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Quantifying the influence of wind power and photovoltaic on future electricity market prices

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ABSTRACT

Variable renewable electricity sources have been shown to reduce wholesale electricity market prices. This is expected to reduce the incentive for investments in new electricity production capacity, and might even make these investments infeasible, if relying only on the income from trade on the current electricity market paradigms. In this paper, a novel approach for quantifying this effect in future energy systems is developed using a holistic energy system approach. The approach is applied to the case of Denmark in 2015, which is part of the Nordic and Baltic wholesale electricity market Nord Pool Spot. A holistic energy system model is created and verified according to both the Danish energy balance and the Nord Pool Spot system price in 2015. Using this verified model, the Nord Pool Spot system price is quantified at increasing amounts of onshore wind power, offshore wind power and photovoltaic in Denmark. It is found that regardless of which variable renewable electricity source is implemented, including a combination of the three, the Nord Pool Spot system price decreases as the amount of energy produced by these sources increases, and this effect occurs immediately as more is introduced.

1. Introduction

Renewable energy sources (RES) are being implemented into energy systems worldwide at an increasing rate. Within the electricity sector, especially variable renewable electricity generating sources (RES-e), such as wind power and photovoltaics (PV), have experienced increased implementation. In 2017, the worldwide installed capacity of wind power was 514 GW and for PV it was 386 GW, up from 17 GW and less than 1 GW in 2000, respectively [1]. These variable RES-e sources have been introduced into existing electricity systems and market setups, though often being accompanied by some form of subsidy [2].

In many countries, electricity is traded on wholesale markets [3], where market participants buy and sell electricity from each other. The setup of these markets often differs between countries and regions, though in the EU, markets using the marginal price principle are common, as shown by Imran and Kockar [4]. In markets using the marginal price principle, every market participant is settled at the same price, which is set by the intersection of the aggregate supply curve and the aggregate demand curve [5]. On the supply side, this principle has been shown to incentivise market participants to provide bids equal to their short-term marginal costs of producing electricity [5]. The demand curve has often been shown to be price inelastic, as found by Bönte et al. [6], that investigated price elasticity in the EPEX market, and Boogen et al. [7], that investigated price elasticity for residential electricity demand in Switzerland, meaning that the majority of the demand for electricity does not react to changes in the price for electricity in the short-term. Hence, historically, the marginal production unit has, to a large extent, set the electricity market price. With different types of electricity production units with varied short-term marginal costs and resulting varied electricity market bids, markets using the marginal price principle have been shown to provide a cost-efficient allocation of the electricity market units [8], and, to some extent, have facilitated the implementation of variable RES-e into the electricity system, as e.g. Grohnheit et al. [9] found for the case of Denmark. As more variable RES-e are implemented in these systems, issues related to the marginal price principle have started to emerge. This is because variable RES-e have short-term marginal cost close to zero, and thereby have been shown to reduce electricity prices, as

Abbreviations: RES, renewable energy sources; RES-e, renewable electricity generating sources; CHP, combined heat and power; PV, photovoltaics; O&M, operation and maintenance; $p_i(t)$, the system market price without the effect of the modelled system [EUR/MWh]; Fac_{depend}, price elasticity [(EUR/MWh)/MW]; p_o, basic price level for price elasticity [EUR/MWh]; $d_{Net\text{-}Import}(t)$, net import of electricity to the system, excluding production that occur due to grid stabilisation requirements [MW]; $p_X(t)$, the resulting system price on the external market after exchange of electricity with the defined system [EUR/MWh

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Traber and Kemfert [10] showed for the case of Germany and as Hvelplund et al. [11] showed using the demand and supply curves. The lowering of electricity prices is often referred to as "The merit-order-effect" [11]. The issue with reduced electricity market prices are two-fold: it makes variable RES-e less profitable, but it also reduces the income for other electricity producers, thus reducing the incentive to invest in traditional electric capacity needed to ensure a stable supply of electricity. This issue is often referred to as the "missing money" issue, as also used by e.g. Joskow [12]. Traditional electric capacity is needed for periods where variable RES-e are not producing, and as such, the "missing money" issue is important in order to ensure a secure and stable electricity system [10]. Hence, it is uncertain whether the marginal price principle will provide sufficient signals for future investments as energy systems worldwide continue to integrate greater quantities of variable RES-e. It is therefore relevant to analyse and quantify how electricity markets using the marginal price principle would be affected by increasing integration of variable RES-e. This has been a subject of research for some time now, as the following literature review details.

Traber and Kemfert [10] developed a computational model for power producers to investigate the effect of wind power supply on the electricity market price in Germany over a one year period from 2007 to 2008. Cludius et al. [13] use time-series regression analysis to identify the historic effect of wind power and PV on German electricity prices, and then use that to build a near-term forecasting method to estimate the effect of increasing wind power and PV. Ketterer [14] uses a generalised autoregressive conditional heteroscedasticity (GARCH) model to evaluate the effect of wind power on the wholesale electricity market price in Germany from 2006 to 2012. Azofra et al. [15] use an artificial intelligence-based technique with empirical data from 2012 to investigate the effect of wind power on Spanish wholesale electricity market prices. Clò et al. [16] use a consolidated methodology to statistically analyse the merit-order effect on Italian electricity market prices for the period 2005–2013. Zipp [17] uses a multivariate regression analysis to analyse the merit-order effect on German-Austrian electricity prices for the period 2011–2013. Djørup et al. [18] used the energy system simulation tool EnergyPLAN and an existing 100% RES energy system scenario to find that due to merit-order-effect the current electricity market structure in Denmark is not be able to financially sustain sufficient amount of wind power needed in a 100% RES energy systems. The model does not include any exchange with exogenous electricity markets. Lagarde and Lantz [19] use a two-regime Markov switching model to assess how RES-e affected the German wholesale electricity market price in 2014–2015.

As seen, the current research within this field is largely based on historical data, and focuses exclusively on the electricity system. In this paper, a holistic energy system approach will be used to analyse and quantify the effect of increasing variable RES-e in an existing electricity market paradigm. To conduct a holistic analysis, the entire energy system of a country is used, not only the electricity system. This is done to include all potential interactions in the energy system that could help integrate variable RES-e. These interactions have been shown to be important for the integration of variable RES-e. For example, Mathiesen et al. [20] showed that integrating the electricity, thermal, and gas grids enable a transition to 100% RES energy systems. Lund et al. [21] showed how 4th generation district heating systems can be used for integrating variable RES-e. Lund et al. [22] showed how electricity smart grids should only be seen as part of an overall solution for integrating variable RES-e. Bačeković and Østergaard [23] showed how local integration of energy sectors enable increased utilisation of variable RES-e. Wolisz et al. [24] showed how coupling the electricity grid with the thermal supply for residential buildings can help integrate variable RES-e. As such, it is relevant to have a method that can quantify the market effects of different technologies that enables such integration.

