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Small-scale combined heat and power as a balancing reserve for wind – The case of participation in the German secondary control reserve

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ABSTRACT

Increasing amounts of intermittent renewable energy sources (RES) are being integrated into energy systems worldwide. Due to the nature of these sources, they are found to increase the importance of mechanisms for balancing the electricity system. Small-scale combined heat and power (CHP) plants based on gas have proven their ability to participate in the electricity system balancing, and can hence be used to facilitate an integration of intermittent RES into electricity systems. Within the EU electricity system, balancing reserves have to be procured on a market basis. This paper investigates the ability and challenges of a small-scale CHP plant based on natural gas to participate in the German balancing reserve for secondary control. It is found that CHP plants have to account for more potential losses than traditional power plants. However, it is also found that the effect of these losses can be reduced by increasing the flexibility of the CHP unit.

Keywords:

Combined heat and power,
balancing reserve,
electricity market

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Abbreviations

CHP	=	Combined heat and power
DH	=	District heating
TSO	=	Transmission system operator
HT	=	Hochtarif
NT	=	Niedertarif
MOL	=	Merit order list
NHPC	=	Net heat production cost
PCR	=	Primary control reserve
SCR	=	Secondary control reserve
TCR	=	Tertiary control reserve
RES	=	Renewable energy sources
EU	=	European Union
ENTSO-E	=	European Network of Transmission System Operators for Electricity

1. Introduction

Increasing amounts of intermittent renewable energy sources (RES) such as wind power and solar power are being integrated into energy systems worldwide [1]. An example of this is the European Union (EU), where the political goal is to increase RES in the energy sector to

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20% of the gross final consumption by 2020 [2]. In 2012 RES accounted for 14.1% of the consumption in the EU, increased from 8.3% in 2004 [3]. Within the electricity sector especially intermittent RES have experienced a large increase in the EU [4].

While intermittent RES have shown promising results with respect to reaching the EU political goal, RES also introduce different challenges to the electricity system. Due to the more unpredictable nature of these sources, they are found to increase the importance of mechanisms for balancing the electricity system [5–7]. Balancing of the electricity systems is paramount, as electricity production must always equal electricity consumption to ensure a stable electricity system. Thus, those responsible for the electricity system balancing have kept reserves ready for balancing. Within the EU, the task of balancing the electricity system falls to the transmission system operators (TSOs). In accordance with the EU Directive 2003/54/EC, the TSOs have to obtain balancing reserves through market-based procurements that are transparent and non-discriminatory [8]. The specific organisation and utilization of the balancing reserves vary between countries; however, the European Network of Transmission System Operators for Electricity (ENTSO-E) defines three types of balancing reserves [9]:

- Primary control reserve (PCR), used to gain a constant containment of frequency deviations. The activation time of units will generally be up to 30 seconds. This reserve is also known as frequency containment reserves.
- Secondary control reserve (SCR), used to restore frequency after sudden system imbalances. The activation time of units will typically be up to 15 minutes. This reserve is also known as frequency restoration reserves.
- Tertiary control reserve (TCR), used for restoring any further system imbalances. The activation time of units will typically be from 15 minutes to one hour. This reserve is also known as replacement reserves.

The PCR is set by ENTSO-E at 3,000 MW for the synchronously interconnected system of continental Europe [9], where each country contributes with an agreed amount of capacity. The practical utilization of the SCR and the TCR, however, differs significantly between countries. The TCR is the primary balancing reserve in, e.g., Denmark, whereas the SCR is the primary balancing reserve in, e.g., Germany [10]. The difference in balancing procurement occurs partly due to differences in planning procedures by the TSOs in the two countries. Both these countries have a relatively high integration of intermittent RES in their electricity system. In Denmark, wind power and solar power accounted for 33.8% of the total electricity production in 2012 [11], and in Germany they accounted for 12.2% in 2012 [12]. As Germany is the largest electricity consumer [1] and producer [13] within the EU and also an important transmission country for electricity, the development of the German electricity system is of particular importance to reaching the EU's goals.

Besides the goals for RES, the EU also has a goal of reducing the primary energy consumption by 20% by 2020 [2]. As a part of reaching this goal, the EU promotes combined heat and power (CHP) production. In Germany, the generation of electricity from CHP plants has increased from 9.3% of the gross electricity generation in 2004 to 12.6% in 2012 [14]. A significant part of this increase is due to an increasing capacity of small-scale CHP plants [15].

As argued by Lund [16], the capacity of large inflexible production units, which traditionally have delivered balancing to the electricity system, is expected to be reduced alongside the increase in intermittent RES. This in turn will make it increasingly more important for flexible units to help maintain the electricity system stability. Small-scale CHP plants based on gas have proven to be flexible, and have, in other countries, demonstrated their ability to participate in the electricity system balancing [17]. In Germany, the SCR is currently mostly provided by large-scale power plants [18]. It is therefore relevant to investigate how flexible small-scale CHP plants can participate in the balancing of the German electricity system by participating in the market for SCR.

