Evaluation of hybrid electric/gas steam generation for a chemical plant under future energy market scenarios

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Abstract
Hybrid electric/gas steam generation is a suitable concept to reduce CO_2 emissions from existing industrial plants while at the same time being able to benefit from shifting between different varying energy carrier markets. In this study, hybrid steam generation was assessed in terms of total annualised cost for a case study chemical plant under current and future energy market conditions using a linear optimisation model. The methodology accounts for hourly steam demand fluctuations as well as hourly variations of energy carrier prices. Consistent future energy market scenarios (energy carrier prices and CO_2 charges) were used to assess the long-term benefits of different investment options. The optimal capacities in terms of total annualised cost of steam production for different energy market conditions were calculated by the model and used as base for three investment decisions that were further assessed in terms of running cost. The assessment considers the impact of on-site CO_2 and electric grid capacity limitations. The results show that flexible hybrid steam generation is an economically robust option compared to investment in a stand-alone gas boiler. This characteristic makes hybrid steam generation a promising technology for the transition from current natural gas-based steam production to steam production from electricity and biomethane.

Introduction
In the EU-28, 21 % of industrial CO_2 emissions are related to production of steam and hot water for industrial processes (Herbst et al. 2018). A detailed analysis of the sectorial breakdown of final consumption of steam and hot water shows a rather equal distribution between industrial sectors (chemicals, pulp and paper, non-metallic minerals, food, and iron and steel). CO_2 emission reduction measures related to steam production can therefore be applied in many industrial sectors. One such technology is steam generation from electric power, as single utility provider or in combination with other technologies. Natural gas is currently the dominating fuel type for steam generation in EU-28 (European Commission 2016). Switching from gaseous fossil fuels to electricity as energy carrier for industrial steam generation could potentially lead to large reductions in CO_2 emissions, assuming that the carbon intensity of the future electricity generation system is sufficiently low. This can be considered as relatively likely given the growth rate of renewable electricity generation within the EU, propelled by decreasing generation costs (especially wind and solar) in conjunction with current and future policy measures to reach climate targets based on the Paris Agreement. This is also in line with ambitious greenhouse gas emission targets set by the EU (European Commission 2019) but also by individual members states (Government Offices of Sweden, 2017). However, market prices for natural gas and electricity, as well as carbon intensities for electricity, vary greatly between the EU member states, leading to potentially different incentives for industrial companies to invest in electric steam generation. Also, it is not obvious how future prices for electricity will develop since a decrease in generation cost and an increase in renewable electricity generation capacity might be outweighed by an

increasing electricity demand in several sectors (e.g. transportation). Furthermore, a substantial increase of electricity usage in industry and the transportation sector will require major investments in electricity transmission and distribution grids, which is likely to be reflected by significantly higher grid fees.

To overcome the uncertainty about future electricity fuel prices and the ensuing reluctance to switch completely from gaseous fossil fuel, especially natural gas, to electricity for steam generation, hybrid gas/electric steam generation can be attractive. A hybrid steam generation system combines an electric boiler with a gas boiler that can run on conventional gaseous fuels or biomethane. This concept allows a transition rather than a radical switch, allowing companies to profit from currently low prices for conventional gas fuels while being prepared to meet further emissions reduction demands in the future. The concept also allows arbitrage, meaning that the hybrid system can use more electricity and less gas in times with low electricity prices and vice versa. Another key advantage of this system is that both technologies have a high TRL level. In addition, no changes to the core process are required as the steam generation only affects the process utility system. This can make hybrid steam generation applicable for many processes and facilitate widespread adoption of the technology. The production of biomethane as natural gas substitute is likely to increase in the future due to the development of new biomethane production technologies such as gasification of lignocellulosic biomass in addition to the current production which is mainly based on anaerobic digestion (Scarlat 2018).

Although both gas boilers and electric steam boilers are off-the-shelf technologies, the concept of combining these technologies to form hybrid systems is not widely adopted in industry. Furthermore, there is very little research about the implications of implementing hybrid steam generation concepts in existing plants under different energy market conditions. So far, research has focussed on investigating the economic feasibility including participation in electricity spot markets as well as providing flexibility via the regulating power market (see for example Wieringa 2015). However, this assessment was not performed for real industrial settings. Other studies (e.g. Kerttu 2019) investigated existing plants but considered only yearly average values for the energy prices. Including the steam demand variations of existing plants is important since the economic feasibility strongly depends on the interplay of the steam demand pattern and the electricity generation pattern from renewables (leading to low electricity prices at times with high wind and solar power production). When both patterns show a high degree of fluctuation (i.e. when the industrial steam demand pattern is characterized by large variations), advanced optimization methods are needed to determine the optimal sizing and operation patterns of the steam generation technologies and the fuel usage in hybrid steam generation systems. However, these aspects are important for industrial decision makers that need to make investment decisions for specific generation capacities that are economically robust not only today but also for a suitably wide range of future energy market conditions. Analysing and including the steam demand pattern of an existing process is also an important preparatory work to investigate how variation management strategies and the participation in intraday or regulating power markets affect the economic feasibility.