2. Methods

To holistically investigate the effect of increasing amounts of variable RES-e in an energy system, it is relevant to utilise a case energy system that can be used for applying and testing the methods. It is relevant to use an energy system where variable RES-e sources are already integrated, where there is a widely used wholesale electricity market using the marginal price principle, and where there already is an integration between the energy sectors. Based on these criteria the energy system of Denmark in 2015 is simulated as a case. Denmark is part of the Nordic and Baltic electricity market Nord Pool Spot. Nord Pool UK is not included in the description here. Nord Pool Spot consists of a day-ahead market and an intraday market. In 2016, 391 TWh was traded through the day-ahead market, while only 5.1 TWh was traded through the intraday market [25]; as such, the focus of this paper is on the day-ahead market. The marginal price principle is used in the day-ahead market, where electricity is traded every day at 12 noon for each hour of the following day. Nord Pool Spot is divided into separate price areas, where the price is settled separately if a bottleneck occurs between a given price area and the remaining Nord Pool Spot areas. Price areas with no bottleneck share the same electricity price, known as the system price. Denmark consists of two separate price areas, DK1 and DK2, connected by a 600 MW transmission cable [26]. The Danish energy system is characterised by an already large share of wind power, a large utilisation of district heating with CHP units, and interconnections with Norway, Sweden, and Germany providing a total electricity export capacity of 6297 MW and import capacity of 5712 MW in 2015. In 2015, wind power in Denmark (DK1 + DK2) produced 14.1 TWh electricity out of a total countrywide electricity production of 29 TWh. In absolute numbers, 2015 had the lowest annual average system price on Nord Pool Spot since 2001 [27]. The net import of electricity to Denmark in 2015 was 5.9 TWh [28].

The energy system analysis tool EnergyPLAN is used to holistically simulate the 2015 Danish energy system. EnergyPLAN has proven to be useful for simulating energy systems with high integration of variable RES-e as well as for the Danish energy system, as e.g. shown by Mathiesen et al. [29] where different scenarios for the Danish energy system was simulated for the years 2035 and 2050. EnergyPLAN is an energy balancing tool that simulates the operation of all sectors of an energy system on an hourly basis through a leap-year, including transmission lines to surrounding areas. The different types of energy producing and consuming units are aggregated in EnergyPLAN based on their unit type. EnergyPLAN has two different simulation strategies; Technical Simulation, where the aim of the simulation is to reduce fuel consumption, and Market Economic Simulation, where the simulation is set up to function like the day-ahead wholesale market of Nord Pool Spot. This latter simulation approach is based on the marginal price principle, where market participants operate based on their short-term marginal cost, starting with the must run units and lowest cost units first, and a resulting system price and internal area price is then calculated [30]. As the aim of this paper is to evaluate the effect of increasing variable RES-e on the wholesale electricity price, the Market Economic Simulation approach is used in this paper. The version of EnergyPLAN used in this analysis is v13.1. The entire energy system of Denmark is simulated assuming that there are no practical restrictions to the flow of electricity between the two Danish price areas. The statistical data used for modelling mainly comes from the Danish Energy Agency and the Danish transmission system operator Energinet.dk. The data used from the Danish Energy Agency are the Danish energy statics for 2015 [28], the master data register of wind turbines from 2017 [31], the register of energy producers for 2015 [32], and the assumptions for socio-economic assessments from 2016 [33]. From Energinet.dk the hourly electricity data [34], statistics of PV capacity [35], and Energinet.dk's analysis assumptions [36] have been used. However, a review of the thermal storage capacity in Denmark by the Danish District Heating Association [37], an analysis of the Danish cooling demand by Rambøll [38], an analysis of the district heating potential in Denmark by Dyrelund et al. [39], and data from "IDA's Energy Vision 2050" by Mathiesen et al. [29] are also used. For distributing the yearly heat demands into each hour, data from the Climate Forecast System Reanalysis [40] are used to calculate heating degree days with a reference temperature of 17 °C. The temperature data used are taken for the point 55.91° N 10.02° E, which is just south of Denmark's second largest city, Aarhus. As the temperature data is only needed for distributing the 2015 national district heating demand into hourly values, the used data is expected to be sufficiently detailed for this analysis. A detailed overview of the data used in this analysis can be found in the Appendix A.

Other researchers have constructed models for historic years in EnergyPLAN and verified the simulation results with statistical data. Verified models of historic years have been developed for a wide range of different energy systems, such as Hungary [41], Ireland [42], Romania [43], Singapore [44], Jordan [45], China [46], Chongming county in China [47], Jiangsu province in China [48], Beijing in China [49], inland Norway [50] and Ontario in Canada [51]. All of these studies used energy balances from the statistics for the given area to verify the simulations accuracy. It has not been possible to find any research where the simulation of an EnergyPLAN model has been verified using the electricity market price, which is relevant when quantifying the electricity market price with increasing amounts of variable RES-e. To be able to use the holistic energy system model, EnergyPLAN, to identify the "merit-order-effect" and the "missing money" issue, it is important to identify a method that makes it possible to verify the model using both the energy balance but also the electricity market price of the given modelled year. As such, a method for this type of model verification is established in this paper.

As the model used in this paper is based on the Danish energy system in 2015, it is important to construct a model that can be verified using the statistical data for both the energy balances and electricity market price available for this year. Part of the data needed for the model include the statistical information of the energy balances, such as demands, capacities, etc., which are also needed when using the Technical Simulation approach. However, when using the Market Economic Simulation approach in EnergyPLAN, it is important to also define the external electricity markets. The external electricity markets are defined by the total transmission capacity between the energy system defined in EnergyPLAN and the surrounding areas, by the average hourly external electricity market prices, and by the effect that import and export of electricity from the system defined in EnergyPLAN has on this external electricity price [52]. As described by Lund and Münster [53], in EnergyPLAN the resulting system price on the external market after exchange of electricity with the defined system, $p_X(t)$, is found for each hour of the simulated year as shown in eq. (1).

$$p_X(t) = p_i(t) + (p_i(t) / p_o) * Fac_{depend} * d_{Net-Import}(t) \quad (1)$$

where $p_i(t)$ is the system market price without the effect of the modelled system [EUR/MWh], Fac_{depend} is the price elasticity [(EUR/MWh)/MW], p_o is the basic price level for price elasticity [EUR/MWh], and $d_{Net\text{-}Import}(t)$ is the net import of electricity to the system, excluding production that occur due to grid stabilisation requirements [MW]. In this paper, $d_{Net\text{-}Import}(t)$ is set to be limited by the transmission capacity. $p_x(t)$, $p_i(t)$ and $d_{Net\text{-}Import}(t)$ are time depend values, changing from hour to hour through the simulated year. Fac_{depend} and p_o are fixed values through one year.

As detailed in Lund et al. [52], in EnergyPLAN $d_{Net\text{-}Import}(t)$ is calculated by first calculating the short-term marginal production and consumption costs of the units in the modelled energy system. Then an hourly basis for the electricity price is found where only the hourly electricity demand and variable RES-e production in the model are considered, the remaining demand is met by import and excess production is exported when possible. Then in each hour the flexible electricity consumption units are activated starting with the units with lowest short-term marginal costs, considering the change in electricity price as defined by Eq. (1). Afterwards the electricity production units are activated in each hour, considering the change in electricity price as defined by Eq. (1). Lastly, the electricity storages are optimised, and the process is repeated.

As also expressed in Eq. (1), the elasticity parameter in EnergyPLAN represents the relation between external and internal electricity market prices as a function of the net import. By applying this as a model for the relation between external and internal electricity market prices, the historical value of the elasticity parameter can be estimated for 2015.

