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Support schemes adapting District Energy Combined Heat and Power for the role as a flexibility provider in renewable energy systems

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Abstract

Combined Heat and Power (CHP) units connected to District Energy (DE) plants have an important role displacing condensing mode power generation and boiler-based heat-only generation. However, often the earnings on the electricity markets are not sufficient to promote the establishment of a desired amount of DE CHPs; therefore, support schemes are needed. When designing a support scheme to promote DE CHP, it is important to consider the changing roles of the DE CHP. In the transition to a renewable energy system, the role changes radically from displacing traditional generation to assisting in the integration of fluctuating renewables and finally providing the electrical capacity needed during hours with insufficient wind and sun.

An energyPRO-based comparison of a premium and a triple tariff support scheme is presented in this article. The comparison shows that, during a 20-year period, the cost to society is less than half when using the triple tariff compared to using the premium scheme for providing a certain CHP capacity. While this CHP capacity displaces the same amount of production from condensing mode power plants, the triple tariff promotes larger thermal energy storage capacity compared to the premium scheme, which is beneficial for DE CHP to fulfil its subsequent tasks in a renewable energy system.

Keywords

Triple tariff
Premium support scheme
Combined Heat and Power
Thermal Energy Storage
Energy transition
Renewable energy systems

Highlights

- District energy plants have major tasks in integrating wind and solar power

- Support is required for making the needed investments in district energy plants
- A methodological comparison of a premium and a triple tariff support scheme
- The cost during a 20-year period is less than half when using the triple tariff scheme
- The triple tariff scheme promotes larger storage capacity than the premium scheme

1 Introduction

Climate change is on the global agenda and most countries are considering how to reduce the emission of greenhouse gases – most notably CO_2 [1] of which the main proportion comes from energy consumption. In the European Union (EU), heating and cooling represent approximately half of the final energy consumption and it is a larger end-use sector than transport and electricity [2]. Furthermore, with only 15% covered by renewable energy sources (RES), this is a carbon-intensive sector. Worldwide, heating and cooling also require special attention as these represent half of the energy used in buildings and are primarily produced from fossil fuels. The United Nations Environment Programme [3] emphasizes the importance of sustainable heating and cooling solutions – not least from a climate change mitigation perspective.

The research project Heat Roadmap Europe [4] found that it is socio-economically feasible to reduce the heat demand in Europe by 30-40% through energy savings. Of the remaining heat demand, it will be socio-economically feasible to cover a large share by district heating and cooling instead of individual heating and cooling. Especially in cities with high heat densities, it becomes feasible to establish systems that provide heating and cooling to more buildings [3]. Among other reasons, the feasibility is due to the ability of the district heating system to exploit waste heat from power plants and industry [5]. Furthermore, a significant economy of scale-effect makes solar collectors at district energy (DE) plants much cheaper to build compared to solar collectors at individual buildings [6]. Also, heat pumps (HP) gain access to a broader range of heat sources when installed at DE plants.
Averfalk et al. [7] studied large HPs in Swedish district heating systems and showed that there is a significant amount of heat to be exploited from sewage systems. Lund et al. [8] mapped potential heat sources for HPs for district heating in Denmark and showed that sea water may be an important heat source. Østergaard et al. [9] showed that for many cities it will be possible to exploit geothermal energy when having DE plants. Østergaard et al. [10] also showed that even a combination of central HPs at DE plants and distributed HPs may be economically feasible. In future energy systems with transport fuels being produced from wind power and photovoltaics (PV), DE systems will be able to make use of the inevitable conversion losses [11]. Similarly, more cooling sources become available, e.g., free cooling from lakes, rivers or oceans [12].

Often electricity prices do not create sufficient commercial feasibility in CHPs and thermal energy storage (TES) for adequate amounts of these to be installed at DE plants. Therefore, support schemes are needed. Different schemes have been applied in different places at different times for supporting DE CHPs, among others feed-in premiums, feed-in tariffs, quota obligations, tax exemptions, tenders and investment aids. Each of these support scheme types can be designed differently and even combined to meet the general aim of the support schemes.

An important factor to consider when deciding on the design of the support scheme promoting DE CHP is that, in the transition to a renewable energy system, the role of CHP at DE plants changes radically.
In fossil-based systems, the role of DE CHP is to displace fossil-fuelled condensing mode power production as well as the production on individual and communal boilers, thus producing as much electricity as the heat demand allows. In RES-based systems, where wind power and PV cover a major part of the electricity demand, the DE CHPs have to participate on a market basis in the integration of these fluctuating productions and produce less electricity [13]. Instead DE plants will have a major task of consuming electricity using HPs or electrical boilers during hours with surplus fluctuating RES-based electricity production and only producing electricity at CHP during hours with lack of fluctuating RES-based electricity production [14].
To fulfil this role, DE plants must be equipped with large CHP and HP capacities [15], and as a consequence of these large capacities, they must also be equipped with large TES providing the DE plants with the needed flexibility to integrate the fluctuating RES.

Two of the most widely used support scheme types are the feed-in premium types and the feed-in tariff types. These are introduced and reviewed in the next two sections.

1.1 The Premium support scheme

In its basic form, the premium support scheme adds a premium to the hourly wholesale electricity price. This simple support scheme has gained ground over the last years and is used as a main support instrument in Denmark, the Netherlands, Spain, the Czech Republic, Estonia and Slovenia [16] and premiums are usually guaranteed for a longer period, e.g. from 10 up to 20 years. In this way, the scheme provides long-term certainty, which is considered to lower the investment risks considerably.
Among other examples, premiums are applied in the case of support for biogas in Denmark, Italy and Slovenia. In Germany, only biogas plants with capacities larger than 750 kW_e are offered premiums. In Slovenia, a market premium scheme has been introduced for operators above 500 kW_e [17].
Schallenberg et al. [18] argue that premium schemes can help creating a more harmonized electricity market, effectively removing the difference between renewable and conventional electricity production.
Haas et al. [19] argue that, in principle, a mechanism based on a fixed premium/environmental bonus reflecting the external costs of conventional power generation can establish fair trade, fair competition and a level playing field in a competitive electricity market between RES and conventional power sources. They mention that from a market development perspective, the advantage of such

a scheme is that it allows RES to penetrate the market quickly if their production costs drop below the electricity-price-plus-premium. Therefore, if the premium is set at the 'right' level (theoretically at a level equal to the external costs of conventional power), it allows RES to compete with conventional sources without the need for entering "artificial" quotas.

Mezősi et al. [20] have made a cost-efficiency benchmarking of European renewable electricity support schemes and found that the premium support schemes in Denmark are the most cost-effective ones.

The EU has dealt extensively with support in more reports [21–23] and recommends to use the premium scheme as it exposes the DE plant to the hourly market prices. Furthermore, according to the EU's Guidelines on State aid for environmental protection [24], Member States are required to convert the existing administratively determined Feed-in Tariff or Feed-in Premium schemes to competitively determined Feed-in Premiums or Green Certificate support schemes for new RES electricity installations from 2017.

However, it is noticeable that Schallenberg et al. [18] found that a premium scheme can occasionally lead to overcompensation. This is based on a study of the Spanish system. Similarly, Gawela et al. [25], studying the system integration of RES through premium schemes on the German market, found a risk of overcompensating producers and found that it is questionable if a premium scheme is gradually leading plant operators towards the market.