Other papers deal with participation in the German SCR. Thorin et al. [19] describe a tool based on mixed integer linear-programming and Lagrangian relaxation to simulate a district heating (DH) plant with steam turbines, gas turbines and fuel boilers participating in the German spot market and providing SCR. Thorin et al. do not include heat storage systems, and do only include a simple participation in the SCR. Koliou et al. [20] investigate the possibilities of having demand response participate in the German balancing markets. Müsgens et al. [21] analyse the market design and behaviour of participants in the German TCR and SCR, and in doing this develop a simple approach using the spot market prices for estimating the costs that a power plant could experience by offering capacity on either of these markets. However, Müsgens et al. do not include CHP plants in the discussion and do not use the method in simulations of the operation of a plant. No research has been found that directly deals with small-scale CHP plants participating in the German SCR. The goal of this paper is hence to fill this gap in the research by investigating and discussing the possibilities for small-scale CHP plants to participate in the German market for SCR using the current rules for this market. It is the goal to provide an understanding of the different challenges in the daily operation of traditional power plants and small-scale CHP plants, respectively, highlighting how the rules for balancing reserves can limit or encourage the participation of small-scale CHP plants.

In this paper, a method for simulating a small-scale CHP plants operation in the German SCR is presented. The method is used to simulate a case plant. The potential gain for the plant from having an increase in the flexibility of the CHP unit is also examined.

2. The German secondary control reserve

The German SCR receives payment for both capacity and activation, and the bids offered in one week cover all of the following week and are final after the clearing. Capacity bids are EUR/MW_e/week and activation bids are EUR/MWh_e. The winning bids are cleared using the pay-as-bid principle, where each winning participant is settled according to that participant's bid. The market is asymmetric, meaning that bids are separated into upward regulation, used when the system is short, and downward regulation, used when the system is long. Two periods are used in the SCR; hochtarif (HT) being the period from 08:00 to 20:00 on workdays, and niedertarif (NT) being all periods outside of HT. Bids are separate for upward and downward regulation, and for HT and NT; as such four different products are traded in the SCR. A bid has to be at least 5 MW; however, it is possible to pool units in order to reach this amount [18].

The SCR is cleared every Wednesday for the next week starting next Monday. Before the clearing day, the four German TSOs publish the capacity needed for the coming week. The four German TSOs are 50 Hertz, Amprion, Transnet BW and TenneT. The clearing day may in some weeks change due to German national holidays. On the clearing day, only the offered capacity payments are used to arrange the bids in a merit order list (MOL) where the cheapest capacity bids are selected first, until the amounts needed by the German TSOs are reached. An exemption to this rule is if a TSO needs units in a specific area in order to ensure a stable grid; then a more expensive unit can be chosen before a less expensive unit. The most expensive winning bid is reduced in size, if the needed amount of capacity is surpassed by this unit. Activations in the SCR must start within 30 seconds and be fully activated within five minutes. Similar to capacity bids, the activation bids are arranged in a MOL where the cheapest activation price is activated first, until the needed amount is reached. Again, conditions in the grid can result in a more expensive unit being activated before a less expensive unit [18]. In 2013, deviations from the activation MOL occurred for periods totalling 2 days, 1 hour and 49 minutes [22].

2.1. Public data for the German secondary control reserve

After the clearing day, the TSOs publish all winning bids in anonymised form, alongside the bids that were not selected due to grid stability needs. For each bid, the capacity offered, the capacity price bid, the activation price bid and whether the bid was accepted are shown. The bids are separated into each of the four products, but not according to control area. The four German TSOs continually publish the amount of SCR activated in MW for both upward and downward regulation in 15-minute periods. Within each 15-minute period, both upward and downward regulation can occur [23].

As the capacity payments for each week are publicly available, it is possible to use the data for capacity payments directly in the simulations. As described in section 1, other studies have investigated the potential income of distributed units in the SCR, but these have only estimated the income from capacity payments. In this study, activations are included in the simulation in order to estimate the potential effect of activations. However, the German TSOs do not publish the figures of payment for activation of the SCR for each 15-minute period. Thus, a method for estimating this is devised.

2.1.1. Estimating activation prices

In order to estimate activation prices in the SCR, several assumptions must be made. Firstly, it is assumed that all activations are chosen solely based on the price of activation, and activations of a more expensive unit due to grid restrictions are not included. Secondly, it is assumed that activations cover the full length of each 15-minute period; however, activations do not necessarily follow these 15-minute periods. Thirdly, if the activation amount in one direction in a 15-minute period is less than 5 MW, then this direction in that period is assumed to have no activations. This assumption is made to reduce the number of activations in periods in which there are clearly no new activations. The marginal activation price in each 15-minute period is then estimated by choosing the cheapest activations until the activated amount for the whole of Germany is reached. The last activated bid is reduced in size, if by activating this bid the registered activated amount is surpassed. Through this approach, the average and marginal activation prices for each 15-minute period are found.

Due to the uncertainties described for this method, the method cannot be used to estimate the potential income from an actual SCR participation, but can be used to highlight how different technologies would operate differently in the SCR.

3. Simulation approach

As a case, a natural gas fired small-scale CHP plant has been simulated. The simulated period is 2013. As CHP units will normally be built based on their feasibility in the wholesale market, a plant set-up is chosen based on its feasibility on the German wholesale market. The chosen plant set-up is based on the plant with one 4 MW_e CHP unit described by Streckienė. et al. [24]. Streckienė et al. analyse the feasibility of several CHP plants with thermal storage systems traded on the German day-ahead wholesale market, EPEX Spot, from here referred to as spot market. The chosen plant set-up was by Streckienė et al. found to be feasible on the spot market. As the plant is generic, the results are not affected by local conditions that could affect the results when specific plants are used, making it easier to see general tendencies in the results.

