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The potential for electrifying industrial utility systems in existing chemical plants

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HIGHLIGHTS

- Electrifying utilities is a cost-effective CO_2 emission reduction strategy.
- Electric boilers with thermal energy storage appear to be the preferred solution.
- Hydrogen as an energy carrier is not selected in any of the scenarios modelled.

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ABSTRACT

The electrification of utility systems in energy-intensive plants is a promising measure for decarbonising the chemical industry in the short term. However, with the increasing deployment of renewable energy sources, the variability of electricity prices will become a challenge for plants with continuous and constant energy demand. It is thus uncertain whether electrification can become financially viable. This work models the electrification of utility systems in combination with storage technologies for five chemical plants with existing fossil fuel-based utility generation and uses historical data as energy price scenarios. The results show that partial electrification is cost-effective when using electricity is cheaper than natural gas for more than 600 h. Regarding the portfolio of technologies, electric boilers are installed first, followed by thermal energy storage and batteries. Hydrogen is not cost-effective in any of the scenarios explored. This is independent of the type of plant, the available grid connection capacity, and the minimal load of existing fossil fuel-based utility generation. This work thus highlights the potential for electrifying industrial utility systems and the role that electric boilers and energy storage units can play in electrification.

1. Introduction

Anthropogenic climate change is caused by the accumulation of greenhouse gases (GHG) in the atmosphere. Today, almost one-fourth of globally emitted energy-related GHG emissions are caused by industry [1] due to the high usage of fossil fuels like oil and gas. The chemical industry has the highest final energy demand in the industrial sector because fossil fuels are used for energy generation and as feedstock [2], and emissions from the chemical industry are estimated to make up 10 % of global GHG emissions [3]. Therefore, the deployment of measures to cut down on the emissions from the chemical industry needs to speed up to achieve climate targets.

The electrification of industrial processes is a measure that is gaining increasing attention [4–7]. The ongoing decarbonisation of electricity generation has led to an increasing use of renewable energy sources (RES) such as wind and solar power, the availability of which is variable in nature. With significant penetration of RES in the power grid, average prices are decreasing, but the uncertainty of electricity prices increases, which imposes a financial risk on the industry if it were to electrify processes because most existing chemical processes are built to operate at their nominal level and need a constant energy supply [8,9].

One measure to cope with variability is demand side management (DSM), where the electricity demand is adjusted to the availability of the electricity supply. The possibility of engaging the chemical

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industry in DSM is receiving increasing attention in literature [10–14]. Electrification will lead to a steep increase in the chemical industry's demand for electricity. The demand from the European chemical industry is estimated to increase to 135 % of the expected EU electricity production in 2050 [15], and estimations for the global chemical industry indicate a future demand six times larger than the current global energy demand [16]. Therefore, DSM in the chemical industry is also a topic of interest for the power sector [17–19].

A requirement for DSM is flexibility. Flexibility in chemical plants can be achieved via flexible process operation. However, the flexibility potential of most chemical processes is still unclear, and previous work showed that stakeholders see opportunities but also plenty of potential limitations [20].

Flexibility in chemical plants can also be achieved by operating the plant's utility system (the in-situ system that delivers the electricity, heat and cooling required by the plant as depicted in Fig. 1) flexibly. About one-third of GHG emissions from the chemical industry stem from energy use [3], indicating that the electrification of utility systems combined with the adoption of storage technologies could allow for a first step towards emission reduction and DSM while ensuring a constant delivery of energy to the processes.

Many studies have presented models that design utility systems for chemical processes (see Table B.17). However, the electrification of utility systems has received limited attention (see Appendix B for a literature review). Therefore, it is still unclear which technology portfolio could best enable electrification and how electrified systems would perform in terms of cost and CO_2 emissions compared to utility systems based on fossil sources.

Currently, incentives to electrify utility generation are limited because most industries have long-term energy contracts with a fixed, constant price for energy. In this work, a scenario is considered in which companies need to pay (fluctuating) market prices for the energy they consume and consider electrifying their fossil-based utility system. The aim is to (1) understand how the electrification of utility systems could look under different combinations of fluctuating electricity, natural gas and CO_2 emission allowance prices and (2) examine if, and to what extent, cost-optimal systems lead to CO_2 emission reductions while delivering constant utilities.

Different processes from the ethylene value chain, an important branch of the petrochemical industry, are analysed. As a base chemical, ethylene is a building block for, among others, plastics such as polyethylene (PE) and polyvinyl chloride (PVC). Global production of ethylene was approximately 230 million metric tons in 2023 and is expected to reach around 290 million metric tons in 2030 [21]. Today, ethylene is produced from fossil feedstock like naphtha or ethane, which is produced from natural gas or petroleum. The most common production process for ethylene is steam cracking, the most energy-intensive process within the chemical industry [22]. Therefore, the ethylene industry is a highly polluting industry with global CO_2 emissions of 366 million tons every year [23], and emission reduction is crucial if the chemical industry wants to meet emission reduction targets. To understand how the utility demand (i.e. the heat and power demand) of a plant impacts its (potential) electrification, the analysis includes four additional plants from an ethylene value chain located at the chemical cluster in the Port of Rotterdam: An ethylene oxide plant, an ethylbenzene plant, an ethylene glycol plant and a PET plant.

1.1. Contributions

Based on the knowledge gaps discussed above, the contribution of the study to the existing literature is threefold.

- It is unknown to what extent electrification can become a cost-effective decarbonisation strategy for utility systems in existing chemical plants. To address this gap, five plants from an ethylene value chain were studied. Six years of historical energy price data were used to assess how energy prices could lead to cost-efficient electrification of utility systems. The results are considered representative beyond the five processes studied in this article, as chemical processes tend to have similar conditions to the ones studied in this work (i.e. low- to high-level temperature demand and low levels of flexibility).
- The results show which portfolio of technologies is selected to replace fossil-based technologies and how utility demand, legacy technologies, fuel costs, technology costs, and the grid connection capacity affect the choice.
- Hydrogen is a required feedstock for many chemical processes, but it is not yet understood whether hydrogen could also be an alternative energy carrier for utility systems. This work investigates whether including hydrogen in the energy carrier mix is economically beneficial, considering the current and reduced technology cost scenarios.

The remainder of this paper is structured as follows. Following the introduction, the methods and the model used are described in detail in Section 2. Section 3 presents the results, and Section 4 discusses them and their limitations. Section 5 provides the conclusion of the findings presented in this article.

2. Methods

Utility systems that allow for a continuous energy supply are modelled under six different combinations of market prices for electricity, natural gas and ETS emission allowances and their techno-economic performance is analysed for five industrial processes with constant utility demands.

Following the current situation in the chemical industry in the Port of Rotterdam, the utility systems are assumed to have a fossil-based utility generation technology already in place. Electricity-based generation and storage units can be added to the technology in place. Since many combinations of generation and storage units are possible, mathematical optimisation is used to find the cost-optimal design of the new utility system. Fig. 2 provides information about the inputs and outputs of the

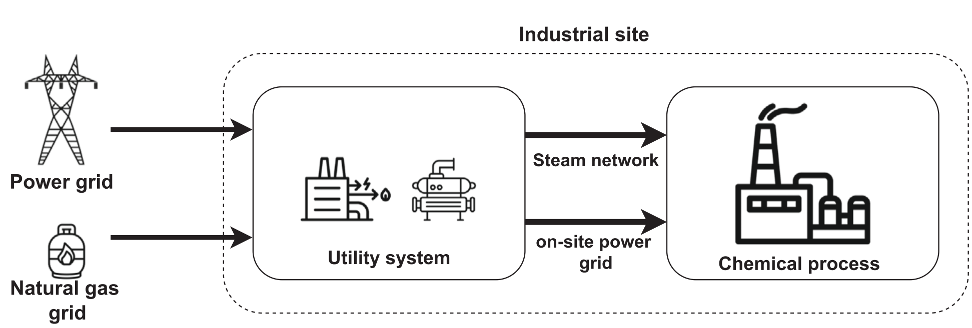


Fig. 1. Sketch of an industrial site including a utility system.

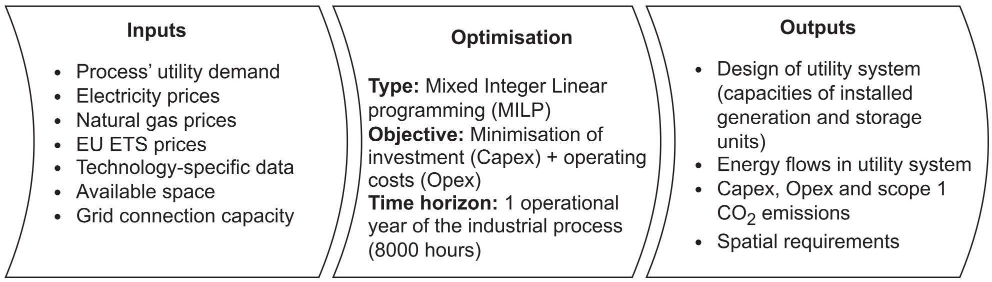


Fig. 2. The optimisation model used to design cost-optimal utility systems.

optimisation model. The mathematical formulation of the model is described in the following section, followed by a brief presentation of the technologies with which the utility systems can be extended. Section 2.3 describes the benchmark system modelling, Section 2.4 presents the price scenarios considered, Section 2.5 discusses the conducted sensitivity analyses, and Section 2.6 describes the industrial processes which serve as the case study in this work.