Dressler [26] pointed out that premium schemes may enhance market power, favour conventional electricity production and may even hamper the increase in production from RES.

1.2 The Feed-in tariff

In most countries, feed-in tariffs are among the preferred choices of support schemes [19]. They are designed in different ways, but in this article, the triple tariff has been chosen for analysis, with a starting point in its implementation in Denmark. The Danish triple tariff included a procedure for calculating the assumed savings at central power plants as well as the saved grid losses and grid investments and was instrumental in the Danish introduction of DE CHP, as shown in Figure 1. The tariff was thus in force in the years when the Danish energy system became decentralized.

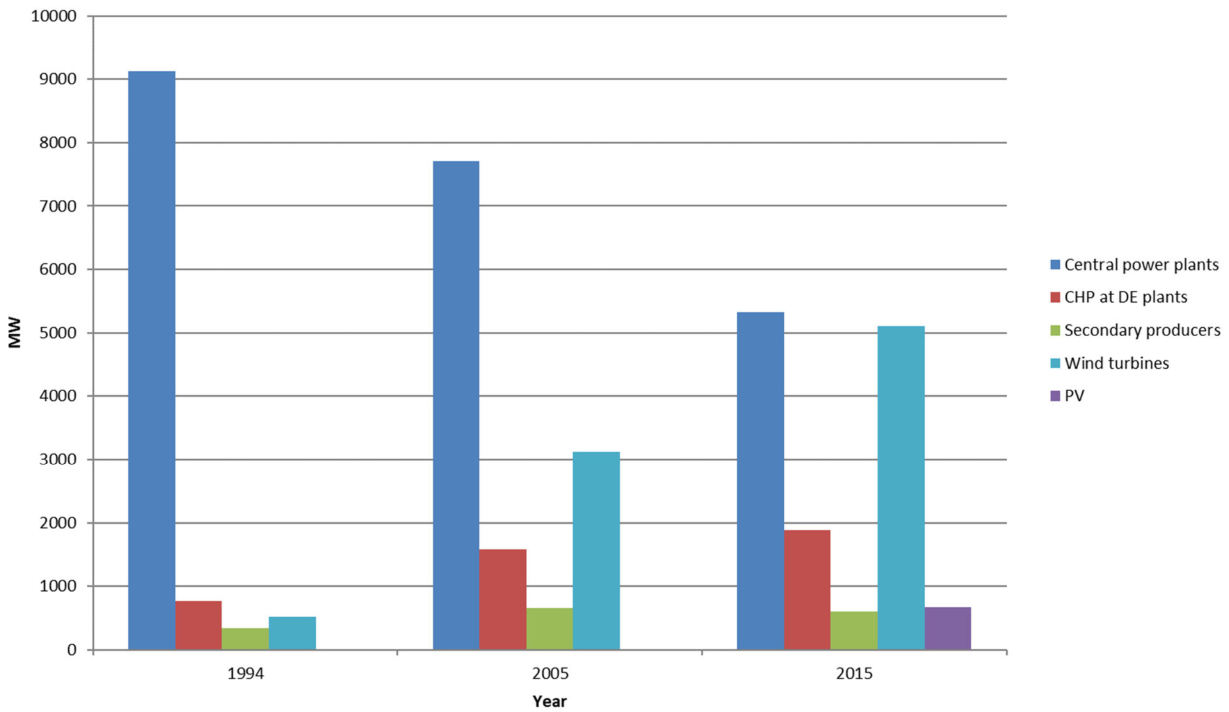

Figure 1: Development in electricity production capacity in Denmark. The central power plants are situated at 16 sites. The secondary producers are industrial producers and waste incineration plants. Based on data from [27]

The Danish Energy Agency has illustrated how this development changed the Danish energy landscape – see Figure 2. From a few power plants in the beginning of the 1980s to thousands of power producing units today. Besides the central power plants, 285 DE CHP plants, 380 industrial and private CHP plants, 5260 onshore wind turbines and 515 offshore wind turbines are in operation [28].

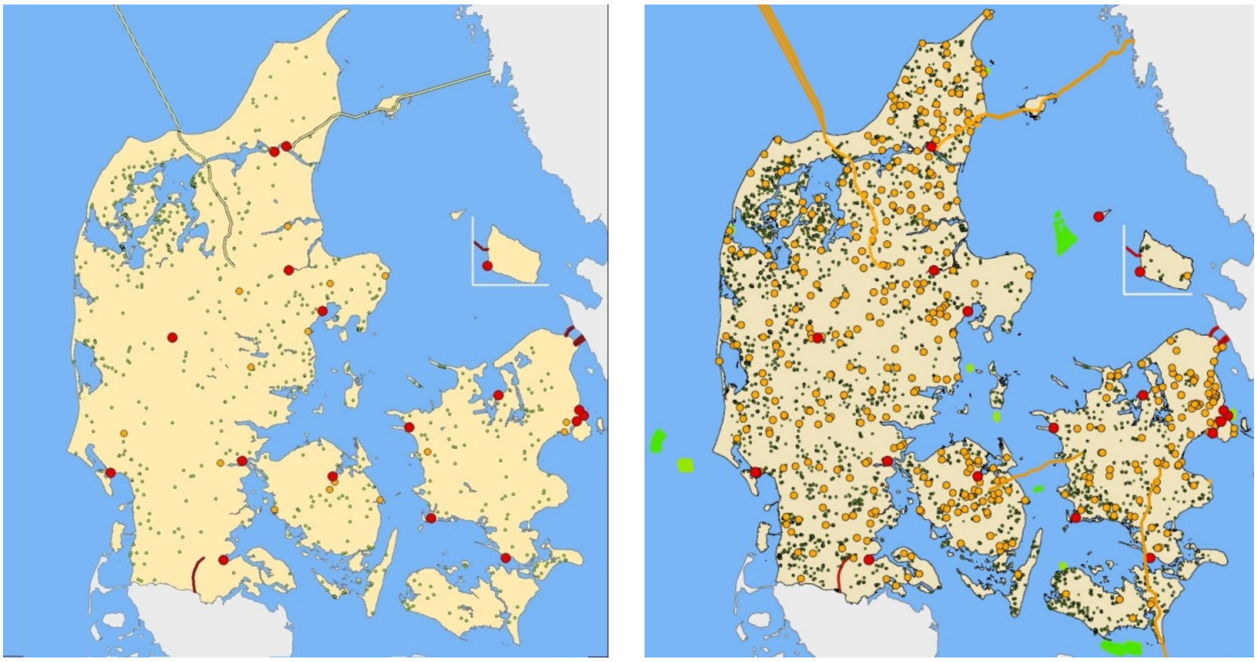

Figure 2: The electrical infrastructure in Denmark in 1985 (left) and 2013 (right). Red circles indicate central power plants, yellow circles DE CHPs and secondary producers above 500 kW. The green dots show wind turbines and green offshore areas show off-shore wind farms [29].