The modelled CHP plant has one natural gas fired 4 MW_e CHP engine with a thermal capacity of 4.7 MW_{th} and an overall efficiency of 87%. Besides the CHP unit, the plant is also equipped with one natural gas fired boiler with a thermal capacity equal to the peak heat demand and an efficiency of 91%. Besides the production units, the plant is also modelled with a thermal storage system of 650 m^3 corresponding to 30 MWh_{th}. The plant delivers ex plant 30,000 MWh_{th} to a local district heating system, and must always cover the heat demand in the district heating system. The only differences between the plant described by Streckienė et al. [24] and the plant simulated for this paper is that the electricity market prices, the temperature data used for distribution of the space heat demand through the year, the subsidies and the costs have all been updated to 2013 figures. See Table 1 for the economic assumptions for the plant described by Streckienė et al. and the 2013 version used in this paper.

The updated natural gas price, CO_2 certificate price, net using bonus and starting cost are assumed values based on the experience of the authors. As can be seen in Table 1, natural gas price and net using bonus are higher in the 2013 version, whereas CO_2 certificate price and starting cost are lower. The net using bonus is a payment for avoided grid costs where the size of the payment depends on the connections' voltage level, connection point (substation or cable) and the grid costs of the distribution grid operator. This value varies quite significantly depending on where in Germany the CHP unit is connected; e.g., in Schwäbisch Hall in southern Germany it is 4.7 EUR/kWh [25], and in Magdeburg in eastern Germany it is 9.9 EUR/MWh [26]. The value used here is an assumed value.

It is assumed that the CHP plant also receives the so-called *KWK-Zuschlag*. The KWK-Zuschlag is an electricity production subsidy given to owners of CHP units for the first 30,000 hours of operation. The size of the subsidy depends on whether the unit went into operation before or after the 19th July 2012 and on the electric capacity of the CHP unit. It is here assumed that the CHP unit went into operation after this date, and it receives 54.1 EUR/MWh_e for the electricity production of the first 50 kW_e of capacity, 4 EUR/MWh_e for the capacity between 50 and 250 kW_e, 24 EUR/MWh_e for the capacity between 250 and 2,000 kW_e and for the capacity above 2,000 kW_e the subsidy is 18 EUR/MWh_e [27]. Thus, the modelled 4 MW_e CHP unit will receive a KWK-Zuschlag of 22.18 EUR/MWh_e for the first 30,000 hours of operation.

The CHP unit is simulated as traded both on the spot market and the German SCR. As SCR is traded several days before the actual delivery and the trade on the spot market is traded day-ahead, the CHP unit will always be traded into the SCR before it is traded

Table 1: Economic assumptions of the CHP plant described by Streckien et al. [24] and the updated 2013 version of the CHP plant used in this paper.

	Streckien et al. plant	2013 version of plant
Natural gas price [EUR/MWh-fuel]	25	35
Fuel tax for gas boiler [EUR/MWh-fuel]	5.5	5.5
CO_2 certificate [EUR/t CO_2]	20	6
Gas boiler O&M costs [EUR/MWh_{th}]	1	1
CHP unit O&M costs [EUR/MWh_e]	8	8
CHP unit starting cost [EUR/turn on]	32	20
Average spot market price [EUR/MWh_e]	40.00	37.78
Net using bonus (CHP unit) [EUR/MWh_e]	1.5	6.7

on the spot market. In order to estimate the gain of increased flexibility of the CHP unit, two different capabilities for the technical flexibility of the CHP unit is made.

For the reference capability, it is assumed that the CHP unit must be in operation in the periods where SCR is won. In these periods, the CHP unit is traded on the spot market with the lowest possible bid, meaning it will always win trade on the spot market in these periods. EPEX-Spot is organised as a marginal price auction, where the market is cleared based on the most expensive winning bid [28]. Trading the CHP unit on the spot market is assumed to never affect the market price. If any non-usable or non-storable heat is produced when the CHP unit is forced to operate to deliver SCR, this heat is rejected. For the SCR trading, it is assumed that the plant is part of a pool with the same bid as the plant, and the plant therefore only needs to offer part of the minimum requirement of 5 MW_e. For the reference capabilities of the CHP unit, it is assumed that the plant offers 1 MW_e in the SCR, meaning in periods where upward SCR is won, the CHP unit will trade 3 MW_e on the spot market, keeping the remaining 1 MW_e ready for activations in the SCR. In periods where downward SCR is won, all 4 MW_e will be traded on the spot market; thus, in periods where the CHP unit is activated, it will be part-loaded to 3 MW_e. It is assumed that part-loading the CHP unit does not affect its efficiency. It is assumed that the unit must always deliver the amount traded in the SCR and it cannot rely on the other plants in its pool to deliver this amount. The plant is assumed not to have breakdowns of its units in the simulated period.

For the increased flexible capability of the CHP unit, it is assumed that the CHP unit does not have to be in operation in order to deliver SCR. Currently, the German TSOs require units delivering SCR to be in operation in periods where SCR is won. However, a simulation of the increased flexible capability of the CHP unit shows the maximal potential gain from increasing the flexibility of the CHP unit. With increased flexible capability of the CHP unit, the full capacity of the CHP unit, 4 MW_e, will be traded on the SCR. Hence, the CHP unit will not be traded on the spot market in periods where upward SCR is won, and in periods where downward SCR is won, the CHP unit's full capacity is traded on the spot market.