Estimation of the elasticity parameter is done on the basis of hourly electricity market data from Energinet.dk [34]. The hourly western Danish electricity prices (price area DK1) are used for $p_i(t)$. This price area is chosen because it is viewed as the dominating price area in Denmark, as 71% of all electricity produced and 60% of all electricity consumed in Denmark in 2015 occurred in DK1. Likewise, the hourly peak gross electricity consumption in DK1 was 3.34 GW in 2015, where in DK2 it was 2.3 GW. DK1 is also the most dominant when considering turnover in monetary units, where DK1 in 2015 accounted for 53% of the total turnover for purchased electricity on Nord Pool Spot in Denmark and 66% of the sold electricity [34]. DK1 is coupled to both the electricity market EPEX in Germany and Nord Pool Spot in the Nordic countries. For each of these electricity markets Fac_{Depend} and the correlation between the model output and real-world data is used to identify which electricity market the DK1 price is closest connected. For Nord Pool Spot, the net import variable, $d_{Net\text{-}Import}(t)$, is defined as the hourly planned trade of electricity between price area DK1 and the price areas NO2 and SE3, and for EPEX $d_{Net\text{-}Import}(t)$ is defined as the hourly planned trade of electricity between price area DK1 and Germany. These quantities may deviate from the actual transferred energy amounts, however, only the traded energy in the wholesale market is included, since only this amount should influence day-ahead prices. The available data also include trade on the intraday market. This is a potential source of error. However, because the traded energy on the intraday market is relatively small in comparison with the day ahead market, as discussed earlier, the available data are considered applicable for the purpose.

As can be seen from Eq. (1) the base price, p_0, is not an absolute number, but are simply relative to Fac_{depend}, and as such, p_0 can simply be assumed to be a certain value. Here it is assumed to be 20 EUR/MWh, which corresponds closely to the average price in the studied area. With the applied assumptions and the available historical market data, the elasticity parameter, Fac_{Depend}, is the only unknown variable. To identify Fac_{Depend} Eq. (1) is rearranged to Eq. (2).

$$Fac_{depend} = ((p_x(t) - p_i(t))/(p_i(t)/p_0))/d_{NetImport}(t) \quad (2)$$

A value for this unknown variable is identified that maximises the model fit. The outcome of the model is a vector of hourly prices for a whole year. The correlation between the model outcome and the historical prices is used as a fitness indicator. The higher correlation between the model price vector and the historical price vector, the better the fitness is considered to be. Through application of the outlined method, the elasticity parameter (Fac_{depend}) is for Nord Pool Spot estimated to be 0.00406 (EUR/MWh)/MW in 2015. The achieved correlation between the model output and the real-world data is 0.76. A similar estimation was done based on the Danish system's connection with EPEX, but this resulted in a lower correlation of 0.61, which indicate that Danish market prices was most closely connected to Nord Pool Spot in 2015.

This closer connection with Nord Pool Spot in 2015 can also be seen by the amounts of electricity traded, where the total planned traded import of electricity to Denmark (DK1 + DK2) from the other Nord Pool Spot price areas was 12.5 TWh and the planned exported amount was 3.4 TWh. For EPEX, the planned imported amount was 2 TWh and the planned exported amount was 5.2 TWh [34]. Therefore, the Nord Pool Spot day-ahead system price is chosen as the external market

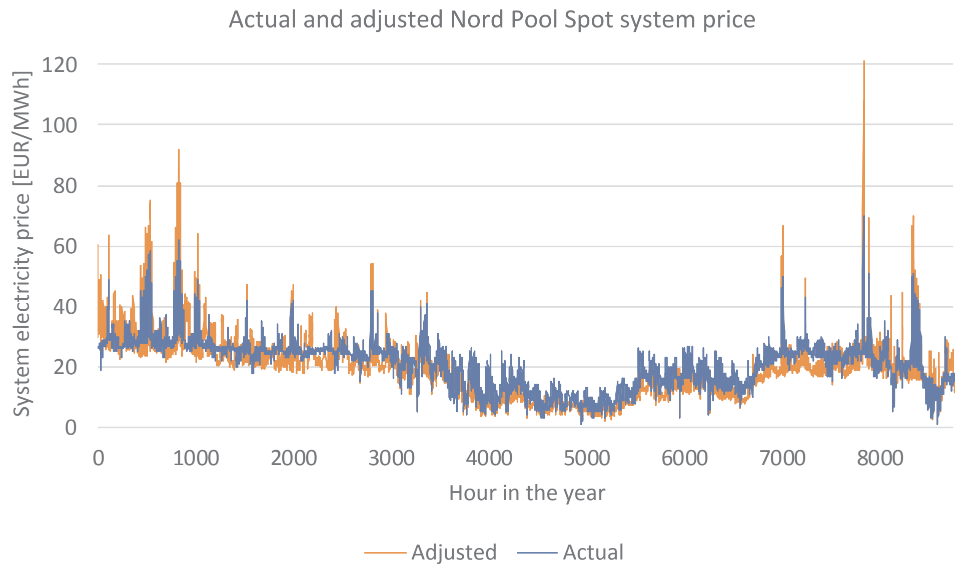

Fig. 1. Actual and adjusted Nord Pool Spot system price for each hour of 2015.

price, $p_x(t)$.

However, it should be noted that when establishing a relation between external and internal market prices, it is not possible to reach an exact replication of historical prices due to some real market events and elements, that are not included in the energy system simulation tool used. The market simulation in EnergyPLAN is, at the outset, a 'perfect market model', as it entails no institutional specifications and implicitly assumes perfect competition. When modelling electricity market prices, the lack of institutional specification may obviously be an important source of deviation from real world prices. The impact of taxes and subsidies could, in principle, be included through the manipulation of input prices. However, this method is not applicable if certain subsidies/taxes target subcategories of the models' aggregated technologies.

Furthermore, events such as the shutting down of interconnectors are not included as part of the model, nor are the explicit dynamics in financial energy markets. The shutting down of interconnectors and similar relatively rare events may create real world price spikes, which will not be represented in the modelled prices. The severity of this shortcoming will depend on the frequency of such events. In addition, what EnergyPLAN calculates as the internal area price may cover a geographical area that consists of several price areas in the real world, although EnergyPLAN will treat the internal price area as a single price area. Hence, possible price deviations between these areas will not be represented in the model. The impact of this simplification will of course have to be judged given the context of the concrete analysed system. In 2015, the unweighted average spot market price in DK1 was 22.9 EUR/MWh and in DK2 it was 24.5 EUR/MWh. Though, the price difference between DK1 and DK2 was less than 1 EUR/MWh for 7134 out of 8760 h, and there was no price difference for 6765 h [34]. It is therefore considered that this price difference will not have any severe impact on the model result for the present purpose.

EnergyPLAN only operates with one external price. As such, the simulation does not include any effect of the Danish energy system being connected to two different electricity markets. The elasticity parameter has been estimated based on the Danish system's connection with the Nord Pool Spot market, but it should be considered that Danish prices are, in principle, also influenced by central European electricity market prices on EPEX. In 2015, the two markets were part of the European Price Coupling of Regions [54].

Nonetheless, it is estimated that EnergyPLAN is, to a large degree, a suitable simulation tool for Nord Pool Spot-like markets. Considering the model simplifications mentioned above, the attained correlation of 0.76 for the applied elasticity parameter is considered an acceptable model fit.