Furthermore, an argument for studying the cost of offering the triple tariff in-depth is that more research has been published studying the effect of triple tariff support schemes. Østergaard [30] analysed the geographical distribution of electricity generation and concluded that the triple tariff influenced the operation of local CHP plants according to a certain fixed diurnal variation, primarily producing in the peak tariff hours on working days. Soltero [31] mentions the Danish triple tariff when considering the potential of natural gas district heating cogeneration in Spain as a tool for decarbonisation of the economy. Fragaki et al. [32], studying the sizing of gas engine and TES for CHP plants in the United Kingdom, mention that the situation resembles the triple tariff electricity sales prices of the Danish system. Sovacool [33] mentions that the Danish triple tariff rewards CHP operators for their provision of peak power; thus improving significantly the feasibility of investments in CHPs. Toke et al. [34] have investigated whether the Danish triple tariff would be able to assist the implementation of CHP in the United Kingdom, arguing that this could help the country in meeting its long-term objective of absorbing high levels of fluctuating RES.

Some articles describe the simulation of energy systems based on the Danish triple tariff, however, without investigating the triple tariff in-depth. Lund [35] and Lund and Münster [36] studied the large-scale integration of wind power into different energy systems using a reference scenario where the CHP plants produce according to the triple tariff. Taljan et al. [37] studied the sizing of biomass-fired Organic Rankine Cycle CHP investigating the optimisation of the plant size against the triple tariff. Gebremedhin [38] mentions the triple tariff when looking into externality costs in energy system models. Heinz and Henkel [39] have considered the triple tariff in connection with a fuel cell population in the energy system. Dominković et al. [40] have considered the application of feed-in tariffs in Croatia, and argued that the feed-in tariff for pit TES will be of significance to the economic feasibility of the investment. Østergaard [41] describes the capability of EnergyPLAN [42] to simulate the operation of national energy systems, where CHP plants are operated according to a fixed triple tariff system. Schroeder et al. [43] mention that a triple tariff system increase the integration of CHP into electricity markets. Hernández [44] have studied photovoltaics in grid-connected buildings, investigating single, double and triple tariff systems in Spain.

1.3 Novelty, scope and structure of the article

A main requirement of a support scheme is that it induces technology deployment at the lowest possible costs to society. The literature review in Sections 1.1 and 1.2 reveals that some authors notice potential excessive cost of premium schemes. At the same time, empirical evidence shows how the triple tariff was instrumental in the introduction of DE CHP in Denmark. Also, while a considerable share of research refer to the support schemes, the review did not reveal any quantitative comparisons of different support schemes in terms of the costs of providing a certain technology deployment in DE plants.

The aim of this article is thus to analyse the costs to society of providing certain CHP and TES capacities at a generic DE plant receiving a triple tariff and a premium scheme, respectively.

Section 2 presents the detailed procedures of the triple tariff and premium support schemes, followed in Section 3 by the method for assessing the CHP capacity promoted by a support scheme. Section 4 describes the DE plant case used in the analysis as well as the external conditions and the technical and economic assumptions about the CHPs and TES. Section 5 shows the results of the comparison of the two support schemes, and finally, discussions and conclusions are presented in Sections 6 and 7.

2 Details of the compared support schemes

This section describes the two support schemes compared as they are implemented in the quantitative analyses in this article. First, the premium support scheme and then a systematic procedure of determining triple tariff prices. Lastly, the method for comparing these two is presented.

2.1 The Premium support scheme

The premium is paid on top of hourly wholesale electricity prices and is made as a flat-rate price supplement paid to CHPs for each produced MWh_e, independent of the time period in which the electricity is produced. No cap is assumed on the premium paid; thus, even if the wholesale electricity price during a certain hour is high, the DE plant will still receive the premium.

2.2 The Triple tariff support scheme

The procedure of determining the triple tariff prices includes both a procedure for determining the time periods and the prices of the Peak, High and Low tariffs. The procedure chosen is similar to the procedure used in the Danish triple tariff as described in the Danish legislation [45] and includes a procedure for calculating the assumed savings at central power plants and the saved grid losses and grid investments. The procedure assumes that all DE CHP production displaces fossil-fuelled condensing mode power production at central plants.

2.2.1 The three load periods

When used in a specific country, the first step in the procedure is to decide the periods of the Peak, High and Low tariffs, which is done by analysing the demand for electricity and grouping it into three load situations with a weekly cycle. These may be further split into seasonal load situations. The periods used in the analysis reported in this article are the ones used in Denmark in 2015; see Table 1. The tariffs paid for electricity delivered from local CHP plants are equal within each of the tariff periods but dependent on the voltage level at which the CHP production is delivered.

	Low tariff periods	High tariff periods on working days	Peak tariff periods on working days
Winter (October-March)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 17.00 19.00 – 21.00	08.00 – 12.00 17.00 – 19.00
Summer (April-September)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 21.00	08.00 – 12.00

Table 1: The separation of the year into low, high and peak tariff periods as applied in the Danish Triple tariff in 2015 [45].

2.2.2 The procedure for calculating savings at central power plants

The total saved costs at central power plants, SC_i, for each reduced production of 1 MWh_e are simply assumed to depend on whether the reduced production takes place in Low, High or Peak tariff periods and illustrated in Equation (1), where the index i designates the tariff period.

$$SC_i = \frac{GP*3.6}{\eta} + V_{Plant} + \frac{(YC_{plant}*I_{plant}+YF_{Plant})*D_i}{FLH_i} \quad (1)$$

In equation (1), η is the net electrical efficiency at central power plants; GP is the natural gas price in EUR/GJ; V_{Plant} is the variable operation and maintenance costs in EUR/MWh_e; YC_{plant} is the yearly capital cost factor of investment; I_{plant} is the investment cost in EUR/MW_e; YF_{Plant} is the yearly fixed operation and maintenance costs in EUR/MW_e; D_i are distribution keys between Low, High and Peak tariff periods for investment and yearly fixed costs, and FLH_i is full load hours of electricity demand calculated for each of the Low, High and Peak tariff periods as the electricity demand in the period divided by the peak demand for electricity of the year.

The saved costs in equation (1) are split into saved fuel, variable operation and maintenance costs, investment cost and fixed operation and maintenance costs. Saved fuel and variable operation and maintenance costs are straightforward, as they relate to the reduced amount of produced electricity. On the other hand, a reduction in produced electricity translates into reductions in investment costs and reductions in fixed operation and maintenance costs and is thus of a more probabilistic nature. In this triple tariff procedure, a method is applied in which a part of the reduced need for investment and reduced fixed operation and maintenance costs is assigned to the reduction in produced electricity in Peak and High tariff periods, respectively, but no reduction is assigned to Low tariff periods.
The yearly capital cost factor - YC_{plant} - is calculated as an annuity (Equation (2) dependent on the discount rate (r) and the lifetime of the investment (L). The yearly capital cost factor thus determines the share of an investment that is attributed to each year of operation.