The objective of this paper is to evaluate the costs associated with implementation of hybrid steam generation based on electricity and gaseous fuels for an existing industrial plant considering current and future energy market conditions. The evaluation is illustrated by a case study for an existing specialty chemicals plant while the developed methodology is applicable to other industrial processes as well. In a first step, the optimal installed capacities of the technologies to reach the lowest total annualised cost (TAC) of steam production for different market conditions are identified. Based on these results, three possible investment decisions (i.e. size of electric boiler and gas boiler) are selected. The economic performance of the investment decisions is thereafter analysed in terms of running cost for three different points in time. All energy market scenarios used in the analysis assume net zero CO_2 emissions from the electricity sector by 2050. Additionally, possible restrictions on on-site CO_2 emissions as well as the maximum power load capacity for the plant's electricity grid connection are considered in the assessment.

Hybrid gas/electric steam generation

Figure 1 shows the hybrid steam generation concept considered in this study, as well as an example of an electric steam generator. The electric steam generator is considered to be a high voltage electrode boiler while the conventional gas boiler can run on either natural gas or biomethane. The flexibility to switch between an electric steam generator and a gas boiler as well as the flexibility to switch between natural gas and biomethane allows the system to meet CO_2 emission reduction targets at an optimal cost. The biomethane option can be of high relevance when CO_2 reduction targets must be met while the access to electricity is limited due to on-site or grid limitations.

Integration of hybrid electric steam generation in existing plants does not require redesign or change in operation of the core processes. However, a new control system is required to control the interplay between the two separate steam generation technologies. Changes in the core processes could enable more far-reaching reductions of greenhouse gas emissions from industrial processes since these could reduce the total demand for external utility or allow a switch to other feedstock or fuels. However, even with such process and efficiency changes there will be a residual steam demand in many processes which has to be covered.

Steam system of the case study plant

The case study in this paper is based on a specialty chemicals plant. The pressure levels in the existing steam system are 40, 28, 20, 6 and 1 bar(g). Over the course of a year, about half of the total plant's steam demand is satisfied by steam generation at 20 bar(g) from process cooling of the exothermic main reaction. However, since this reaction is non-continuous, the daily steam production varies between 20 and 40 MW. The remaining steam demand is satisfied by three boilers, of which two operate at 40 bar(g) and one works at 28 bar(g). One of the two 40 bar(g) boilers is fuelled by organic residues and ventilation gases from the plant site that occur during normal plant operation and provide a low share of the total steam demand. The other 40 bar(g) boiler is fuelled primarily with fuel gas (mix of

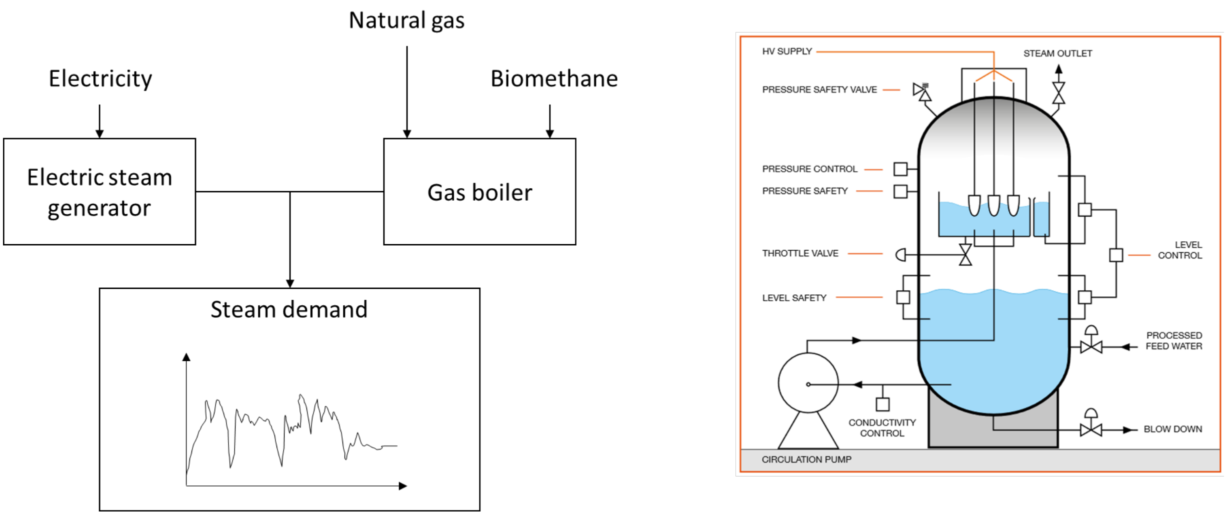

Figure 1. The hybrid steam generation concept considered in this study (left) and an example of a stand-alone electric steam generator (Parat 2020) (right).