2.1. Optimisation model

The following section presents the model that is used to determine the technology portfolio and operation of cost-optimal utility systems for chemical plants. The following assumptions are made: Each utility system supplies one individual plant. The heat and power demands of the plant have to be fulfilled at all times. A legacy technology (a CHP or a gas boiler) can be operated at no additional investment cost. If the heat demand of the plant is similar to the power demand, a CHP is assumed to be the legacy technology. For processes with a much higher heat demand than power demand, a gas boiler is assumed to be the legacy technology. The capacity of the legacy technology is equal to the heat demand of the plant. If the legacy technology is a CHP, power can be sold to the grid at the current market price. Selling steam is not considered. Electricity and natural gas are available at all times and have to be bought at the (fluctuating) market price of the respective national markets. No new fossil-based utility technologies can be installed, only non-fossil-based technologies and storage capacity for electricity and heat can be added to the existing utility systems. The assumed grid connection capacity limits the maximum power flow from the grid, but comes at no additional cost. The cost of electricity consumption peaks is not considered.

The model is formulated in Python, using the 'Pyomo' package for optimisation. It is a mixed-integer linear programming problem (MILP) solved using Gurobi's solvers. The objective of the optimisation is to minimise the sum of the required investment CapEx_i for newly installed technology i and the operational cost OpEx(t) of the utility system over the 8000 annual operating hours of the chemical plant (Eq. C.47).

$$\min \sum_{t=0}^{t=8000} \mathrm{OpEx}(t) + \sum_i \mathrm{CaPex}_i \tag{1}$$

The OpEx is calculated according to Eq. (2) and consists of three components: first, the cost of consuming grid electricity minus the potential revenue from selling excess electricity from the CHP to the grid, if applicable; second, the cost of consuming natural gas; and third, the payments for purchasing CO_2 emission allowances within the European Emission Trading System (EU ETS).

$$\begin{aligned} \mathrm{OpEx}(t) = {} & \mathrm{p_{el,\,grid}}(t) \cdot \sum (P_{gr,i}(t) - P_{i,gr}(t)) \cdot \Delta t \\ & + \mathrm{p_{NG}}(t) \cdot NG_{in}(t) \cdot \Delta t \\ & + \mathrm{p_{EUA}}(t) \cdot NG_{in}(t) \cdot \Delta t \cdot \mathrm{EF_{NG}}, \end{aligned} \tag{2}$$

The first component is the cost of purchasing electricity from the grid, with $\mathrm{p_{el,\,grid}}(t)$ being the hourly market price in [eur/MWh]. Power flow from the grid to technology i is denoted as $P_{gr,i}(t)$ and power flow from technology i back to the grid as $P_{i,gr}(t)$. Both are expressed in [MW], and Δt is $1h$. Note that taxes and other fees for selling power back to the grid are neglected. The second component of the operating cost is the cost of purchasing natural gas with market price $\mathrm{p_{NG}}(t)$ at time t in [eur/MWh], required to fuel the legacy technology. The quantity of gas consumed over time is denoted by $NG_{in}(t)$ and measured in [MW]. The last component is the cost for emission allowances for the CO_2 emissions produced by the legacy technology (scope 1 emissions). The price per ton of CO_2 emitted at time t is $\mathrm{p_{EUA}}(t)$ in [eur/ton$_{\mathrm{CO_2}}$]. The emissions caused per MWh of combusted natural gas are calculated with the emission factor $\mathrm{EF_{NG}} = 0.2t_{\mathrm{CO_2}}/\mathrm{MWh}$.

The CaPex for each technology i is calculated in Eq. (3), where s_i denotes the size of an equipment and c_i the cost per unit of equipment size. Since the model is run for only one year, the required investment for added technologies is annualised using an annualisation factor AF_i, which is calculated as stated in Eq. (4).

$$\mathrm{CaPex}_i = s_i \cdot \mathrm{c}_i \cdot \mathrm{AF}_i \tag{3}$$

$$\mathrm{AF}_i = \frac{\mathrm{r}}{1 - (1+\mathrm{r})^{-\mathrm{LT}_i}} \tag{4}$$

With the annualisation factor, the costs are annualised over the lifetime LT_i of equipment i. The discount rate r is set to 10 %, as in [24].

Since most chemical plants are designed to operate at their rated capacity continuously, the electricity demand $\mathrm{P_{dem}}$ and the heat demand $\mathrm{H_{dem}}$ of the plants need to be fulfilled at all times. Eqs. (5) and (6) describe the equality constraints that ensure a constant supply of utilities, where $\mathrm{P_{dem,\,plant}}(t) = \text{const.}$ and $\mathrm{H_{dem,\,plant}}(t) = \text{const.}$

$$\mathrm{P_{dem,\,plant}}(t) = \sum P_{i,\mathrm{plant}}(t) \tag{5}$$

$$\mathrm{H_{dem,\,plant}}(t) = \sum H_{i,\mathrm{plant}}(t) \tag{6}$$

$P_{i,\mathrm{plant}}(t)$ are electricity flows from equipment i to the plant. $H_{i,\mathrm{plant}}(t)$ are heat flows from equipment i to the plant.

How much heat or electricity can be delivered by the generation technologies is determined by their size s_i in Eq. (7), where $P_{i,j}(t)$ is the power flow from technology i to technology j, and $H_{i,j}(t)$ the respective heat flow.

$$\begin{aligned} & s_i \geq \sum P_{i,j}(t) \text{ or} \\ & s_i \geq \sum H_{i,j}(t) \end{aligned} \tag{7}$$

The required inflow into the equipment is calculated using Eq. (8). The energy type input and output depend on the equipment. For example, the CHP's energy input is natural gas, and the energy output is heat or electricity.

$$\sum \mathrm{Energy}_{i,in}(t) \cdot \eta_i = \sum \mathrm{Energy}_{i,out}(t) \tag{8}$$

The flexibility of the legacy technologies is limited. To avoid damage, cold starts are avoided by defining a minimal load under which the load of the unit cannot drop, as described in Eq. (9).

$$\sum \text{Energy}_{\text{CHP/GB},out}(t) \leq s_{\text{CHP/GB}} \cdot \eta_{\text{CHP/GB}} \cdot \text{MinLoadFactor}_{\text{CHP/GB}} \tag{9}$$

How much energy can be taken from the storage units depends on their state of energy SOE_i. All storage units are empty at the beginning of the optimisation. For $t > 0$, the state of energy is found by Eq. (10).

$$SOE_i(t) = \begin{cases} 0, & \text{if } t = 0 \\ SOE_i(t-1) + \sum \text{Energy}_{j,i}(t-1) \cdot \eta_{\text{charge},i} - \\ \sum \text{Energy}_{i,j}(t-1)/\eta_{\text{discharge},i}, & \text{otherwise} \end{cases} \tag{10}$$

The maximum state of energy is constrained by the unit's size s_i according to Eq. (11).

$$SOE_i(t) \leq s_i \tag{11}$$

For the battery and the thermal energy storage, the charge and discharge power are constrained by a charge rate (crate_i) of the technology, as described in Eqs. (12) and (13), respectively. To prevent simultaneous charging and discharging, a binary variable b_i is implemented as described in Eqs. (12) and (13). If $b_i(t) = 1$, the discharge power can only be 0, if $b_i(t) = 0$, the charge power can only be 0.

$$\begin{aligned} P_{j,i}(t) &= 0, \quad \text{if } t = 0 \\ P_{j,i}(t) &\leq s_i \cdot \text{crate}_i/\Delta t \cdot b_i(t), \quad \text{if } t \geq 0 \end{aligned} \tag{12}$$

$$\begin{aligned} P_{i,j}(t) &= 0, \quad \text{if } t = 0 \\ P_{i,j}(t) &\leq s_i \cdot \text{crate}_i/\Delta t \cdot (1 - b_i(t)), \quad \text{if } t \geq 0 \end{aligned} \tag{13}$$

Since the utility systems are connected to the national power grid, the total power flow from the grid to the utility system and from the utility system to the grid is constrained by the capacity of the utility system's connection to the grid cap_{gr}. This is reflected in Eq. (14) and Eq. (15).

$$\sum P_{gr,i}(t) \leq \text{cap}_{\text{gr}} \tag{14}$$

$$\sum P_{i,gr}(t) \leq \text{cap}_{\text{gr}} \tag{15}$$

A complete formulation of the model and the nomenclature is listed in Appendix C.

To validate the model, it was run with the (fixed) energy prices that energy-intensive industries are paying at the moment. No new technologies were installed in the resulting cost-optimal utility systems, and the utility generation was fully fossil fuel-based. This mirrors the current situation in the chemical industry.

2.2. Technologies

The technologies included in the optimisation model have been selected based on their suitability to supply the required utilities and their technological maturity. Only commercially available technologies are considered. The following subsection describes the technological options, while Tables 1 and 2 provide an overview of the data used for modelling those technologies.