$$YC = \frac{r}{1-(1+r)^{-L}} \quad (2)$$

2.2.3 The procedure for calculating saved grid losses and grid investments

The electricity delivered to the 60 kV grid is assumed to replace an amount of electricity to be delivered from the central power plants. However, one unit of electricity delivered to the 60 kV grid replaces more than one unit from the central power plant as grid losses in the 150 and 400 kV grids are avoided. Also, as grid losses increase with the transmission system load, the value of the electricity delivered to the 60 kV increases according to the load level. Furthermore, the electricity delivered to the 60 kV grid is assumed to reduce the need for investments in the 150 kV grid, and again, this reduced investment is larger at higher load levels, using the same arguments that led to equation (1). Thus, the compensation for electricity delivered in the 60 kV grid, $P@60_i$, depends on whether the production takes place during Low, High or Peak tariff periods and is given by equation (3).

$$P@60_i = SC_i/(1 - NL150_i) + YC_{grid} * I_{150} * D_i/FLH_i \quad (3)$$

$NL150_i$ is the load and tariff period-dependent net loss percentage in the combined 150 and 400 kV grid used to calculate the increased value of delivering energy to the 60 kV grid, thus increasing the total saved costs at central power plants, SC_i, by avoiding net loss. YC_{grid} is the yearly capital cost factor of investment in electrical grids and I_{150} is investment cost in the 150 kV grid in EUR/MW_e.
Similar conditions apply when delivering electricity to the 10 kV grid or to the 0.4 kV grid. Thus, the paid compensations of electricity delivered to the 10 kV grid, $P@10_i$, and to the 0.4 kV grid, $P@0.4_i$, are given by Equations (4) and (5).

$$P@10_i = P@60_i/(1 - NL60_i) + YC_{grid} * I_{60} * D_i/FLH_i \quad (4)$$

$$P@0.4_i = P@10_i/(1 - NL10_i) + YC_{grid} * I_{10} * D_i/FLH_i \quad (5)$$

Here $NL60_i$ and $NL10_i$ are the net loss percentages in the 60 and 10 kV grids, respectively, and I_{60} and I_{10} are investment costs in the 60 and 10 kV grids, respectively, in EUR/MW_e.

Finally, supplying electricity to the 0.4 kV grid directly at the site of consumption is also assumed to reduce grid losses and reduce the need for investment in the 0.4 kV grid. Thus, the compensation to be paid for electricity delivered to the consumer, $P@consumer_i$, is given by Equation (6)

$$P@consumer_i = P@0.4_i/(1 - NL0.4_i) + YC_{grid} * I_{0.4} * D_i/FLH_i, \quad (6)$$

where $NL0.4_i$ is the net loss percentage in the 0.4 kV grid and $I_{0.4}$ is investment cost in the 0.4 kV grid in EUR/MW_e.

Notice that the procedure for calculating paid prices is cumulative – i.e. supplying at 0.4 kV also provides savings in 10, 60, 150 and 400 kV grids, thus, the rationality of the equations is that prices at higher voltage levels always influence prices at lower voltage levels.

2.2.4 The data used to calculate the triple tariff prices

The triple tariff prices are calculated with the power plant and grid data shown in Table 2, and the tariff period-dependent data shown in Table 3. The applied power plant’s net electrical efficiency is high but comparable to the efficiency expected in 2020 by the Danish Energy Agency [46].
The fuel costs saved at power plants are based on a gas price, GP, that is set as equal to the average natural gas price at the Gaspoint Nordic [47] market in 2016, which was approximately 13

EUR/MWh$_{\text{higher calorific value}}$, equal to approximately 4.0 EUR/GJ$_{\text{lower calorific value}}$. Fuel prices and efficiencies refer to lower calorific values of the fuels. A transmission tariff of 0.4 EUR/GJ results in a natural gas price at power plants of 4.4 EUR/GJ.

Power plant net electrical efficiency	η	58%	
Power plant, Variable operation and maintenance costs	V_{Plant}	2.54	EUR/MWh$_e$
Power plant, Yearly fixed operation and maintenance costs	YF_{Plant}	13,597	EUR/MW$_e$
Real discount rate	r	3%	
Investment cost in power plant	I_{plant}	0.905	MEUR/MW$_e$
Lifetime of power plant	L_{plant}	25	years
Yearly capital cost factor of investment in power plant	YC_{plant}	0.05743	
Investment cost in the 150 kV grid	I_{150}	0.286	MEUR/MW$_e$
Investment cost in the 60 kV grid	I_{60}	0.095	MEUR/MW$_e$
Investment cost in the 10 kV grid	I_{10}	0.054	MEUR/MW$_e$
Investment cost in the 0.4 kV grid	$I_{0.4}$	0.054	MEUR/MW$_e$
Lifetime of electrical grids	L_{grid}	25	years
Yearly capital cost factor of investment in electrical grids	YC_{grid}	0.05743	
Gas price at power plant	GP	4.4	EUR/GJ

Table 2: The power plant and grid data not depending on the tariff periods, used for calculating the Triple tariff.

		Low tariff	High tariff	Peak tariff
Hours per year	H_i	5010	2498	1252
Full load hours of electricity demand	FLH_i	2475	1728	1097
Distribution keys for investment and yearly fixed costs	D_i	0	0.5	0.5
Net Loss percentage in the 150 + 400 kV grid	$NL150_i$	2.8%	4.2%	4.7%
Net Loss percentage in the 60 kV grid	$NL60_i$	2.1%	3.2%	3.6%
Net Loss percentage in 10 kV grid	$NL10_i$	1.4%	2.7%	3.5%
Net Loss percentage in 0.4 kV grid	$NL0.4_i$	2.8%	5.1%	6.8%

Table 3: The power plant and grid data depending on the tariff periods, used for calculating the Triple tariff.

The shown data are equal to the data used in the Danish triple tariff at the end of 2015. They represent a simplification that could be further developed. As an example, the distribution keys between Low tariff, High tariff and Peak tariff of investment and yearly fixed costs are the same for all voltage levels. An improvement could be to consider if the lower voltage grids are sized larger and hence experience other distribution keys.

2.2.5 The resulting tariff prices in the triple tariff

The resulting tariffs are shown in Table 4. The DE plant considered in this article is assumed to deliver electricity to the 10 kV grid and therefore the prices used in the triple tariff are equal to the prices in P@10.

EUR/MWh	Low tariff	High tariff	Peak tariff
Saved fuel costs at power plants	27.31	27.31	27.31
Saved variable operating costs at power plants	2.54	2.54	2.54
Saved fixed operating costs at power plants	0.00	3.93	6.20
Saved investment costs at power plants	0.00	15.04	23.69
Total saved at power plants	**29.85**	**48.82**	**59.74**
Saved grid loss in 150 + 400 kV grid	0.86	2.14	2.95
Saved grid expansion of 150 kV grid	0.00	4.75	7.49
To be paid for electricity delivered at the 60 kV grid, P@60	**30.71**	**55.72**	**70.17**
Saved grid loss in 60 kV grid	0.66	1.84	2.62
Saved grid expansion of 60 kV grid	0.00	1.58	2.49
To be paid for electricity delivered at 10 kV grid, P@10	**31.37**	**59.14**	**75.28**
Saved grid loss in 10 kV grid	0.45	1.64	2.73
Saved grid expansion of 10 kV grid	0.00	0.90	1.41
To be paid for electricity delivered to the 0.4 kV grid, P@0.4	**31.81**	**61.67**	**79.42**
Saved grid loss in 0.4 kV grid	0.92	3.31	5.79
Saved grid expansion of 0.4 kV grid	0.00	0.90	1.41
To be paid for electricity delivered at the consumers, P@consumer	**32.73**	**65.89**	**86.63**

Table 4: Resulting tariffs in the Triple tariff.

