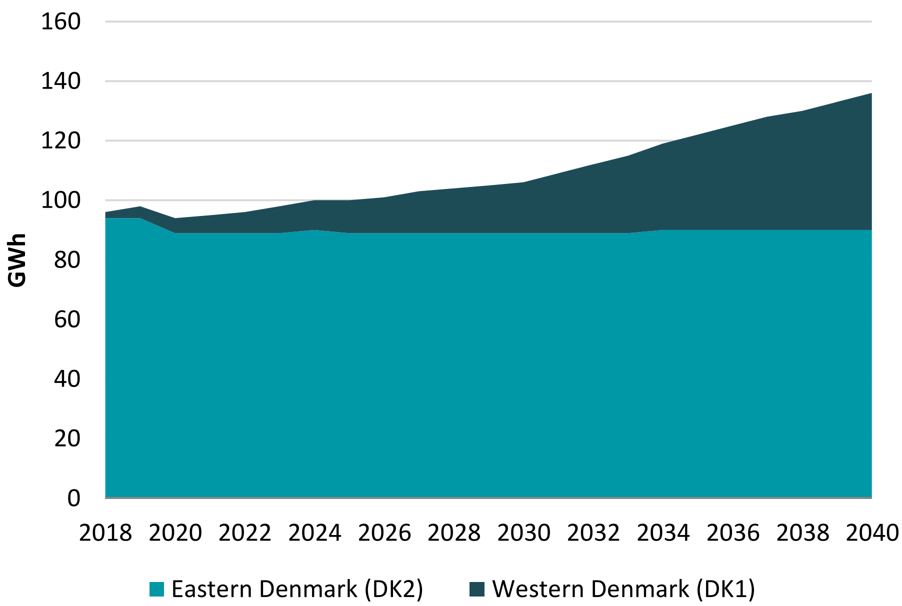


3.4.2 Trends in electricity demand by sea transport

Electricity demand for purely domestic routes, i.e. routes connecting two Danish ports, is based on an analysis by Siemens (Siemens, 2016) which examines how many routes could potentially (technically and financially) shift to electricity. To this is added electricity demand for ferry services to foreign ports using the same projection as Energinet in PGSO-IP17.

The development in electricity demand for sea transport broken down between western and eastern Denmark is shown in figure 20, which shows that the greatest potential for shifting to electricity is in ferry services in western Denmark, because the ferry services in eastern Denmark have already been converted to electricity.

Figure 20: Trends in expected electricity demand for sea transport, western and eastern Denmark



3.4.3 Trends in electricity demand by road transport

Electricity demand by road transport includes electricity for cars and vans (electric cars as well as plug-in hybrid cars), lorries and busses. Developments in electricity demand for cars and vans (i.e. light road transport) have been modelled in the Danish Energy Agency's Transport Model, and have been described e.g. in (Danish Energy Agency, 2018c). The projection for electric cars is based on a choice-of-car model, while the projection for electricity demand by lorries and busses (i.e. heavy road transport) is using a simpler approach. Electrification of road transport is expected to start out relatively slowly but is expected to gain speed and increase significantly when technological developments and market maturity reach a level where electric cars are price competitive and their driving range can satisfy the mileage needs of consumers. As the need arises, the infrastructure and framework conditions will probably be adapted to promote electricity in the transport sector and to allow the transport sector to contribute to meeting national targets and international requirements in the energy and climate area.

Technological developments and the price and tax differences between electricity and fuels are the most crucial factors for when electrification of the transport sector will take place. These parameters are particularly determinant for investment costs, driving range and energy efficiency and, thus, for the individual consumer's choice of car and the sales share for electric cars.

The projection of electricity demand by light transport follows DECO18 up to and including 2024, i.e. the first period of the 2018 Energy Agreement. This period therefore does not include initiatives in the transport areas that are expected to have an effect in the short term. Some elements in the Energy Agreement might, however, have some effect on developments in the sales of electric cars in the long term. These include the tax relief and the funding set aside to support greener solutions in the transport sector. The projection builds on a rough assumption that sales of new cars and vans will consist exclusively of electric and plug-in hybrid cars by 2040. At the same time, the share of purely electric cars (non-hybrid) is expected to increase from 60% in 2030 to 80% in 2040. The projection does not take account of a scenario in which hydrogen cars account for a smaller share of the green transition in light road transport.

It should be noted that it has not been possible to include the effect of the government's climate proposal for a stop to sales of petrol and diesel cars by 2030 in the basic scenario. However, it has been estimated that the proposal will only have a minor effect on the transmission grid, although a separate analysis has been launched to examine this in more detail. The results of this analysis will be included in next year's power and gas sector outlook. Furthermore, the ambition that all new cars be low-emission cars by 2030 and zero-emission cars by 2035 has been reflected in the range of outcomes for electricity demand for passenger cars and vans. This means that the government's expectation for 1 million electric cars, plug-in hybrid cars or similar green cars in Denmark by 2030 has been included in the sensitivity analysis.

It is expected that electricity will also play a minor role in heavy road transport. However, DEA has not performed a more detailed analysis of this. Therefore, it is assumed - as a rough estimate - that electricity demand by heavy road transport will correspond to around 10% of total electricity demand by light road transport throughout the period up to 2040.

Annual electricity demand in western and eastern Denmark broken down by light and heavy road transport, respectively, is shown in figures 21-22. There is considerable uncertainty concerning projections of electricity demand for the transport sector. This has been described in more detail in the sections on sensitivities.

Figure 21: Trends in expected electricity demand for light road transport, western and eastern Denmark

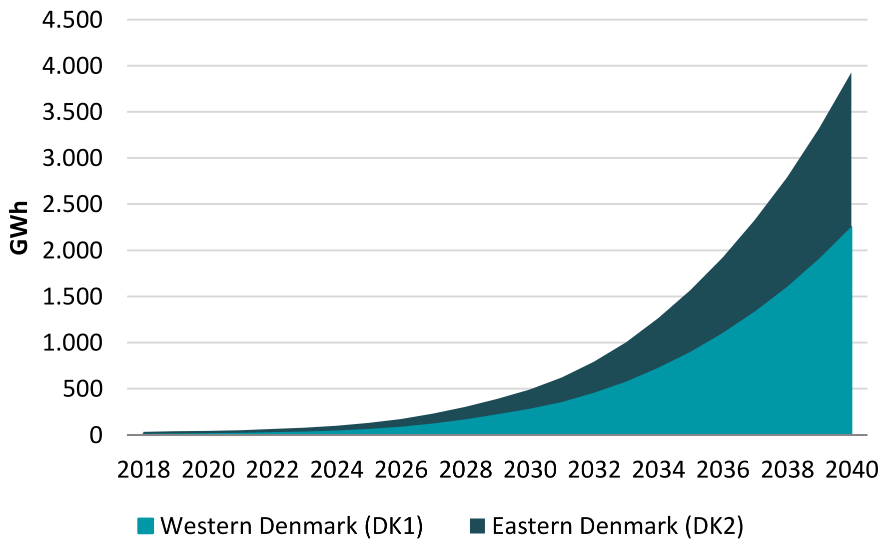
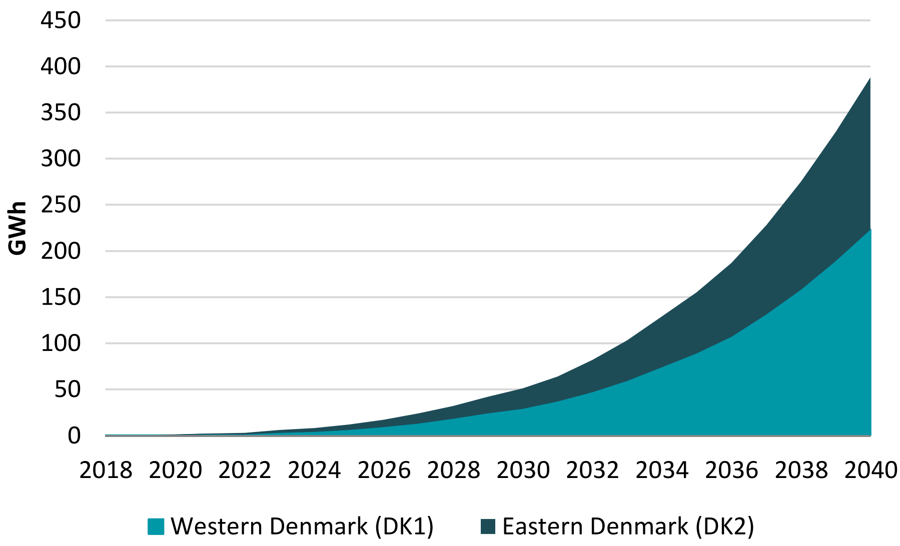


Figure 22: Trends in expected electricity demand for heavy road transport, western and eastern Denmark



3.4.4 Sensitivity

The development for light as well as for heavy road transport is very uncertain. For example, if technological development progresses at a slower pace than predicted, so that the driving range of electric vehicles is not significantly improved and the prices do not become competitive vis-a-vis petrol and diesel-driven cars as quickly as assumed, the growth in sales of electric cars will be smaller. Conversely, a faster technological development, changes to preferences and/or greater political efforts (e.g. as follow-up on the proposal to phase out petrol and diesel cars by 2030 in the government's Climate and Air Proposal) will promote sales of electric cars. Figures 23 and 24 indicate a range of outcomes for developments in electricity demand for light and heavy road transport, respectively. For light road transport, the range of outcomes is defined by an assumption of a 50% sales share for electric and plug-in hybrid cars by 2040 for the lower estimate, and a 100% sales share by 2030 for the upper estimate (in the upper estimate, sales of hybrid cars have been phased-out by 2035 as set out in the government's proposal. Both estimates deviate from DECO18 in the period 2020-2024). For heavy road transport, the range is defined by the assumption that electricity demand for heavy road transport will correspond to around 5% and 15%, respectively, of light road transport.

Figure 23: Range of outcomes for trends in expected electricity demand for light road transport

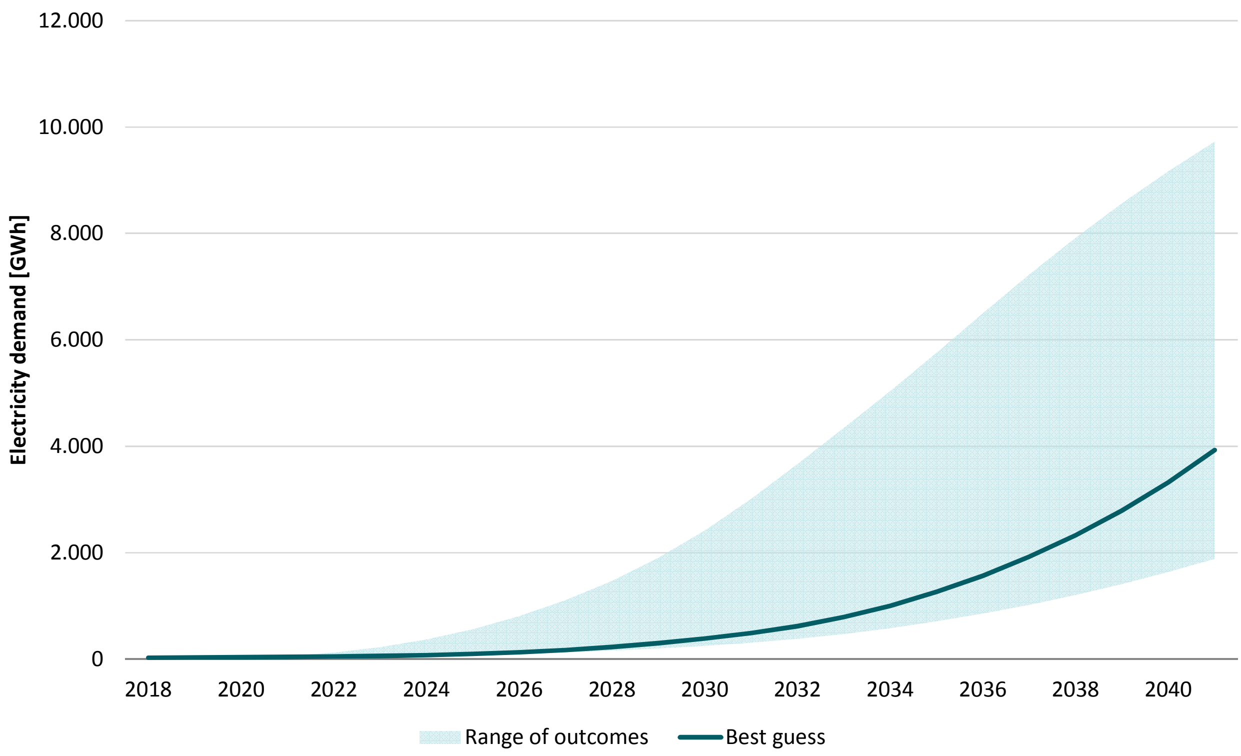
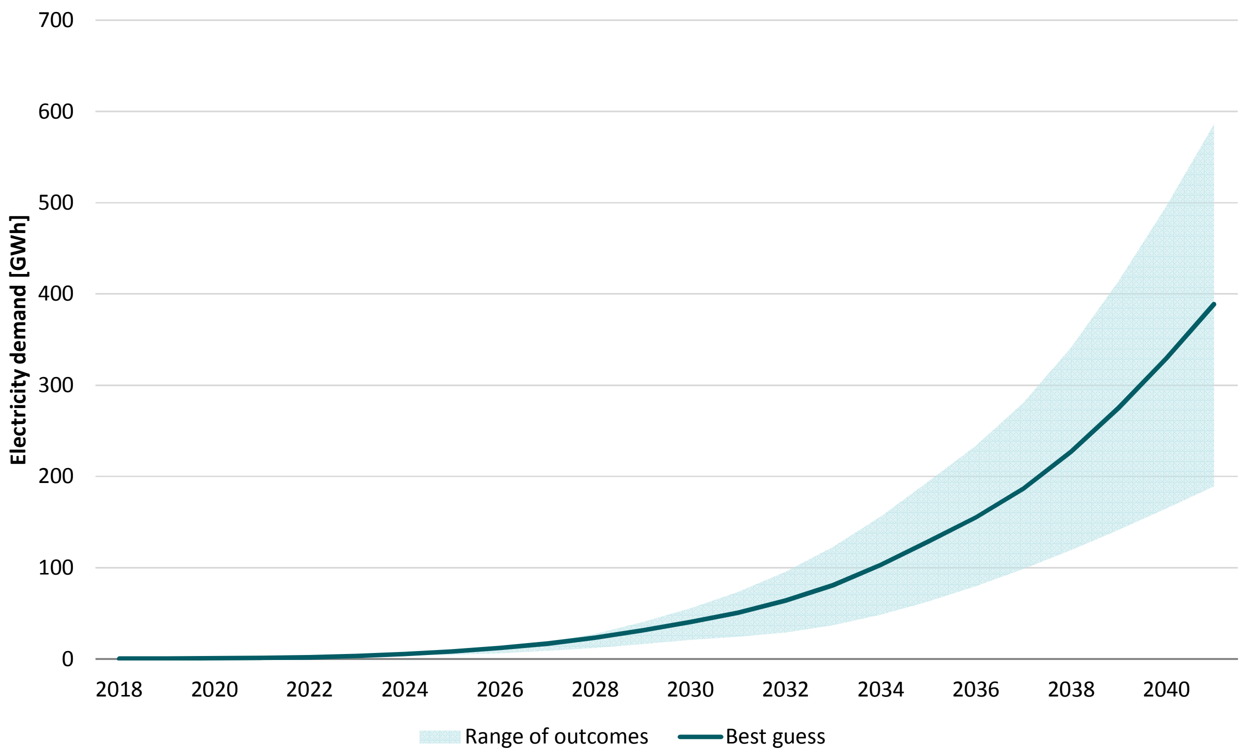