2.2.1. Utility generation technologies

In many existing utility systems, the energy demand is supplied by a CHP or a gas boiler fueled by natural gas [8]. Therefore, it is assumed that either a CHP or a gas boiler has been installed in the past and can operate without any additional investment cost or spatial requirement. Electricity from the CHP can be sold to the power grid. An electricity-based alternative for heat generation is an electric boiler. Electric boilers are frequently mentioned in literature as a key technology for the electrification of industrial heat demand [15,25,26], and companies are running pilot projects with electric boilers [27]. Electric boilers are a mature technology [28], can start up quickly, and have high ramp rates [29]. They can produce saturated steam of up to 350 °C [30]. Another alternative technology for steam production is a hydrogen boiler (H2 boiler). Hydrogen boilers have been implemented in various industrial sectors [31], for example, in the chlorine industry to increase the economic performance of the plant by using the by-product hydrogen energetically instead of venting it into the atmosphere [32,33]. In the model, the hydrogen that fuels the hydrogen boiler is produced onsite from water electrolysis. The electrolyser is assumed to be a proton exchange membrane (PEM) electrolyser because its flexibility is higher than that of alkaline electrolysers [34]. Note that even though existing electrolysers are of limited capacity (operating PEM electrolysers have reached capacities around 20 MW), the capacity of the electrolyser is not limited in our model. Table 1 lists the data used to model the generation technologies.

2.2.2. Storage units

To allow the utility system to use energy at a different time than it is generated or procured, three storage units are included in the utility system models: Lithium-ion batteries, high-temperature sensible thermal energy storage and hydrogen storage tanks (H2 Storage). Table 2 provides the data used to model the storage units.

Fig. 3 depicts how the technologies presented above can be interconnected in the case of a plant with an existing CHP. Electricity flows are depicted in yellow, natural gas flows in grey, hydrogen flows in blue and steam flows in red.

2.3. Benchmark utility system

In this study, the benchmark utility systems consist of a connection to the national power grid and a natural gas-fueled CHP if the plant's heat demand is approximately the same as its power demand or a gas boiler if the heat demand is much higher than the power demand. The thermal capacity of the CHP or gas boiler is assumed to be just enough to fulfil the heat demand of the respective plant, and the ratio between heat and electricity generation of the CHP is assumed to be constant. This can result in a mismatch between the plants' electricity demand and the electricity generated by the CHP, which is why additional electricity is bought, or excess electricity is sold via the connection to the national power grid.

The benchmark systems operate under the same energy market price scenarios as the new utility systems (Table 3). The resulting operational costs and CO_2 emissions are calculated using the equations described in Appendix C.2.

2.4. Energy price scenarios

This study considers several combinations of market price data for electricity, natural gas and CO_2 emissions allowances. Six different independent years are explored, and an operational time of 8000 h is considered for a plant. The combinations of price data correspond to historical data from 2018 to 2023. Even though those years include the COVID pandemic and increased gas prices due to Russia's invasion of Ukraine, they are considered interesting to assess because the rise in gas prices and electricity price fluctuations is likely to continue with the increasing decarbonisation of the global economy. Data of the Dutch Day-ahead electricity market was retrieved from the ENTSO-E transparency platform [45], data for the natural gas market (Dutch TTF) was retrieved from an online source [46] and EU ETS emission allowance prices were obtained from Ember [47] and Sandbag [48]. Since the gas price data was only available per day and because the market is not operating on the weekends, the data had to be treated before running the optimisation. The opening price of the day was assumed to last for all 24 h of the day, and the previous existing value replaced non-existing

Table 1
Data used to model conversion technologies.

	CHP	Gas boiler	Electric boiler	Electrolyser	H2 boiler
Capacity					
Thermal [MW_{th}]	H_{dem}	H_{dem}	Decision variable	Decision variable	Decision variable
Electric [MW_{el}]	$H_{dem}/\eta_{th,\mathrm{CHP}} \cdot \eta_{el,\mathrm{CHP}}$				
Efficiency η [%]	η_{th} = 40, η_{el} = 30 [35,36]	η_{th} = 90 [24]	99 [25,26,29]	69 [34]	92 (based on [37,38])
Minimal load factor [% of max. load]	50 [39]		0	0	0
Cost [Eur/GW]	Not included in model		70 [29]	700 [34]	35 [31]
Lifetime lt [years]	Not included in model		20 [29]	15	20 [31]

Table 2
Data used to model storage technologies.

	Battery	Thermal energy storage	H2 Storage*
Capacity [MWh]	Decision variable	Decision variable	Decision variable
Efficiency			
η_{ch} [%]	95 [24]	90 [40]	90 [24]
η_{disch} [%]	95 [24]	100	100
Ramp rate rr [% of max. load]	100	100	100
Cost [Eur/GWh]	300 [41]	23 [40]	10 [40]
Lifetime [years]	15 [41]	25 [42]	20 (based on [43])

* A type I tank (the simplest storage tank version [44]) that stores hydrogen at 200 bar.

values. The EU ETS emission allowance data was also only available in daily resolution and treated the same way as the natural gas price data.

Table 3 shows the mean and the variance of the electricity price and the cost of using natural gas (the sum of the natural gas price and the EU ETS emission allowance price per MWh of natural gas used) per scenario. Of all years, 2020 has the lowest mean prices, but the variance is the lowest in 2019. 2022 shows the highest mean prices and variance in electricity and gas use costs. While mean prices are similar in 2021 and 2023, the variance in 2021 is higher than in 2023, especially in the cost of using natural gas. The table also shows the number of hours during which using electricity is cheaper than using natural gas.[1] This number increases significantly after 2019 (more than fivefold), and 2023 has the highest amount of hours favouring electricity use. Note that while the mean and variance of electricity price and cost for gas use are somewhat similar in 2021 and 2023, the respective number of hours with lower electricity prices differs almost by a factor of 2.

2.5. Sensitivity analyses

The sensitivity of the results to three parameters is tested: first, the available grid connection capacity; second, the minimal load of the legacy technology; and third, the technology cost for batteries, thermal energy storage, and electrolysers.

2.5.1. Grid connection capacity

Sufficient grid connection capacity is key for electrification, but it might not be readily available to industrial sites. In the Netherlands, for example, the current situation of the power grid imposes a barrier to electrification plans which require additional connection capacity [49]. Therefore, it is important to examine if/how the conclusions of this work are affected by the assumed grid connection capacity. Hence, the model is run for different grid connection capacities as follows.

If the parameter $\mathrm{f_{grcap}}$ in Eq. (16) is equal to 1, the grid connection capacity $\mathrm{cap_{gr}}$ in Eq. (14) and Eq. (15) is big enough, yet not larger than necessary, to allow for a fully electrified utility supply in the utility generation "chain" with the lowest conversion efficiency.

$$\mathrm{cap_{gr}} = \mathrm{f_{grcap}} \cdot \frac{\mathrm{P_{dem}} + \mathrm{H_{dem}}}{\eta_{\mathrm{bat}} \cdot \eta_{\mathrm{bat}} \cdot \eta_{\mathrm{H2E}} \cdot \eta_{\mathrm{H2S}} \cdot \eta_{\mathrm{H2B}}} \tag{16}$$

For the sensitivity analysis, $\mathrm{f_{grcap}}$ takes values between 0.5 and 1.2, which represent grid connection capacities between 50 % and 120 % of what is required for a fully electrified utility system, respectively.

2.5.2. Minimal load on the legacy technology

Since the new utility systems include a fossil-based legacy technology, they might depend on the flexibility of the latter, which is limited by the minimal load. As described in Section 2.1, the legacy technology is assumed to be unable to shut down and to operate at a minimum of 50 % of its capacity to avoid damage. Therefore, it is explored if/how the conclusions of this work would change if a more optimistic value of 30 % for the minimal load factor $MinLoadFactor_{\mathrm{CHP/GB}}$ in Eq. (9) is chosen.

2.5.3. Cost of new utility equipment

The costs for batteries, thermal energy storage and water electrolysers are considered the most uncertain among the technology portfolio. Hence, the sensitivity of the results to these parameters is tested by repeating the model runs with distinct technology cost (TC) scenarios. Per run, the cost of one technology was either increased or decreased by 25 %. This resulted in the six TC scenarios described in Table 4.

2.6. Case study

In this work, the model presented above is run for plants from an ethylene value chain. The case study includes five plants: An olefins plant, an ethylbenzene plant, an ethylene oxide plant, an ethylene glycol plant, and a PET plant. The processes have different utility demands (in magnitude and ratio of power to heat demand), which allows analysis of the impact of the demand on the technology portfolio of the new utility system. Table 5 provides an overview of the plants' utility demand and their production capacities. Energy demand data was obtained from existing Aspen Plus twin models of an ethylene value chain located in the chemical cluster of the Port of Rotterdam, the Netherlands [50]. Currently, the energy demand from the plants in the cluster is supplied by natural gas combustion and, in the case of the olefins plant, by the combustion of waste gases from the process itself for the generation of very high-pressure steam required in the steam cracker. For this study, the utility generated from waste gas combustion is not considered since it is assumed that the core processes remain unchanged, and therefore, waste gases continue to be available. The remaining steam requirements do not exceed medium-pressure steam at 265 °C. Note that the model data might overestimate utility demands compared to data from real plants since heat integration is likely more advanced in practice than in the models.

As shown in the table, the olefins plant has the highest production capacity (in terms of kilotons per year) and the highest energy demand. Electricity demand and heat demand are almost equal. The remaining plants have a higher heat demand than electricity demand. In terms of

[1] The number of hours when $\mathrm{p_{el,\,grid}}(t) < \mathrm{p_{NG}}(t) + \mathrm{p_{EUA}}(t) \cdot \mathrm{EF_{NG}}$.