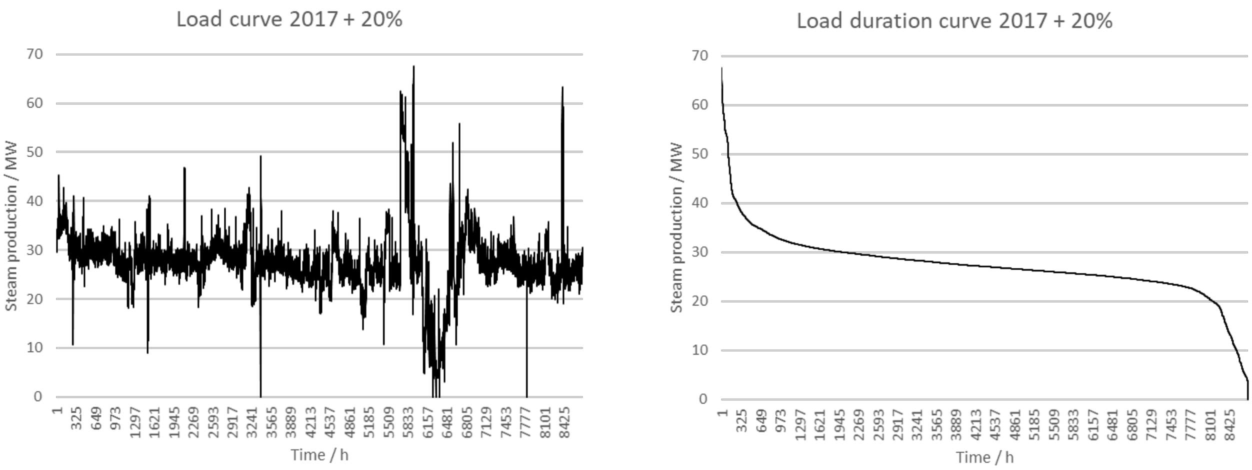

Figure 2. Load and load duration curves for the two boilers that will be replaced for 2017 (based on hourly values) including an expected production increase of 20 %.

natural gas and residual fuel gas purchased from a neighbouring plant). The 28 bar(g) boiler can only be fuelled with gas and has a low operating time since it is used as backup boiler only. There is no steam accumulator and there are no steam turbines in the system.

In this study, it is assumed that the waste incineration boiler at 40 bar(g) is retained for handling waste streams. The two other boilers (the main boiler at 40 bar(g) and the backup boiler at 28 bar(g)) have reached the end of their service lifetime and are assumed to be replaced by a hybrid steam generation concept.

Figure 2 shows the steam production load curve and the corresponding duration curve for the two boilers that will be replaced including an increase by 20 % due to an expected production increase in the future. The fluctuations are due primarily to the changes in steam production from process cooling of the exothermic main reaction. However, fluctuations also occur at constant steam production from the process cooling, meaning that the steam demand from the different parts of the plants also varies.

As can be seen, the load curve shows a high degree of fluctuation around a base value of approximately 30 MW. Almost all hourly load fluctuations are within a range of ±10 MW while there are some hours in which these fluctuations are as high as ±45 MW. It should be noted that the large drop in steam production occurring around hour 6,200 is caused by the annual revision shutdown of the plant.

Assessment methodology

The methodological approach used in this study to evaluate hybrid steam generation in terms of costs consists of two steps. In the first step, a linear optimisation model was used to identify the optimal installed capacities and the optimal operating pattern to reach the minimum Total Annual Cost (TAC) of steam production for different market conditions and restrictions for on-site CO_2 emissions and electric grid connection. This assessment was performed for conditions in Southern Sweden and Southern Germany to investigate how a different plant location would impact the TAC. After the optimal installed capacities were identified from these runs, three investment decisions were identified and assessed further in terms of running cost for three different future energy market conditions in Southern Sweden (What-if analysis). For this purpose, the optimisation model was also used but with fixed installed capacities according to the investment decisions.

LINEAR OPTIMISATION MODEL

The objective function in the linear optimisation model used was to minimise the TAC of steam production. Costs included in the model were annualised capital costs for the investment in the different boiler technologies, fixed maintenance costs proportional to the installed capacity, as well as running costs from fuel demand, variable operation cost, grid cost, as well as cost for on-site CO_2 emissions. The objective function was defined as:

$$\boldsymbol{min}\Bigg[\boldsymbol{r} * \sum_{\boldsymbol{u}}[\boldsymbol{P}(\boldsymbol{u}) * \boldsymbol{c_{inv}}(\boldsymbol{u})] + \sum_{\boldsymbol{u}}[\boldsymbol{P}(\boldsymbol{u}) * \boldsymbol{c_{fix}}(\boldsymbol{u})] \quad (1)$$
$$+ \sum_{\boldsymbol{t}}[(\boldsymbol{c_{el}}(\boldsymbol{t}) + \boldsymbol{c_{var,el}} + \boldsymbol{c_{grid,el}}) * \frac{\boldsymbol{Q_{out,el}}(\boldsymbol{t})}{\boldsymbol{\eta_{el}}}]$$
$$+ \sum_{\boldsymbol{t}}[(\boldsymbol{c_{ng}}(\boldsymbol{t}) + \boldsymbol{c_{var,gas}} + \boldsymbol{c_{grid,gas}} + \boldsymbol{c_{CO_2}}(\boldsymbol{t}) * \boldsymbol{e_{CO_2,ng}}) * \frac{\boldsymbol{Q_{out,ng}}(\boldsymbol{t})}{\boldsymbol{\eta_{gas}}}]$$
$$+ \sum_{\boldsymbol{t}}[(\boldsymbol{c_{bm}}(\boldsymbol{t}) + \boldsymbol{c_{var,gas}} + \boldsymbol{c_{grid,gas}} + \boldsymbol{c_{CO_2}}(\boldsymbol{t}) * \boldsymbol{e_{CO_2,bm}}) * \frac{\boldsymbol{Q_{out,bm}}(\boldsymbol{t})}{\boldsymbol{\eta_{gas}}}]\Bigg]$$