The CHP unit will be simulated as only trading in one direction at a time, resulting in a total of four scenarios:

- Scenario 1: Reference capability, where the CHP unit is only traded as upward regulation on the SCR.
- Scenario 2: Increased flexible CHP unit, where the CHP unit is only traded as upward regulation on the SCR.
- Scenario 3: Reference capability, where the CHP unit is only traded as downward regulation on the SCR.
- Scenario 4: Increased flexible CHP unit, where the CHP unit is only traded as downward regulation on the SCR.

Income from heat sales is not included as it is the same in all scenarios. In periods where SCR is not won, the CHP unit is traded on the spot market, if the resulting heat production can be either used or stored. Outside won SCR periods, the CHP unit will be operated in blocks of at least 3 hours. The operation of the CHP plant is simulated using energyPRO version 4.1. energyPRO is a simulation tool developed primarily for simulating district heating plants. The simulation objective of energyPRO is to minimize the net heat production cost (NHPC). energyPRO was also used for simulating the plant in Streckienė et al. [24], and is hence usable for the simulations presented in this paper.

3.1. Bidding strategy for the spot market

The assumed goal of the CHP plant is to produce the demanded heat as cheap as possible. The EPEX-Spot is organised as a marginal price auction and the optimal bidding strategy on such markets is bidding with the short-term marginal costs of the unit [28]. Thus, the spot market bid should be based both on the short-term marginal costs of operating the CHP unit and the reduced costs related to reduced boiler operation. Hence, the spot market bid of the CHP unit (B_{spot}) is calculated as shown in Eq. (1).

$$B_{spot} = \left(VHC_{CHP} - VHC_{boiler}\right) * CAP_{CHP-th} / CAP_{CHP-e} \tag{1}$$

Where VHC_{CHP} is the short-term marginal costs in EUR per MWh_{heat} produced on the CHP unit, VHC_{boiler} is the short-term marginal costs in EUR per MWh_{heat} produced on the boiler, CAP_{CHP-th} is the thermal capacity of the CHP unit in MW, and CAP_{CHP-e} is the electric capacity of the CHP unit in MW.

Using the data for the CHP plant shown in Table 1, the spot market bid excluding start costs of the CHP unit is found to be 15 EUR/MWh_e, rounded up. It is assumed that if the plant's bid is less than the spot market price, then the plant wins spot market trade without affecting the spot market price.

3.2. Participation in the secondary control reserve

For trade simulation in the SCR, it is assumed that if the plant's bid is lower than the marginal SCR bid, then the plant wins SCR. This applies both to capacity and activation in the SCR. Due to the pay-as-bid principle, the winning participants in the SCR are paid their asking price. Nielsen et al. [28] indicate that the participants in recurrent pay-as-bid auctions are prone to gamble on the auction, e.g., by trying to estimate the highest possible winning bid of the coming auction in order to increase their income from auction participation. For the purpose of these simulations, it is assumed that the plant will not gamble on the SCR. The bid will instead be calculated based on the plant's own expected costs of participating in the SCR.

The SCR capacity payment is for the purpose of these simulations, seen as the payment that the plant needs in order to cover any costs related to the activation of SCR. For the simulated CHP plant, the following potential costs from SCR participation are identified:

1. The plant has to produce non-useable or non-storable heat by operating the CHP unit in order to be able to deliver SCR. (L_1)
2. The spot market price in the won SCR periods is lower than the normal spot market bid of the CHP unit. Meaning that it would be cheaper to operate the boiler instead of operating the CHP unit. (L_2)
3. In the case of upward SCR, high spot market prices in the won SCR periods can provide an opportunity loss, since the CHP unit will only be offered in part-load on the spot market in order to be able to deliver upward activation in SCR. (L_3)
4. The SCR participation reduces the spot market trading in high price periods outside of the won SCR periods. This can occur due to the displacement of heat production using the thermal storage system. (L_4)

For plants where the activation price is not solely based on the plant's own costs, as is the case of the simulated plant, a fifth potential cost could be included in the list. This fifth cost would be the opportunity to earn income from activations, and would normally be a negative cost.

The optimal approach to calculating the sum of these costs is to compare the NHPC if the plant did not participate in the SCR with the NHPC when participating in the SCR. In other words, the comparison of NHPC would be between a scenario in which the CHP unit is traded only on the spot market and another scenario in which the CHP unit in the SCR periods is traded on the spot market with the lowest possible bid price, as well as traded normally on the spot market in the remaining periods. The difference in NHPC between these two scenarios reflects the income needed from the capacity bid. Though in principle comparing the NHPC of these two scenarios would be the optimal approach, in practice this approach is problematic. The reason for this is that the clearing day for SCR is more than four days before the first day of potential SCR operation, and forecasts of, e.g., spot market prices and heat demand for the period are very uncertain. To highlight this challenge it is relevant to include forecasts in the simulations. For the purpose of the simulations presented in this paper, a simple approach to forecasting is used. The forecasts are produced based on the knowledge that a plant would have on the SCR clearing day. The clearing day is assumed to be only on Wednesdays. Only heat demand and spot market price forecasts are included.