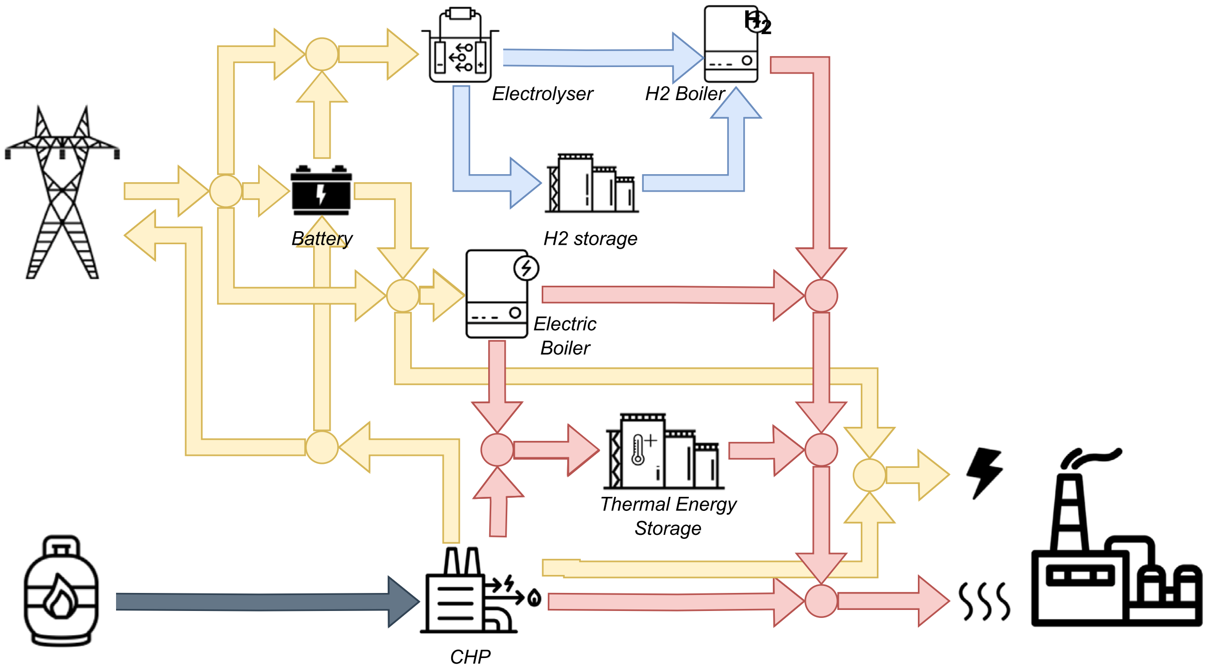


Fig. 3. Illustration of the options to configure the utility system with a CHP as legacy technology. A connection to the national power grid and a natural gas-fueled CHP are assumed to be in place. In addition, the model can choose to add a battery, an electric boiler for steam generation, thermal energy storage, a hydrogen tank and/or a hydrogen boiler. Electricity flows are yellow, natural gas flows grey, hydrogen flows blue and steam flows red.

Table 3
Average and variance of the considered prices for electricity and the cost of using natural gas (equal to natural gas price + cost for EU ETS CO_2 allowance) and number of hours during which the electricity price is lower than the cost of using natural gas. Based on [45–48].

Year	Electricity price		Cost of using natural gas		Electricity price < using natural gas
	Mean [Eur/MWh]	Variance [(Eur/MWh)^2]	Mean [Eur/MWh]	Variance [(Eur/MWh)^2]	Number of hours [hours]
2018	52	233	25	16	99
2019	42	128	20	10	62
2020	31	199	14	13	518
2021	90	3263	51	783	611
2022	240	16,886	150	2813	1280
2023	98	2383	59	120	1153

Table 4
Technology cost data per technology cost (TC) scenario.

TC scenario	Electric boiler [Euro/GW$_{th}$]	Battery [Euro/GWh]	TES [Euro/GWh]	Electrolyser [Euro/GW]	H2 boiler [Euro/GW$_{th}$]	H2 storage [Euro/GWh]
Bat-High	70	375	23	700	35	10
Bat-Low	70	225	23	700	35	10
TES-High	70	300	28.75	700	35	10
TES-Low	70	300	17.25	700	35	10
H2E-High	70	300	23	875	35	10
H2E-Low	70	300	23	525	35	10

energy intensity per unit of product, the olefins plant has the highest specific energy intensity, and the ethylbenzene plant has the lowest.

Table 5 also shows the assumed fossil fuel-based legacy technology for each plant. As explained in Section 2.3, the legacy depends on the ratio of the plant's heat and power demand. If the demand is in the same order of magnitude, a CHP is assumed to supply the plant's demand. If the heat demand is higher than the power demand, the legacy technology is assumed to be a gas boiler. In both cases, a connection to the national power grid is required to supply electricity to the plant. This is because the electricity generation by the CHP does not match the plant's demand. Table 6 provides the thermal and electric capacities of the benchmark systems consisting of a CHP and the mismatch between electricity demand and generation.

3. Results

3.1. Cost-optimal utility systems for different opex scenarios

This section presents the cost-optimal utility systems for all plants and (individual) years considered. The results show which technology portfolios are chosen per plant and year and how the economic and environmental performance of the new utility systems compares to the respective benchmark system. First, the results are presented for the

Table 5
Overview of the chemical plants analysed in this study, including their production capacities, utility demands, and assumed legacy technologies.

Chemical plant	Capacity	Electricity demand		Heat demand*			Legacy technology
	[kilotons/ year]	Power [MW]	Cooling [MW]	LPS [MW]	MPS [MW]	HPS [MW]	
Olefins	878 (ethylene)	37.67	138.48	180.85	0	0	CHP
Ethylene oxide	293	5.13	15.04	30.07	0	0	CHP
Ethylbenzene	758	0.3	0.6	0	2.3	41.06	Gas boiler
Ethylene glycol	113	1.06	1.14	0	44.32	0	Gas boiler
PET	231	0.67	0.49	0	0	24.49	Gas boiler

* LPS at 155 °C, 5.5 bar; MPS at 214 °C, 12 bar; HPS at 265 °C, 51 bar.

Table 6
Thermal and electric capacity of the CHP and the mismatch between the process' electricity demand and the electricity generated by the CHP, which has to be supplied by or sold to the national power grid.

System	Thermal capacity CHP [MW_{th}]	Electric capacity CHP [MW_{el}]	Electricity mismatch $P_{dem} - P_{CHP}$ [MW_{el}]
CHP Olefins	181	136	40
CHP Ethylene oxide	30	23	−2

plants with an existing CHP and subsequently for those with an existing gas boiler. Note that the new utility systems have enough grid connection capacity available for complete electrification of the utility demand of the respective plant and that the minimal load of the fossil-based legacy technology is set to 50 % of its maximum capacity.

3.1.1. Plants with an existing CHP

Tables 7 and 8 show that the utility systems remain fossil-based for 2018 and 2019 because the energy and ETS prices are not incentivising new investments. In the remaining four years, a partially electrified system results in lower total costs than the Opex of the benchmark system (which is equal to the total cost since no Capex is required).

For 2020 and 2021 prices, an electric boiler is installed to supply the remaining heat demand of the plant when the CHP is operating at its minimum load because consuming natural gas is more expensive than electricity. The costs of using natural gas include its market price and the price for the required CO_2 emission allowances. In 2022, the mean prices and fluctuations of natural gas and electricity are high enough to install a battery that shifts fuel use to hours with low electricity prices and enables cheap heat generation with the electric boiler. In 2023, no more battery capacity is installed because prices have fallen to lower levels than those for prices from 2022. Mean prices are lower than in 2021, but the variance is lower. However, the number of hours during which using electricity is cheaper than using gas is higher than in 2021. Therefore, heat storage is financially beneficial. The boiler size equals the grid capacity minus the power demand of the process, which has to be supplied by the grid when the gas boiler is not operating during hours with negative electricity prices. Since no battery is installed, more grid capacity is available for the electric boiler, and hence, its capacity is bigger than in 2022.

The results show that with an increasing number of hours during which using electricity is cheaper than using natural gas, electric boiler capacity is installed first. Next is TES capacity and, third, battery capacity. Hydrogen technologies are not installed for any of the years considered at the assumed technology costs. Partial electrification of the utility system leads to reductions in scope 1 CO_2 emissions of the olefins plant of minimum 5 and maximum 24 %.

For the utility system of the ethylene oxide plant, the trends regarding which technologies are installed in which year are similar to those for the utility system of the olefins plant. The results can be found in the (Appendix Tables D.19 and D.20). Compared to the benchmark system, CO_2 emission reduction (scope 1) ranges from 5 % to 24 %.

3.1.2. Plants with an existing gas boiler

Tables 9 and 10 show results similar to those for the olefins plant, with the difference that no additional technologies are installed for the utility system in 2020. For the sole production of steam, the gas boiler is more efficient than a CHP. Hence, increased natural gas use costs have a lower impact on a system with a gas boiler than on a system with a CHP. In 2020, the gas use costs are not sufficiently high (and/or the power prices are not often enough cheaper than the gas use costs) for installing a power-to-heat unit.

A cost-efficient partial electrification of utility systems enables CO_2 emission reductions between 5 % and 19 % compared to the benchmark utility system for the ethylbenzene plant.