2.3 Method for comparing support schemes

The method used for comparing support schemes includes a method for assessing the investment in CHPs and TES that a given support scheme stimulates. The development and test of this method have been described in detail in [48]. The method is based on the energyPRO simulation model [49] which is used for finding the optimal operation based on a given system configuration and given economic conditions. An important reason for applying energyPRO to this analysis is that it is widely used by consultants for designing DE plants with an economically optimal sizing of productions units and TES [50].

An external shell calling energyPRO iteratively is used for determining the optimal system configurations and is described in the following section. The following section introduces the two-step procedure used for comparing the support schemes.

2.3.1 The system configuration optimisation method

The system configuration optimisation method used is based on a Net Present Value (NPV) calculation of the changed cash flows caused by new production units and TES. For instance, the changed cash flow when assessing an investment in CHPs and TES at a boiler-based DE plant includes the investments as well as the sale of electricity, support paid through the chosen support scheme, additional fuel purchase, because CHP units use more fuel than boilers to produce the same amount of heat, as well as the extra use of CO_2 quotas and fixed and variable costs of the CHPs. Furthermore, the changed cash flow includes the reduced variable cost of the existing boilers, due to their lower production when implementing CHP.

The external shell used for making the iterative calls of energyPRO is implemented in an Excel spreadsheet that performs these calls through Visual Basic for Application (VBA) coding.

For a certain DE plant and a certain support scheme, the optimal sizes of the CHPs and TES are determined in a two-dimensional matrix calculation. In this method, the path in the matrix to the optimal NPV starts with zero CHP and zero TES. First, the size of CHP is increased until the NPV decreases in the matrix. Then, keeping this CHP size fixed, the TES is increased until the NPV decreases. Then again, the size of the CHP is increased keeping the size of the TES fixed. This procedure is repeated, until no improved NPV is found. The method is described in detail in [48].

A simpler heuristic method would be to calculate all combinations and find the lowest cost in the table, but the described heuristic method is significantly faster due to the scenario reduction.

The optimal solution found when optimising the NPV may result in different sizes of CHPs and TES compared to what in fact will be established, since other factors will often be included in the investment decision. But the calculation still represents an important estimate of the sizes of the CHPs and TES that will be installed.

2.3.2 The two-step procedure for comparing the two support schemes

A two-step procedure for comparing the two support schemes is applied in the analyses.

The first step is to calculate the optimal CHP and TES in terms of business economy applying the triple tariff and using the method described in Section 2.3.1. The next step is to determine the support level of the premium scheme that results in the same optimal CHP capacity, using the same method described in Section 2.3.1 at different levels of support.

The economically optimal CHP and TES capacities found for these two support schemes are then used in the calculation of the costs related to the support schemes, which in this analysis are set as equal to the NPV of the paid support in the planning period. The support is calculated for each hour during the planning period and is subsequently summed up in an NPV calculation to determine the total support in the planning period.

For the premium scheme, the cost of the support during a certain hour is calculated simply as the premium multiplied by the electricity produced on the CHPs during that hour.
For the triple tariff, the support during a certain hour is calculated as the tariff minus the day-ahead price during that hour. This difference is then multiplied by the electricity produced on the CHPs during that hour. This interpretation of support is consistent with the way in which a triple tariff is often administered. The payment of a triple tariff often involves either the transmission system operator or a trader (balancing responsible party), who is responsible for selling the produced electricity on the day-ahead market. Thus, it is only the discrepancy between the triple tariff and the day-ahead price during that hour that makes up the support, often to be paid by the consumers through a grid tariff. This also implies that if, during a certain hour, the price in the day-ahead market is higher than the triple tariff, the support will be negative during that hour.

3 Technical and economic DE plant case characteristics

This section describes the DE plant case used in the comparison of the two support schemes, as well as the external conditions and the technical and economic assumptions about the CHPs and TES.
The planning period is set to 20 years from 2017 to 2026, and the real discount rate is set to 3%, which is comparable to using a nominal discount rate of around 4-5%, reflecting the costs of a loan for financing the investments. All prices are listed in 2016 levels.

3.1 Wholesale electricity prices

Electricity prices from the Scandinavian day-ahead market are used. This market is organised as a marginal price market [51]. Thus, each producer gets the same price for the produced electricity equal to the most expensive bid accepted during the hour in question [52]. To keep it simple, the day-ahead prices for all years in the planning period are set as equal to the hourly prices in West Denmark in 2016 [53], which gives an average price of 26.7 EUR/MWh$_e$, a minimum price of -53.6 EUR/MWh$_e$ and a maximum price of 105.0 EUR/MWh$_e$.

3.2 Ambient temperatures

Ambient temperatures are used for modelling yearly variations of the heat demand. The analysis is based on a time series with a yearly mean temperature of 8.1°C, a daily mean temperature during the coldest day of -9.0°C and a daily mean temperature during the warmest day of 22.2°C. The time series are discussed further in [48].

3.3 Natural gas price at the DE plant

In Section 2.2.4, a natural gas price at power plants of 4.4 EUR/GJ is argued for and used. The gas price at DE plants is found by adding a distribution tariff around 1.2 EUR/GJ, resulting in a gas price at DE plants of 5.6 EUR/GJ for both CHPs and boilers. No taxes are included, the same gas price is used for all years in the analyses and no yearly variation is assumed.

3.4 CO_2 quota price

An estimation of the CO_2 quota price made by the Danish Energy Agency [54] for 2016 is approximately 8 EUR/tonne. This value is used in all the years in the analyses.

3.5 The DE plant case

The DE plant case is similar to the case used in [48] and shortly recapitulated in this section. The yearly heat delivered to the district heating grid is 40 GWh of which grid loss and domestic hot water represent 40% and are assumed to be constant and thus also weather independent.
The remaining 60% is the space heating, which is assumed to be linearly dependent on the ambient temperature. It is assumed that space heating is only required on days with an average temperature below 15°C. A diurnal variation is assumed based on empirical evidence from Danish DH systems

[55]; as the delivered heat demand is approximately 20% lower during nocturnal hours compared to daytime hours. The resulting heat demand requires an average heat supply from the plant of 4.6 MW, with a maximum heat supply from the plant of 11.6 MW and a minimum of 1.6 MW.

As a reference for the analysis of investment in CHPs and TES, an existing DE plant is assumed to produce the heat on existing heat-only boilers. These boilers are assumed to have an efficiency of 97.1% and variable operation costs of 1.10 EUR/MWh$_{heat}$. In the reference and under the assumed economic conditions described in this section, this results in an annual heat production cost of 0.938 M EUR.

Investment and operation costs are assumed to be strictly proportional to the sizes of the CHPs; thus, it is not important into how many units the CHPs are split. However, it is chosen to split the CHP capacity into two CHP units, as shown in Figure 3, which is in accordance with the actual design of DE plants, as exemplified by online presentations at [55]. Splitting the CHP capacity into more units also reduces the need for including partial load operation characteristics. Anyhow, most DE CHPs have their maximum efficiency at full load and the access to large TES will make it favourable only to produce at full load.