The heat demand forecast is created for the SCR trading period using the heat demand from the seven days before the clearing day, being the period from and including the former week's Wednesday up to and including the Tuesday before clearing day. The heat demand from the former week's Wednesday is then used as a forecast for the following Monday, etc. It is assumed that the CHP plant aims to not reject any heat by participating in the SCR. For each clearing day, three different simulations based on the heat demand forecast are carried out for the following SCR trading period, representing an increasing amount of hours traded on the SCR. In the first simulation, the CHP unit operates at full load in all HT periods, as there in any given week will always be fewer hours of HT than NT. In the second simulation, the CHP unit will be operated at full load in all NT periods. In the last simulation, the CHP unit will be operated at full load in all periods. If in one of these simulations a rejection of heat is found, then no SCR trading is carried out in that period. E.g., if based on the heat demand forecast a rejection of heat is found by operating the CHP unit at full load in the NT periods, then SCR trading is only done in HT periods. No spot market trading is done in these tests, and the heat storage system is assumed to be empty at the beginning and the end of the week. With this method, the rejection of heat can still occur, as the heat demand is based on a forecast; however, the heat demand is vastly reduced compared with not taking into account the heat demand before trading SCR. In reality, a CHP plant would be able to purchase heat forecasts more advanced than the one used in these simulations; however, more advanced forecasts have not been available for these simulations.

To forecast spot market prices for the upcoming SCR trading period, the seven days before the clearing day's average spot market price in each of the two periods (HT/NT) are used as a forecast for the corresponding upcoming periods. It is assumed that spot market price averages covering these periods will provide a less uncertain spot market price forecast than when forecasting all price variations on the spot market. However, using this forecast approach removes the possibility of simulating a normal spot market trading, since the forecasted spot market will only have two prices, one for NT periods and one for HT periods. It is not possible in the simulations to estimate the potential loss, L_4. However, the spot market price forecast is seen as a good approximation to how actual forecasting could occur for such a plant.

With the economic loss from L_1 reduced to a very small loss and the spot price forecast removing the potential for using the explained optimal approach to estimate L_4, a simpler approach to calculating the capacity bids is used instead. For upward SCR capacity bids, the simpler approach will be based on the one presented for power plants by Müsgens et al. [21]. Müsgens et al. calculate the capacity bid of a power plant delivering upward SCR by using only the power plant's own cost in the capacity bid. Müsgens et al.'s approach to the upward capacity bid of a power plant is shown in Eq. (2).

$$B_{Up-cap} = \begin{cases} \left(B_{spot} - p_{spot}\right) * \dfrac{CAP_{OP}}{CAP_{Of}}, \text{ if } B_{spot} > p_{spot} \\ p_{spot} - B_{spot} \qquad\qquad\quad , \text{ if } B_{spot} > p_{spot} \end{cases} \tag{2}$$

Where $B_{Up\text{-}cap}$ is the capacity bid for upward regulation in EUR/MW/h, B_{spot} is the spot market bid of the power plant, p_{spot} is the average spot market price in the period, CAP_{op} is the load in MW_e at which the power plant operates to deliver upward SCR, and CAP_{of} is the capacity offered as upward SCR.

As seen in formula 2, Müsgens et al. include the losses L_2 and L_3 in the capacity bid of the power plant, which is the only two of the listed four losses that a power plant could experience by providing upward SCR. However, as a CHP plant is simulated in this paper, the loss L_4 should also be included in the capacity bid. Ideally L_4 should be found as shown in Eq. (3).

$$L_4 = Inc_{spot} - \left(B_{spot} * P_e\right) \tag{3}$$

Where Inc_{spot} is the period's total spot market income in EUR as gained if SCR is not traded and P_e is the electricity trade won on the spot market in MWh_e if SCR is not traded. B_{spot} is the spot market bid for the CHP unit as calculated in Eq. (1).

Based on the earlier discussions, Inc_{spot} and P_e cannot be calculated using the spot market forecast utilized in this paper. Therefore, L_4 is instead fixed through the simulated period, and assumed to be 30 EUR/MWh_e.

This corresponds to the difference of the average spot market price for prices above B_{spot} in 2013 and B_{spot}, rounded up. L_4 is added to the spot market bid of the CHP unit, B_{spot}. Eq. (4) shows the changed Eq. (2), and Eq. (4) is the calculation method used in this paper for capacity bids for upward SCR.

$$B_{Up-cap} = \begin{cases} \left(B_{spot}+L_4-p_{spot}\right) * \dfrac{CAP_{OP}}{CAP_{Of}}, & \text{if } B_{spot}+L_4>p_{spot} \\ p_{spot}-\left(B_{spot}+L_4\right) & \text{, if } B_{spot}+L_4 \le p_{spot} \end{cases} \tag{4}$$

For downward SCR, only the losses L_2 and L_4 need to be included in the capacity bid. The capacity bid for downward SCR is calculated as shown in Eq. (5).

$$B_{Down-cap} = \begin{cases} \left(B_{spot}+L_4-p_{spot}\right) * \dfrac{CAP_{OP}}{CAP_{Of}}, & \text{if } B_{spot}+L_4>p_{spot} \\ 0 & \text{, if } B_{spot}+L_4 \le p_{spot} \end{cases} \tag{5}$$

Where $B_{Down-cap}$ is the capacity bid for downward SCR. CAP_{op} is here equal to the full electric capacity of the CHP unit, as the unit will be operated at full load when providing downward SCR.