Figure 24: Range of outcomes for trends in expected electricity demand for heavy road transport



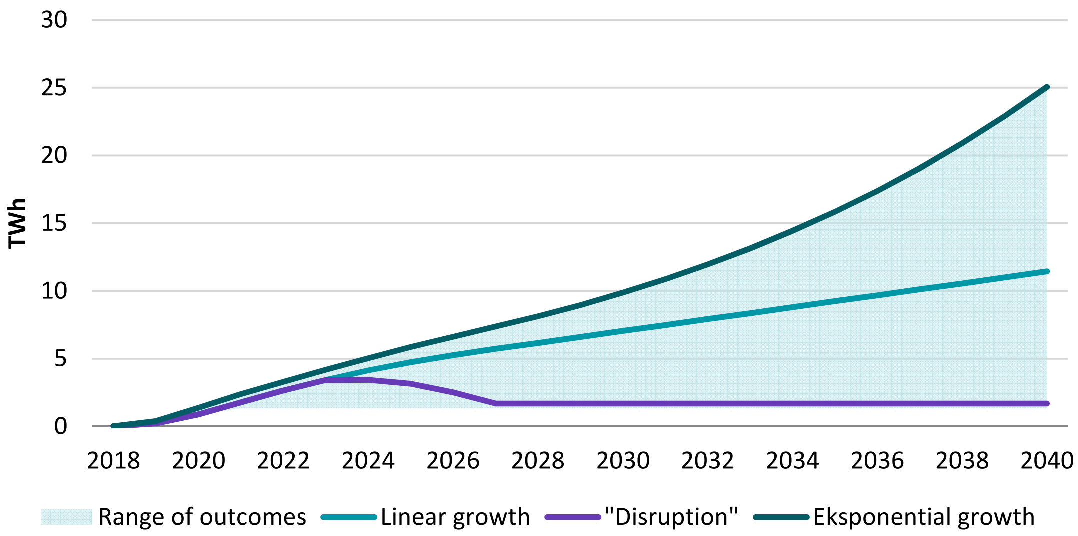
3.5 Large data centres

On behalf of the Danish Energy Agency, COWI has analysed the expected deployment of large data centres (so-called Hyper-Scale Data Centres HSDC) in Denmark and the derived impact on electricity demand and on electricity and district heating systems (COWI, 2018). COWI assesses that, by 2030, there will be around six large data centres with an average electricity output for IT equipment of 150 MW each. This is an average figure, which means there may be both more and smaller, or fewer and larger data centres; however, what is important is the installed server capacity and thus the expected electricity demand and resulting load on the system. Electricity demand by large data centres is expected to increase additionally up to 2040, if the linear growth in data volumes continues. In this scenario, total electricity demand by large data centres will be at around 7 TWh in 2030 and then 11 TWh in 2040, corresponding to a share of total electricity demand in 2030 and 2040 of about 16% and 22%, respectively. We are currently aware of plans to establish six large data centre projects in Denmark.

3.5.1 Sensitivity

There is considerable uncertainty concerning future developments. Among other things, this is because, at relatively short notice, data operators can decide to relocate data centres to countries with more attractive framework conditions. COWI therefore works with several possible scenarios for developments in electricity demand by data centres, see figure 25. In addition to a main scenario with linear growth, COWI describes a scenario with an exponential growth in electricity demand by data centres and a scenario in which Denmark is shunned, i.e. no new development in data centres in Denmark. Moreover, because technological developments are linked with great uncertainty, COWI has also included a scenario describing the implications in the event of 'disruptive' new techniques for data storage and processing. For a more detailed description of the scenarios and possible range of outcomes for electricity demand by data centres, see (COWI, 2018).

Figure 25: Scenarios for developments in electricity demand by hyper-scale data centres (HSDCs) in Denmark



Note: The scenario in which Denmark is shunned is reflected in the lower section of the range.

4 Power load

4.1 From energy to power

For the sake of grid planning, it is vital to have a picture of how the transmission system may be affected at any given time. Grid planning is therefore based on power load rather than energy consumption. For planning purposes, in addition to knowledge about power load in the system, Energinet also needs to be able to distribute electricity demand and new electricity generation capacity by geographical area. The methodology for this geographical breakdown has been described in PGSO-IP17 (Energinet, 2017), but the breakdown has not been included in the Danish Energy Agency's power and gas sector outlook for Energinet (except for the split between eastern and western Denmark).

In the PGSO-IP, projections of electricity demand are converted to power load, and in order to gain a picture of variations in the load on the system, both the maximum load and the minimum load are determined. The methodology for calculating maximum and minimum load are the same as in PGSO-IP17.

The PGSO-IP includes a specified as well as an unspecified power consumption. For the specified power consumption, connection point and load can be identified, while the unspecified power consumption is only described as the total electricity demand for eastern and western Denmark, respectively. Specified power consumption includes consumption by large data centres, railways and large heat pumps and electric boilers, while unspecified consumption includes traditional consumption as well as consumption by individual heat pumps and electric cars. Note that electricity demand on Bornholm has been deducted from electricity demand in eastern Denmark in connection with the calculation of load.

For unspecified consumption, energy consumption is converted to maximum and minimum load values on the basis of utilisation times that in turn have been determined on the basis of metered annual energy consumption and maximum and minimum hourly loads (MWh/hour) over the past ten years. Hourly loads are available from Energinet's market data.

4.1.1 Calculation of utilisation times for unspecified electricity demand

Utilisation time is the ratio between total annual electricity demand and the metered hourly load. Because the utilisation time and the power load are inversely proportional to each other, the minimum utilisation time is required to calculate the maximum hourly load. Conversely, the maximum utilisation time is required to calculate the minimum hourly load.

A low utilisation time reflects a situation with many or very large peak-load events. The lowest utilisation time over the past ten years has been chosen for the conversion from electricity demand to maximum load for the projection period.

Consumption and hourly loads for calculating the lowest utilisation time in eastern and western Denmark are shown in tables 9 and 10. The coloured cells show the lowest utilisation times applied as conversion factors in PGSO-IP18 for eastern and western Denmark, respectively.

Table 9: Historical maximum load, consumption and utilisation time for western Denmark (DK1)

Maximum load				Consumption	Calculated Utilisation time
Date	Hour	MW	% of max	MWh	Hours
03-01-2008	18	**3,748**	99.5	21,622,136	5,769
06-01-2009	18	3,677	97.6	20,555,026	5,590
01-12-2010	18	3,743	99.4	21,120,621	5,643
05-01-2011	18	3,665	97.3	20,707,454	5,650
07-02-2012	9	3,677	97.6	20,442,016	**5,560**
16-01-2013	18	3,563	94.6	20,105,782	5,643
30-01-2014	18	3,541	94.0	20,123,553	5,683
15-01-2015	12	3,427	91.0	20,305,110	5,925
07-01-2016	18	3,672	97.5	20,532,763	5,591
29-10-2017	3	3,684	97.8	20,622,251	5,598

Table 10: Historical maximum load, consumption and utilisation time for eastern Denmark (DK2)

Maximum load				Consumption	Calculated Utilisation time
Date	Hour	MW	% of max	MWh	Hours
03-01-2008	18	**2,660**	99.0	14,476,732	5,442
05-01-2009	18	2,614	97.3	14,050,927	5,375
14-12-2010	18	2,615	97.3	14,376,107	5,497
05-01-2011	18	2,556	95.1	13,888,456	5,434
06-02-2012	18	2,559	95.2	13,698,186	**5,354**
16-01-2013	18	2,521	93.8	13,465,046	5,341
29-01-2014	18	2,500	93.0	13,319,237	5,327
20-01-2015	18	2,337	87.0	13,311,223	5,695
06-01-2016	18	2,444	90.9	13,454,088	5,504
05-01-2017	18	2,419	90.0	13,395,851	5,537

A high utilisation time shows a situation without or with very few peak-load events. The highest utilisation time over the past ten years has been chosen for the conversion from electricity demand to minimum load for the projection period.

Consumption and hourly loads for calculating the highest utilisation time in eastern and western Denmark are shown in tables 11 and 12. The coloured cells show the highest utilisation times applied as conversion factors in PGSO-IP18 for eastern and western Denmark, respectively.

Historically, the minimum load value constitutes between around 35% and 40% of the maximum value.

Table 11: Historical minimum load, consumption and utilisation time for western Denmark (DK1)

Minimum load				Consumption	Calculated utilisation time
Date	Hour	MW	% of max	MWh	hours
20-07-2008	6	**1,301**	34.5	21,622,136	16,621
19-07-2009	6	1,266	33.6	20,555,026	16,234
18-07-2010	6	1,309	34.8	21,120,621	16,132
24-07-2011	6	1,306	34.7	20,707,454	15,857
22-07-2012	6	1,209	32.1	20,442,016	**16,911**
04-08-2013	6	1,353	35.9	20,105,782	14,857
27-07-2014	6	1,373	36.4	20,123,553	14,662
02-08-2015	6	1,365	36.2	20,305,110	14,878
17-07-2016	6	1,331	35.3	20,532,763	15,430
23-07-2017	6	1,348	35.8	20,622,251	15,297

Table 12: Historical minimum load, consumption and utilisation time for eastern Denmark (DK2)

Minimum load				Consumption	Calculated utilisation time
Date	Hour	MW	% of max	MWh	hours
20-07-2008	6	**922**	34.3	14,476,732	15,705
25-07-2009	6	892	33.2	14,050,927	15,747
18-07-2010	6	906	33.7	14,376,107	**15,862**
17-07-2011	6	897	33.4	13,888,456	15,490
15-07-2012	6	873	32.5	13,698,186	15,691
21-07-2013	6	898	33.4	13,465,046	15,001
08-06-2014	6	898	33.4	13,319,237	14,827
19-07-2015	6	886	33.0	13,311,223	15,021
17-07-2016	6	883	32.8	13,454,088	15,245
16-07-2017	6	898	33.4	13,395,851	14,926

The utilisation times applied for unspecified consumption in PGSO-IP18 are summarised in table 13. These utilisation times have not been changed compared with PGSO-IP17.

Table 13: Utilisation times applied in the calculation of load impact for unspecified electricity demand, hours

	Western Denmark	Eastern Denmark
Maximum load	5,560	5,354
Minimum load	16,911	15,862

4.1.2 From utilisation times to maximum and minimum loads for unspecified consumption

The conversion of load impact for unspecified consumption includes the full traditional consumption, the full consumption by individual heat pumps, and 25% of energy consumption for electric cars, because it is assumed that charging electric cars only affects the peak load for 25% of the time. In the conversion to loads, 2% is added to/deducted from the maximum/minimum load value in order to include any possible fluctuations during an individual hour.

Table 14 summarises how traditional energy consumption and consumption by individual heat pumps and electric cars are converted to loads in PGSO-IP18.

Table 14: Calculation of maximum load and minimum load on the basis of consumption and utilisation times

	Traditional electricity demand and Individual heat pumps	Electric cars
Maximum load	$Y = \frac{X}{t^*} \cdot 1{,}02$	$Y = \frac{X}{t^*} \cdot 1{,}02 \cdot 0{,}25$
Minimum load	$Y = \frac{X}{t^*} \cdot 0{,}98$	$Y = \frac{X}{t^*} \cdot 0{,}98 \cdot 0{,}25$

t* indicates the chosen minimum/maximum utilisation times as summarised in table 13, while X is the gross electricity demand and Y is the maximum/minimum load (respectively) in a given year.

4.1.3 Maximum load

The maximum load linked to unspecified consumption has been calculated as outlined in table 14 above. The remaining (specified) consumption includes consumption by large data centres, by railways and by large heat pumps and electric boilers.

The maximum load from data centres is based on COWI's separate analysis on large data centres (COWI, 2018) According to this analysis, there are no considerable variations in electricity demand across the year, and maximum consumption is assessed to not exceed 20% of average consumption. This assumption has been used as the basis for calculating the maximum load from data centres. For the maximum load from large data centres, the utilisation time is therefore 7,300 hours (corresponding to 8,760/1.2). This maximum load is assumed to affect the peak load by 100%.

The utilisation time for railways is 2,000 hours and this is the same figure as in PGSO-IP17 (Energinet's assessment is based on information from Banedanmark). This maximum load is assumed to affect the peak load by 100%.

Consumption by large heat pumps and electric boilers is assumed not to affect the peak load.

Maximum load trends for use in planning the transmission grid are shown in figures 26 and 27.

Figure 26: Trend in maximum loads in western Denmark

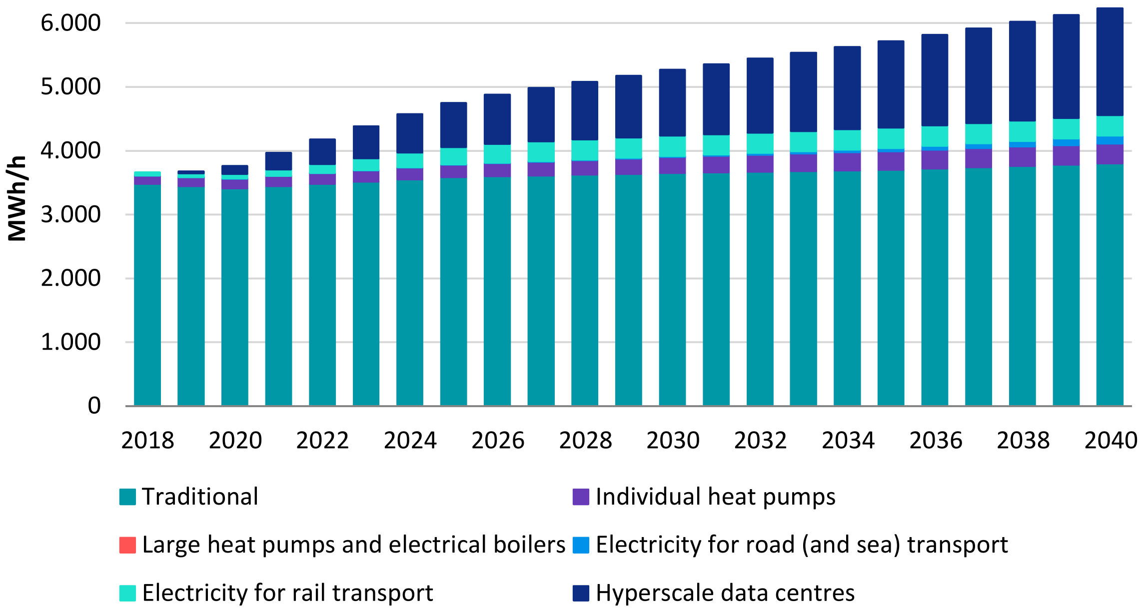
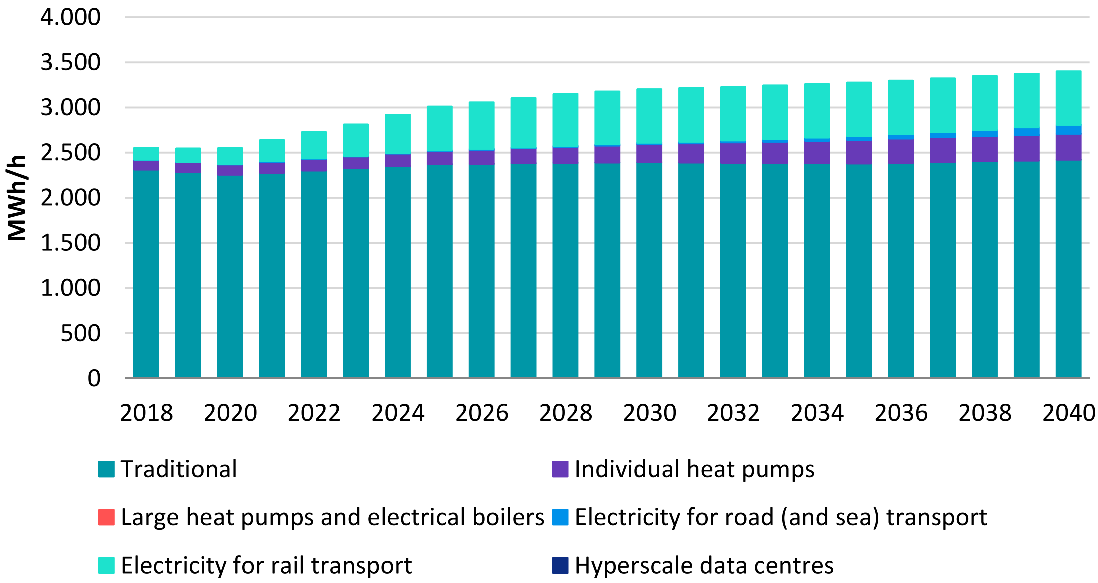


Figure 27: Trend in maximum loads in eastern Denmark



4.1.4 Minimum load

The minimum load linked to unspecified consumption has been calculated as outlined in table 14 above. The remaining (specified) consumption includes consumption by large data centres, by railways and by large heat pumps and electric boilers. Consumption by railways and large heat pumps and electric boilers is, however, assumed not to affect the minimum load.