The technology portfolio in the different years for the ethylene glycol and the PET plant is the same as for the ethylbenzene plant, only the capacities are different, as shown in Tables D.21 and D.23. The economic and environmental performance of the new utility systems is presented in Tables D.22 and D.24. CO_2 emission reduction differs per plant in terms of absolute numbers but remains between 5 % and 19 % compared to the benchmark system.

3.2. Sensitivity analyses

3.2.1. Grid connection capacity

Plants with an existing CHP. Independent of the grid connection capacity, no additional capacity is installed in 2018 and 2019, and no hydrogen-based technology is installed in any year for the olefins plant. The newly installed capacities in 2020 and 2021 are not affected by the grid connection capacity, either. Fig. 4 shows only the results affected by the grid connection capacity. The complete results are presented in Appendix D.25.

Fig. 4 shows that although the grid connection capacity does not impact which technologies are installed in which year, it affects the capacities of the newly installed technologies. When the connection capacity is lower than required for a fully electrified utility supply, the capacities decrease because of the limited power inflow from the grid. When the grid connection capacity increases after it has reached a capacity at which a fully electrified supply is possible, the installed capacities of the electric boiler and the TES increase, but the battery capacity remains stable. The findings support the previous observation that the grid connection capacity is the limiting factor for the electric boiler capacity and that the TES capacity depends on it in 2022 and 2023. If more grid connection capacity is available, investments in higher electric boiler and TES capacities pay off from shifting energy consumption in time.

Table 7
Additionally installed utility technologies for a cost-optimal utility system for an Olefins plant for six energy price years and a grid connection capacity of 692.4 MW.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	90.4	0.0	0.0	0.0	0.0	0.0
2021	90.4	0.0	0.0	0.0	0.0	0.0
2022	423.6	741.7	2591.7	0.0	0.0	0.0
2023	511.1	0.0	2103.2	0.0	0.0	0.0

Table 8
Total cost and scope 1 CO_2 emissions of the benchmark and new utility system for the Olefins plant for distinct energy price data and a grid connection capacity of 692.4 MW.

Year	Total cost [Million euro]			Scope 1 CO_2 emissions [kiloton]		
	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	107.8	107.8	0.0	723.4	723.4	0.0
2019	84.7	84.7	0.0	723.4	723.4	0.0
2020	59.4	58.9	0.8	723.4	684.2	5.4
2021	212.9	207.5	2.5	723.4	659.6	8.8
2022	619.5	559.9	9.6	723.4	548.9	24.1
2023	245.0	227.2	7.3	723.4	554.2	23.4

Table 9
Additionally installed utility technologies for cost-optimal utility system for an ethylbenzene plant for six years' energy price data and a grid connection capacity of 85.8 MW.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	21.7	0.0	0.0	0.0	0.0	0.0
2022	83.3	3.8	385.4	0.0	0.0	0.0
2023	84.1	0.0	361.3	0.0	0.0	0.0

Table 10
Total cost and scope 1 CO_2 emissions of the benchmark and new utility system for an ethylbenzene plant for distinct energy price years and a grid connection capacity of 85.8 MW.

Year	Total cost [Million euro]			Scope 1 CO_2 emissions [kiloton]		
	GB-based system	New system	Reduction [%]	GB-based system	New system	Reduction [%]
2018	10.1	10.1	0.0	77.1	77.1	0.0
2019	7.9	7.9	0.0	77.1	77.1	0.0
2020	5.5	5.5	0.0	77.1	77.1	0.0
2021	20.2	20.0	1	77.1	73.5	4.7
2022	59.5	55.7	6.4	77.1	62.6	18.8
2023	23.5	21.5	8.5	77.1	62.7	18.7

Since this is not the case for battery capacity, battery capacity is likely too expensive for energy-shifting purposes. The results for utility systems for the ethylene oxide plant differ in terms of capacities but reveal the same findings (see Appendix D.2).

Plants with an existing GB. The results for plants with existing gas boilers support the findings described above. As an example, the results for the ethylbenzene plant are shown in Fig. 5. In the years with the highest number of hours during which using electricity is cheaper than using gas, 2022 and 2023, the electric boiler and TES capacity increase with increasing grid connection capacity, but the battery capacity remains constant. The complete results are shown in Appendix D.2.

3.2.2. *Minimal load of legacy technology*

Plants with an existing CHP. A lower minimal load of the CHP (which means an increase in flexibility) does not lead to additional capacity for the utility system for the Olefins plant in 2018 and 2019, and none of the years leads to the use of hydrogen-based technologies. The results in Table 11 show that a lower minimal load of the CHP also does not affect the 'merit order' in which the technologies are installed (electric boiler first, then TES capacity and then battery capacity). Compared to the utility systems with a higher minimal load of the CHP, the reduced minimal load leads to lower total costs and CO_2 emissions (see Table 12) and different capacities of the newly installed technologies.

For prices from 2020, 2021, 2022 and 2023, the electric boiler capacity increases because the CHP can be operated at a lower load than in previous utility systems. With 2022 prices, the lower minimal load of the CHP leads to a smaller battery and TES. Since the CHP can supply less heat to the plant when natural gas is expensive, more heat has to be supplied by the electric boiler. Since most of the heat from the boiler goes to the plant, less can go to the TES, which explains why the TES capacity is lower than in the runs with a higher minimal load of the CHP. Since the electric boiler requires more grid power, less power flow is available to charge the battery, and hence, the battery capacity is also smaller. With 2023 prices, the TES capacity is higher than in the run with a higher minimal load of the CHP. If the CHP can be operated at a lower minimal load, more money is saved when the gas price is high. These savings in OPEX are available to be invested in capacity that enables shifting from natural gas to electricity (like the electric boiler) and

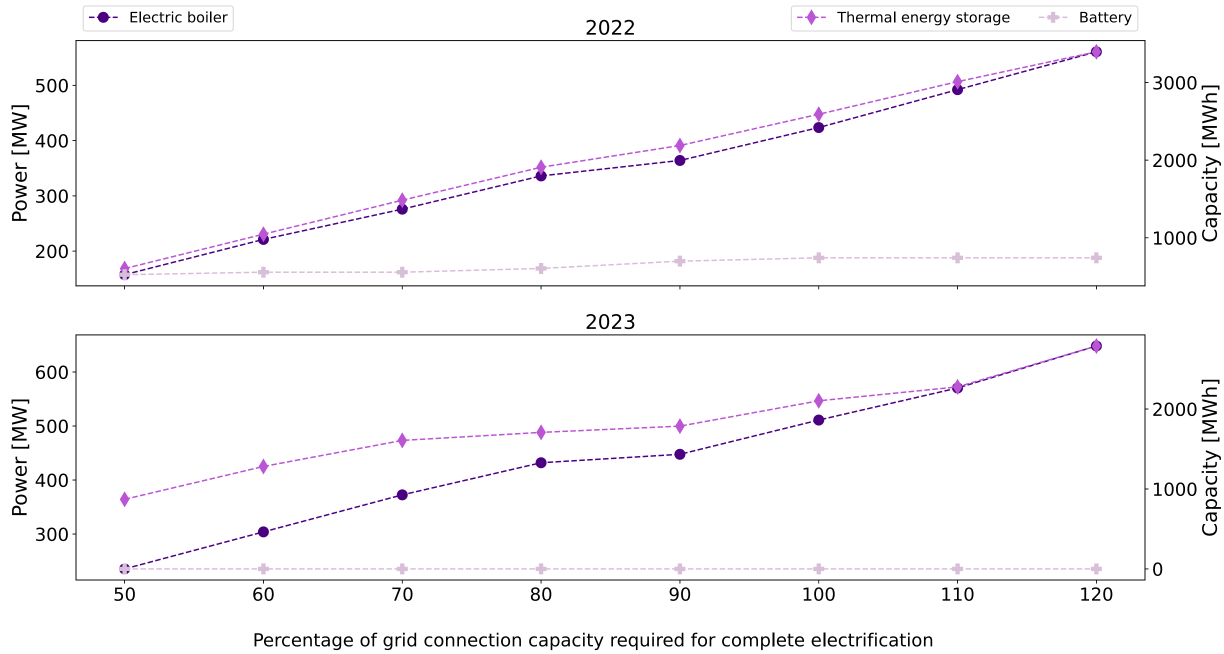


Fig. 4. Newly installed capacity for the olefins plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