Bspot excluding start costs is found to be 15 EUR/MWh$_e$, assuming 8 hours of operation. B_{spot} incl. start costs is 16 EUR/MWh$_e$, rounded up. With a L_4 for the CHP unit of 30 EUR/MWh$_e$, the capacity bid for a 4 MW$_e$ engine offering 1 MW$_e$ would be as shown in Figure 1. On each graph, the CHP unit is only offered in one SCR direction.

The capacity bids presented in Eq. (4), Eq. (5) and Figure 1 are in EUR/MW/h; however, SCR capacity bids are given in EUR/MW/week. These capacity bids have to be multiplied with the number of hours of the respective SCR period in the given week.

For the purpose of the simulations in this paper, the activation bids are fixed through the simulated period. The bid for upward activation is fixed at 46 EUR/MWh$_e$, being B_{spot} + L_4, and the bid for downward activation is fixed at -16 EUR/MWh$_e$, being -B_{spot}. L_4 should not be included in the downward activation bid, as L_4 is already covered for the full capacity of the CHP unit through the downward capacity bid.

3.3. Example of simulation approach

Figure 2 shows the simulated heat production of scenario 1 in the period from 21st to the 28th of October 2013. The clearing day for the period is the 16th of October. The forecasted heat demand for the period was 499.9 MWh$_{th}$, and it was found that SCR delivery in the NT periods would result in rejection of heat, and as such SCR was only traded in the HT periods. The actual heat demand in the period is 364.7 MWh$_{th}$ as such the heat demand is significantly lower than expected. The forecasted average spot market price in the HT periods was 58.14 EUR/MWh$_e$. Hence, the capacity bid was 728.4 EUR/MW/week, corresponding to 12.14 EUR/MW/h. The marginal capacity bid in the market is 1.054 EUR/MW/week and hence the plant won upward SCR in the HT periods. The actual average spot market price in the HT periods is 46.41 EUR/MWh$_e$.

Figure 2 shows three different graphs: the top graph being the spot market price, the middle graph shows the heat production of each production unit, heat demand and rejection of heat and the bottom graph shows the energy content of the thermal storage system.

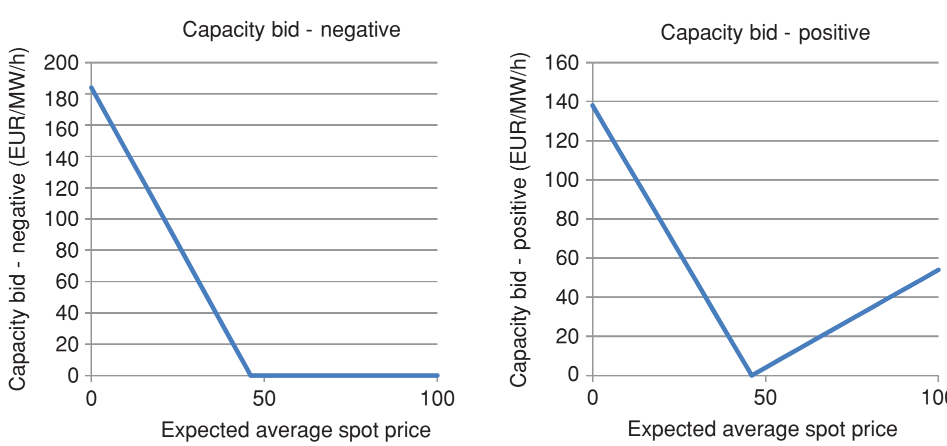

Figure 1: Capacity bids for downward SCR and upward SCR.