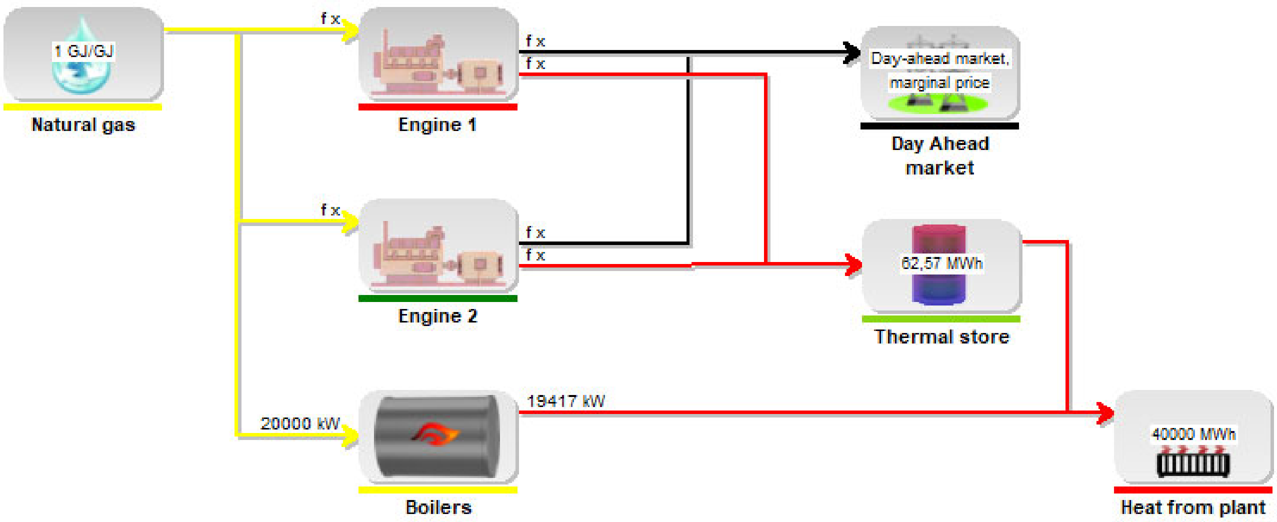

Figure 3: The generic DE plant used in the test of the two support schemes, consisting of existing boilers and the new units - two CHPs and a TES.

3.6 Technical and economic assumptions

In the analysis, efficiencies are maintained as constant over time and with no size dependency. A similar simplification has been made regarding investment and operation costs, which are being modelled being proportional to the sizes of both the CHPs and TES. An overview of the technical and economic data used in the comparison is shown in Table 5. The data correspond to the data used in [48]. The electrical efficiency of 44.0% of DE CHP compared to the assumed net electrical efficiency of the power plant of 58%, as given in section 2.2.4, is in accordance with the fact that large power plants producing only electricity have higher electrical efficiencies.

Gas price	5.60	EUR/GJ
CO_2 quota price	8.00	EUR/tonne
Existing boilers		
Heat efficiency	97.1%	
Variable operation costs	1.00	EUR/MWh_{heat}
CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fixed operation costs	10000	EUR/MW_e/year
Variable operation costs	5.4	EUR/MWh_e
Investment in CHPs	650000	EUR/MW_e
Non-availability periods per year	16	days
Investment in installation	350000	EUR/MW_e
Thermal storage		
Investment in thermal storage	200	EUR/m^3

Table 5: Technical and economic characteristics (2016 prices) used in the comparison of the two support schemes. Data based on [46].

4 Results of the comparison of the two support schemes

The results of the comparison of the two support schemes on the DE plant case are presented in section 4.1. A sensitivity analysis on selected parameters is presented in Section 4.2. As the price level in West Denmark has been higher both before and after 2016, the sensitivity analysis includes a higher price level created in two different ways. Moreover, the sensitivity analysis includes a higher gas price.

4.1 Main results of the comparison of the two support schemes

As mentioned in section 2.3.2, the first step in comparing the two support schemes is to calculate the optimal CHP and TES with the triple tariff in terms of business economy. The result of this calculation is shown in Figure 4, with an optimal total CHP capacity of 7 MW_e and a TES size of 3000 m^3 (approx. 140 MWh).

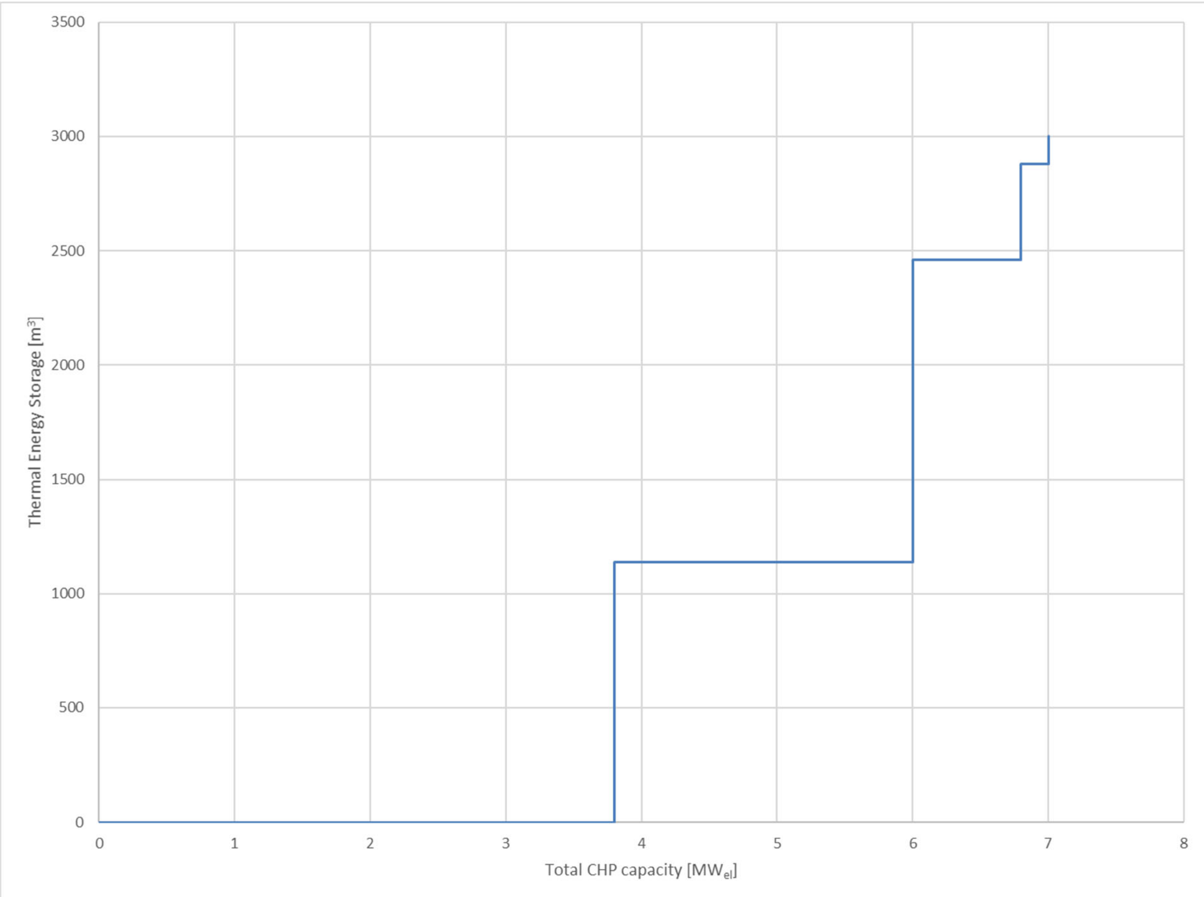

Figure 4: For a certain DE plant and a certain support scheme, the optimal size of the CHPs and TES are determined in a two-dimensional matrix calculation. This figure shows the path to the optimal NPV according to the size of the CHPs and TES applying the Triple tariff.