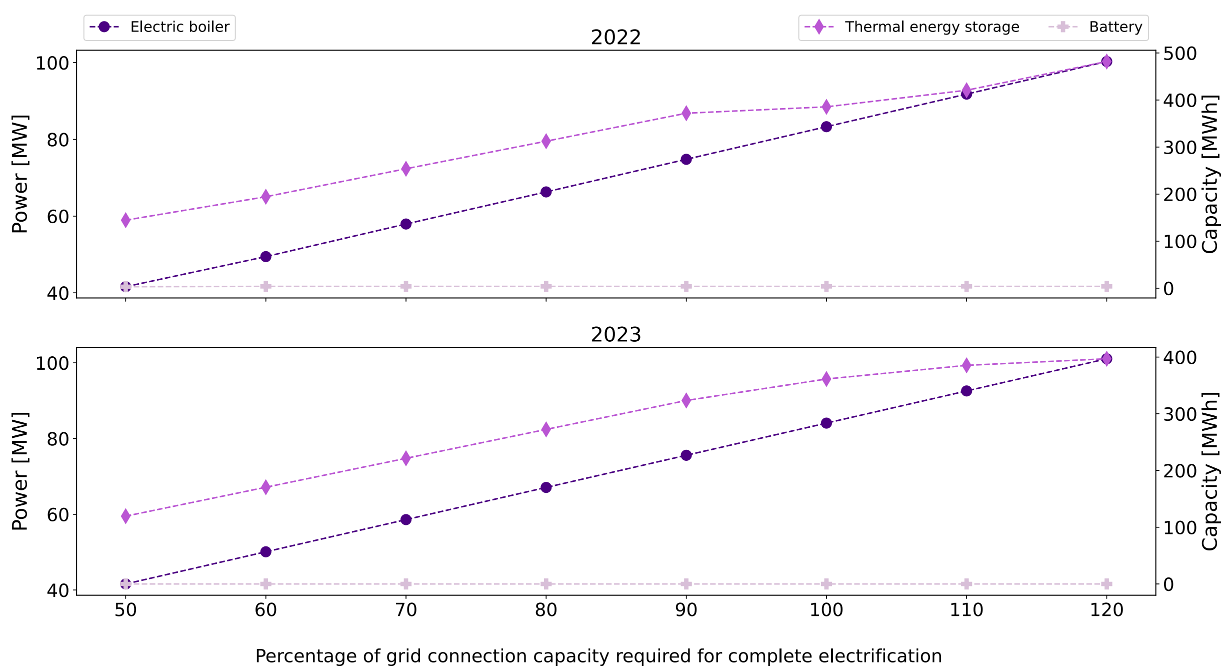


Fig. 5. Newly installed capacity for the ethylbenzene plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

shifting heat generation in time (like the TES). As the results for the ethylene oxide plant are in line with the discussion above, they are shown in Appendix D.3.

Plants with an existing gas boiler. The results for the plants with an existing gas boiler lead to findings similar to those for the olefins plant. The change in minimal load does not affect the energy price years for which it is cost-effective to install new technologies. Neither does it affect which technology portfolio is installed in which year. Nevertheless, the lower minimal load impacts the capacities of the electric boiler and TES, as Table 13 shows for the ethylbenzene plant. For the electric boiler, the effect differs depending on the year. In 2021, the capacity increases because when the GB operates at its minimal load, additional electric boiler capacity must supply the remaining heat. In 2022, the lower minimal load of the GB leads to (a) less fossil- and more electricity-based heat delivered to the plant and (b) less fossil- and more electricity-based heat delivered to the TES. Despite the smaller capacity of the TES, the overall energy delivered to the plant by the TES slightly increases compared to the system with a CHP with a higher minimal load. The Sankey

Table 11
Additionally installed utility technologies for a cost-optimal utility system for an Olefins plant for four energy price years, a grid connection capacity of 692.4 MW and the lower minimal load of the CHP.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2020	126.6	0.0	0.0	0.0	0.0	0.0
2021	126.6	0.0	0.0	0.0	0.0	0.0
2022	445.4	609.8	2531.9	0.0	0.0	0.0
2023	551.3	0.0	2391.2	0.0	0.0	0.0

Table 12
Total cost and scope 1 CO_2 emissions of the benchmark and new utility system for the Olefins plant under distinct energy prices, a grid connection capacity of 692.4 MW and the lower minimal load of the CHP.

Year	Total cost [Million euro]			Scope 1 CO_2 emissions [kiloton]		
	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2020	59.4	58.7	1.2	723.4	668.6	7.6
2021	212.9	205.3	3.6	723.4	634.1	12.3
2022	619.5	547.8	11.6	723.4	496.1	31.4
2023	245.0	219.0	10.6	723.4	501.7	30.6

Table 13
Additionally installed utility technologies for a cost-optimal utility system for an ethylbenzene plant for three energy price years, a grid connection capacity of 692.4 MW and the lower minimal load of the GB.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2021	30.4	0.0	0.0	0.0	0.0	0.0
2022	83.4	3.8	371.5	0.0	0.0	0.0
2023	84.1	0.0	322.4	0.0	0.0	0.0

Table 14
Total cost and scope 1 CO_2 emissions of the benchmark and new utility system for the ethylbenzene plant for distinct energy price years, a grid connection capacity of 85.8 MW and the lower minimal load of the GB.

Year	Total cost [Million euro]			Scope 1 CO_2 emissions [kiloton]		
	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2021	20.2	19.9	1.5	77.1	72.1	6.5
2022	59.5	54.9	7.7	77.1	59.6	22.7
2023	23.5	21.1	10.2	77.1	60.6	21.4

diagrams in Fig. 6b show the energy flows in the respective systems in 2022.

In 2023, the electric boiler capacity remains the same as in the utility system with a less flexible GB, but the TES capacity decreases. Less heat is sent to the TES from the GB. Slightly more heat is sent to the TES by the electric boiler, but overall, the TES supplies the plant with a slightly lower amount of heat, while the heat supplied by the electric boiler increases.

The reduced minimal load leads to higher savings in total cost and CO_2 emissions (compare Tables 10 and 14). The complete results for the plants with an existing gas boiler are shown in Appendix D.3.

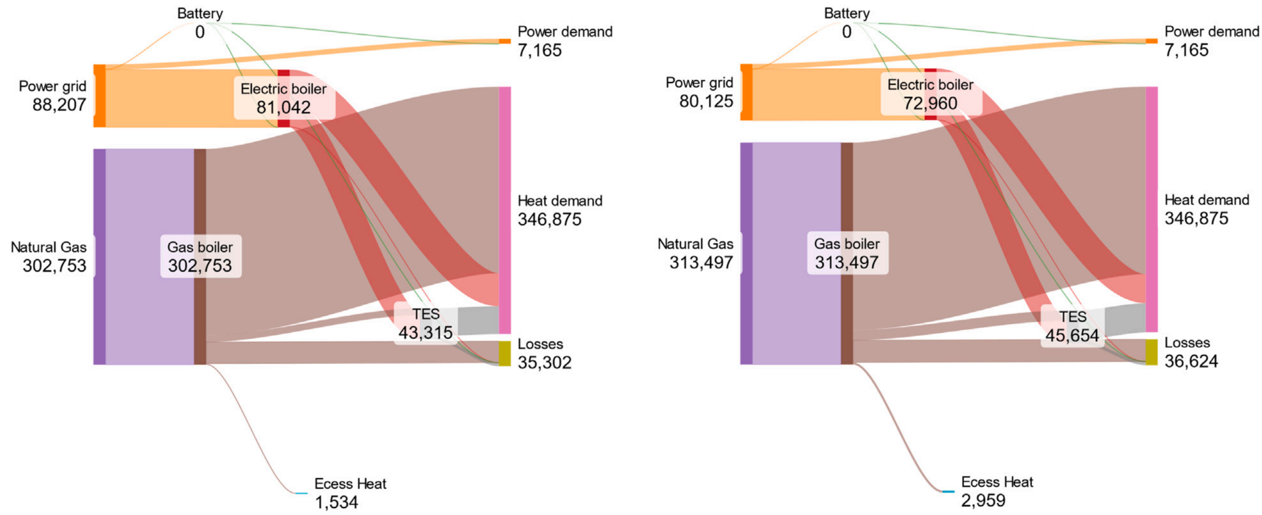
3.2.3. Technology cost scenarios

In the following, results from the utility system model runs with the technology cost data in Table 4 are presented to show how changes in the investment cost required for battery, TES, and electrolyser capacity impact the previous findings. The data underlying those findings are presented in Appendix D.4.

Plants with an existing CHP. The technology portfolio per year is not affected by the technology cost (TC) scenarios 'Bat-High', 'TES-High', 'H2E-High' and 'H2E-Low' in 2018, 2019, 2020 and 2021. No additional investment is made in 2018 and 2019, and electric boiler capacity is installed to supply 50 % of the plant's heat demand while the CHP is operating at its minimal load in 2020 and 2021. In 2022 and 2023, the technology selection remains the same, but the capacities change for the scenarios 'Bat-High' and 'TES-High': TES capacity is added to the electric boiler in 2022 and 2023, and battery storage is cost-effective only in 2023 in both TC scenarios. However, less TES capacity is installed in 'TES-High' compared to the previous results. Furthermore, less battery capacity is installed in 'Bat-High' in 2023, and the electric boiler and TES capacities increase, compared to previous results.

TC scenarios 'Bat-Low' and 'TES-Low' with a 25 % decrease in the battery price and TES price, respectively, lead to changes in the technology portfolio in one year, as a battery is added to the technology portfolio in 'Bat-Low' in 2023, and the electric boiler and TES capacity are decreased. An example of the resulting energy flows in the utility system for the olefins plant is shown in Fig. 7. The Figure shows that the battery is mainly charged from the grid, but also from the CHP when the difference between the gas use and electricity cost is small enough for a cost-effective power supply to the plant by the grid (indicated by the beige dots). The battery enables the utility system to sell power back to the grid when the electricity price is high because it supplies the power demand of the plant (indicated by khaki squares), while the CHP supplies the heat but sells the electricity it produces (indicated by the brown stars). The electric boiler capacity is decreased because the battery takes up part of the grid connection capacity. Hence, less power can flow from the grid to the electric boiler. Since the electric boiler is smaller, the TES can decrease in size, too, enabling savings in investment costs.