The minimum load from data centres is based on COWI's separate analysis on large data centres (COWI, 2018) According to this analysis, there are no considerable variations in electricity demand across the year, and minimum consumption is assessed as being no lower than 10% less than average consumption. This assumption has been used as the basis for calculating the minimum load from data centres. For the minimum load from large data centres, the utilisation time is therefore 9,733 hours (corresponding to 8,760/0.9), and the minimum consumption by data centres is assumed to affect the minimum load. Minimum load trends are shown in figures 28 and 29.

Figure 28: Trend in minimum loads in western Denmark

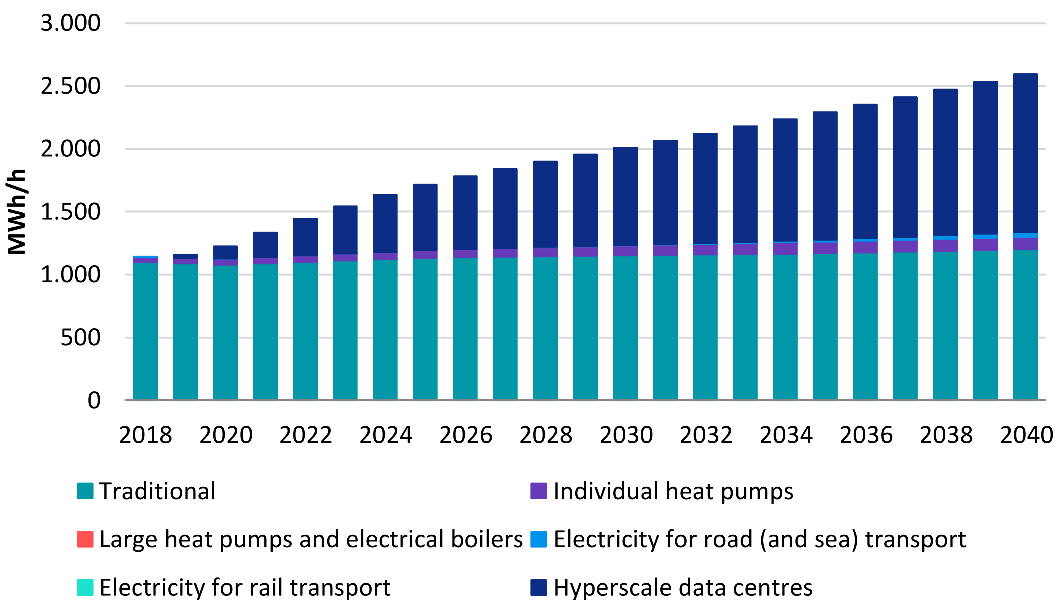
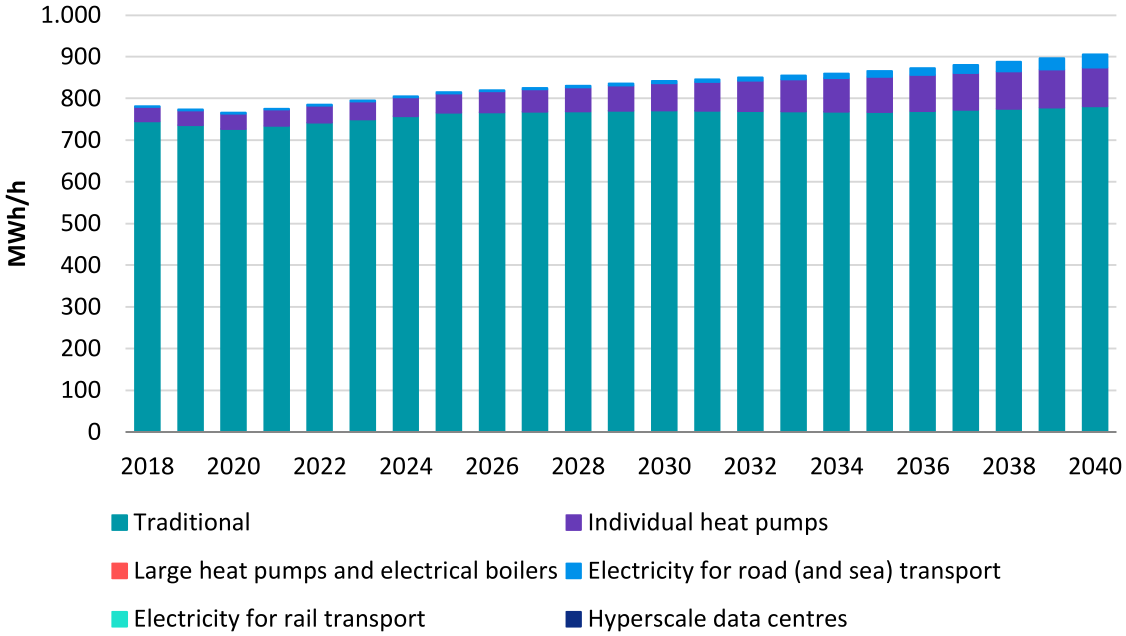


Figure 29: Trend in minimum loads in eastern Denmark



4.2 Methodological uncertainty

There are certain challenges associated with the methodology applied to calculate power consumption. If the dimensioning worst case summer/winter scenario does not occur, or only occurs extremely rarely, the calculated loads will be incorrect.

Sensitivity analyses are therefore also important in connection with load calculations for grid planning. Furthermore, alternative methodologies for calculating loads could be considered in the future, e.g. based on electricity demand per hour and by sector. However, this would require improved data, and a methodology is yet to be established. These considerations will be addressed further in connection with next year's power and gas sector outlook.

5 Electricity production capacities

Compared with DECO18, the long-term trend in capacities has been adjusted to take account of the ambition in the 2018 Energy Agreement for a 55% renewables share by 2030, full phase-out of coal by before 2030 and fossil fuel independent energy supply by 2050. At the same time, the political call for increased deregulation of the district heating sector and for lower electricity taxes has been taken into account.

5.1 Power plants

Projections by the Danish Energy Agency of central and decentral power plant capacity are based on the following:

- Energy production statistics, which provide insight into current-day operating patterns
- Knowledge about concrete applications for conversions, commissioning and decommissioning
- Assessments of concrete declarations of intent from the government and other large-scale players
- Interviews with stakeholders
- Evaluations of changes to framework conditions and how these will affect plant owners' strategies

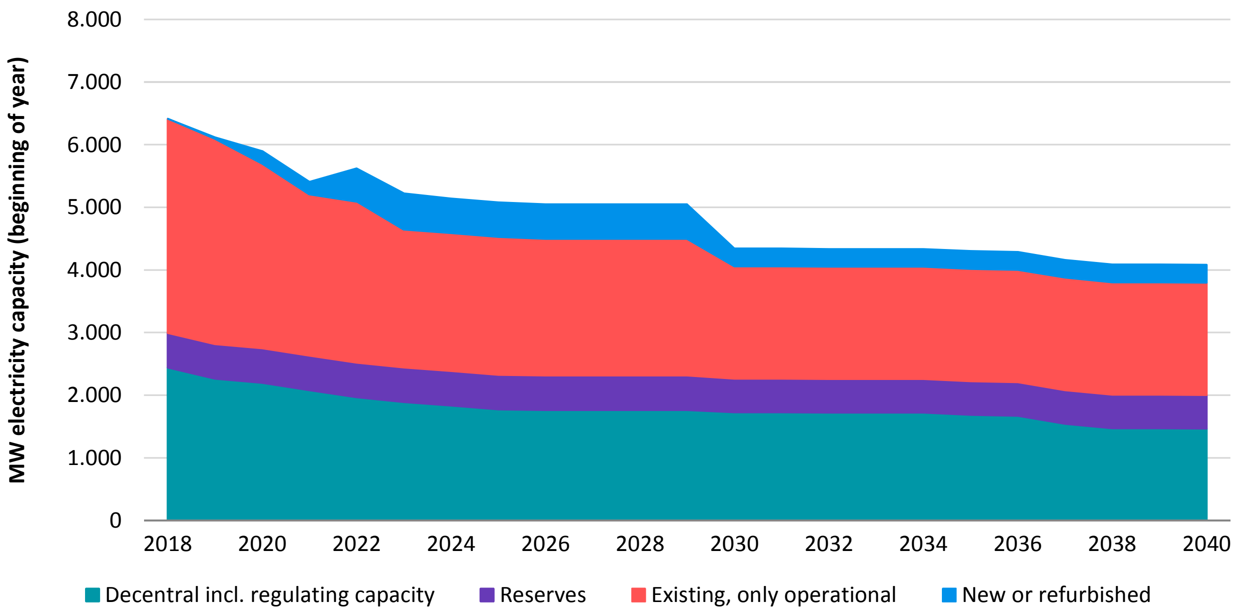
On the basis of DECO18, the long-term trend has been adjusted to take account of the ambition in the 2018 Energy Agreement for a 55% renewables share by 2030, coal-free energy supply by 2030 and fossil fuel independent energy supply by 2050. At the same time, lower electricity taxes and the political call for increased deregulation of the district heating sector, including abandonment of the requirement for cogeneration of heat and power, as expressed in the 2018 Energy Agreement, have been taken into account.

Figure 30 describes operational central and decentral power plant capacity in the projection period. Capacities have been grouped by existing central units, new or retrofitted central units, central reserves, and decentral units including regulating-power units. A more detailed outline of installed production capacity by western and eastern Denmark is in the Data Sheet for PGSO-IP18 (Danish Energy Agency, 2018e).

Generally speaking, total electricity capacity based on thermal plants has fallen over the past couple of years, and it is probable that this development will continue. As a result of this, it is expected there will be a decrease in natural-gas-fired CHP capacity, which will be replaced by more heat pumps in the district heating system. The Danish Energy Agency's best guess at the total operational power plant capacity available is that it will be reduced by around 35% by 2040, compared with today's level. Note that this is a guess at the total installed (i.e. available) capacity, which means that all of the total capacity available is not necessarily used but can increasingly serve as back-up capacity during shortages of renewables-based electricity in the system.

The projection is associated with considerable uncertainty because the plans for the future for many of the plants are uncertain. Consequently, sensitivity analyses have been performed for developments in central power plant capacity on the basis of data from the sector. However, as follow-up to the 2018 Energy Agreement, future power and gas sector outlooks will involve more in-depth analyses, and these will form the basis for more informed projections.

Figure 30: The Danish Energy Agency's assessment of expected developments in the nominal electricity capacity of power plants in Denmark in the period 2018-2040



5.1.1 General trends

Generally speaking, total electricity capacity based on thermal plants has fallen in recent years, and it is probable that this development will continue.

Today, the plants predominantly base their business on heat production rather than electricity generation as previously. Among other things, this manifests itself in low electrical efficiency rates at retrofitted units. In most cases, the existing statutory requirement for co-generation og heat and power is probably the real reason for the continued electricity generation.

On the other hand, recent investment decisions in CHP plants seem to suggest continued interest in cogeneration in some situations. However, the overall assessment is that boilers or other heat production without cogeneration of electricity will out-compete cogeneration at smaller plants under fully competitive conditions. The picture is different for larger plants because these often have lower costs per MWh and higher efficiency rates.

Condensation power plant capacity is only economically feasible with adequately long and frequent periods of high electricity market prices, e.g. as during the summer of 2018. However, in overall terms, recent years' electricity prices do not support the deployment of new condensation capacity.

Similarly, no new biomass-based power plant capacity is expected, regardless of any continued subsidies for this type of production, except for in areas where major coal-based large-scale CHP plants are expected to be decommissioned (Esbjerg, Aalborg and Odense). Here, it is assumed that the heating demand bases are large enough to incorporate medium-large biomass-based CHP plants. Furthermore, regulatory changes, including removing the requirement for cogeneration of electricity and heat, will make it likely that the plants will focus on production and supply of district heating based on biomass or heat pumps.

5.1.2 Central plants

A drop in capacity from the current level of around 4,000 MW to around 2,600 MW in 2030 is predicted for large-scale plants. After 2030 and up to 2040, central electricity production is expected to remain constant.

At present, several central power plants have plans to convert or are already in the process of converting their old, fossil-fuel-fired units to biomass. In western Denmark, for example, work to convert unit 3 to wood chips has been completed at the plant in Skærbæk, while the service life of unit 3 at the plant in Studstrup was prolonged and converted to wood pellets in 2016. Due to the call for a phase-out of coal in electricity generation before 2030 in the 2018 Energy Agreement, it has been assumed that a large number of plants will be converted to biomass and supplemented with heat pumps. Total electricity capacity is expected to be reduced considerably as a result of this.

In eastern Denmark, new wood-chip-fired CHP units are in the process of being established at the plants in Amager and Asnæs, replacing the existing coal-fired units at these plants. Unit 1 at the Amager plant is based on biomass and unit 3 will be closed down in 2019, when a new biomass-fired unit 4 is to be commissioned.

Unit 1 at the Avedøre plant was converted to wood pellets in place of coal in 2016, and unit 2 can fire with both biomass and natural gas.

The plant in Rønne on Bornholm has also been retrofitted so that it can fire exclusively with wood chips in back-pressure mode, and unit 6 at Østkraft was retrofitted to fire primarily with biomass in 2016.

For plants about which there are no known plans for the future, the development has been assessed on the basis of investment opportunities in new units or in prolonging the service life of existing units. These assessments are based on the heating demand basis for the individual plant and on economic assumptions. The assessments also consider possibilities to establish heat pumps to meet heating demand bases and that some plants are likely to convert to biomass-based and heat-only production, leading to lower or zero electricity capacity. The reason for this is that focus will be on cheaper and carbon-neutral heating. It has been assumed that the service life of plants will be prolonged by 15 years from the time of retrofitting. Furthermore, large-scale biomass plants and waste incineration plants are assumed to be in operation up to and including 2040, or for even longer.

5.1.3 Decentral plants

The total installed capacity of decentral CHP plants totalled around 2,400 MW at the beginning of 2018, representing around 1,000 larger or smaller plants. This capacity is expected to be reduced to around 1,700 MW by 2030 and around 1,470 MW by 2040, corresponding to a reduction of around 40% up to 2040.

The drop is due primarily to discontinuation of the support scheme for decentralized natural gas based CHP plants at the end of 2018, but it is also due to expected higher prices of natural gas and deregulation of the heating sector, including abandonment of the CHP and fuel obligations, as set out in the 2018 Energy Agreement. However, this projection is linked with great uncertainty and moreover depends on local-government plans for fossil-free heat production.