with:

r	annuity factor (or capital recovery factor) in 1/a
u, t	sets for units (electric boiler and gas boiler) and periods (hours)
$P(u)$	installed capacities for each boiler technology (gas boiler and electric boiler) in MW
$c_{inv}(u)$	specific investment cost for each boiler technology in €/MW
$c_{fix}(u)$	specific fixed maintenance costs related to the two boiler technologies in €/MW/a
$c_{el}(t)$, $c_{ng}(t)$, $c_{bm}(t)$	prices for electricity, natural gas and biomethane in €/MWh
$Q_{out,el}(t)$, $Q_{out,ng}(t)$, $Q_{out,bm}(t)$	hourly steam production from electricity, natural gas and biomethane as fuel in MWh
η_{el}, η_{gas}	efficiencies of the boiler technologies
$c_{var,el}$, $c_{var,gas}$	variable operating and maintenance cost related to the boiler technologies in €/MWh
$c_{grid,el}$, $c_{grid,gas}$	electricity/gas grid cost in €/MWh
$c_{CO2}(t)$	CO_2 emission charge in €/tCO_2
$e_{CO2,ng}$	specific on-site CO_2 emissions (natural gas combustion for steam production) in tCO_2/MWh natural gas
$e_{CO2,bm}$	specific on-site CO_2 emission from biomethane combustion for steam production in tCO_2/MWh natural gas

The decision variables were the installed capacities $P(u)$ of the two generation technologies (electric steam boiler and gas boiler in MW), as well as the hourly steam production from the three different fuels $Q_{out,el}(t)$, $Q_{out,ng}(t)$ and $Q_{out,bm}(t)$ leading to the different fuel demands. It was assumed that the optimisation model could choose freely between the different fuels. The investment cost (full capital cost) was estimated by multiplying the equipment cost by a factor 4 to allow for installation costs, engineering etc. The annuity factor of 0.08 was calculated from an assumed lifetime of 20 years and an interest rate of 5 %. Constraints included in the model were:

Demand constraint:

$$Q_{out,el}(t) + Q_{out,ng}(t) + Q_{out,bm}(t) = Q_{demand}(t) \quad \forall t \quad (2)$$

Constraint on the electricity grid connection capacity:

$$\frac{Q_{out,el}(t)}{\eta_{el}} \leq P_{el,max} \quad \forall t \quad (3)$$

Constraint on the annual on-site CO_2 emissions:

$$\sum_{t}[e_{CO_2,ng} * \frac{Q_{out,ng}(t)}{\eta_{gas}} + e_{CO_2,bm} * \frac{Q_{out,bm}(t)}{\eta_{gas}}] \leq E_{CO_2,max} \quad (4)$$

with

$Q_{demand}(t)$	hourly steam demand from the two boilers that will be replaced in MW
$P_{el,max}$	maximum electric grid connection capacity in MW
$E_{CO2,max}$	maximum allowed yearly on-site CO_2 emissions in tCO_2/a

The demand constraint limits the hourly total steam production from the different fuels to the hourly steam demand and does not allow for investments in over-capacity since the sum of the installed boiler capacities was assumed to be exactly equal to the level needed to satisfy the maximum steam demand. The input data to the model consisted of technology-related assumptions as shown in Table 1, as well as prices for the different energy carriers (electricity, natural gas and biomethane) and charges for on-site CO_2 emissions (Table 2). The latter are included in the scenarios that are described in the following section. It was assumed that both the gas and electric boilers are able to cope with the steam load fluctuations.

The GNU Linear Programming Kit (GLPK 2020) was used to solve the linear optimisation problem.

ENERGY PRICE AND CO_2 CHARGE INPUT DATA TO THE MODEL

Energy prices (electricity, natural gas and biomethane) and CO_2 emission charges are exogeneous variables for the optimisation model. Corresponding input data was collected for reference conditions based on historical data (2019) and for future conditions based on scenarios. Table 2 shows an overview of this input data. It was assumed that any costs related to upstream CO_2 emissions associated with incoming electricity, natural gas and biomethane are included in the market prices and that corresponding off-site CO_2 emissions are not allocated to the industrial plant. Consequently, only on-site CO_2 emissions are assumed to affect the costs of the plant directly through the CO_2 charge. Furthermore, since the constraint on emissions was con-

Table 1. Technology-related assumptions.

Description	Formula symbol	Electric steam generator	Gas boiler (natural gas and biomethane)	Source
Investment cost	c_{inv}	€188,000/MW	€380,000/MW	Information from suppliers
Fixed maintenance cost	c_{fix}	€1,500/MW*a	€2,500/MW*a	Goop 2012
Variable operating cost	c_{var}	€1/MWh	€1.5/MWh	Goop 2012
Boiler Efficiencies	η	99 %	90 %	Parat 2020, Wieringa 2015

Table 2. Reference and scenario-based market and electricity generation conditions included in this study.