To simulate a specific year, the historic electricity prices for the external energy systems would typically be used, but these prices already include the modelled energy system's influence. As such, to be as precise as possible, it is relevant to define an external electricity market price without the effect of the simulated energy system ($p_i(t)$), as well as finding suitable values for the price elasticity. Eq. (1) can be rearranged to eq. (3), where eq. (3) is used for calibrating the external electricity market price, so that it can be used in the simulation.

$$p_i(t) = (\ p_X(t){*}p_0)/(\ d_{Net-Import}(t){*}Fac_{depend} + p_0) \tag{3}$$

Using this relationship, the values for Fac_{depend} and p_0 discussed earlier, and the energy system defined in EnergyPLAN, it is possible to adjust the external electricity price to estimate what the electricity market price would be without the effect of the defined energy system ($p_i(t)$), here referred to as "adjusted". The hourly day-ahead system price of Nord Pool Spot is used as $p_X(t)$. $d_{Net\text{-}Import}(t)$ is the net import simulated in EnergyPLAN, excl. electricity production that occur due to grid stabilisation requirements.

3. Results and discussion

The results are individually discussed with respect to the actual and adjusted Nord Pool Spot system prices, the verification of the created reference model, and the quantification of the electricity market price at different levels of variable RES-e.

3.1. Nord Pool Spot system price without the simulated energy system

The actual and adjusted Nord Pool Spot system prices for each hour of 2015 can be seen in Fig. 1. In 2015, actual Nord Pool Spot system price was on average 21 EUR/MWh, with a maximum system price of 70 EUR/MWh, a minimum system price of 1 EUR/MWh, and a median system price of 23 EUR/MWh. The adjusted system price is on average found to be 19.3 EUR/MWh, with a maximum system price of 121 EUR/MWh, a minimum system price of 1 EUR/MWh, and a median system price of 19 EUR/MWh.

The adjusted Nord Pool Spot system price is then used as the external market price in EnergyPLAN.

Table 1
Comparison of the total primary energy consumption in all sectors in Denmark in 2015. DEA-stat is adjusted with biogas and upgraded biogas included in "Gas", biodegradable waste included in "Waste", and heat gained from low temperature sources for heat pumps are not included here.

[TWh]	DEA-stat	Simulated
Biomass	31.94	31.98
Coal	21.22	21.74
Gas	35.10	34.78
Oil	77.41	77.24
Variable RES	15.16	15.13
Waste	11.31	11.31

3.2. Verification of the reference model

In this section, the simulation in EnergyPLAN is verified by comparing the results with the yearly statistics from the Danish Energy Agency for 2015 [28], from here on referred to as DEA-stat. Firstly, the simulation results are verified according to the energy balances, in the same manner as done by other researchers, as discussed in Section 2. Table 1 shows the total primary energy consumption for all sectors (electricity, heating, transport, industry, etc.) in Denmark in 2015, as found in the DEA-stat and the simulated results from EnergyPLAN, respectively.

As shown in Table 1, the simulated results are close to those found in the DEA-stat. There are some minor differences in the energy sector. These differences are due to the fuels used the production of electricity and district heating, where there are differences in the utilisation of units between DEA-sat and Simulated. To show this Table 2 shows the electricity and district heating production in 2015, as found in the DEA-stat and the simulated results from EnergyPLAN, respectively.

As seen in Table 2, there is a relatively large deviation between the DEA-stat and the simulated results in the categories "Small-scale CHP units" and "Autoproducers". "Autoproducers" are here understood as electricity producers whose main task is not the production of electricity or district heating, such as CHP units at industry and waste incineration plants. The reason for these deviations, is that the "Small-scale CHP units" category in the DEA-stat include waste incineration plants and biogas plants, which have been moved to the "Autoproducers" category in the EnergyPLAN simulation. The reason for this is that the "Small-scale CHP units" category in EnergyPLAN is operated flexibly according to the electricity market price, but in the Danish energy system biogas plants operate as baseload units; including them in the "Autoproducers" category in EnergyPLAN sets their production as baseload, thus delivering a more accurate picture of the actual situation. The total moved from "Small-scale CHP units" to "Autoproducers" is 0.75 TWh electricity. Adjusting for this, the difference between the two categories changes to 0.11 TWh electricity. The remaining difference is due to small biomass-fired CHP units that receive an electricity production subsidy, and hence are producing in hours where the electricity prices would normally be too low for them to operate profitably. Likewise, differences can be due to breakdowns and maintenance of the different units not being included in the simulation. As discussed earlier, it is not possible to include production subsidies for a subset of the aggregated units in EnergyPLAN. However, as the difference is small, this is not seen as having a significant effect on the results. The additional 0.21 TWh district heating production of the "Heat only units" in the simulated results is due to the lower production of the "Small-scale CHP units", as the "Heat only units" must make up for the amount not produced by the CHP units in EnergyPLAN.

Table 2
Comparison between electricity and district heating production from different units, including net import of electricity.

	Electricity supply		District heating supply	
[TWh]	DEA-stat	Simulated	DEA-stat	Simulated
Power plants	2.48	2.57	–	–
Large CHP units	7.90	7.90	14.09	14.09
Small-scale CHP units	1.75	0.89	4.34	1.66
Autoproducers	2.05	2.80	7.12	9.18
Photovoltaics	0.60	0.60	–	–
Wind turbines	14.13	14.15	–	–
Heat only units	–	–	9.89	10.52
Net import	5.91	5.96	–	–

It is relevant to compare the actual Nord Pool Spot system price, as also shown in Fig. 1, with the resulting system price simulated in EnergyPLAN, here referred to as the resulting system price. A plot of the two prices are shown in Fig. 2, alongside a doted 1:1 line. The hourly resulting system price simulated in EnergyPLAN deviates from the actual historical hourly Nord Pool Spot system price between an interval of −12 EUR/MWh to 12 EUR/MWh, with an average difference of 0.47 EUR/MWh, an average absolute deviation of 0.76 EUR/MWh, and a median difference of 0.00 EUR/MWh. The coefficient of determination is found to be $R^2 = 0.961$. It is expected that these deviations are due to the uncertainties related to estimating the price elasticity used in EnergyPLAN, as also discussed in Section 2.

It has been shown in this section that it is possible to closely approximate the actual operation of the Danish energy system in 2015 using the EnergyPLAN model, both with respect to the energy balances and for the system price on Nord Pool Spot.

3.3. Quantifying future electricity market prices

To quantify the effect of increased variable RES-e capacity in Denmark on the Nord Pool Spot system price the installed capacity of onshore wind power, offshore wind power and PV is increased in the EnergyPLAN simulation. The capacity increase of each technology is limited to the installed capacity of each technology in the scenario IDA 2050 from [29], which is a scenario for a Danish energy system in 2050 with 100% RES in all energy sectors. As such, the limit for onshore wind power is set to 5 GW, for offshore wind power it is 14 GW and for PV it is 5 GW. The capacity factor is unchanged compared to the 2015 capacity factors. When the capacity of one technology is increased, the other technologies remain unchanged in the system. The resulting total variable RES-e production for increasing intervals of 200 MW variable RES-e capacity is found in Fig. 3. The total variable RES-e production in the Danish energy system in 2015 was 14.77 TWh. For these analyses the minimum grid stabilisation share needed from CHP and power plants has been removed, as it is expected that variable RES-e and other units, such as transmission capacity, will increasingly provide this [55].