In 'TES-Low', TES capacity and the required additional electric boiler capacity are added to the technology portfolio installed in 2021 for plants with an existing CHP. The TES is charged during hours with a low electricity price, when the additional electric boiler is operating at



(a) Minimal load of GB = 30% of its capacity. (b) Minimal load of GB = 50% of its capacity.

Fig. 6. Sankey diagrams visualising the accumulated energy flows in the cost-optimal utility system for the ethylbenzene plant in 2023 with GBs with different minimal load constraints. The grid connection capacity is 85.8 MW, enough to electrify the plant's utility demand completely.

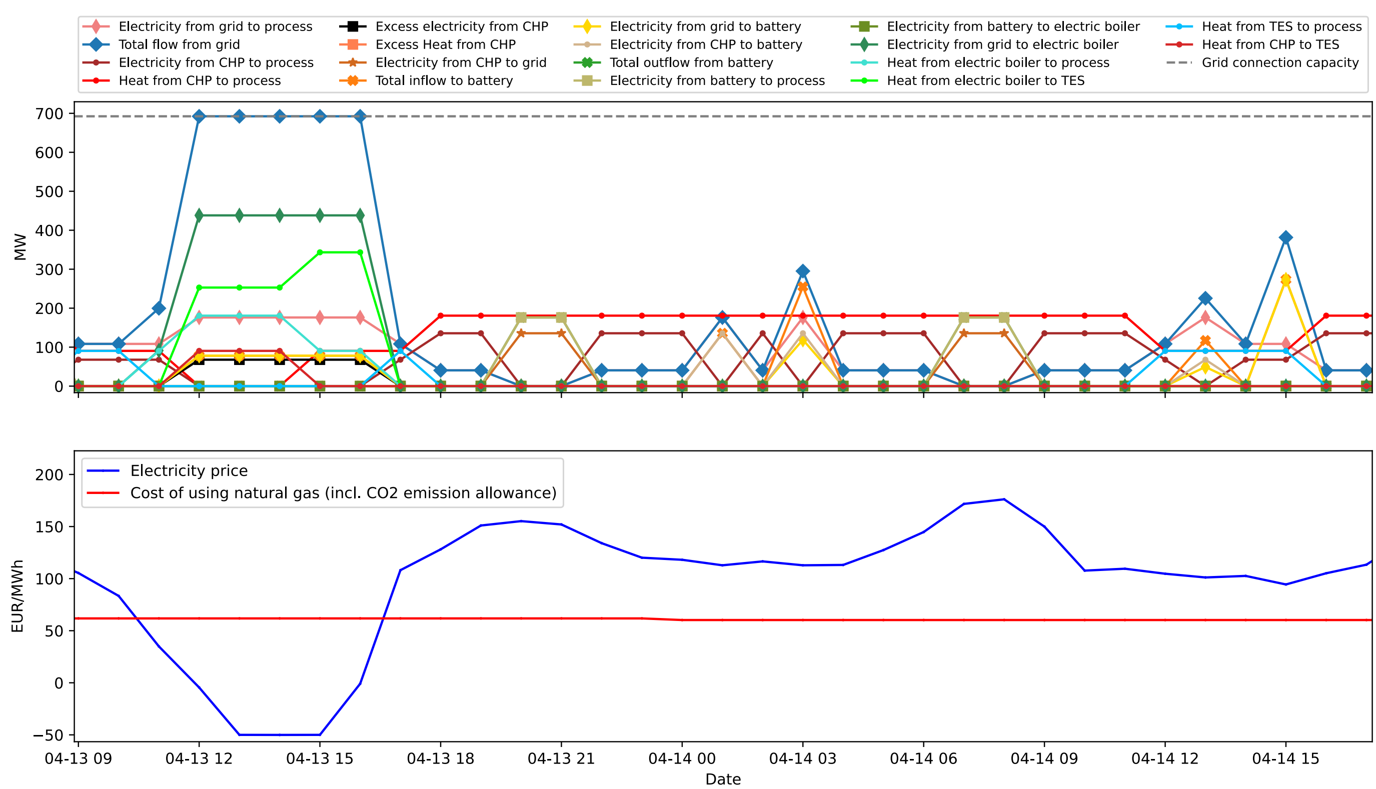


Fig. 7. The energy flows of the cost-optimal utility system for an olefins plant in 2023 and technology cost scenario 'Bat-Low'.

its maximum. This allows for more heat to be generated from electricity during those hours, enabling savings in operational costs (and CO_2 emissions).

Plants with an existing gas boiler. For the plants with an existing gas boiler, all observations made about the results for the plants with a CHP are made for the plants with gas boilers, except in TC scenarios 'Bat-Low' and 'TES-Low'. In 'Bat-Low', the additional battery capacity in 2023 is small compared to the remaining capacities, as shown in the Sankey diagram for the aggregated energy flows in the utility system for the ethylbenzene plant in Fig. 8. This is because its role is to supply the power demand of the plant (less than 1 MW) when electricity is expensive.

No additional TES capacity is added to the cost-optimal utility system in the TC scenario 'TES-Low' in 2021. The savings in operational costs enabled by the additional electric boiler and TES capacity are not enough to pay off the required investment because the share of the operational

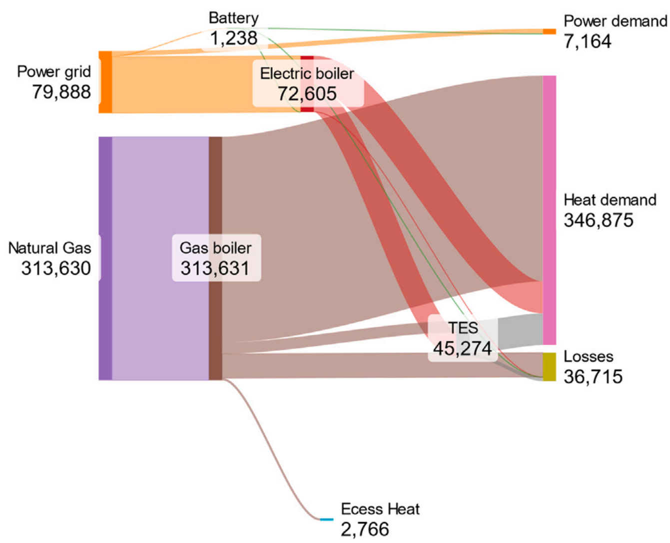


Fig. 8. Sankey diagram visualising the accumulated energy flows in the cost-optimal utility system for an ethylbenzene plant in 2023 and technology cost scenario 'Bat-Low'.

cost in the total cost is lower than in the case of plants with a CHP. This is because of the gas boiler's higher efficiency compared to the CHP.

Results including hydrogen in the energy mix. As hydrogen technologies have not been included in the utility systems presented in the previous sections, the technology cost for the electrolyser was decreased further to explore how much the cost would need to decrease until it is cost-optimal to invest in hydrogen.

Tables 15 and 16 show that hydrogen technologies are installed in the utility system for the olefins plant when the cost of the electrolyser falls to 68 euro/kW and for the ethylbenzene plant when the cost falls to 48 euro/kW. For both plants, this only happens for 2023 energy prices. Note that these prices are an order of magnitude lower than the electrolyser costs assumed in previous model runs.

4. Discussion and limitations

The results presented show that if industries are subject to fluctuating costs for their utilities, using a mix of electricity and gas and investing in electric boilers, as well as electricity and heat storage is economically and environmentally beneficial in years when the number of hours with cheaper electricity than gas is higher than 600 (7.5 % of the plant's operational hours in a year). This is independent of the ratio of their heat to power demand, the available grid connection capacity, and technology cost developments. However, there are limitations in the chosen methodology and scenarios, which need to be considered before drawing strong conclusions from these findings.

An optimisation model has perfect foresight of market prices. In reality, perfect foresight is impossible. Hence, the numbers presented are likely too optimistic. Furthermore, the optimisation model does not capture the practical difficulties of managing fluctuations that do not follow the predicted price dynamics. Therefore, the presented model can show the potential but not the actual flexibility of the system. Future studies should explore how the proposed cost-optimal systems would perform in actual (uncertain) operational conditions. In addition, optimisation results in a single outcome. Analysing sub-optimal results would allow an understanding of the impact of the type and sizing of new investments on the total cost and indicate which investments are less risky.

Since the model optimises the total cost of the utility system for one operational year, the discount rate is a parameter that influences the model outcomes. The discount rate of 10 % was chosen because, to the authors' knowledge, 10 % is common practice for considering investments in industry. A lower discount rate would lead to lower Capex and, therefore, higher capacities for newly installed technologies. Hence, it would favour electrification and support our conclusion about the financial viability of electrification.

From the energy flows in the cost-optimal utility systems, it follows that the use of the generation and storage units fluctuates strongly. Degradation and part-load efficiencies could be added to the model, where applicable, to increase the accuracy of our model. Both lead to cost changes; degradation leads to an increase in Capex, and part-load efficiencies affect the Opex. Since we considered scenarios with increased technology costs (i.e. increased Capex) and energy price data that result in a wide Opex range, the main conclusions of this work (i.e. the potential for cost-effective electrification and the 'merit order' of newly installed technologies) would likely remain unaffected if the degradation and part-load efficiencies were accounted for.

The CHP was modelled in a simplified way, i.e. without backup and integration boilers and with a fixed ratio between heat and power generation. A more flexible CHP model could lead to different results, potentially decreasing the extent to which electrification is economically optimal. Further work should address this limitation.