	Description	Formula symbol	Value	Source
Reference conditions (2019)	Electricity price	$c_{el}(t)$	Time-dependent, hourly resolution	Nordpool 2020
	Natural gas price	c_{ng}	€20/MWh	SCB 2020
	Biomethane price	c_{bm}	€77/MWh	Göransson et al. 2019
	CO_2 emission charge	c_{CO2}	€25/tCO_2	EEX 2019
	Grid cost	c_{grid}	Electric grid: €9/MWh Gas grid: €15/MWh	SCB 2020
	Specific on-site CO_2 emissions	e_{CO2}	NG: 0.202 tCO_2/MWh	Koffi et al. 2017
			Biomethane: 0 tCO_2/MWh	IPCC 2006
Scenario data	Electricity price	$c_{el}(t)$	Time-dependent, 3h resolution for 8 scenarios: 1. SWE NoColl 2030 2. SWE NoColl 2040 3. SWE Coll 2030 4. SWE Coll 2040 5. GER NoColl 2030 6. GER NoColl 2040 7. GER Coll 2030 8. GER Coll 2040	Göransson et al. 2019
	Natural gas price	c_{ng}	€22/MWh	
	Biomethane price	c_{bm}	€77/MWh	
	CO_2 emission charge	c_{CO2}	€40/tCO_2 (2030), €100/tCO_2 (2040)	
	Grid cost	c_{grid}	Electric grid: €9/MWh Gas grid: €15/MWh	SCB 2020
	Specific on-site CO_2 emissions	e_{CO2}	NG: 0.202 tCO_2/MWh	Koffi et al. 2017
			Biomethane: 0 tCO_2/MWh	IPCC 2006

sidered to be site-specific, it also only applies for on-site emissions. The factor for the specific on-site CO_2 emissions from biomethane combustion was set to zero. This assumption is in line with the IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) that determine that CO_2 emissions from the use of biomass for energy are included in the Agriculture, Forestry and Other Land-Use (AFOLU) sector.

The input data for the scenarios is based on (Göransson et al. 2019) who investigated the impact of collaboration between large electricity consumers for different regions in Europe for 2030 and 2040. The focus of their study was to explore different possible pathways for achieving net zero emissions from the electricity generation system by 2050. In the collaboration scenarios (denoted "Coll") the electricity and heat demand for different sectors (transport, industry and heat sector) are integrated in the electricity and heating system. This means that sector coupling strategies related to charging of electric vehicles, hydrogen storage, natural gas replacement by electricity for heating and heat storages in the district heating system are enabled. Furthermore, variation management techniques such as load shifting are allowed. This leads to differences in terms of electricity prices since variation management techniques in which electricity demands are shifted to times with higher generation from renewable sources reduce the occurrence of peak electricity prices.

In this study, two geographical regions were investigated regarding how the economic feasibility changes depending on the electricity generation mix. For this purpose, Southern Sweden (SWE) as current plant location with a high share of hydro and nuclear power was compared to Southern Germany (GER) that has a high electricity generation from photovoltaics. This leads to a total number of eight scenarios, i.e. years 2030 and 2040 with and without collaboration for the two different regions. It should be noted that constant prices for natural gas and biomethane were assumed, i.e. time variations for these prices were not considered in this investigation.

Table 3 contains a more detailed description of the reference conditions and the eight scenarios. The biomethane price was based on the break-even production cost of state-of-the art biomass gasification (Thunman et al. 2019) assuming a biomass price of €40/MWh, a biomass-to-biomethane conversion efficiency of 70 % and a specific capital cost of €20/MWh (assuming year-round full-load operation). The biomethane price was assumed to be constant while the natural gas price for reference conditions were different from the natural gas price used in the scenarios. The CO_2 emission charges for 2030 and 2040 were in line with levels assumed to be required to achieve net zero emissions in 2050. Since the electricity price in the scenarios data had a resolution of three hours while the optimisation model used hourly values, it was assumed that the electricity price is the same during the corresponding three hours.

OPTIMISATION RUNS

Identification of optimal installed capacities

The goal of the first optimisation runs was to identify the optimal installed capacities for the electricity and gas boilers, as well as the optimal operating patterns (i.e. the amount of steam produced based on each of the three energy carriers per hour) to minimise the TAC of steam production. The optimisation was first performed for reference market conditions and for the eight scenarios. Thereafter, an additional constraint on on-site CO_2 emissions was activated and new optimisation runs were performed for the eight scenarios only. This constraint forced the on-site CO_2 emissions to be in line with a trajectory that follows the Swedish target of net zero emissions by 2045. For this purpose, a linear decrease from current combustion-related emissions of 56 ktonCO_2/a to zero in 2045 was assumed, leading to allowed emissions of 33.6 ktCO_2/a for 2030 and 11.2 ktCO_2/a in 2040. Finally, the constraint on the maximum power load for the grid connection was activated and applied for the eight scenarios. The limitation was set to 30 MW which corresponds to around 50% of the electric power load needed to satisfy the steam demand of the plant completely by electricity, but which is larger than the current grid connection power capacity of around 20 MW. In total, 25 optimisation runs were carried out.

What-if analyses

In this step, the economic performance of different investment decisions based on the previous optimisation runs for different conditions was evaluated in terms of running cost (What-if analyses). According to the objective function, the running cost is the sum of fuel and electricity cost, variable operating cost, grid cost and cost from the CO_2 charge. For the What-if analyses, the following investment decisions were defined:

a. Investment in a new gas boiler.

b. Investment in a hybrid system which is optimised for the scenarios for Southern Sweden in 2030 and 2040 without limitations on on-site CO_2 emissions and grid connection capacity (Opt. 1).

c. Investment in a hybrid system which is optimised for the scenarios for Southern Sweden in 2030 and 2040 including limitations on on-site CO_2 emissions and grid connection capacity (Opt. 2).