Fig. 4 shows the resulting yearly average system price at the different levels of total variable RES production shown in Fig. 3. The yearly average system prices are based on the hourly calculated electricity prices in EnergyPLAN.

As shown in Fig. 4, regardless of the type of additional variable RES-e installed, the yearly average Nord Pool Spot system price decreases as more variable RES-e are introduced. In general, the decrease is proportional with the increase in electricity production from the variable RES-e, until the transmission capacity starts limiting the effect on the external Nord Pool Spot system price. This also means that the effect is largest per installed MW of offshore wind power, as offshore wind power produces the most per installed capacity. However, the results also show a small variation in this effect, as PV affects the system price less than wind power, even when considering PV's lower production. For example, at 5 GW PV the total variable RES-e production is 18.05 TWh, at which the system price is 20.26 EUR/MWh. The same total variable RES-e production can alternatively be gained by instead increasing the offshore wind power capacity to 2132 MW, at which the system price is 20.00 EUR/MWh. The reason for this difference is likely due to the already high integration of wind power and comparably low

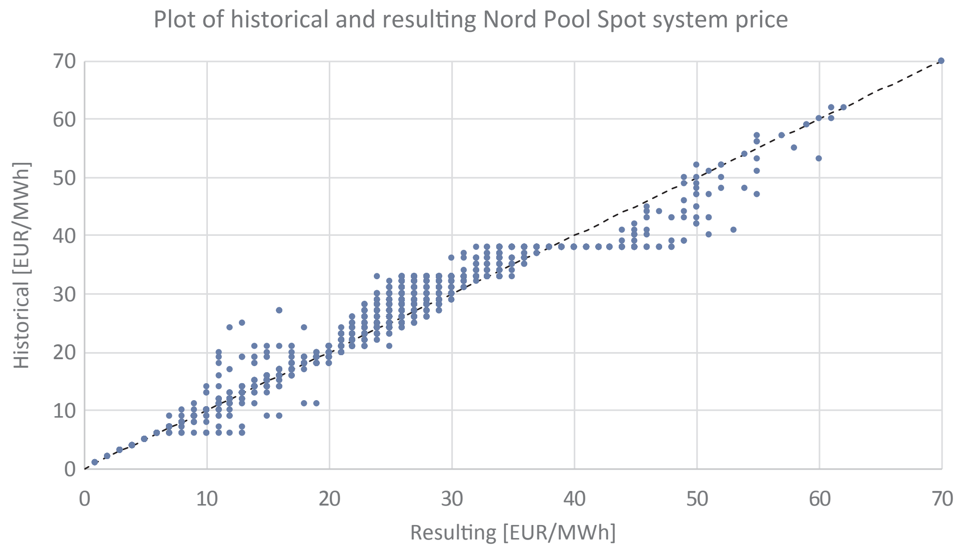

Fig. 2. Plot of the historical and resulting Nord Pool Spot system price.

integration of PV in the Danish energy system. Though, the difference is very small.

It is also relevant to investigate whether the effect seen for each individual technology is similar when a mix of the three technologies are introduced. For this purpose, a potential path of development of variable RES-e capacity is introduced based on the two scenarios IDA 2035 and IDA 2050 from [29]. IDA 2035 is an intermediate scenario for going to a 100% RES energy system in IDA 2050. In IDA 2035, the capacity of onshore wind power is 3.88 GW, offshore wind power is 5.89 GW, and PV is 3.13 GW. Assuming a linear development from 2015 to IDA 2035 and then onwards to IDA 2050, the development in variable RES-e capacity would be as shown in Fig. 5.

Using the development shown in Fig. 5 and simulating each year in EnergyPLAN, in the same manner as presented earlier in this paper, the development of the yearly average Nord Pool Spot system price is as shown in Fig. 6.

As seen in Fig. 6, a mixed implementation of variable RES-e shows the same tendency as shown for the individual technologies in Fig. 4. As the electricity production of the different units and the corresponding Nord Pool Spot system price is simulated for each hour in EnergyPLAN, it is possible to also use these simulation results to quantify the thermal plants' and variable RES-e units' income from Nord Pool Spot market sale. The thermal plants are here the total CHP and power plant capacity in Denmark excl. "Autoproducers" as these units are operated regardless of electricity market price. The average income from sale of electricity on Nord Pool Spot for these two unit types are shown in Fig. 7.

In Fig. 7, the average simulated income from Nord Pool Spot for variable RES-e is found to be 20.71 EUR/MWh$_e$ with the 2015-level of variable RES-e, whereas for the thermal plants it is 27.29 EUR/MWh$_e$. The income is found by for each hour multiplying the production of electricity with the resulting simulated electricity market price in Denmark. The income shown in Fig. 7 does not include e.g. sale of heat from CHP plants, sale of balancing reserves, subsidies for renewable electricity production, etc., meaning the income shown is not the full income for the units, but only the simulated sales on the Nord Pool Spot market. As such, Fig. 7 only shows the impact of the "merit-order effect" and the "missing money" issue, and not the full income, as it is found in the holistic energy system simulation. As seen in Fig. 7, the Nord Pool Spot market income for variable RES-e is reduced at a faster rate than the thermal plants at increasing levels of total electricity production from variable RES-e. For the thermal plants the average spot market income per MWh$_e$ produced stabilise at around 18 EUR/MWh$_e$, which is due to decrease in electricity production from these units. As such, the thermal plant electricity production at the 2015-level of variable RES-e is around 9.2 TWh and at the full IDA 2050-level of

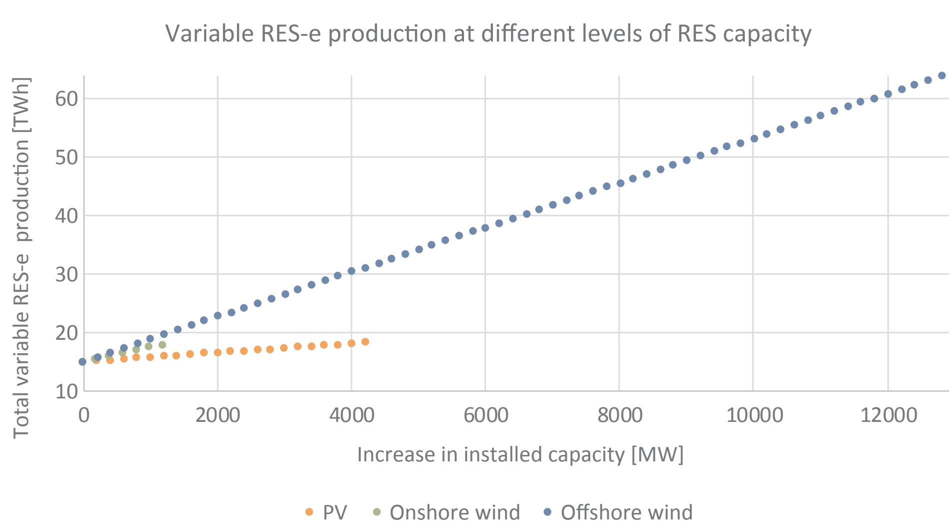

Fig. 3. Total electricity production from variable RES-e at different levels of increased capacity of PV, onshore wind power and offshore wind power.