Trends pointing towards a lower level of decentral electricity capacity can be summarised as follows:

- Removal of the basic-amount support scheme resulting in poorer financial conditions for plants with few or no full-load hours
- The spot price of electricity is expected to continue to be relatively low in the future due to increased price pressure form deployment of wind turbines and solar PV. As a result, cogeneration will be less feasible.
- An expected increase in natural-gas prices will lead to reduced use of gas turbines.
- Increased deregulation of district heating, reduced requirement for cogeneration and reduced obligation to connect to the district heating network. This will result in increased use of cheaper alternatives to CHP production (boilers, heat pumps and, possibly, private end-user heating)
- Lowering of the tax on electric heating will lead to better framework conditions for heat pumps and electric boilers

Trends pointing towards continuation of decentral electricity capacity:

- Increase in renewables and discontinuation of plants can lead to higher prices on the reserve power market and increased requirements to introduce a capacity market, i.e. increased demand for peak-load capacity.
- Fewer full-load hours on gas turbines and gas engines mean longer service lives for these plants
- Increased electricity demand due to data centres, more electric heating and more electric cars may lead to higher spot prices in the future (but Danish electricity demand will only have a small impact on the spot price as the electricity markets are closely inter-connected in Northern Europe)

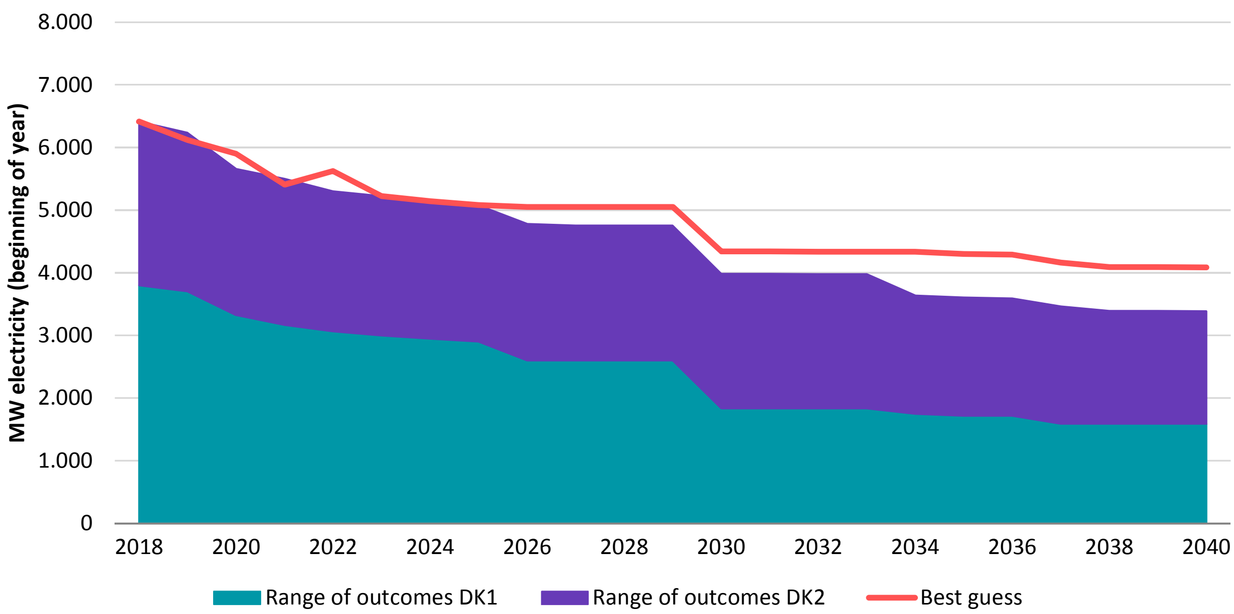
It is assumed that the trends pointing towards a lower level of decentral electricity capacity weigh heaviest, and that, overall, there will be a reduction in electricity capacity and that many small natural-gas-fired gas-engine-based units will close as a consequence. These units will not necessarily be scrapped, but can relatively quickly (around one month) be put into operation again and made available if the right framework conditions are in place. It is assessed that only relatively few plants will have actual service-life-extension work done.

Waste incineration based electricity capacity has been assumed to be kept at the same level throughout the period. This assumption is based on the Danish Environmental Agency's waste forecast, which indicates fairly constant or increasing volumes of waste for incineration. This represents the result of two opposing trends. Economic growth pulls waste volumes up, while recycling reduces the volumes going to incineration.

5.1.4 Sensitivity

As mentioned, there is considerable uncertainty concerning future power plant capacities. Actual data from the sector on the expiry of heating agreements at a number of central plants has been used as the basis for a range of outcomes with a lower estimate for central plants. Furthermore, the phase-out of coal at Fynsværket and Esbjergværket has been brought forward in this range of outcomes. This results in a range of outcomes in which large-scale power plant capacity falls by around 50%, as opposed to only 35% in the best guess scenario. No range of outcomes has been set up for decentral power plants, even though projections in this area are also associated with considerable uncertainty. The reason for this is that the Danish Energy Agency is pending results of an analysis of the collective heat supply system as follow up on the 2018 Energy Agreement. According to plan, this analysis will be included in next year's power and gas sector outlook. Figure 31 illustrates the range of outcomes for developments in total power plant capacity in DK1 and DK2. The figure also includes a comparison with the best guess scenario.

Figure 31. Possible range of outcomes for developments in power plant capacity



Note that the power and gas sector outlook describes a guess at how a long-term green transition might unfold and that the outlook does *not* suggest which specific further initiatives could be necessary to ensure the development described.

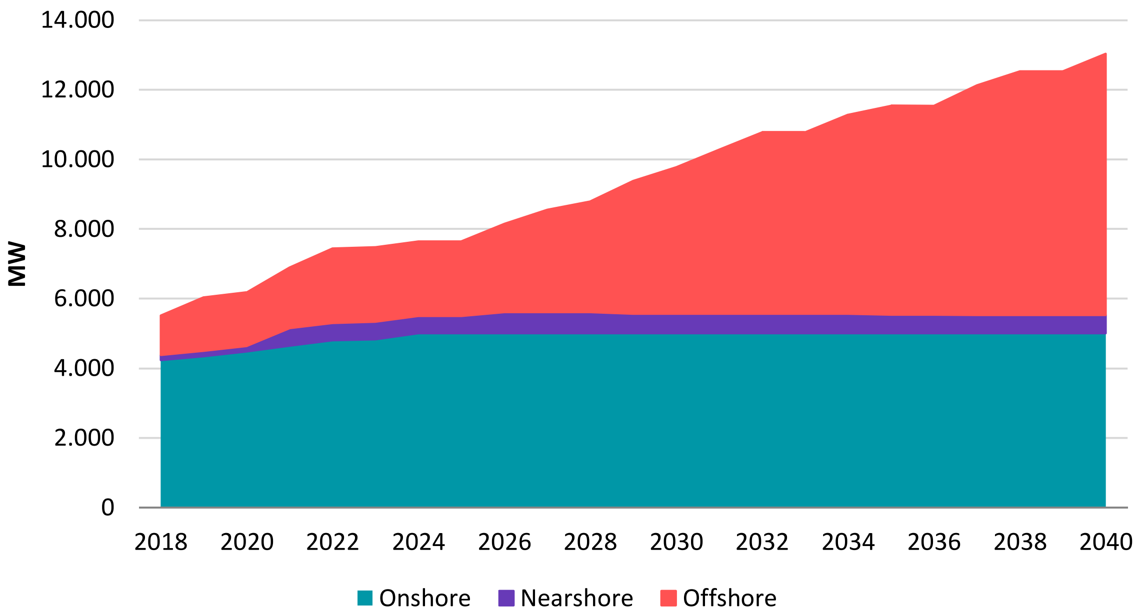
5.2 Wind turbines

The political initiatives and the recently adopted 2018 Energy Agreement will principally determine future wind capacity. Onshore wind will be based largely on technology-neutral tendering procedures, while offshore wind will be based on politically determined tendering of large farms as well as on the long-term goal of fossil-fuel independence.

A considerable amount of new capacity is still being installed and much already installed capacity is approaching technical end-of-life status. The projection therefore includes a projection of establishment and dismantling of onshore, nearshore and offshore wind turbines connected to the Danish electricity grid. For onshore wind turbines of various ages, dismantling is based on expected service life[1].

[1] Assumed service life is 29 years for old turbines (installed before 2008), 25 years for other turbines (installed 2009-2019), and 27 years for turbines in the categories 2020-2030 and 2031-2040, see (Danish Energy Agency, 2017a).

Figure 32: Expected capacity development for wind turbines, by turbine location



5.2.1 Onshore wind

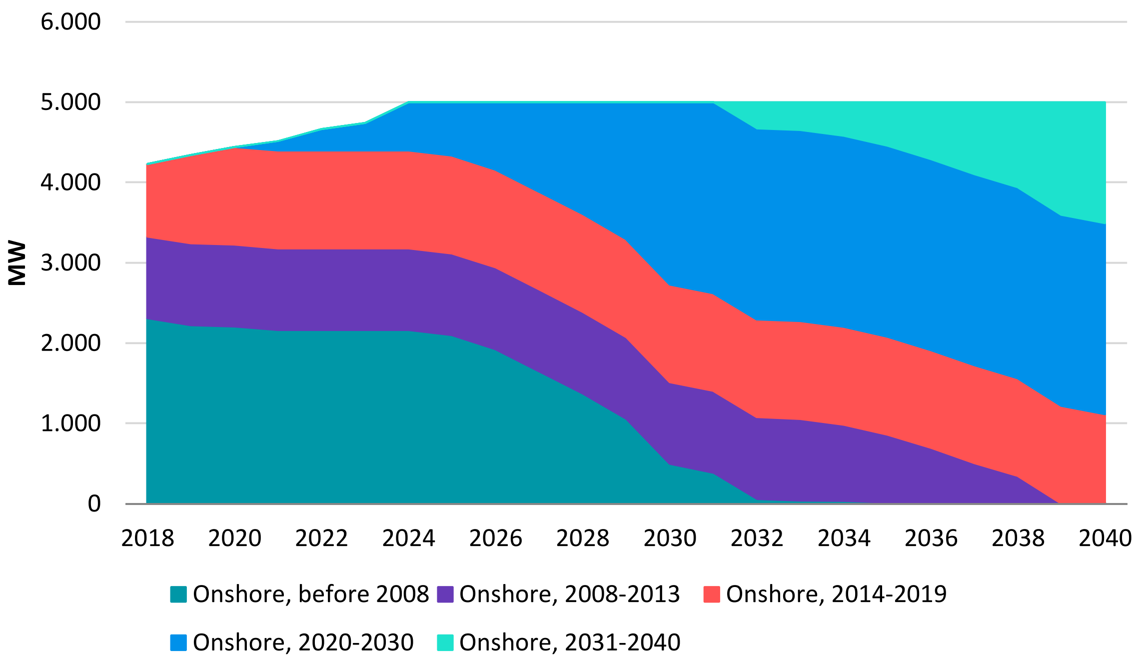
Energy production from onshore wind has followed an even upwards trend over the years. The master data register for wind turbines (Danish Energy Agency, 2018f) reveals an average annual gross onshore deployment of around 200 MW since 2010. However, the question is whether this deployment can continue, e.g. given local opposition but also given the suitability of new sites and the costs of property buy up and loss-of-value-scheme payments.

The expected development in capacity for onshore wind turbines has been determined on the basis of the most recent historical data on local-government project approvals, expected technological and market developments, as well as an overall assessment of the onshore wind potential. Furthermore, account has been taken of the circumstance that the number of onshore wind turbines will be reduced from a current around 4,300 to a maximum of 1,850 turbines in 2030 as a consequence of the 2018 Energy Agreement.

The current capacity of around 4,200 MW is expected to increase towards 5,000 MW up to 2024, after which it will even out. DEA has analysed the potential for onshore wind capacity from 2020 to 2030 and has described a guess at the expected realisable deployment, see (Danish Energy Agency, 2018g). The analysis is initially based on a geographically modelled theoretical potential based on the current legislative framework. The analysis is then adjusted on the basis of an analysis of the current efficiency rate for potential areas and historical data on the establishment of new turbines broken down by municipality.

The analysis shows an expected, realisable gross deployment of around 2 GW from 2020 to 2030. This means that the current onshore-wind capacity of 4.2 GW can realistically be increased by around 1 GW, reaching around 5 GW in 2030 due to the concurrent extensive dismantling of old turbines in the period up to 2030. It is assumed that the current number of turbines will be markedly reduced (as agreed in the 2018 Energy Agreement) and replaced by fewer but substantially larger turbines. Figure 33 shows the expected development in onshore wind capacity by period of installation.

Figure 33: Expected capacity development for onshore wind turbines, by period of installation



The additional capacity expected to be installed via the technology-neutral invitations to tender in 2018 and 2019 has been estimated at 189 MW (70 MW in 2018 and 119 MW in 2019). To this should be added an expected deployment of 134 MW test turbines with a three-year service life in 2019 in connection with the transition scheme for onshore wind turbines that was adopted in September 2017.

After 2020, the 2018 Energy Agreement has set aside funds for more technology-neutral invitations to tender. It has been assumed that these will result in 200-230 MW new onshore wind capacity annually during the period 2020-2030, even though the Energy Agreement initially only covers the period 2020-2024. The expected realisable capacity of 5 GW will be have been installed by 2024, because expected dismantling is relatively small during the first half of the 2020s.

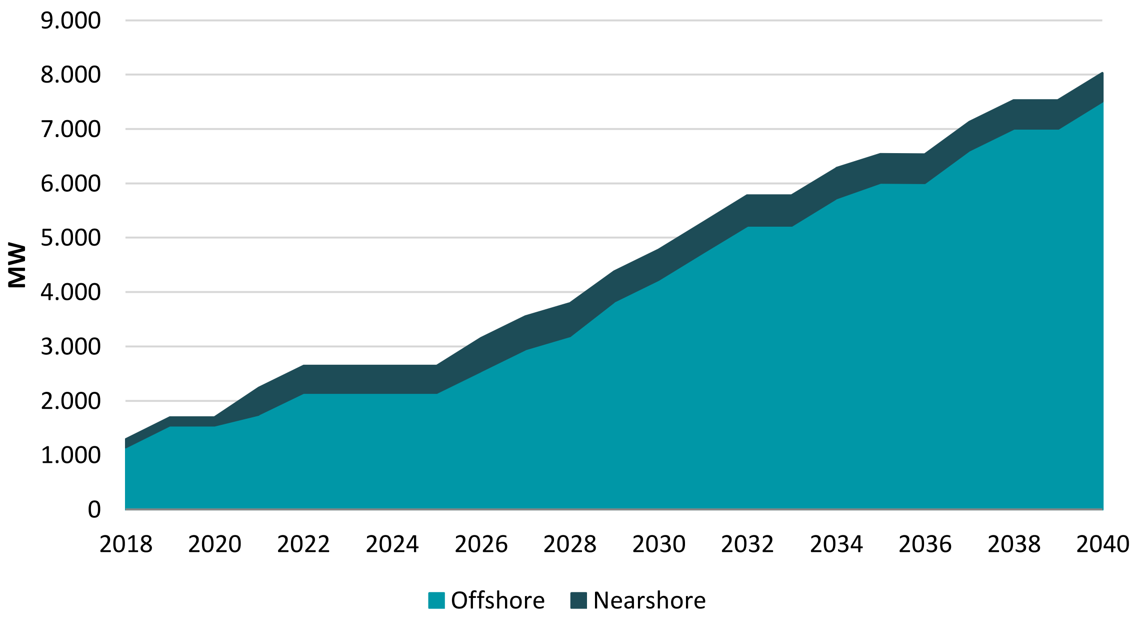
On the other hand, a substantial number of old and end-of-life turbines are expected to be dismantled during the period 2025-2030. It has been assumed that, during this period, the same level of new capacity will be installed (either through new technology-neutral tendering or through PPAs or other locally-anchored wind farms), so that total onshore wind capacity will be maintained at around 5 GW during the second half of the 2020s. Average dismantling of old turbines in the period 2020-2030 will be around 180 MW annually based on the expected service life of onshore wind turbines.