Investment decision (a) was defined as reference case for the assessment. For investment decisions (b) and (c), the installed capacities were based on the average of the optimal installed capacities for 2030 and 2040 and for the “NoColl” and “Coll” each. Since the installed capacities were fixed during the What-if analyses runs, the model minimized the running cost under different market conditions by adjusting the amount of steam which is produced from the different fuels while respecting the installed capacities of the electric steam generator and the gas boiler.

There are several reasons for focusing the running cost only in the What-if analyses. First of all, results from the initial optimisation runs indicated clearly that the running cost is dominating in the objective function (81–86 % of the TAC). Furthermore, only small differences in investment cost between the optimised hybrid systems were observed.

The What-if optimisation runs were performed for all investment decisions for reference market conditions (2019), as well as for the no collaboration scenarios for Southern Sweden in 2030 and 2040. For 2030 and 2040, additional optimisation runs with limitations on on-site CO_2 emissions were performed for 2030 and 2040. Table 4 provides an overview of the resulting 15 What-if optimisation runs.

Results

IDENTIFICATION OF OPTIMAL INSTALLED CAPACITIES

Table 5 shows the optimal installed capacities for reference and future market conditions with and without constraints on on-site CO_2 emissions and grid connection capacity for the two possible plant locations. It should be noted that all values ex-

Table 3. Description of the eight electricity price scenarios mentioned in Table 2 including their average, standard deviation and maximum.

No.	Name	Description			Electricity price / €/MWh		
		Region	Year	Collaboration?	Average	Std. deviation	Maximum
0	Reference	Sweden	2019	no	38	10	109
1	SWE NoColl 2030	Southern Sweden	2030	no	33	28	289
2	SWE NoColl 2040		2040		44	36	148
3	SWE Coll 2030		2030	yes	33	27	260
4	SWE Coll 2040		2040		39	39	119
5	GER NoColl 2030	Southern Germany	2030	no	40	29	289
6	GER NoColl 2040		2040		49	36	148
7	GER Coll 2030		2030	yes	39	28	260
8	GER Coll 2040		2040		43	40	119

Table 4. What-if analysis optimisation runs for the three investment decisions.

Run	Investment decision	Scenario	On-site CO_2 limitations
1	a) Gas boiler only	Reference conditions (2019)	none
2	b) Optimised hybrid system 1		
3	c) Optimised hybrid system 2		
4	a) Gas boiler only	SWE NoColl 2030	
5	b) Optimised hybrid system 1		
6	c) Optimised hybrid system 2		
7	a) Gas boiler only	SWE NoColl 2040	
8	b) Optimised hybrid system 1		
9	c) Optimised hybrid system 2		
10	a) Gas boiler only	SWE NoColl 2030	33,600 tCO_2/a
11	b) Optimised hybrid system 1		
12	c) Optimised hybrid system 2		
13	a) Gas boiler only	SWE NoColl 2040	11,200 tCO_2/a
14	b) Optimised hybrid system 1		
15	c) Optimised hybrid system 2		

Table 5. Average values for TAC and optimal installed capacities (for 2030 and 2040 and for NoColl and Coll) with and without constraints on on-site CO_2 emissions and grid capacity. The maximum deviations from the average values in any of the four scenarios are given in brackets.

	Southern Sweden			Southern Germany	
	Reference conditions	2030/2040, NoColl and Coll, no on-site CO_2 emission and grid constraints	2030/2040, NoColl and Coll, with on-site CO_2 emission and grid constraints	2030/2040, NoColl and Coll, no on-site CO_2 emission and grid constraints	2030/2040, NoColl and Coll, with on-site CO_2 emission and grid constraints
TAC/M€/a	12.2	11.0 (-0.7/+1.2)	11.6 (-0.9/+1.5)	11.7 (-0.6/+1.3)	12.4 (-1.1/+1.7)
Electric boiler optimal installed capacity/MW	37.8	38.6 (-0.3/+0.5)	29.7 (±0)	38.0 (-0.1/+0.2)	29.7 (±0)
Gas boiler optimal installed capacity/ MW	29.8	29.1 (-0.5/+0.3)	38.0 (±0)	29.7 (-0.2/+0.1)	38.0 (±0)

cept for the reference case are average values over four scenarios (NoColl and Coll for 2030 and 2040 each). The results for constraints on on-site CO_2 emissions only are not shown here.

The results from all optimisation runs show that hybrid steam generation is favourable not only under future conditions but also under reference conditions based on values from 2019. The latter can be explained by the low average electricity price in Sweden due to a high share of hydro and nuclear power in the electricity generation system. The optimal installed capacities are rather similar for the NoColl and the Coll scenarios for 2030 and 2040 for Southern Sweden and Southern Germany. This can be seen in Table 5 by the small variations for the installed capacities in relation to the average values. This indicates that the differences in electricity prices do not justify a larger investment in electric gas boiler capacity. Also, the hourly steam generation from the different fuels varies only slightly. In contrast, the variation in TAC for the different cases is rather large. This can be explained by higher average electricity prices and a higher CO_2 charge for 2040 compared to 2030. Also, the TAC is lower for the Coll scenarios due to the price dampening effect of variation management strategies. The comparison between Southern Sweden and Southern Germany shows higher TACs for Germany due to a higher average price for electricity. Accordingly, the optimal installed capacities for the non-constrained cases are lower.