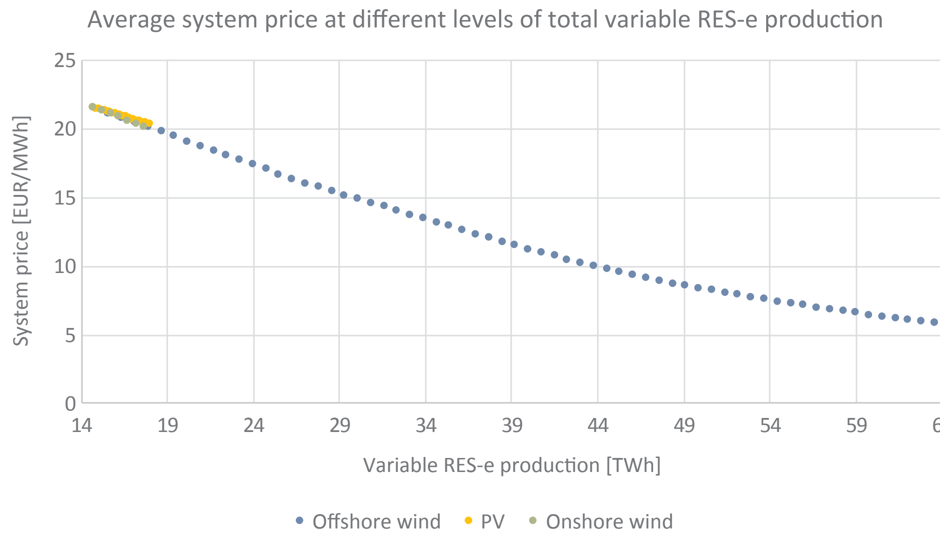

Fig. 4. Resulting yearly average system price at different levels of total electricity production from variable RES-e.

variable RES-e it is reduced to 4.7 TWh.

4. Conclusion

In this paper, a novel approach for investigating variable renewable electricity sources' effect on wholesale electricity market prices is developed using a holistic energy system approach. The approach is applied to the case of Denmark in 2015. The Danish energy system influences the day-ahead system price of the Nordic and Baltic electricity market Nord Pool Spot. The effect of import and export from Denmark on the Nord Pool Spot system price in 2015 is quantified in the form of a price elasticity. This price elasticity is used to estimate what the hourly Nord Pool Spot system price would have been in 2015, had there been no influence from the consumption and production of electricity in Denmark. It is found that without the Danish energy system, the Nord Pool Spot day-ahead system price would have been 19.3 EUR/MWh on average in 2015, as opposed to the actual average of 21 EUR/MWh.

Using this adjusted Nord Pool Spot system price and statistical data for the Danish energy system in 2015, a model of the Danish energy system is created in the holistic energy system analysis tool EnergyPLAN. The model is then verified according to the actual energy balance and Nord Pool Spot system price in 2015. It is found that this approach is capable of producing a simulation in EnergyPLAN that closely resembles the actual operation of the Danish energy system in 2015, both with respect to the energy balance, and the actual system price on Nord Pool Spot.

Using this verified model, the effect of increasing amounts of variable renewable electricity sources in Denmark on the Nord Pool Spot system price is quantified. The investigated variable renewable electricity sources are onshore wind power, offshore wind power and photovoltaic. It is found that regardless of which variable renewable electricity source is implemented, including a combination of the three, the wholesale system price decreases as the amount of energy produced by these sources increases, and this effect occurs immediately as more is introduced. The effect is only reduced as the export transmission capacity limit from Denmark is reached in a greater number of hours. Likewise, it is also quantified how the thermal plants' and variable RES-e units' income from Nord Pool Spot market sales are affected by increasing amounts of variable RES-e production. It is found that both unit types see a decreasing income per unit of electric energy produced, but that the variable RES-e units' income drops significantly faster at increasing levels of variable RES-e production, compared with the

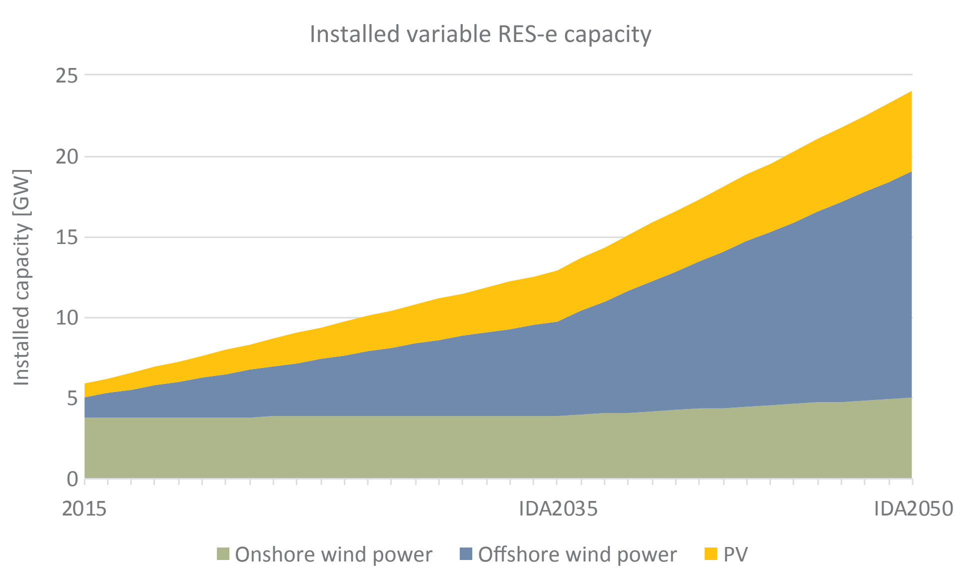

Fig. 5. Installed variable RES-e capacity for a linear development in capacity from 2015 to 2035 and 2050 based on the scenarios IDA 2035 and IDA 2050 from [29].

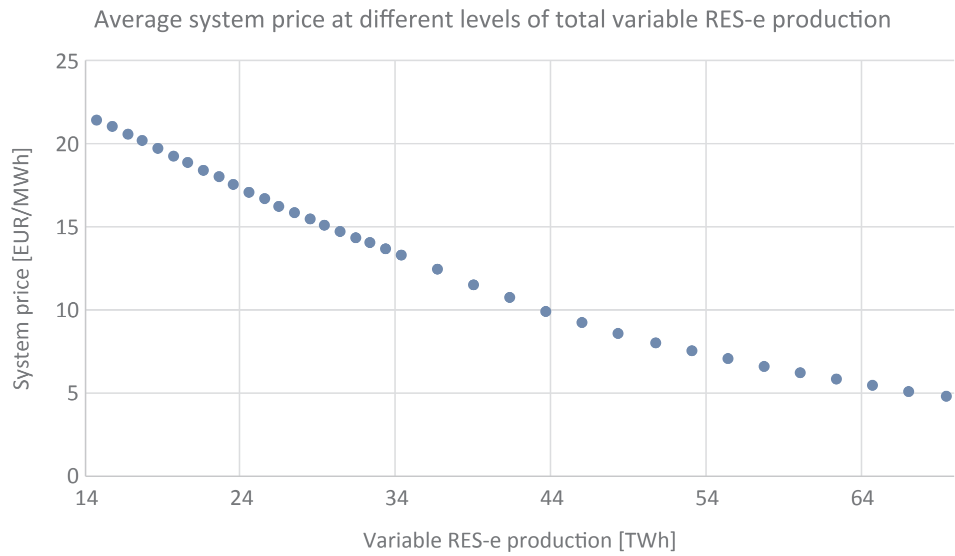

Fig. 6. Resulting yearly average system price at different levels of total electricity production from variable RES-e using a mixed increase of technologies.