It is assumed that, after 2030, the new gross onshore capacity will correspond to the capacity dismantled, so that a total capacity level of 5 GW is maintained. This corresponds to annual installation of around 160 MW new gross onshore wind capacity after 2030. Note that dismantling of old turbines and installation of new capacity in reality will take place as a more gradual process, so that the total capacity will not necessarily be at 5 GW during all years after 2024 but rather will vary more.

5.2.2 Offshore and nearshore wind

Figure 34 shows the expected development in total offshore and nearshore wind capacity in the projection period.

Figure 34: Expected development in total offshore and nearshore wind capacity



The current offshore wind turbine capacity of around 1,100 MW (beginning of 2018) is expected to increase steadily up to 2040, presumably having reached in excess of 7,000 MW at that time.

The 2018 Energy Agreement included an agreement to put out to tender in 2019/20 a new offshore wind farm of around 800 MW with grid connection during the period 2024-2027. It is expected the wind farm will be located in DK1 off the west coast of Jutland. The siting is however uncertain and is pending detailed screening.

Furthermore, it has been agreed to put out to tender two additional offshore wind farms of at least 800 MW in 2021 and 2023, respectively. These wind farms are expected to be installed and put into operation in 2028 (likely in DK2) and 2029 (likely in DK1), respectively.

The most recent screenings completed for offshore wind farm sitings are from 2011 (large-scale offshore wind farms) (Danish Energy Agency, 2011) and 2012 (nearshore wind turbines) (Danish Energy Agency, 2012). The screenings were conducted based on work in 2007 by the previous Offshore Wind Turbine Committee (Offshore Wind Turbine Committee, 2007). As several fundamental parameters may have changed since 2007 in step with changes in environmental conditions, new regulation etc., the 2018 Energy Agreement proposes that a new screening be made of Danish waters. The survey is to cover locations for up to 10 GW new offshore wind.

DEA considers there to be a significant potential for additional offshore wind in Denmark. On the basis of this, and in view of the long-term goal of fossil fuel independence, it is assumed that an additional 300-350 MW offshore wind will be deployed annually on average over the period 2030-2040, primarily in DK1. This includes extending or repowering end-of-life offshore wind farms.

There is a significant theoretical potential for nearshore wind turbines. However, as is the case with onshore wind, nearshore wind turbines are likely to meet considerable opposition.

In addition to the nearshore wind turbines already put out for tender (Vesterhav Syd and Vesterhav Nord), an additional 150 MW new nearshore wind capacity has been incorporated in PGSO-IP18 (broken down by 100 MW in DK2 and 50 MW in DK1). This assumption is based on applications received by the Danish Energy Agency. The current capacity of around 150 MW is assumed to increase to 500 MW in 2021 and then to 600 MW in 2026 after which it will even out. However, there is considerable uncertainty about whether an additional increase in capacity will take place.

5.2.3 Full-load hours

The number of full-load hours for onshore wind is calculated for the categories in table 15 broken down by eastern and western Denmark and on the basis of observed full-load hours adjusted for wind availability. For future turbines, full-load hours have been based on the Technology Catalogue.

Table 15: Full-load hours for onshore wind

Year	Eastern Denmark	Western Denmark
Before 2008	1,850	1,900
From 2008-2013	2,700	2,950
From 2014-20191[1]	3,000	3,000
From 2020-2030	3150	3,150
From 2031-2040	3,200	3,200
Test turbines	3,000	3,000

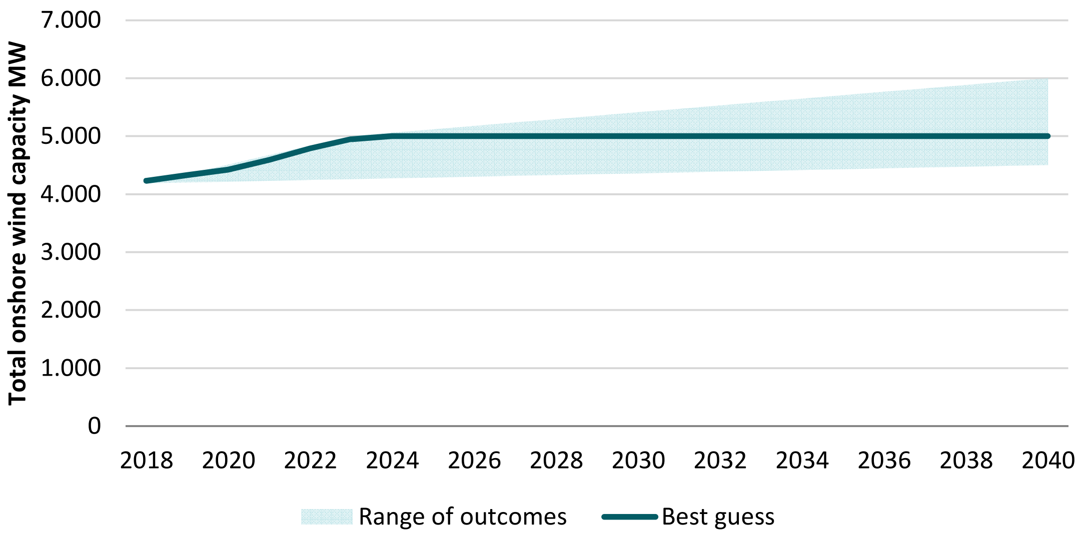
[1] The figure for 2014-2019 has been slightly reduced because DEA suspects that the figure will be lower than it was, e.g. in 2015 and 2016. This is because the new onshore wind locations are not as 'good' as the locations that have already been exploited.

DEA has applied the same methodology to calculate full-load hours for nearshore and offshore wind turbines as for onshore wind turbines. The wind farms' first year has not been included because it is not representative and the full-load hours have been adjusted for wind availability on the basis of a geographical breakdown, as provided in the Danish Wind Index. For future turbines, full-load hours have been based on the Technology Catalogue (Danish Energy Agency, 2018h). Full-load hours for concrete projects may, however, vary considerably from the above.

5.2.4 Sensitivities regarding wind power

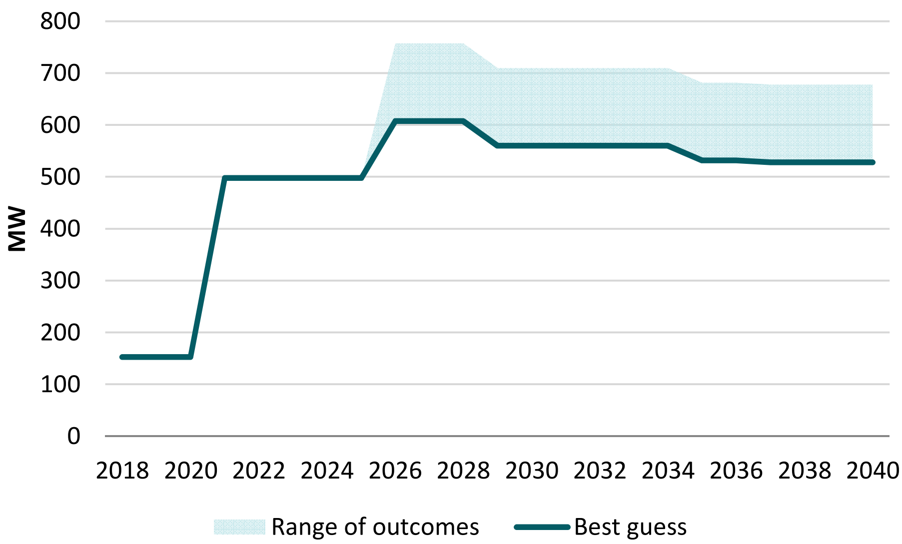
A more positive view of onshore wind in some municipalities could lead to larger onshore wind capacity in the long term, whereas more opposition from the local community and increased costs of compensation will pull in the opposite direction. Furthermore, onshore wind developments depend on developments in the costs of technology, renewable energy subsidies (through tendering) and the expected developments in electricity prices. In addition to this, it is not certain that, in practice, all end-of-life turbines will be dismantled and replaced in the same year as end of service life. Dismantling old and establishing new capacity will moreover depend on the future plan for a reduction in the number of onshore wind turbines. This uncertainty is illustrated with a possible range of outcomes in figure 35.

Figure 35: Possible range of outcomes for onshore wind capacity in alternative scenarios



There is also an obvious uncertainty linked to the assessment of developments in offshore wind capacity, for the period up to 2040 in particular. This will depend on developments in electricity demand, for example. More specifically, for nearshore wind turbines a range of outcomes has been incorporated, describing a scenario in which 200 MW new capacity is established in DK2 and 100 MW new capacity nearshore wind turbines is established in DK1 in addition to the capacity from Vesterhav Nord and Vesterhav Syd, see figure 36.

Figure 36: Range of outcomes for nearshore wind capacity



5.3 Solar PV

There is solar PV capacity totalling 1,000 MWp installed in Denmark today. During periods when the sun shines this corresponds to the production at two large power plants. Technological advancements within solar PV could lead to a manifold increase in solar PV capacity over the next 25 years.

To a larger degree than for wind, solar PV capacity is subject to a limitation determined by economic aspects. This is due to the combination of the relatively low number of full-load hours in a year and the circumstance that the more solar PV modules installed, the more the pressure on electricity prices during hours when the sun is shining and the modules produce at their highest. With time, this could make investing in solar PV less attractive. The assessment is that electricity production from solar PV will amount to a maximum of around 15% of total electricity demand. This is an assessment that the solar PV industry in Denmark agrees with. This assessment is a determining factor in the projections of solar PV capacity in Denmark in PGSO-IP18 and also aligns with other studies on solar PV potentials.

Solar PV can be deployed on buildings (private homeowners, enterprises and public institutions) or as open-field ground-mounted installations. There is a significant potential for installing more solar PV modules on Danish rooftops. However, whether this potential will be exploited in practice depends on the future subsidy system, tax structure, trends in the solar-weighted electricity price, battery technologies and battery prices, etc.

The electricity tax relief set out in the 2018 Energy Agreement and the transition to instant settlement are expected to slow down solar PV deployment outside the tendering rounds, so that the period up to 2030 will see a total deployment of only around 100 MWp. After this, the deployment is expected to increase steadily to around 500 MWp in 2040. All solar PV capacities in PGSO-IP18 have been calculated as panel capacities. Previous power and gas sector outlook calculated the solar PV capacity as inverter capacities.

The development in solar PV on buildings has been modelled in the Danish Energy Agency's solar potential model. This model only describes the solar PV deployment covered by open schemes or which is expected to take place on commercial terms. Deployment of installations via special pools and tendering procedures has not been included. The model has been described in more detail in a memorandum on assumptions for DECO18 (Danish Energy Agency, 2018c).

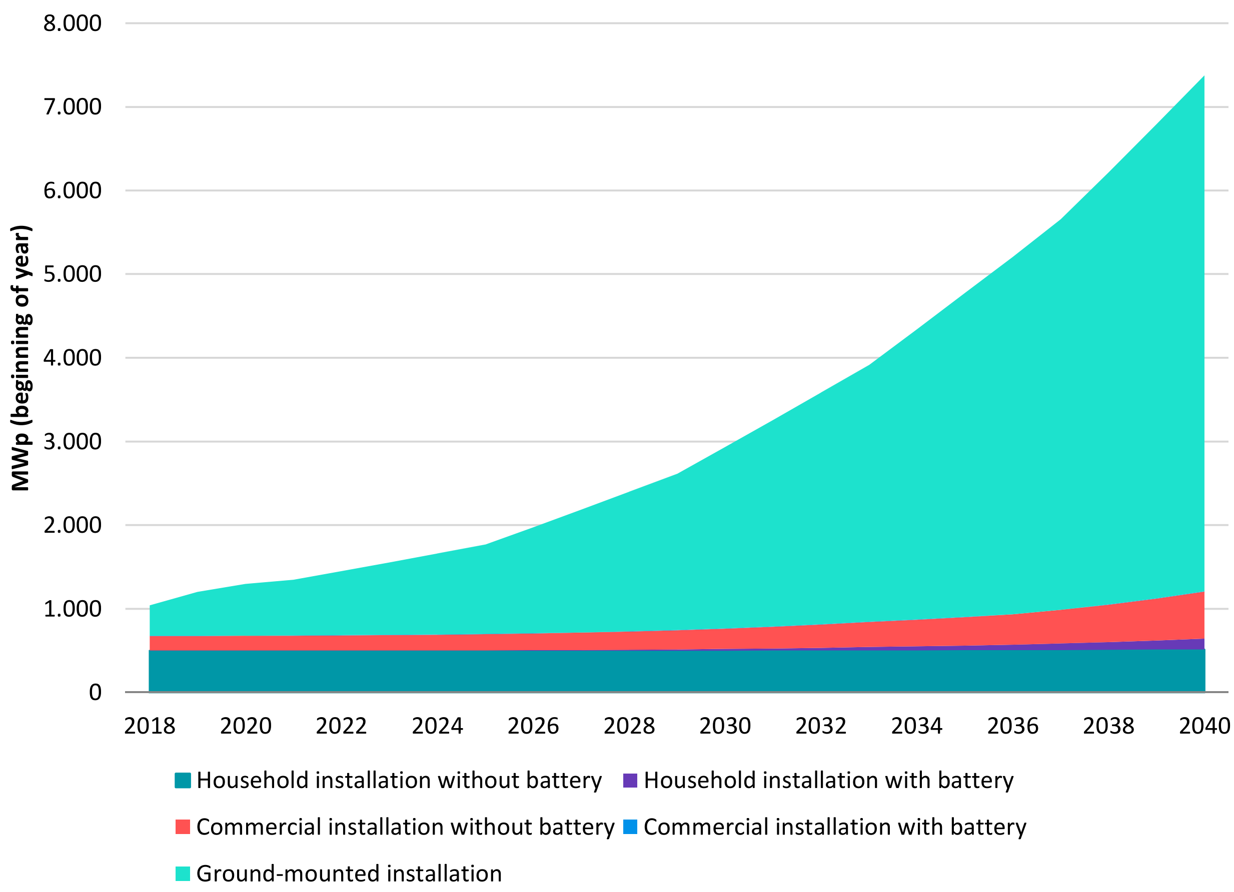
To this should therefore be added solar PV's expected share in the upcoming technology-neutral invitations to tender. For Denmark, the capacity increase is primarily expected to be realised as ground-mounted solar farms, which can submit tenders in the technology-neutral tendering rounds and obtain a certain price premium, until solar PV is able to compete on market terms.

The results of the future technology-neutral invitations to tender are uncertain because they set a total economic framework but not a total capacity, and because the allocation between onshore wind and solar PV is inherently unknown. The invitations to tender involve a framework amount set aside for the first tendering rounds in the period 2018-2019 and in the 2018 Energy Agreement for the period 2020-2024. However, there is also great uncertainty about the development of prices of solar PV and batteries and, thus, about how the technology will develop on market terms.

PGSO-IP18 assumes that solar PV capacity will increase gradually until it peaks at an estimated maximum capacity of around 7,000 MWp in 2040, corresponding to around 15% of total estimated Danish electricity demand, see figure 37. This also corresponds to the expected trend in 2040 outside Denmark; see the TYNDP-18 Sustainable Transition scenario (ENTSO-E, 2018). In this scenario, Europe's total solar PV power generation is expected to account for 15% of total electricity demand in 2040.