WHAT-IF SCENARIOS

The average values for 2030 and 2040, as well as NoColl and Coll, for Southern Sweden were used for the What-if analysis of investment decisions which are shown in Table 6.

It can be seen that the investment cost for the gas boiler only is much higher compared the hybrid systems due to the higher specific investment cost. Furthermore, there is only a small difference in investment cost (+9.9 %) when comparing the system which is optimised for constrained on-site CO_2 emissions and electric grid connection capacity limitations with the system which does not have these limitations. The three investment decisions were evaluated for different market scenarios and CO_2 targets to assess how different options would perform under various conditions and constraints. Table 3 shows the results in terms of running cost and steam production from the different fuels for the 15 What-if optimisation runs described in Table 4.

The results from the What-if analyses show that the running cost for the three investment decisions is rather similar for reference conditions (runs 1–3). However, the running cost is slightly lower for the hybrid systems since they switch to elec-

Table 6. Installed capacities and investment cost for the three investment decisions.

Investment decision	Size electric boiler MW	Size gas boiler MW	Investment cost M€
a) Gas boiler only (as today)	0	67.7	25.7
b) Optimised for 2030/2040 without on-site CO_2 and electric grid connection capacity limitations (Opt1)	37.9	29.8	18.2
c) Optimised for 2030/2040 with on-site CO_2 and electric grid connection capacity limitations (Opt2)	29.7	38.0	20.0

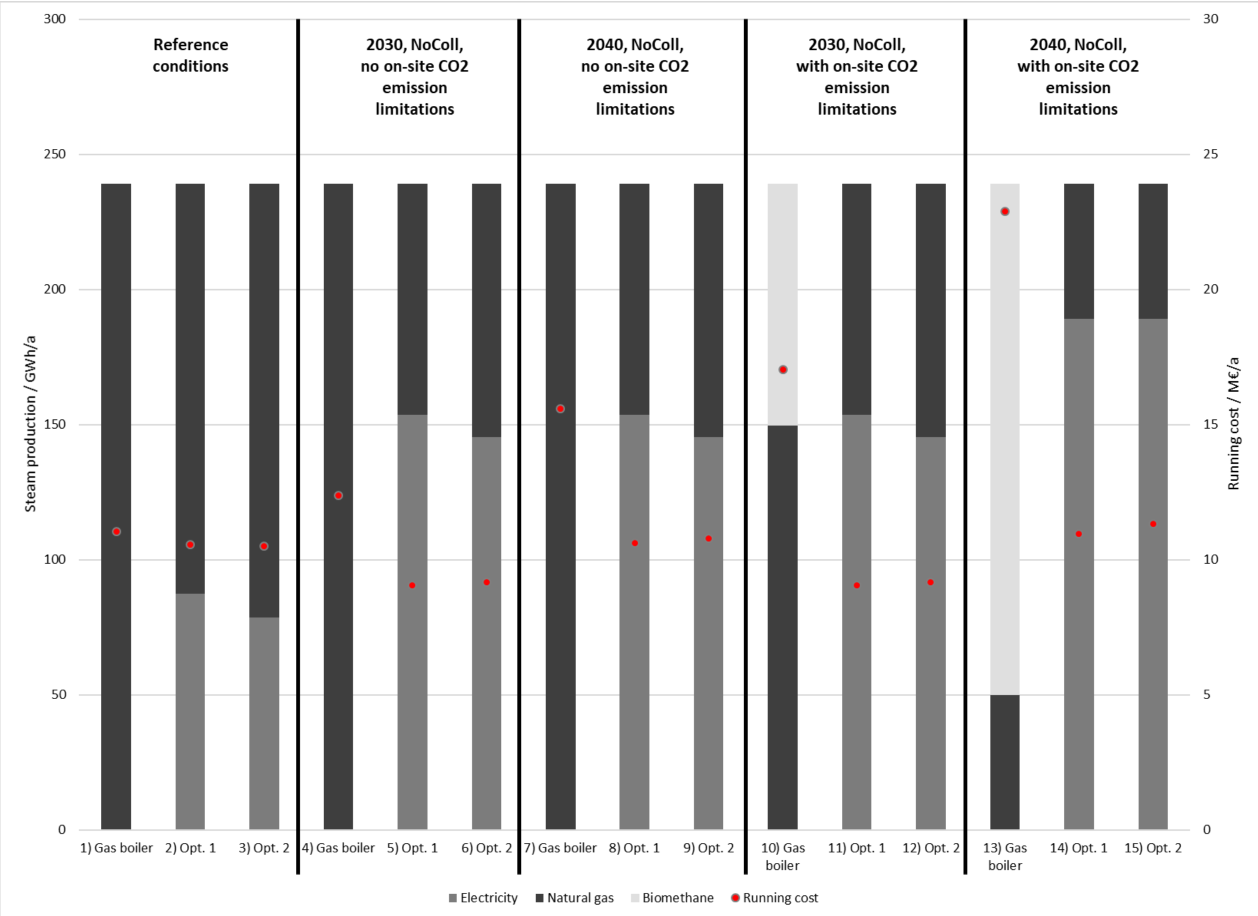

Figure 3. Steam production from different fuels and running cost for the three different investment decisions for current market conditions, 2030 and 2040 and for the cases with and without limitations on on-site CO_2 emissions. The numbers below the bars are related to the description of the What-if analysis runs in Table 4.