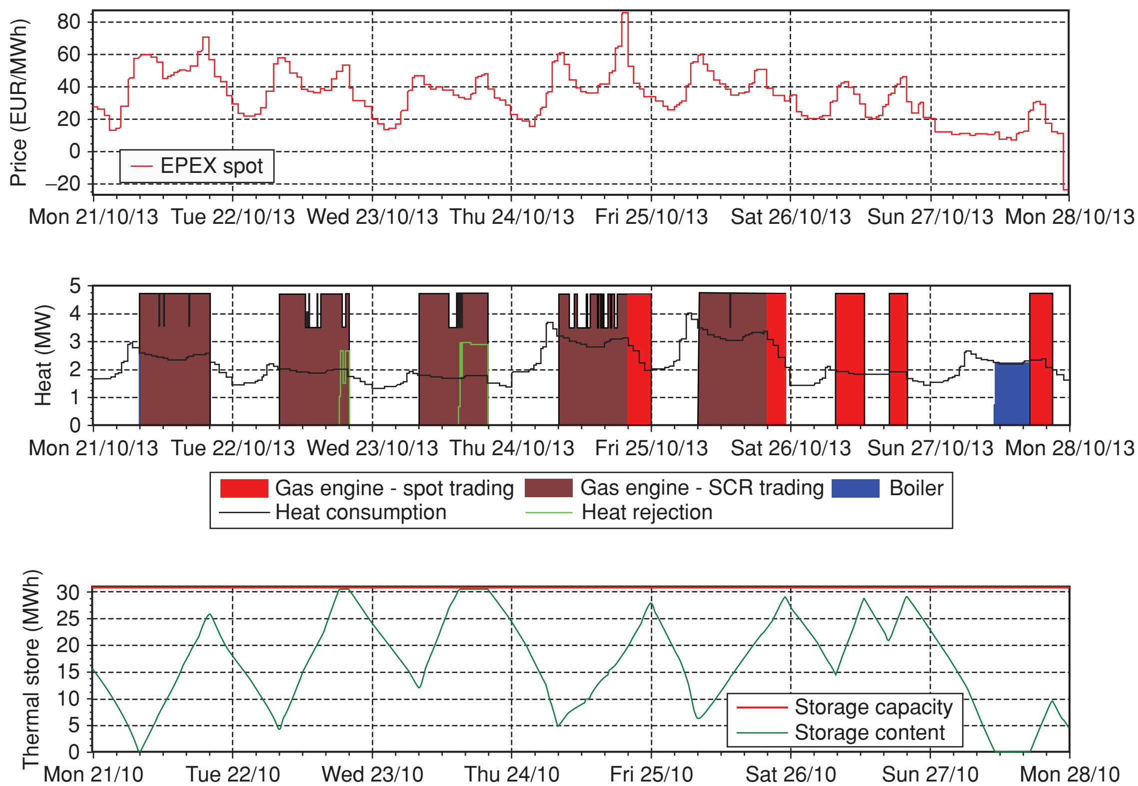

Figure 2: Example of one week's simulated heat production in scenario 1.

As can be seen in Figure 2, in the shown period the plant wins upward SCR in HT periods. In the rest of the week the engine can be used for trading in the spot market, and spot market trading is won in several periods in the end of the week. The heat demand forecast did, however, underestimate the heat demand and in periods the 22nd and the 23rd non-useable and non-storable heat is produced resulting in rejection of heat.

Figure 3 shows the simulated heat production of scenario 2. The shown period is the same as in Figure 2. As in Figure 2, in the shown period the plant wins upward SCR in HT periods, however, as the engine here is assumed to be able to deliver upward SCR activation without being in operation beforehand, the engine is only in operation when being activated as upward SCR, and when traded into the spot market outside of the HT periods.

4. Results of the simulations

Each unit's heat production is shown in Table 2 alongside the rejection of heat in each scenario.

As seen in Table 2, the rejection of heat especially occurs when the CHP unit has the reference flexibility, as in scenarios 1 and 3. The corresponding costs and revenues excluding income from the sale of heat in each scenario are shown in Table 3.

As seen in Table 3, spot revenue is similar in every scenario except for scenario 2. The reason is that, in scenario 2, it is assumed that the CHP unit does not have to be in operation in order to deliver upward regulation, and in periods where SCR is won, the CHP unit is not traded on the spot market. Instead a high income from SCR activation is found. The resulting total costs in each scenario are similar in size, which is due to the utilized bidding strategy reflecting the plant's own costs. Though a decrease in the total costs can be seen in scenarios in which the CHP unit is modelled with increased flexibility. Using a different bidding strategy could increase this difference.

It should be noted that the income from activation is highly uncertain, since the data used for activation is created for this paper using public available data, as described in section 2.1.1. Activation of SCR is depended on where in Germany the participant is located, and as such, the activation income for a specific participant can vary significantly from the activation income presented here.