The deployment of solar PV in Denmark is expected to distribute with 70% in western Denmark (DK1) and 30% in eastern Denmark (DK2).

Figure 37: Expected development in total solar PV capacity in the period 2018-2040



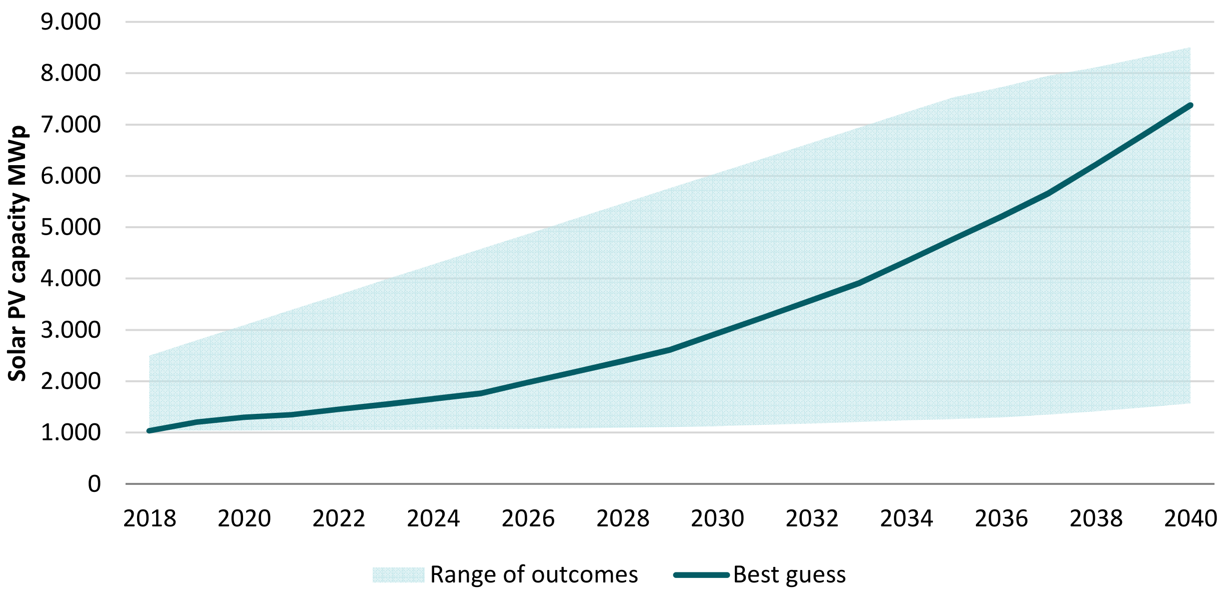
5.3.1 Full-load hours

The expected deployment of solar PV is based on number of full-load hours at PV panel level, i.e. peak FLH measured as kWh/kWp. For new PV systems, the number of full-load hours has been calculated on the basis of the Technology Catalogue and by interpolation between years. In general, solar PV has around 900-1,000 full-load hours annually, depending on whether the solar PV system in question is a residential solar PV system or a ground-mounted solar farm. The number of full-load hours is expected to follow a slight upward trend over the period, driven by technological advancements (Danish Energy Agency, 2018e).

5.3.2 Sensitivity

There is great uncertainty about future prices of solar PV and batteries and, thus, about how the technology will develop on market terms. The possible range of outcomes is assessed to lie somewhere between the outcomes from the solar PV potential model and 15% of total annual electricity demand in the long term (the estimated maximum potential). This results in a very wide range, which is narrower in the short term because it is not realistic that solar PV power generation will reach 15% of electricity demand until later in the projection period. This is illustrated in figure 38.

Figure 38: Possible trend in solar PV capacity (MWpeak) 2018-2040



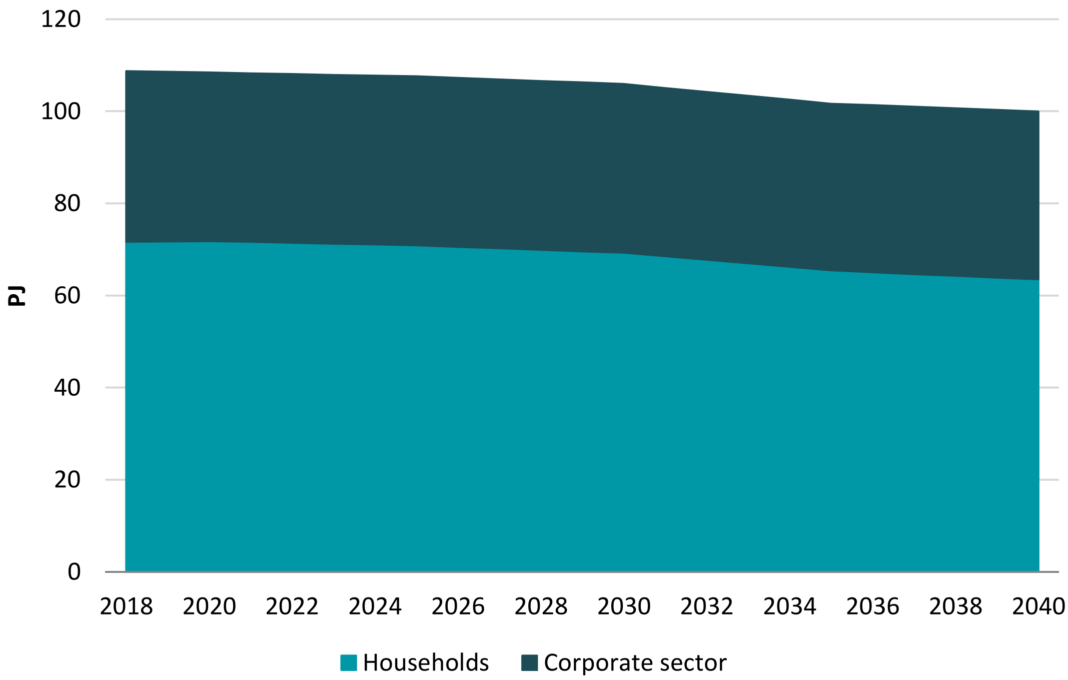
Note that the calculations of the solar PV potential for residential systems and commercial systems have been based on a standard electricity demand. This means that solar PV systems with batteries may become feasible in a situation with flexible consumption and wide use of individual heat pumps and electric cars. This will be studied in more detail in connection with future power and gas sector outlooks.

6 District heating demand

Knowledge about developments in district heating is important in Energinet's planning, partly because cogeneration makes up a large share of Danish electricity generation and gas consumption, and partly due to the increasing electrification taking place in the heating sector. It is therefore important to determine the heating demand of the district heating areas so as to ensure that the energy system is realistically reflected in Energinet's calculation models.

The Danish Energy Agency has projected the Danish district heating demand up to 2040 using the RAMSES model as shown in figure 39. The trend in demand follows a slight downward trend up to 2030, after which the 'best guess' reflects a somewhat steeper fall up to 2040. Amongst other things, energy savings in the corporate sector and deployment of individual heat pumps will drive this trend.

Figure 39: Trend in district heating demand in the projection period broken down by households and the corporate sector (excluding losses, i.e. in-situ consumption)



7 Foreign data and electricity transmission links abroad

Due to a considerable number of interconnectors, Denmark is closely linked with neighbouring countries and is therefore reliant on electricity systems in neighbouring countries. Just how much Denmark is reliant on other countries is reflected directly in the electricity prices. On average since 2010, Denmark has only had its own electricity price for 10% of the time. For the remaining hours, the electricity price has been identical to the electricity price in countries to the north (50%), to the south (20%) or in both directions (20%), see (Energinet, 2016).

Foreign data and interconnectors are therefore included as an important element in both Energinet's and the Danish Energy Agency's analyses of developments in the Danish energy system. However, the foreign data and interconnectors are only briefly described here.

PGSO-IP18 includes data on interconnectors between Denmark and neighbours as well as on the expected maximum NTC (Net Transfer Capacity) of these interconnectors. Furthermore, the Great Belt Link between western and eastern Denmark has also been included. However, the analyses also generally assume a number of other types of data, including:

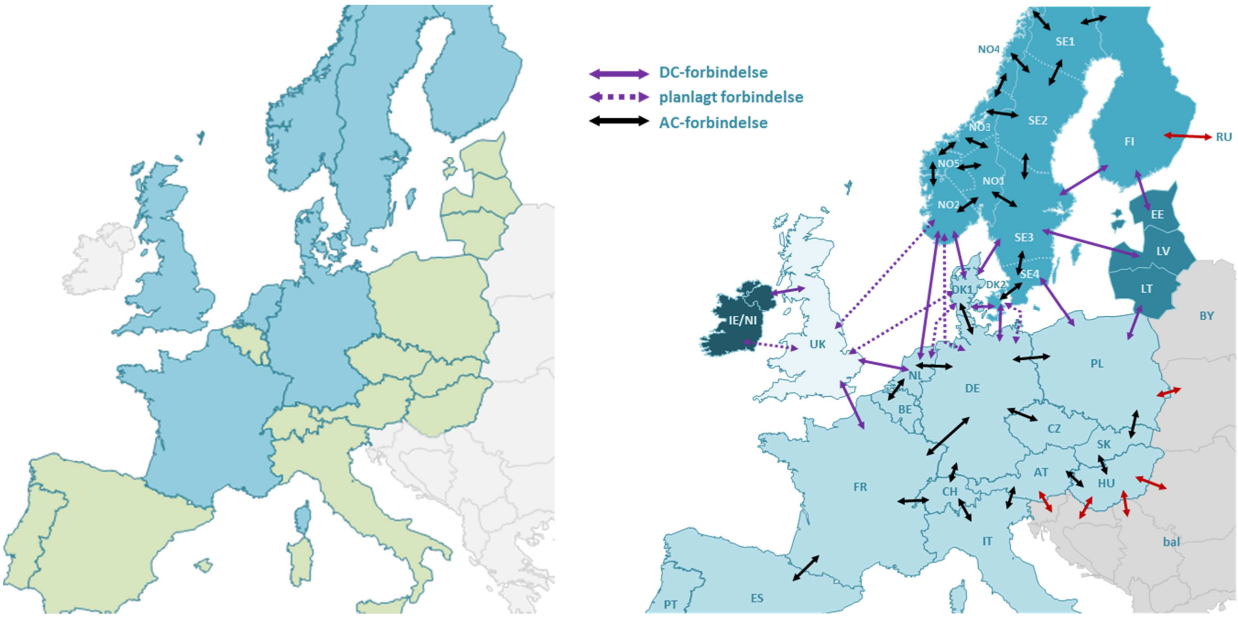
- Geographical scope
- Production capacity for different types of plant
- Other technical details about plants abroad (efficiency rate, fuel mix, etc., which are also included for Danish plants)
- Time profiles (hourly) for production from relevant technologies (solar, wind, and, partially, CHP)
- Electricity demand and consumption hourly profile (hourly rate)
- Transmission links between other modelled counties

As a general rule, the data has been included for each country/electricity area for each year modelled in the projections.

7.1 Geographical scope

To ensure better representation of foreign data in the Danish Energy Agency RAMSES model, the geographical scope was expanded in DECO18 and PGSO-IP18 from the seven countries included in DECO17 (NO, S, FI, NL, UK and FR) to most of Europe, i.e. 23 countries grouped in 15 price zones: Denmark (2 electricity price areas), Norway (1), Sweden (1), Finland (1), Germany + Austria + Luxembourg (1), The Netherlands (1), Belgium + France (1), United Kingdom + Ireland (1), Spain + Portugal (1), Switzerland (1), Italy (1), Poland + Czech Republic + Slovakia (1), Estonia + Latvia + Lithuania (1), Hungary (1), see figure 40.

Figure 40: Countries modelled in the Danish Energy Agency's RAMSES model



DEAs geographical scope reflects nicely the countries modelled by Energinet, although Energinet models each country separately rather than combining them into price zones.

7.2 Electricity demand and production capacities

Data in the RAMSES model on current electricity generation abroad is based on data for Europe from Platts' World Electric Power Plants Database. Data on future capacity abroad has generally been based on data from the 2007 Mid-Term Adequacy Forecast (MAF) by ENTSO-E (capacities for 2020 and 2025) and the ENTSO-E TYNDP 2018 Scenario Report (ENTSO-E, 2018) (capacities for 2030 and 2040, based on the Sustainable Transition scenario[2]). This is publically available data.

In addition to capacity broken down by fuels, the RAMSES model needs a number of other input data in order to model electricity production, fuel consumption, electricity prices, etc. The most important input data is efficiency rates, operating costs, availability and subsidies. For Denmark, the Danish Energy Agency's annual energy production statistics have been used, while for Europe, Platts' World Electric Power Plants Database has been used. This contains data on technology, fuels, and year of establishment, etc. Comparisons are made with similar Danish plants.

For CHP plants abroad, an efficiency rate has been applied which reflects the fuel saved on heating (this is assumed to be the same as in Denmark). This method has been applied because PGSO-IP18 and DECO18 do not model heat production abroad directly in RAMSES. See the memorandum on assumptions for DECO18 (Danish Energy Agency, 2018c) for more details about this.

[2] Note that the EU's climate objectives are not entirely met in the Sustainable Transition scenario, but this scenario has been assessed to be the most representative because it is based on reports from the relevant countries about expected developments.

Electricity demand in electricity areas outside Denmark is based on statistics from the IEA. Trends in electricity demand are based on ENTSO-E data, and calculations have been performed in the same way as for capacities, i.e. consumption in 2030 and 2040 is based on the Sustainable Transition scenario in TYNDP 2018.

The data on countries outside Denmark is not directly a part of the power and gas sector outlook (except for interconnector capacities); however this data does affect model outcomes. Therefore, in the preparation of PGSO-IP18, efforts have been made to align foreign data used by Energinet in its BID model and by the Danish Energy Agency in its RAMSES model as much as possible. However, certain differences in assumptions, sources and data sets remain, e.g. concerning the Nordic countries, because information from the internal TSO work has not been available to the Danish Energy Agency. Note also that Energinet does not use the Platts database but rather data from ENTSO-E and from the Nordic TSO cooperation work.

Furthermore, it is important to remember that the Danish Energy Agency's and Energinet's models have different areas of focus. For example, the Danish Energy Agency's models have focused more on modelling the impact of different policy scenarios on total energy consumption rather than testing the effect of the market on the transmission grid. However, with PGSO-IP18 the Danish Energy Agency has begun to focus more on the effect on the transmission grid. Interconnectors play an increasingly important role, not least due to large trading capacities with other countries (relatively speaking in comparison to domestic load on the system). As this aspect is expected to become more significant in the future, the market situation in Denmark will be even more sensitive to assumptions about developments in Europe.

DEA will therefore continue its cooperation with Energinet about foreign data and interconnectors, and this cooperation will focus on ensuring the best possible alignment of data in the models.

7.3 Transmission capacities

Transmission capacities for mainland Europe are based on TYNDP2018 (ENTSO-E 2018). For the Nordic countries they are based on data from Energinet's cooperation in the Baltic Sea Market Modelling Group (BSMMG). PGSO-IP18 describes the maximum available capacity for Danish interconnectors. Except for the interconnector between western Denmark and Germany (see below), these capacities are used as the basis for Energinet's analyses.

However, experience has shown that the transmission links are not always fully available to the market. Knowledge about downtime and varying availability in the transmission grid matters significantly for the models' ability to provide a realistic picture, e.g. of fuel consumption in Denmark. The Danish Energy Agency has examined foreign availability factors and expected future trading capacity via AC interconnectors. The RAMSES model has adjusted the capacities for existing connections downwards, so that modelling is based on the average trading capacity for 2016 and 2017, and this is also applied for the remaining projection period. This affects the projections of electricity and gas consumption in PGSO-IP18. The significance of this in terms of Energinet's grid planning will be addressed in more detail in the future.