tricity for steam production in times with low electricity prices. The cost advantage of the hybrid systems compared to the gas boiler becomes much larger for future conditions due to the increased CO_2 emission charges (runs 4–9). In the hybrid systems, the majority of steam is now produced from electricity. The picture looks different for future conditions when limitations on on-site CO_2 emissions are introduced. The only option for the gas boiler to comply with the CO_2 emission limits is to switch to steam production from relatively expensive biomethane, leading to high running costs. The hybrid systems instead can switch to electricity, resulting in running costs similar to the cases without limitations on on-site CO_2 emissions. As can be seen, the running cost for the two hybrid systems is very similar in all cases.

Discussion

The results in this study identified hybrid steam generation as a flexible and robust concept that can adapt to price signals from electricity and gas fuel markets to optimise the running cost. Especially for future market conditions, hybrid systems achieved better economic performance compared to investing in a new gas boiler (which is the currently used technology). It is plausible that hybrid systems are optimal for the reference and future conditions considered in this study since the variable electricity prices fluctuate around the natural gas and biomethane prices (i.e. none of the fuels is cost-optimal year-round). Due to its high relative cost, biomethane is not used in the hybrid systems because switching to electricity is enough to comply with the on-site CO_2 emissions in case these apply.

However, using biomethane is the only and costly option for a stand-alone gas boiler to reduce on-site CO_2 emissions. The comparison between Southern Sweden and Southern Germany showed that the TAC is higher for the German case but that the optimal installed capacities are similar. Subsequently, the renewable electricity generation for Southern Germany with a high share of photovoltaics during the day does not have a large impact. This can be explained by a frequent mismatch of the fluctuating steam demand with electricity generation from solar energy. If the steam demand was mainly high during the daytime, the optimal installed capacity for the electric boiler would have been larger.

The main limitations of the study are connected to the design of the objective function in the model and the technology and market-related assumptions. The objective function is the total annualised cost of steam production and gives the optimal investment and operating decisions for one specific year. This key figure is only partly eligible for economic investigations over the whole lifetime of a plant. However, since the running cost is dominating over the investment cost, the TAC is a good indication to compare the investment decisions.

The study also assumed the same natural gas and biomethane prices for all future scenarios. This assumption was adopted to be coherent with the assumptions of the study in which the scenarios for future electricity market conditions were developed. This can be questioned since it is likely that a higher demand for biomass as feedstock in 2040 compared to 2030 will increase the biomethane price. However, biomethane only plays a role in enabling the stand-alone gas boiler to meet tight emission constraints. There is also uncertainty about the investment cost of the two boiler technologies provided by single technology providers which is not critical since the annualised capital cost only represents a small share of the TAC. Also, the assumption that current grid transmission and distribution costs will remain stable is probably an over-simplification since these costs can be expected to increase with higher demand for the electric grid connection.

Compared to other studies related to hybrid steam systems, the approach taken in this study combines a model that takes into account both the fluctuating steam demand of a real plant as well as variations in the electricity price with scenarios for future energy market conditions. In comparison to simple sensitivity analyses of individual parameters, the scenarios provide more consistent values that account for interdependencies. For example, the CO_2 charges assumed in the scenarios to reach net zero emissions in 2050 affect the electricity production and thus the electricity price. The utilisation of data for a real plant revealed strong fluctuations in steam demand for the plant that was considered. This is due to the operating conditions at the case study plant, which includes steam generation from cooling a non-continuous reaction and can be different compared to other plants with a more constant steam demand.

Considering both fluctuations in the steam demand as well as the electricity price is important since the economic feasibility of hybrid steam generation systems highly depends on the correlation between peaks in steam demand and electricity prices while the latter is depending on the renewable electricity generation. If the steam demand coincides with low electricity prices for a large share of the time, a larger installed capacity of the electric boiler will be beneficial. In any case, including both hourly fluctuation patterns reveal such effects that would not be seen when only yearly average values for steam demand and electricity prices are considered.

Conclusions

A linear cost-optimisation model to assess hybrid gas/electric steam generation was successfully developed and applied to a real chemical plant for current and future energy market conditions. The assessment methodology included identifying a number of possible investment decisions corresponding to optimal installed capacities and operating patterns to reach lowest total annualized steam production costs, for different energy market conditions. Hybrid steam generation was shown to be optimal not only for future conditions in Southern Sweden and Southern Germany, but also for reference conditions in Sweden based on data from 2019. Afterwards, three investment decisions were fixed and assessed in terms of running cost for Swedish reference and future energy market conditions. The results showed that, compared to a standalone gas boiler, hybrid systems can lead to decreases in running cost of between 30 % to 50 % in 2040 for the cases without and with constraints for on-site CO_2 emissions that follow a linear trajectory to net zero emissions in 2045, respectively. At the same time, the investment cost for the hybrid systems is lower (-28 %). The model developed in this study considered variations in steam generation and energy-related prices simultaneously and can be used to assess hybrid steam generation for other processes as well.

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