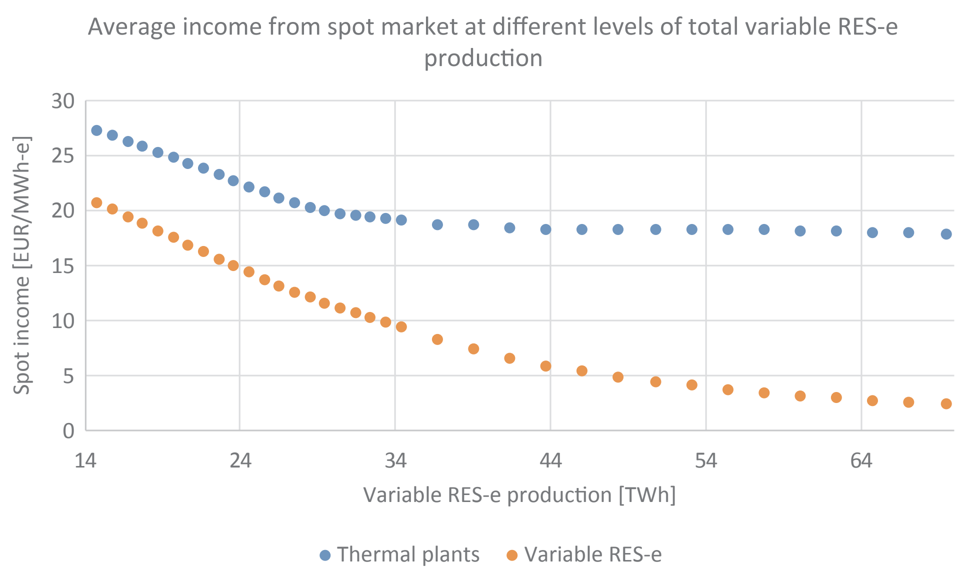

Fig. 7. Average income from Nord Pool Spot market sales for thermal plants and variable RES-e per produced MWh_e at different levels of total electricity production from variable RES-e using a mixed increase of technologies.

thermal plants' income. This is partly due to the thermal plants' reducing its production at lower electricity market prices.

The approach presented in this paper is useful for evaluating wholesale electricity market prices in future energy systems. As such, the approach can be used to analyse whether current electricity market setups provide sufficient incentive for investments in new electricity production capacity. As EnergyPLAN has proven useful for simulating a broad variety of energy systems, the approach can be applied to a wide range of different cases and can be useful for quantifying the market effects of implementing different technologies in an energy system.

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Appendix A

A.1. Electricity production

Input	Value	Ref.	Note
Electricity demand (TWh/year)	31.27	[28]	Electricity demand including grid losses, excluding demands for heating, cooling, and transport

A.1.1. Wind (onshore)

Input	Value	Ref.	Note
Capacity (MW)	3797.5	[31]	
Annual production (TWh)	9.31	[34]	

A.1.2. Offshore wind

Input	Value	Ref.	Note
Capacity (MW)	1271.1	[31]	
Annual production (TWh)	4.84	[34]	

A.1.3. Photo voltaic

Input	Value	Ref.	Note
Capacity (MW)	779.9	[35]	
Annual production (TWh)	0.6	[34]	

A.1.4. River hydro

Input	Value	Ref.	Note
Capacity (MW)	6.9	[28]	
Annual production (TWh)	0.02	[28]	

A.1.5. Thermal power production

Input	Value	Ref.	Note
Large CHP units condensing power capacity (MW)	4584	[32]	
Large CHP units condensing power efficiency	0.45	[28]	The value represents the expected annual average efficiency based on fuel consumption and production of these units as found in [28]
Condensing power plant capacity (MW)	1033	[32]	
Condensing power plant efficiency	0.239	[32]	The value represents the annual average efficiency

A.2. District heating

A.2.1. Decentralised district heating

Input	Value	Ref.	Note
District heating production (TWh/year)	15.37	[28,32]	The distribution of heat demand between decentralised and central district heating areas is from [32]. The total is from [28]
Fuel boiler capacity (MW)	6354	[32]	Excl. units using biogas
Fuel boiler efficiency	0.983	[32]	
Small-scale CHP - Electric capacity (MW)	1626	[32]	Excl. units using biogas
Small-scale CHP - Electric efficiency	0.31	[32]	The value represents the annual average efficiency.
Small-scale CHP - Thermal capacity (MW)	3042		Based on average efficiencies and the electric capacity excl. units using biogas.
Small-scale CHP - Thermal efficiency	0.58	[32]	The value represents the annual average efficiency
Fixed boiler share	0		
Grid loss	0.2	[28]	
Thermal storage capacity (GWh)	33.2	[37]	
Solar thermal input (TWh/year)	0.232	[28]	
Industrial heat supply (TWh/year)	0.736	[32]	The number includes production units using biogas as a fuel
Industrial electricity supply (TWh/year)	0.853	[32]	The number includes production units using biogas as a fuel
Compression heat pump electric capacity (MW)	3.8	[32]	
Compression heat pump COP	3.8	[32]	Yearly average COP
Electric boiler capacity (MW)	336	[32]	

A.2.2. Central district heating

Input	Value	Ref.	Note
District heating production (TWh/year)	20.07	[28,32]	The distribution of heat demand between decentralised and central district heating areas is from [32]. The total is from [28]
Fuel boiler capacity (MW)	6109	[32]	
Fuel boiler efficiency	0.922	[32]	
Large CHP - Electric capacity (MW)	3175	[32]	Calculated using the thermal capacity from [32] and the total production of heat and electricity from central CHP units from [28]

Large CHP - Electric efficiency	0.3	[28]	The value represents the expected annual average efficiency based on fuel consumption and production of these units from [28]
Large CHP - Thermal capacity (MW)	5662	[32]	
Large CHP - Thermal efficiency	0.535	[28]	The value represents the expected annual average efficiency based on fuel consumption and production of these units from [28]
Fixed boiler share	0		
Grid loss	0.2	[28]	
Thermal storage capacity (GWh)	15.7	[37]	
Industrial heat supply (TWh/year)	0.871	[32]	The number includes production units using biogas as a fuel
Industrial electricity supply (TWh/year)	0.276	[32]	The number includes production units using biogas as a fuel
Electric boiler capacity (MW)	186	[32]	

A.3. Cooling

Input	Value	Ref.	Note
Electricity for cooling (TWh/year)	1.67	[38]	
Electricity for cooling efficiency	4.55	[38]	

A.4. Fuel distribution and consumption

A.4.1. Fuel distribution for heat and power production

These relations indicate for each of the plant type the fuel mix for used for each plant type (Coal/Oil/Gas/Biomass)

Input	Value	Ref.	Note
Small-scale CHP units	0.097/0.013/1.48/1.672	[32]	The gas usage is excl. biogas, as this fuel consumption is included in "Natural gas, various"
Large CHP units	19.739/0.269/2.617/8.595	[32]	
Boilers in decentralised district heating	0.024/0.065/3.57/4.763	[32]	The gas usage is excl. biogas, as this fuel consumption is included in "Natural gas, various"
Boilers in central district heating	0/0.148/1.097/0.526	[32]	
Condensing operation of large CHP units	19.739/0.269/2.617/8.595	[32]	
Condensing power plants	0/1/0/0	[32]	