Figure 41: Existing and adopted Danish interconnectors

Figure 41 shows the existing and adopted Danish interconnectors included in PGSO-IP18, including the Great Belt Link. The link between Sweden and Bornholm has not been included in the power and gas sector outlook.

Below is a description of Denmark's interconnectors to neighbouring countries that have been included in PGSO-IP18. As mentioned above, the values for import and export capacity express the maximum trading capacity (maximum net transfer capacity, NTC) available to the market. The capacities have been adjusted for grid losses (Energinet, 2014).

7.3.1 Interconnectors in western Denmark

The electricity system in western Denmark is linked to mainland Europe through an AC transmission line that is operated as a synchronous area run at the same frequency. The line to Germany comprises four AC interconnections. The maximum export capacity is 1,640 MW and the import capacity is 1,500 MW. The restriction on the import direction is due to part of the capacity being kept unavailable to the market in the event of outages elsewhere in the electricity system that would require import of electricity from Germany. The export direction has been restricted for some time due to internal bottlenecks in the North German electricity grid (TenneT, 2012). In 2017, the Danish and German governments therefore agreed on a minimum capacity up to 2021. The agreed minimum capacity was 700 MW from 1 January 2018 and it will grow to 1,100 MW from 1 January 2020. Energinet uses this minimum capacity in its analyses.

The electricity system in western Denmark is connected to Sweden and Norway through DC transmission lines. The transmission line to Sweden, Konti-Skan, comprises two DC interconnections with a total export capacity of 740 MW and a total import capacity of 680 MW. In addition to covering grid losses, the difference in capacity reflects a requirement to meet historical planning criteria for security of supply in connection with outages (Energinet, 2014).

The transmission line to Norway, Skaggerak, comprises four DC interconnections. The line was expanded most recently in 2014, and the total capacity is today 1,632 MW in both directions.

The western Denmark electricity system will have even more cross-border interconnections in the future.

Together with the Dutch TenneT, Energinet is in the process of establishing an electricity link between Denmark and the Netherlands, the CORBRA cable, which was approved by the Danish government in 2014. The cable will comprise a DC interconnection with a transfer capacity of 700 MW. Expected commissioning is sometime during 2019. Thus, the first whole operating year will be 2020.

Energinet is moreover cooperating with German TenneT TSO GmbH to upgrade the current connection between western Denmark and Germany. This will result in an increase in the transfer capacity in both directions to 2,500 MW and will also increase the capacity availability via the connection considerably. The expansion is expected to be in operation for its first full year in 2021. In spring 2017, the government approved the establishment of a 1,400 MW DC transmission line to the UK together with the West Coast Line, which is an AC interconnection between Endrup (east of Esbjerg) to the German border. This new link will increase the maximum trading capacity across the Danish-German border from 2,500 MW to 3,500 MW.

Viking Link is a planned interconnector between Denmark and the UK. The link is expected to lead to a more efficient use of renewables-based electricity generation, increased access to sustainable energy supplies and increased security of supply. Energinet is planning the Viking Link together with National Grid Interconnector Holdings Ltd. and expects the link to be in operation for its first full year in 2024 (one year later than expected in PGSO-IP17). At the same time, Energinet and TenneT TSO GmbH are planning the establishment of the West Coast Line. The West Coast Line is also expected to be in operation for its first full year in 2024.

7.3.2 Interconnectors in eastern Denmark

The electricity system in eastern Denmark is linked to Sweden through an AC interconnection, and thus to the rest of the Nordic system, which is operated as a synchronous area run at the same frequency. The Øresund interconnector to Sweden comprises six AC interconnections with a total export capacity of 1,700 MW and a total import capacity of 1,300 MW. The import capacity is restricted due to bottlenecks in the Swedish grid. The Øresund interconnector is currently being renovated as the cables have reached the end of their service life. The renovation is not expected to affect long-term transfer capacity.

The eastern Denmark system is moreover linked to Germany through a DC interconnection, Kontek, which has a total export capacity of 585 MW and a total import capacity of 600 MW. The difference in export and import capacity is due to grid losses (Energinet, 2014).

In 2019, eastern Denmark and Germany will be connected through a cable via Kriegers Flak in the Baltic Sea. The Kriegers Flak DC interconnection will have a transfer capacity of 400 MW in both directions. The link's export and import capacity will be restricted by the current electricity generation from the offshore wind farm at Kriegers Flak.

Furthermore, Bornholm is connected to southern Sweden through an AC interconnector with a capacity of 60 MW in both directions. This link is normally excluded from Energinet's model calculations of the eastern Denmark electricity system, and the link has not been included in PGSO-IP18.

7.3.3 Great Belt Link

Western and eastern Denmark are connected through a DC transmission line, the Great Belt Link. Obviously, this link is not an interconnector as such, as it connects two Danish price zones, i.e. DK1 and DK2. However, it is operated in the same way as interconnectors and is included in the market on the same terms as interconnectors. The Great Belt Link was put into operation in August 2010. The capacity from western to eastern Denmark is 590 MW, and the capacity in the opposite direction is 600 MW. The difference in export and import capacity is due to grid losses (Energinet, 2014).

8 Gas data

For many years, natural gas has played an important role for energy supply in Denmark, both in terms of reducing the reliance on oil and as part of efforts to promote efficient small-scale CHP plants. Danish gas consumption and production is however facing radical change in the transition to renewable energy sources. Consumption and production of fossil gas will subside, but there will also be an expected increase in production of green gases, including biogas. There is considerable uncertainty about the role that gas, and the Danish gas infrastructure, will come to play in the future. Gas could potentially become an weighty factor, e.g. in the transport area. However, there is also a real possibility that gas consumption will eventually phase out completely. The development depends on carbon and fuel prices, as well as on the technological development, but also, and to a considerable extent, by political decisions regarding energy saving initiatives and subsidies for biogas.

The 2018 Energy Agreement set aside funds to prepare a gas strategy that will focus on how the Danish gas infrastructure can be exploited in the future, including in the green transition. The strategy will also look at the framework conditions for competitive deployment of biogas and other green gases, as well as at overall total balances in the Danish gas sector, including investments and activities in the North Sea and possible scenarios for a long-term phase-out of natural gas. Furthermore, the strategy will look at the framework conditions for integrating energy systems, including the possibilities for converting and storing electricity as gaseous fuel, e.g. via methanation.

In the short term, assessing the supply picture for the period when the Tyra gas field is being redeveloped from the end of 2019-2022 will pose a special challenge. During this period, imports of gas from German and use of natural gas from Danish natural gas stores will play an important role in the Danish gas supply.

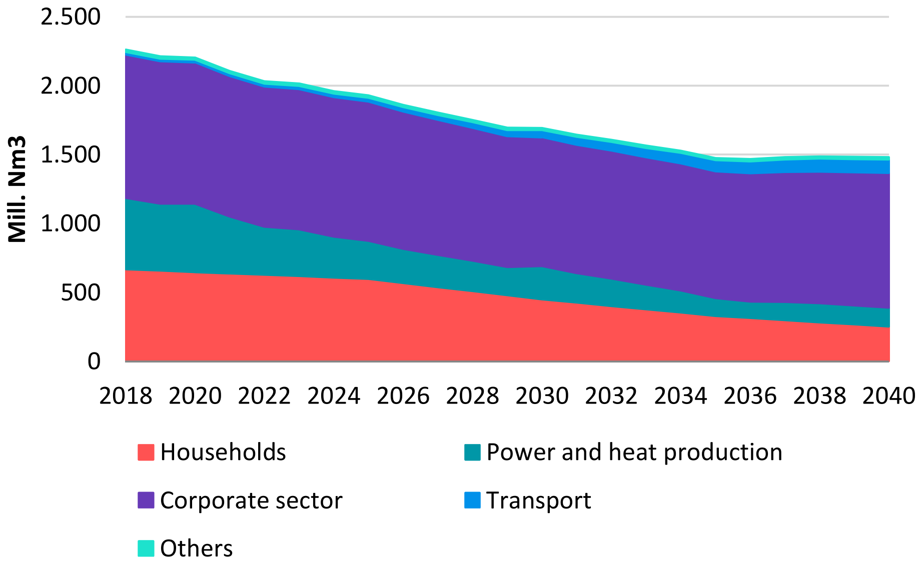
8.1 Demand in Denmark

Danish grid-connected gas demand has been assessed to fall considerably over the period - from overall demand of more than 2,200 million Nm^3 in 2018 to around 1,500 million Nm^3 in 2040, see figure 42. Gas demand includes both natural gas and biogas upgraded to natural-gas-grade for use in the gas grid. Demand for the latter will increase over the period as described in more detail in section 8.3. Preliminary estimates suggest that observed gas demand in 2018 will be higher than the 2018 figure in PGSO-IP18. This is primarily due to 2018 not looking to be a representative year, e.g. because of a cold winter in combination with a dry summer and low wind production. Because of this, and because of the special circumstances surrounding redevelopment of the Tyra gas field, a sensitivity calculation has been performed for gas demand in the short term, see section 8.5.

Gas demand in Denmark includes demand CHP and district heating production, for individual heating systems in households, for the corporate sector and for the transport sector.

Gas for power production and district heating is projected in the Danish Energy Agency's RAMSES model, while gas demand by the corporate sector and households is projected in the IntERACT model. Gas for transport is assessed separately, and only heavy transport and sea transport are expected to have any real potential for using gas. The use of gas for the production of heat and power is expected to fall significantly over the period, from more than 500 million Nm^3 (corresponding to 21 PJ) in 2018 to only 137 million Nm^3 (6 PJ) in 2040. This fall is primarily attributable to the expected decommissioning of natural-gas-fired decentral CHP plants and, in the somewhat longer term, the expected transition to renewable energy throughout the power and district heating sector.

Figure 42: Expected trend in gas demand in Denmark, by category of demand



The corporate sector which consumes natural gas for a number of energy-intensive processes accounts for the greatest share of Danish gas demand throughout the period. The level of demand is relatively stable - with only a slight downward trend up to 2035 as a result of energy savings and technological developments. After 2035, there is a minor increase in demand.

Gas demand for heating by households is expected to fall considerable, e.g. due to energy savings and the introduction of electric heat pumps in place of gas-fired boilers.

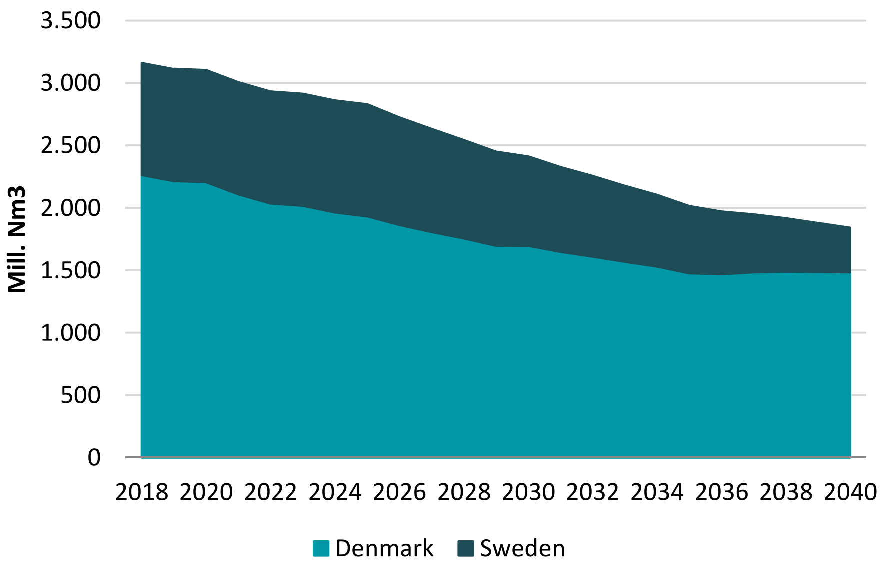
Gas for transport has been assessed to increase during the period, albeit from a low starting point, and gas demand for transport is not expected to be higher than 100 million Nm^3 (5 PJ) in 2040. For heavy road transport, the use of gas is expected to serve as a transition technology, which could be replaced by electricity in the future. It is expected there will be a gradual phase-in of gas for heavy road transport after 2025 and up to 2040 when gas demand is expected to make up 10% of total energy demand for heavy road transport. The guess at the trend in gas demand for sea transport has not been revised, and the figures for gas demand for sea transport are therefore identical to those used by Energinet in PGSO-IP17.

8.2 Demand in Sweden

All natural gas supplied to Sweden is delivered via the Danish natural gas infrastructure. The forecast of transport of gas to Sweden therefore, indirectly, serves as a forecast of natural gas demand in Sweden. The Danish Energy Agency has not performed a detailed forecast of gas demand in Sweden for PGSO-IP18. Instead, it has been assumed that the natural gas demand in

Sweden will be reduced at around the same pace as in Denmark. This assumption is based on the observation that Sweden has more or less the same climate objectives as Denmark and is therefore expected to use natural gas to the same extent as Denmark. However, this assessment is associated with great uncertainty.

Figure 43: Expected trend in gas demand in Denmark and Sweden



8.3 Gas production

8.3.1 Production of natural gas

The Danish Energy Agency prepares annual statements of Danish North Sea oil and gas resources and, on the basis of this statement of reserves, prepares forecasts of natural gas (and oil) production in the years to come. These forecasts describe both how much natural gas is likely to be produced; how large a share of the gas is used in fuel consumption for North Sea oil and gas production; and how much goes to gas flaring and to subsea injection, respectively.

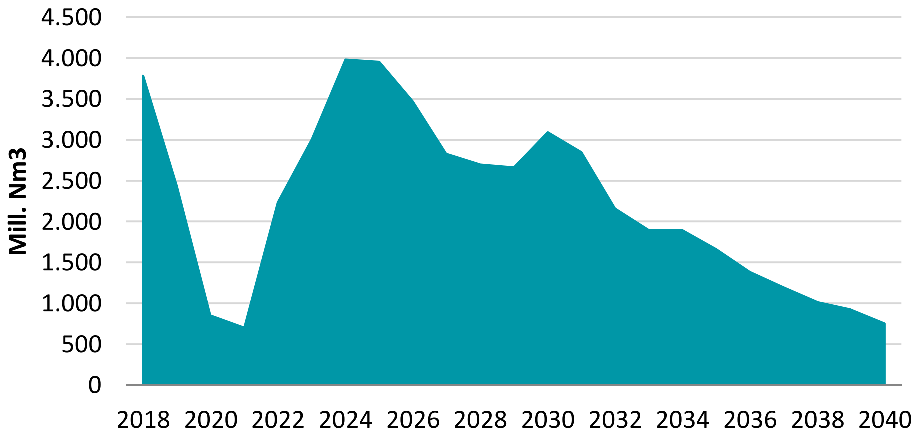
PGSO-IP18 is based on the Danish Energy Agency's most recent forecast of oil and gas production in the North Sea (Danish Energy Agency, 2018i). However, the power and gas sector outlook also include gas from the Norwegian Trym field.

What is interesting in this context is how much gas is supplied from the North Sea, i.e. what is called *sales gas*, because this tells us how much gas is available in the Danish grid[3]. The expected trend in the production of sales gas is shown in figure 44. The considerable drop in production in the short term is attributable to the shut down in connection with redevelopment of the Tyra field. In the long term, production will subside as the gas resources in the North Sea are gradually depleted.

[3]This clashes with DECO, in which forecasts of gas production in the North Sea have not been directly included in the baseline projection of energy consumption. On the other hand, DECO includes fuel consumption from North Sea oil and gas production and projects emissions from flaring.

Some of the sales gas from the North Sea is sent directly to the Netherlands see section 8.4, and not all sales gas from the North Sea is therefore available in the Danish gas grid.