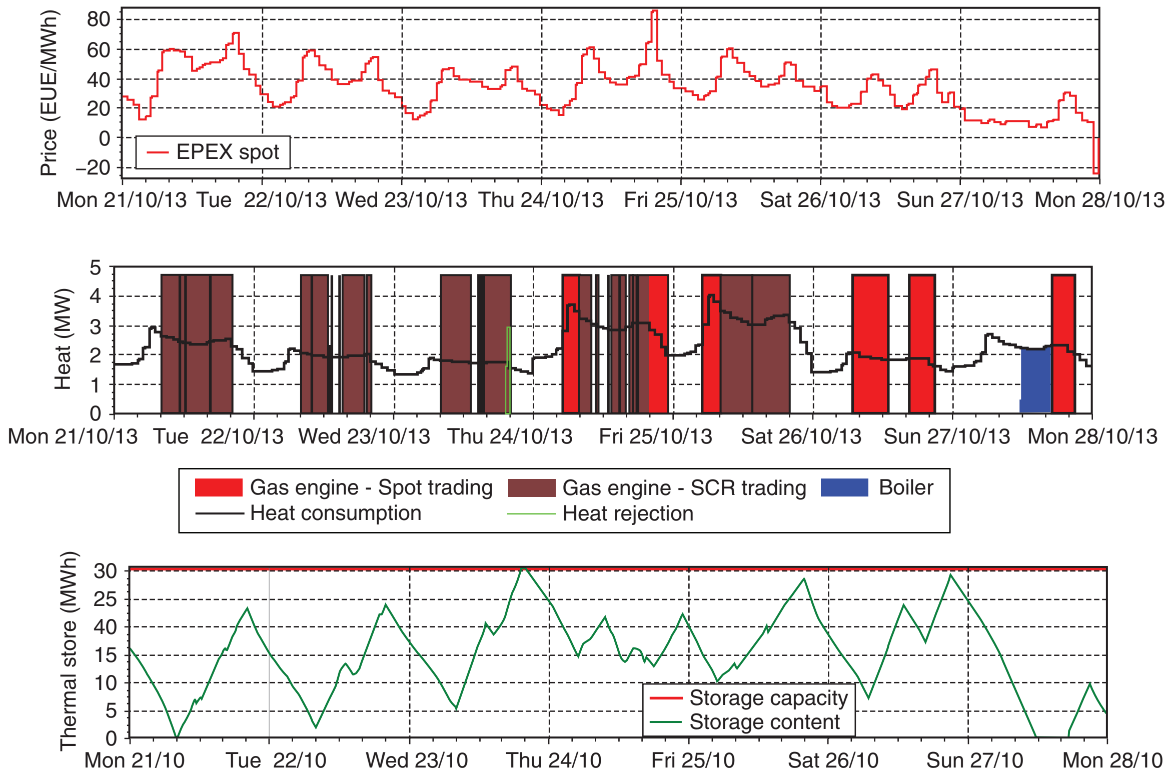

Figure 3: Example of one week's simulated heat production in scenario 2. The week is the same as in Figure 2.

Table 2: Heat produced and heat rejected in each scenario.

[MWh_{th}]	CHP unit	Boiler	Heat rejected
Scenario 1	26,770	3,337	107
Scenario 2	25,358	4,731	89
Scenario 3	26,631	3,629	260
Scenario 4	23,118	6,917	35

Table 3: Costs and revenues excluding income from sale of heat in each scenario.

[1,000 EUR]	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Fuel, taxes and CO2-costs	2,230	2,185	2,233	2,112
O&M incl. start costs	194	208	195	188
Spot trade revenue	961	507	1,009	1,026
SCR capacity revenue	5	17	4	27
SCR activation revenue	32	501	–10	–70
Subsidy revenue	658	623	654	568
Total costs	**768**	**744**	**770**	**749**

4.1. Sensitivity analyses on L_4

In order to estimate the effect of the chosen L_4, a sensitivity analysis has been made for L_4. L_4 is in the reference set at 30 EUR/MWh$_e$. Here L_4 is tested for each 5 EUR/MWh$_e$ increment from 15 EUR/MWh$_e$ to 75 EUR/MWh$_e$. The resulting total costs for each scenario are shown in Figure 4.

As seen in Figure 4, scenario 2 is mostly affected by a change in L_4. The reason is the change in capacity bids, where in scenario 2 the bid for spot prices estimated at below $B_{spot} + L_4$ is zero, as the CHP unit does not have to be in operation in order to deliver activation. In scenario 2, at a low L_4, the CHP unit wins upward SCR in only a few hours and, at a high L_4, the CHP unit wins upward SCR in many hours with a capacity bid of zero. Scenario 2 provides lower total costs than scenario 1 with a L_4 from around 30 EUR/MWh$_e$ to 60 EUR/MWh$_e$. In the shown range of L_4, Scenario 4 provides lower total costs than scenario 3.

5. Conclusion

In this paper, an approach to simulating the participation of a small-scale CHP plant in the German SCR is discussed. Part of the simulation approach is the bidding strategy of the CHP plant, where the discussed strategy aims at making the bid reflect the plant's own costs. The discussion of the bidding strategy takes its departure in the current research of bidding strategies for power plants as discussed by Müsgens et al. [21], adjusting it to the special circumstances for small-scale CHP plants. It is found that the CHP plant's participation in the German SCR is affected by four potential losses that do not affect the participation of a traditional power plant.

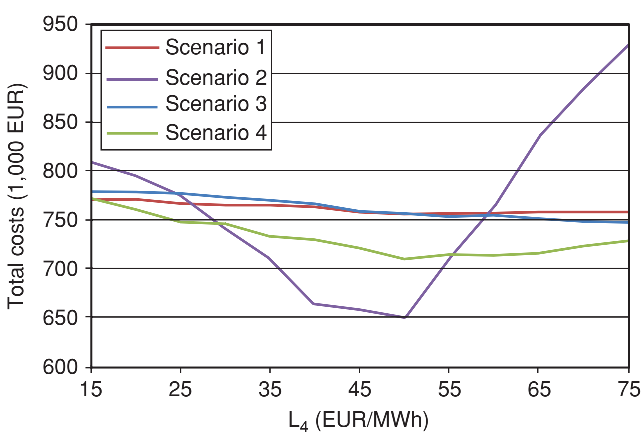

Figure 4: Total costs at different L_4 in each scenario.

Each of these losses should be included in a CHP plant's bid in order for the bid to be cost-reflective; however, the effect of these losses will, due to the time span between market clearing and actual operation, have to be estimated based on relatively uncertain forecasts. In order to make it more attractive for the small-scale CHP plants to participate in the German SCR, the rules for the SCR should help minimize these losses and reduce the corresponding uncertainties. Specific suggestions for changing the rules of the SCR have not been presented in this paper; however, e.g. having the clearing day closer to the first delivery day and granting market participants the possibility to change activation bids after the clearing day, would result in reduced uncertainty for the small-scale CPH plants.

In this paper, it is also investigated how different capabilities for the technical flexibility of the CHP unit affect the potential gain from participating in the German SCR. An increased flexibility of the CHP unit is found to increase the potential gain that the CHP plant can attain in the German SCR, especially when offering upward regulation in the SCR. The results are especially sensitive to the bidding strategy utilized by the plant.

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