The next step is to determine the support level of the premium scheme that results in the same optimal CHP capacity of 7 MW_e. This is done by using the method shown in Section 2.3.1 at different

levels of support. Figure 5 illustrates the way of finding the support level of the premium scheme that gives the same CHP capacity of 7 MW_e. The support level is found to be 66.67 EUR/MWh_e.
As illustrated in the figure, a premium scheme support below 10 EUR/MWh_e will not promote any CHP capacity installation, and from a level of support of around 25 EUR/MWh_e, the growth in electrical CHP capacity becomes smaller, as the operation is restricted by the limited heat demand at the DE plant. The slightly irregular shape of the graph is due to the fact that when identifying the optimal NPV, the step value for electrical capacity is set at 0.2 MW_e and the step value for the TES size is set at 60 m^3. These step sizes are chosen to reduce the calculation time without compromising the conclusions based on the calculation.

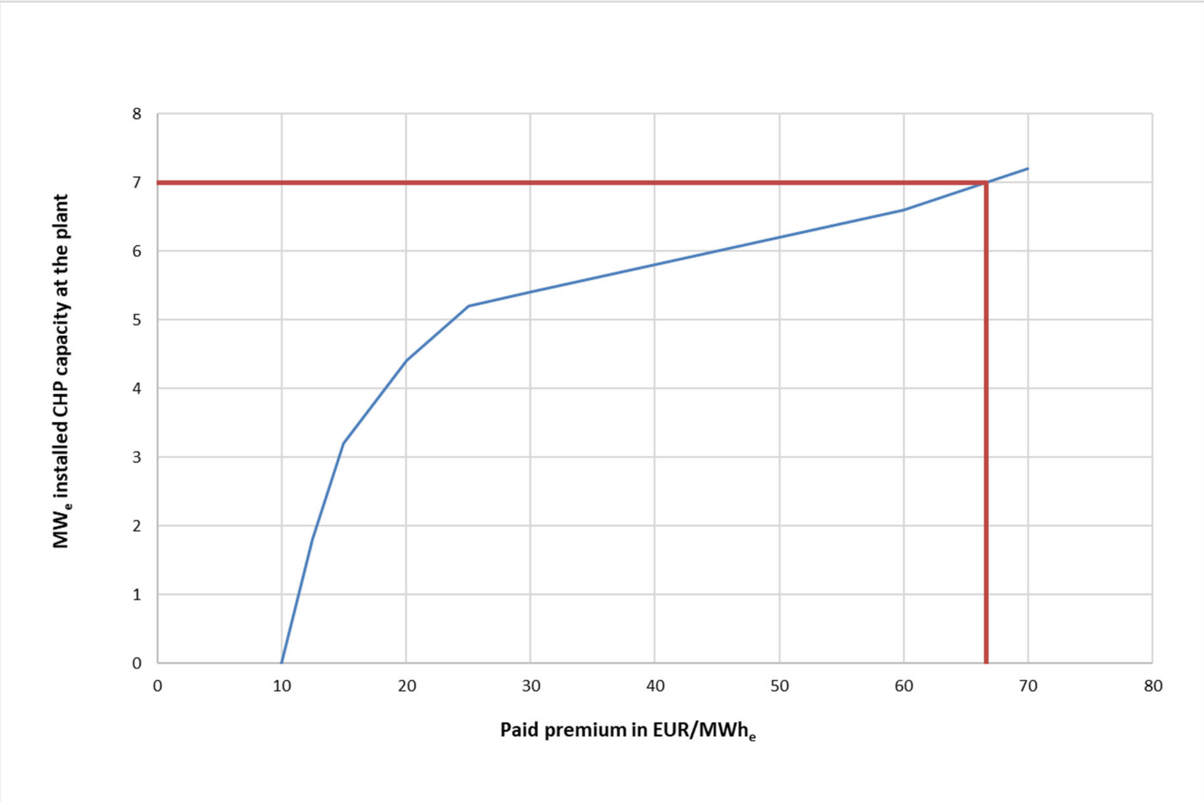

Figure 5: Determining the paid premium resulting in a total CHP capacity of 7 MW_e being equal to 66.67 EUR/MWh_e.

The results are shown in Table 6. It is seen that, at this total CHP capacity of 7 $MW_{e,}$ the associated TES capacity is the double when using the triple tariff compared to using the premium scheme. This also implies a total investment in CHP and TES capacities that is slightly larger when comparing the triple tariff and the premium scheme.

When using the premium scheme, the net present value in a 20-year period (NPV_{20}) of the changed cash flow (as described in Section 2.3.1) caused by the investment in the CHPs and TES is around 22 M EUR higher. This is also reflected in the extra NPV_{20} of support to the plant when using the premium scheme compared to the triple tariff scheme.

This is the most thought-provoking result; that the cost of providing a certain CHP capacity is nearly three times higher when using the premium scheme than when using the triple tariff scheme.

Day-ahead price level 26.7 EUR/MWh_e						
	CHP capacity [MW_e]	TES size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and storage [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity production [MWh_e]
Triple tariff	7.00	3000	7.60	3.90	12.92	34447
Premium scheme (66.67 EUR/MWh_e)	7.00	1520	7.30	25.48	34.05	34345

Table 6: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MW_e.

4.2 Sensitivity analyses

Three sensitivity analyses are made. The first is the day-ahead electricity prices scaled up from the current spot market price level of 26.7 EUR/MWh_e to an average price of 36.7 EUR/MWh_e by multiplying the hourly prices with the factor 36.7/26.7. The second is the day-ahead electricity prices scaled up from the current spot market price level of 26.7 EUR/MWh_e to an average price of 36.7 EUR/MWh_e by adding 10 EUR/MWhe to the hourly prices. The third is the gas price raised with 10% from 5.6 to 6.16 EUR/GJ.

The three sensitivity analyses are made in the same way as the main case shown in section 4.1. The results are shown in Table 7, Table 8 and Table 9 and in Figure 6.

As illustrated in Figure 6, even a premium scheme support lower than 10 EUR/MWh_e causes the installation of CHP capacity when the average price is 36.7 EUR/MWh_e.