Figure 44: Production of sales gas from the North Sea, including the Norwegian Trym field



8.3.2 Production of biogas

There is considerable uncertainty about how the production of bio natural gas (and other renewable energy gases) will develop in the long term and a positive development will depend on a strong subsidy regime and reductions in the manufacturing costs for biogas.

The short-term projection of biogas production takes account of anticipated construction projects, while the long-term projection takes account of the biogas production potential and subsidies for production of biogas. The most recent forecast from the Danish Energy Agency covers the period 2018-2023 and includes an assessment of where the biogas is used, including the proportion of biogas upgraded for use in the gas grid. This forecast was applied in DECO18, which assumes that production of biogas will be constant after 2023 (Danish Energy Agency, 2018c). PGSO-IP18 only includes biogas that is upgraded to natural-gas grade and supplied in the grid. However extra production volume has been added to the baseline projection figures for 2021 to 2023 to include the expected result of the extra biogas support agreed in the 2018 Energy Agreement. After this, biogas production for the gas grid is assumed to stay at a fixed level up to 2030, followed by a slight increase up to 2040.

All in all, this means that production of biogas for the grid is expected to increase from the current level of 198 million Nm^3 (9 PJ) to 436 million Nm^3 (19 PJ) in 2040. As total gas consumption is expected to fall by around 35% up to 2040 in step with transitioning of the CHP sector and phase-in of individual heat pumps in households, the increased amount of biogas will mean that the share of renewable energy gas in the grid increases from a current level of around 8% to around 30% in 2040.

These projections are associated with great uncertainty and there are several factors which could pull developments in the direction of an even higher share of renewable-energy gas in 2040. Natural gas consumption could decrease by even more if the transition of corporate-sector gas consumption, in particular, takes place at a higher pace than expected, and it is possible that the gas strategy to be prepared as follow-up to the 2018 Energy Agreement will identify additional opportunities to incorporate renewable-energy gas into the energy system.

8.4 Cross-border gas flows

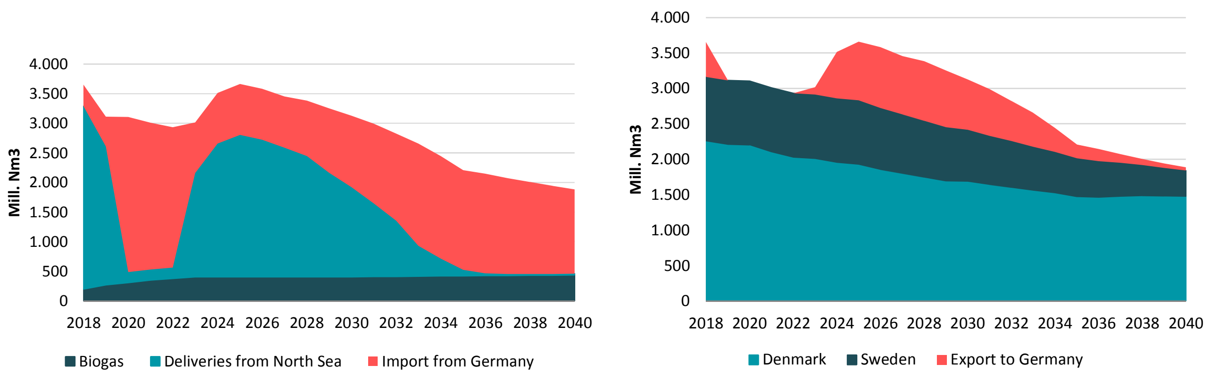
Natural gas produced in the North Sea can flow to either Denmark (via Nybro) or to the Netherlands. It has been assessed that gas will be delivered primarily to Denmark. However, there is great uncertainty about the picture after redevelopment of the Tyra field. How much gas will flow to Denmark or the Netherlands, respectively, will depend on market conditions and the gas transit price, the development of which may, in turn, be influenced by many different factors.

Danish gas traders can import gas from Germany, and are likely to do this during periods when gas from Germany is cheaper than gas from the North Sea. However, on the other hand, gas will also flow in the opposite direction as exports from Denmark to Germany when the market conditions are optimal for this. Also here, the assessment of future flows is characterised by considerable uncertainty.

A possible guess at future gas flows to the Netherlands and to/from Germany to ensure physical balance in the grid has been prepared for PGSO-IP18. On the basis of the assumed distribution of future gas flows, the overall supply picture is as illustrated in figure 45.

If the supply of gas (natural gas from the North Sea and biogas) to the Danish grid exceeds consumption in Denmark and Sweden, there will be average net exports to Germany[4], and in contrast there will be net imports to Denmark from Germany if consumption exceeds the gas volumes available in the Danish gas grid from the North Sea and from up-graded biogas. Whereas, historically, Denmark has been a net exporter of natural gas to Germany, the period with redevelopment of the Tyra field will see considerable net imports from Germany. After this will follow some years with a more or less balanced exchange between Denmark and Germany, followed by increased Danish dependence on imported gas in step with depletion of the North Sea resources.

Figure 45: Input of gas to Denmark (left) as well as consumption and exports to Germany (right)



[4]To be completely correct, these figures should be adjusted somewhat to reflect the fact at a limited share of the North Sea supply comes from the Norwegian Trym field.

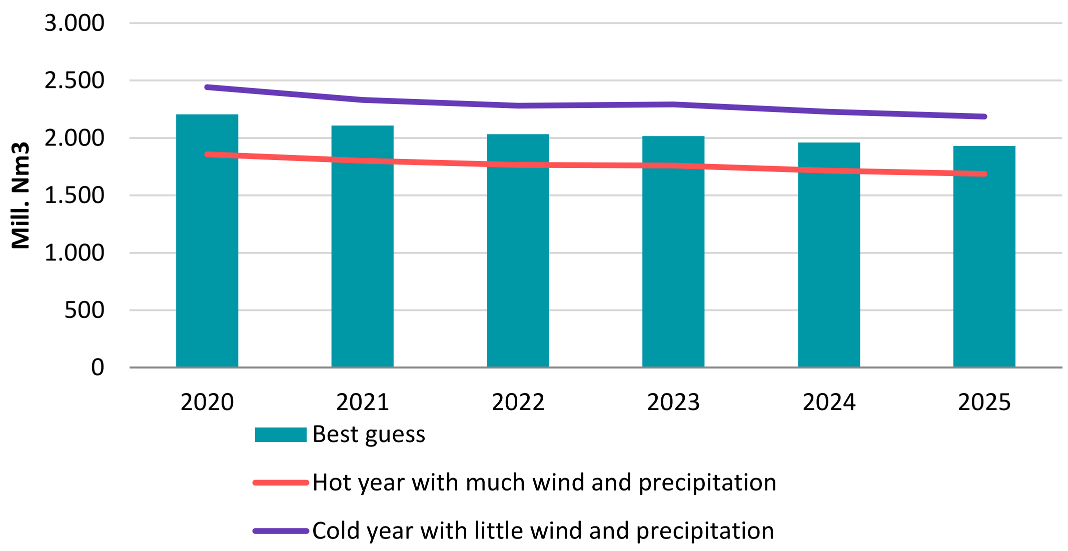
8.5 Sensitivities

To take account of the exceptional situation during redevelopment of the Tyra field, it has been examined how variations in temperature (cold/hot year) and in the electricity market (wind and precipitation) could influence gas consumption within the individual year in the short term. A range of outcomes has been established by looking at two extreme situations: A hot year with much wind and precipitation and a cold year with little wind and precipitation.

High temperatures and very windy and wet weather leading to extensive build-up of Nordic hydro reservoirs will result in lower gas consumption. The temperature will affect gas consumption directly through a lower demand for heating, while windy and wet weather will influence the scenario indirectly through a lower price of electricity as a consequence of the generous production of electricity from wind power and hydropower.

On the other hand, low temperatures and limited precipitation and wind will result in an increase in gas consumption due to a greater demand for heating and higher electricity prices. This variation, in particular, is important to note in connection with plans to ensure security of the gas supply in Denmark during redevelopment of the Tyra field. Assuming these extreme climate challenges, the Danish Energy Agency assesses that, in the short term, gas consumption could be between 10-15% higher or lower than the 'best guess' scenario in PGSO-IP18, see figure 46.

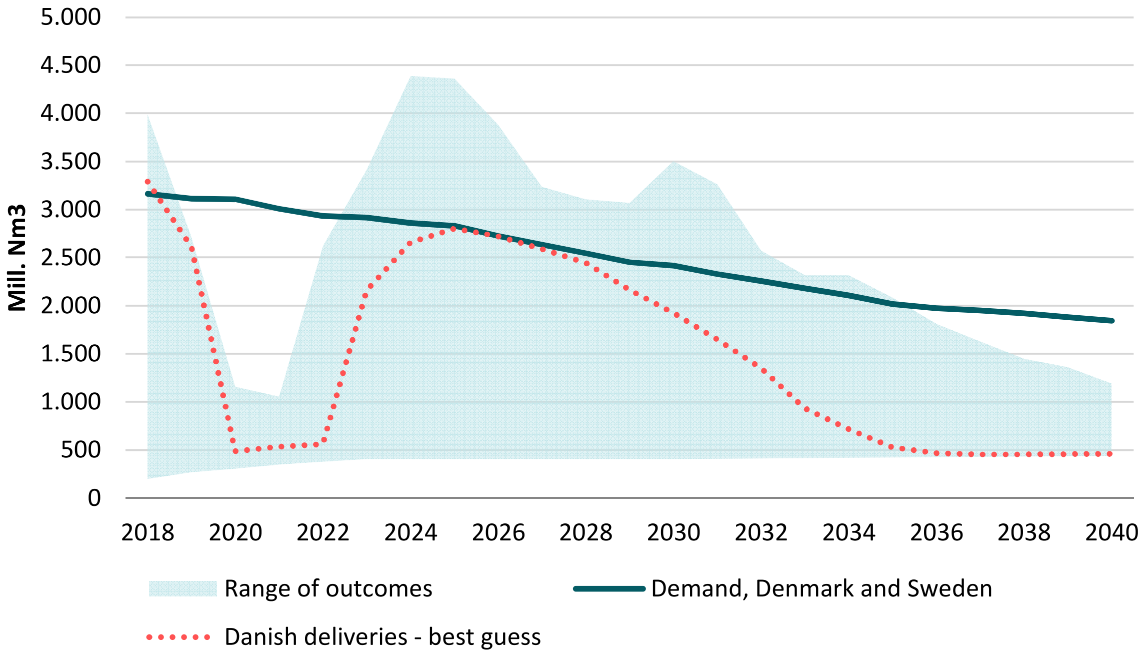
Figure 46: Short-term variation in gas consumption with different climate assumptions



For PGSO-IP18, focus has been on sensitivity in relation to gas consumption in the short term in connection with the shutdown of the Tyra field. As described in section 8.4 above, developments after this time are associated with great uncertainty about the assessment of how gas will flow in the system and across national borders.

To illustrate the significance of this great uncertainty about whether gas from the North Sea will flow to Denmark or the Netherlands, figure 47 has been included below to illustrate a possible range of outcomes for Danish gas supplies (North Sea plus biogas) compared with PGSO-IP18's gas consumption in Denmark and Sweden. The range of outcomes does not reflect any assumptions about the likely routes for gas from the North Sea; rather the range has been set up to illustrate the significance of whether all the gas from the North Sea flows to Denmark (upper section of the range) or to the Netherlands (lower section of the range).

Figure 47: Possible range of outcomes for Danish gas supplies



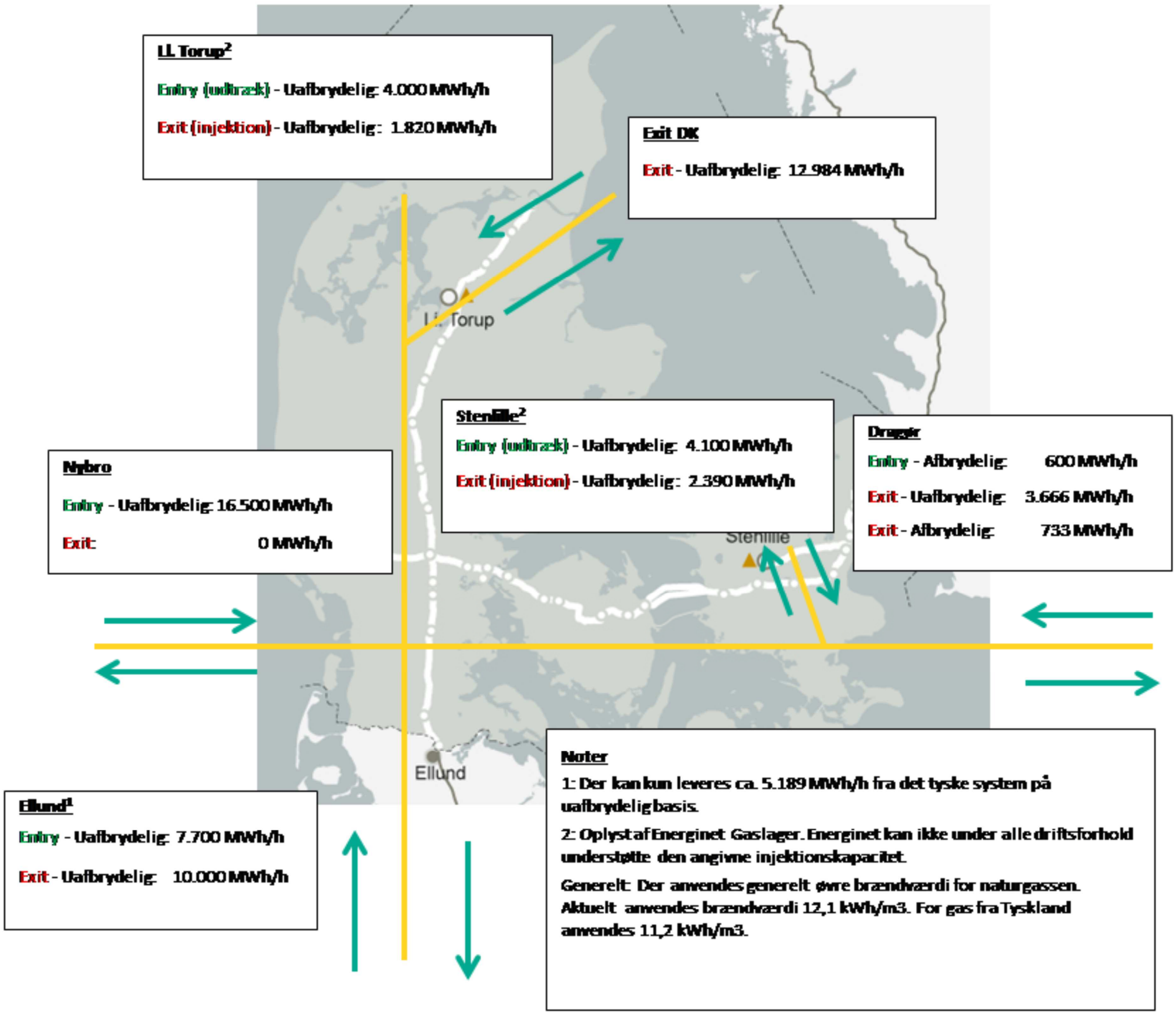
In addition to uncertainty about the gas flows, there is also considerable uncertainty about the role of gas and the Danish gas infrastructure in the transition to a fossil-free energy system up to 2050. Long-term structural sensitivity analyses are therefore required.

The Danish Energy Agency intends to continue its work to assess and analyse gas flows and developments in the gas system for future power and gas sector outlooks.

9 Gas interconnectors

Existing gas interconnectors in the Danish gas transmission network are shown in figure 48.

Figure 48: Gas interconnectors in the Danish gas transmission system



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