A.4.2. Additional fuel consumption (TWh/year)

Input	Value	Ref.	Note
Coal in industry	1.37	[28]	
Oil in industry	10.66	[28]	
Natural gas in industry	10.41	[28]	
Biomass in industry	2.19	[28]	
Coal, various	0	[28]	The fuel consumption in "Various" includes own consumption in the energy sector for producing and refining fuels. It also includes non-energy use of fuels
Oil, various	8.07	[28]	
Natural gas, various	9.05	[28]	Is incl. biogas consumption at CHP and boiler units

A.5. Transport

A.5.1. Conventional fuels (TWh/year)

Input	Value	Ref.	Note
JP (Jet fuel) - fossil	10.83	[28]	
Diesel - fossil	28.49	[28]	
Petrol - fossil	16.14	[28]	
Grid gas	0.02	[28]	
JP (Jet fuel) - biofuel	0	[28]	
Diesel - biofuel	1.98	[28]	
Petrol - biofuel	0.51	[28]	

A.5.2. Electricity (TWh/year)

Electricity dump charge	0.4	[28]

A.6. Waste conversion

A.6.1. Waste incineration in decentralised district heating

Input	Value	Ref.	Note
Waste input (TWh/year)	3.76	[28,32]	The distribution of waste input between decentralised and central district heating areas is from [32]. The total is from [28]
Thermal efficiency	0.655	[28]	Adjusted according to the total heat production from waste incineration from [28], and the district heating consumption in central areas not produced by other units
Electric efficiency	0.148	[28]	Average electric efficiency for all waste incineration plants

A.6.2. Waste incineration in central district heating

Waste input (TWh/year)	7.55	[28,32]	The distribution of waste input between decentralised and central district heating areas is from [32]. The total is from [28]
Thermal efficiency	0.677	[28]	Adjusted according to the total heat production from waste incineration from [28], and the district heating not produced at waste incinerators in the central areas
Electric efficiency	0.148	[28]	Average electric efficiency for all waste incineration plants

A.7. Individual heating

A.7.1. Coal boilers

Input	Value	Ref.	Note
Fuel consumption (TWh/year)	0	[28]	
Efficiency	0.7		Assumed annual average value

A.7.2. Oil boilers

Input	Value	Ref.	Note
Fuel consumption (TWh/year)	2.68	[28]	
Efficiency	0.85		Assumed annual average value
Solar thermal input (TWh/year)	0.02	[28]	The total solar thermal input from [28] is distributed on the fuel boiler types according to the fuel consumption

A.7.3. Natural gas boilers

Input	Value	Ref.	Note
Fuel consumption (TWh/year)	6.93	[28]	
Efficiency	0.95		Assumed annual average value
Solar thermal input (TWh/year)	0.05	[28]	The total solar thermal input from [28] is distributed on the fuel boiler types according to the fuel consumption

A.7.4. Biomass boilers

Input	Value	Ref.	Note
Fuel consumption (TWh/year)	11.18	[28]	
Efficiency	0.8		Assumed annual average value
Solar thermal input (TWh/year)	0.07	[28]	The total solar thermal input from [28] is distributed on the fuel boiler types according to the fuel consumption

A.7.5. Heat pumps

Input	Value	Ref.	Note
Heat demand (TWh/year)	2.3	[28]	
COP	3		Assumed annual average value

A.7.6. Electric heating

Input	Value	Ref.	Note
Heat demand (TWh/year)	0.75	[28]	

A.8. Biogas production

Input	Value	Ref.	Note
Biogas production (TWh/year)	1.76	[28]	

A.9. Electricity exchange

Input	Value	Ref.	Note
Transmission line capacity (MW)	6005	[36]	The transmission capacity is the average between the import and export capacity in 2015

A.10. Balancing

Input	Value	Ref.	Note
Minimum grid stab. share	0.285		Used to replicate the condensing power plant production in 2015
Stab. Share of CHP2	0.1		Used to increase the small-scale CHP electricity production slightly
Minimum CHP in group 3 (MW)	10	[34]	Based on minimum operation of all central plants in 2015
CEEP regulation strategy	2,3,4,5		

A.11. Distributions

The distributions do not influence the total annual energy, but allocates the total onto each hour of the year.

Input for distribution	Ref.	Note
Electricity demand	[34]	Total electricity demand for East and West Denmark in 2015
Individual heat demand	[40]	Heat demand outside district heating areas in Denmark 2015. Generated using heating degree days with a reference temperature of 17 °C and a temperature dependent of 75%. Hourly outdoor temperature from CFSR data [40]
Individual solar thermal	[39]	Solar thermal production in Denmark
District heating demand	[40]	Demand for district heating (incl. grid loss) in Denmark 2015. Generated using heating degree days with a reference temperature of 17 °C and a temperature dependent of 75%. Hourly outdoor temperature from CFSR data [40]
District heating solar t-hermal	[39]	
Offshore Wind	[34]	Offshore wind power production in Denmark 2015
Onshore Wind	[34]	Onshore wind power production in Denmark 2015
Photo Voltaic	[34]	Photovoltaic power production in Denmark 2015

A.12. Price assumptions

The model does not consider potential price variations through the year or differences in prices for consumers within the same category, as the prices incurred by the different individual producers and consumers are not known. For example, some CHP plants might have a natural gas contract with a yearly fixed price and others might have a contract where the daily price follows the market price on Gaspoint Nordic. As such, the fuel price and CO_2 quota price assumptions used for the model are based on the yearly national averages, as found by the Danish Energy Agency.

The fuel prices and handling costs are shown in Table 3. All fuel prices and handling costs are fixed through the simulated year. The handling costs include costs for transportation of the fuel to the place of consumption, storage of the fuel, and profits.

The CO_2 quota price is set at 7.62 EUR/t through the year, being the registered average traded CO_2 quota price in Denmark in 2015 [33].

The variable operation and maintenance (O&M) cost is for the fuel boilers sat at 0.15 EUR/MWh_{th}, for CHP units it is 1 EUR/MWh_e, for heat pumps it is 0.27 EUR/MWh_e, for electric heating it is 1.35 EUR/MWh_e and for condensing power plants it is 2.654 EUR/MWh_e [29].

The variable O&M for CHP units has been reduced from 2.7 (as found in [29]) to 1 EUR/MWh_e to reflect the relative high percentage of CHP units that operated with subsidies in 2015, especially the CHP units in decentralised district heating areas.

Table 3
Fuel prices and handling costs in 2015 [33].

[2015-EUR/GJ]	Coal	Natural gas	Fuel oil	Diesel fuel/Gas Oil	Petrol/JP1	Biomass	Dry biomass
Fuel price	2.17	6.05	6.77	10.83	10.68	6.17	8.46
Handling costs							
Power plants	0.05	0.19	0.29	–	–	0.59	0.54
Small plants and industry	0.05	0.93	0.29	–	–	0.58	–
Households	–	4.12	–	3.9	–	4.16	–
Road transport	–	–	–	3.9	4.76	–	–
Aviation	–	–	–	–	0.29	–	–

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