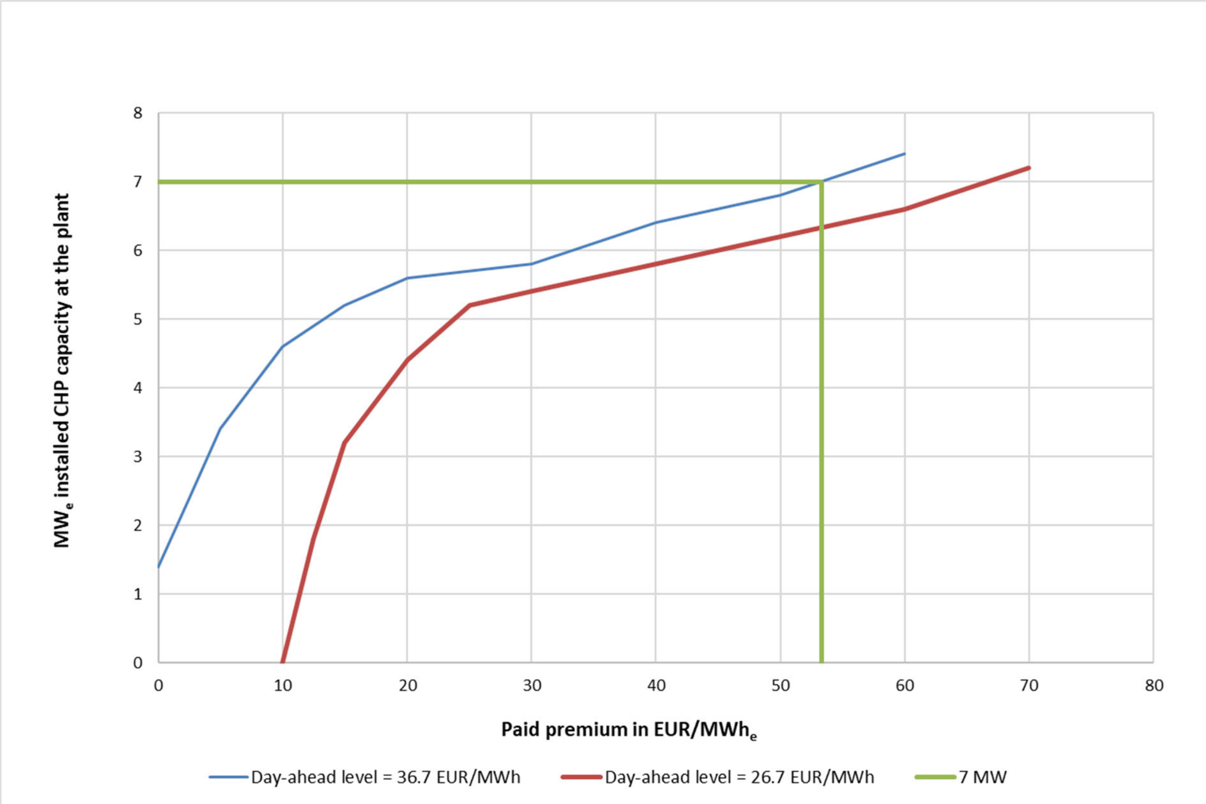

Figure 6: Determining the paid premium resulting in the same total CHP capacity of 7 MW_e being equal to 53.33 EUR/MWh_e when the day-ahead level is 36.7 EUR/MWh_e.

	CHP capacity [MW_e]	TES size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and storage [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity production [MWh_e]
Triple tariff	7.00	3000	7.60	3.59	7.63	34477
Premium scheme (53.33 EUR/MWh_e)	7.00	1900	7.38	24.15	27.24	33646

Table 7: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MW_e, when each hour price is multiplied by 36.7/26.7, giving a day-ahead price level of 36.7 EUR/MWh_e.

	CHP capacity [MW_e]	TES size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and storage [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity production [MWh_e]
Triple tariff	7.00	3000	7.60	3.59	7.79	34477
Premium scheme (56.57 EUR/MWh_e)	7.00	1520	7.30	25.49	28.96	34131

Table 8: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MW_e, when each hour price is added 10 EUR/MWh_e, giving a day-ahead price level of 36.7 EUR/MWh_e.

	CHP capacity [MW_e]	TES size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and storage [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity production [MWh_e]
Triple tariff	6.40	2580	6.92	2.43	12.16	33746
Premium scheme (56.57 EUR/MWh_e)	6.40	1320	6.66	18.46	27.50	32606

Table 9: Results of the comparison of the Triple tariff and the Premium scheme, when gas price is raised by 10% from 5.6 to 6.16 EUR/GJ.

5 Discussion

In Denmark, as shown in Figure 1, a triple tariff scheme triggered the installation of around 2,000 MW_e of CHP capacity with large TES. The results of this research indicate that the cost of the support schemes differ to a large extent, as the installation of the same amount of CHP capacity in Denmark would have been more than 5,000 M EUR more expensive if applying a premium scheme instead of a triple tariff scheme. This is based on the example from Table 6 where providing a 7 MW_e capacity is around 20 M EUR more expensive with a premium than a triple tariff support scheme.

It is beyond the scope of this paper to deal with other factors than optimising NPV when making investment decisions, but it must be acknowledged that most DE plants are small and decision-making board members are not necessarily skilled within CHP and investment optimisation. It is probable that these members will consider a triple tariff a more secure condition for an investment decision than a premium scheme, simply due to the considerable uncertainty about the future price level in the day-ahead market, compared to the well-known triple tariff prices.

Personal communication with the managers of three DE plants - Lemvig Varmeværk [56], Skagen Varmeværk [57] and Ringkøbing Fjernvarmeværk [58] - confirms that the more certain investment conditions constituted by the Danish triple tariff prices promoted their decisions regarding investments in large CHP and TES capacities.

The introduction outlines more factors to be considered, when deciding on the design of a support scheme. Apart from these factors and as detailed in [48], another important factor to keep in mind is that the role of CHP changes radically in the transition to a 100% RES system. When developing wind power and PV, the power plants and the CHPs have to produce less electricity. As a consequence, the plants must contribute to the integration of these intermittent RES-based productions. If a speedy development of wind power and PV is planned or expected compared to, e.g., a 20-year period for making the CHP investment feasible, it should be considered to reduce the number of years with support. However, this will eventually reduce the installed capacity.

Future research could deal with the importance of the assumptions concerning constant of sizes, over the year and over all years. However, it is expected that our finding is robust; thus, the cost of the support schemes promoting a certain amount of CHP capacity is around three times higher when using a premium scheme compared to using a triple tariff scheme. Furthermore, the triple tariff scheme promotes larger TES capacity compared to the premium scheme.

6 Conclusion

Combined heat and power units and large thermal energy storages at district energy plants are important instruments to reduce fossil fuel-based condensing mode power production, to reduce fossil fuel-based heat-only boiler production and to integrate fluctuating renewable energy productions. However, often electricity prices do not create sufficient business economic feasibility for these units to be installed, and therefore, support schemes are required.

This article has shown that the design of a support scheme highly influences the size of combined heat and power and thermal energy storage capacities installed. It shows that the cost to society of the support schemes promoting a certain amount of combined heat and power capacity is a factor three times higher when applying a premium scheme compared to a triple tariff scheme.

Furthermore, the triple tariff scheme promotes a larger thermal energy storage capacity compared to the premium scheme, which is beneficial to district energy combined heat and power units to fulfil their subsequent tasks as flexibility providers in a renewable energy system.

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