Costs resulting from retrofitting the legacy technologies are not included in the total cost, nor are system integration costs or costs for additional spatial requirements. Adding the investment cost required for retrofitting the legacy technologies would likely increase electricity use and might result in larger electric boilers. Adding system integration costs or costs for additional land use would likely reduce the capacities of new technologies.

Maintenance costs are not considered in the Opex as they were found to be negligible for the electric boiler, thermal energy storage and battery [24,29]. Since the model selects no hydrogen technologies, adding their maintenance costs would not change the study's findings.

The energy demand data of the plants is subject to uncertainty and might be higher than in existing plants because heat integration was not the focus of the process modelling work conducted in-house. Since the conclusions discussed above are the same for all five plants considered in

Table 15
Additionally installed utility technologies for the cost-optimal utility system for an olefins plant with a grid connection capacity of 692.4 MW and electrolyser technology cost of 68 euro/kW. Note that hydrogen was only part of the energy mix with 2023 energy prices.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2023	492.3	0.0	2009.4	18.9	5.4	130.7

Table 16
Additionally installed utility technologies for the cost-optimal utility system for an ethylbenzene plant with a grid connection capacity of 85.8 MW and electrolyser technology cost of 48 euro/kW.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2023	77.9	0.0	337.2	6.3	1.3	31.8

this work, even though their utility demand ranges from approximately 25 MW to 350 MW, they are not expected to be affected by the potential overestimations in the demand data.

As this work looks mainly at the cost-effectiveness of electrification from an industry's perspective, the chosen energy price data are considered to represent a wide enough range in terms of absolute prices and price variability to gain insights relevant to industries. However, they do not allow conclusions to be drawn about the role of each of the individual cost components, i.e. the role of the electricity prices versus the role of the price for CO_2 emissions allowances versus the role of the natural gas price. In the future, the model could be used for such an analysis, which could be helpful for policymakers who want to promote CO_2 emission savings. Extending the analysis from solely looking at scope 1 CO_2 emissions to, e.g. including scope 2 emissions would enhance the environmental assessment.

The sensitivity of the results toward the technology cost of, among others, electrolysers was tested, but did not result in changes in the results, i.e. the installation of hydrogen equipment. To understand when using hydrogen could become economically feasible, additional model runs were done, and it was found that hydrogen started appearing in the energy mix when the cost for the electrolyser fell below 70 euro/kW for plants with an existing CHP and below 50 euro/kW for plants with an existing gas boiler. This is in the range of the minimum cost studies predict for future PEM electrolyser costs [34]. The results thus indicate that, as long as the temperatures required by the process do not exceed what electric boilers or alternative power-to-heat technologies can deliver, electrolyser costs must decrease significantly for hydrogen to become a cost-optimal option for utility electrification. In the explored case studies, hydrogen is also not required as a feedstock. If processes with a hydrogen feedstock demand were to be included in the analysis, the results and conclusions would likely be different.

Heat pumps are not considered in this work for two reasons. Firstly, employment at the required scale is still rare. Second, the integration of heat pumps is specific to the respective plant and its available excess heat and needs to be modelled with greater detail than the model in this work allows. However, their deployment is advancing rapidly. Hence, future work should extend the model and consider heat pumps. Industries could also decide to invest in power generation from renewable sources and build, i.e. a wind or solar park. Future work could consider this investment instead of buying electricity and fuel from the market.

Flexibility in demand or variable demand is not considered in this work because plants in the ethylene value chain commonly run continuously at capacity. Considering plants with a more variable demand would allow us to expand the conclusions of this work to plants or industries beyond those with a continuous and constant utility demand.

Furthermore, instead of planning utility systems for individual plants, centralising utility generation in industrial clusters could be beneficial because of improved utilisation of the generation technologies and storage units. Since larger capacities are required when more plants are supplied with utilities, centralised utility systems could benefit from reduced technology costs due to economies of scale.

Finally, the findings in this study cannot be extended to greenfield situations or future processes with different utility 'profiles', especially when electricity-based processes are considered, e.g. ethylene production via electrolysis.

5. Conclusion

This work examined the potential for electrifying industrial utility systems in scenarios with highly fluctuating energy prices, using five existing chemical plants as a case study. For this purpose, utility systems for a continuous energy supply were modelled for six independent years of historical market prices for electricity, natural gas and ETS emission allowances (2018–2023). The utility systems consisted of a fossil fuel-based legacy technology to which the model could add electricity-based technologies and storage units. The utility systems of the five industrial processes were compared, a techno-economic analysis was conducted, and their CO_2 emissions were calculated.

The results show that electrification and storage technologies enable the cost-effective decarbonisation of utility systems in a scenario where industries were to pay increasingly variable gas and electricity prices. For plants with a heat and power demand which are of the same order of magnitude and an existing CHP, years with more than 500 h during which using electricity for heat generation is cheaper than burning natural gas resulted in a cost-effective partial electrification of the utility system, despite electricity prices being on average twice as expensive as using natural gas in some of these years. For plants with a power demand one order of magnitude lower than their heat demand and an existing gas boiler, partial electrification was cost-effective in years with more than 600 h of cheaper electricity than natural gas use.

The results also show that electric boilers, thermal energy storage, and batteries were selected for the cost-optimal utility systems. This was independent of the type of plant, the available grid connection capacity, and the minimal load of the CHP or gas boiler. Which combination of those three technologies was chosen depended on the energy price data. With an increasing number of hours during which using electricity is cheaper than using natural gas, electric boiler capacity was installed first. Next was TES capacity, and third was battery capacity. Changes in the investment costs for thermal energy storage and batteries led to minor changes in the capacities of the chosen technologies and changed the technology portfolio in particular years. Power-to-hydrogen-to-power or heat was not selected for any of the plants and years unless electrolyser costs were below 50 euro/kW.

This work thus highlights the potential for electrifying industrial utility systems and the role of electric boilers and energy storage units in pursuing CO_2 emission reduction in existing plants.

CRediT authorship contribution statement

Svenja Bielefeld: Writing – review & editing, Writing – original draft, Visualisation, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualisation. **Miloš Cvetković:** Writing – review & editing, Supervision, Methodology, Conceptualization. **Andrea Ramírez:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualisation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. List of abbreviations

Bat	Battery
CapEx	Capital expenditure
CHP	Combined heat and power plant
DSM	Demand-side management
EU ETS	EU Emissions Trading System
GB	Gas boiler
GHG	Greenhouse gases

H2 boiler	Hydrogen boiler
H2 storage	Hydrogen storage tank
MILP	Mixed-integer linear programming problem
OpEx	Operating expense
PEM electrolyser	Proton exchange membrane electrolyser
RES	Renewable energy sources
TC scenarios	Technology cost scenarios
TES	Thermal energy storage

Appendix B. Literature review

Many studies have presented models that design utility systems for chemical processes (see Table B.17). Among these, some focus on utility systems for the petrochemical industry [30,51–57]. Table B.17 shows that most studies focus on reducing CO_2 emissions. However, only some [9,30,58] address the electrification of utility systems as CO_2 emission reduction strategy. For instance, Bauer et al. [9] model a utility system consisting of a CHP for baseload energy generation with an additional electric boiler. Options to replace the CHP for baseline energy supply are qualitatively discussed but not quantitatively studied. Hofmann et al. [58] studies a flexible utility system for batch production consisting of an electric boiler, a biomass boiler, a thermal energy storage unit (TES) and a heat exchanger network. The study considers that flexibility is required due to variations in production but assumes no variation in prices for electricity and gas. Only one paper [30] was found that considers fully electrified scenarios: The author presents two case studies with electrified core processes and utility systems. While the paper proposes design strategies for the long-term goal of completely electrifying chemical production, solutions to reduce emissions in the short term are not considered. The study also does not include energy storage. According to Hofmann et al., energy storage might benefit a fully electrified system [58]. The papers just discussed are the only literature found on the electrification of utility systems for chemical plants as a measure to decrease CO_2 emissions in the chemical sector.

In the literature on utility systems for other industrial sectors, there is more attention on electricity-based technologies such as electric boilers, batteries, and heat pumps. Atabay presents a model for capacity-expansion planning which allows energy export and considers CHPs, gas boilers, immersive heaters, batteries and TES [59]. The study focuses on a green field and shows that batteries are not invested in with the assumed technology cost. In another study, Baumgaertner et al. consider a wide range of technological options (among others, electric boilers, heat pumps, compression chillers, batteries and TES) for a pharmaceutical facility [60]. Unlike Atabay, Baumgaertner et al. do consider time-dependent electricity prices, but gas prices are assumed to be constant. The technology portfolio in Baumgaertner et al. was extended to include pumped heat storage (a power-to-heat-to-power system) in a study by Reinert et al. [61]. Neither Baumgaertner et al. nor Reinert et al. include hydrogen in their scope.

Two studies on utility systems for other industries consider using hydrogen as an energy carrier. In the first study, Kostelack et al. analyse four utility system concepts based on hydrogen produced with power from a PV plant [62]. They show that hydrogen can reduce operational costs if electricity prices are lower than natural gas prices and that hydrogen reduces risks due to a decreased exposure to energy price increases. However, capital expenditures for hydrogen technologies are neglected, and the study assumes some flexibility in the processes' energy demand, which is unlikely to be available in the chemical industry. The second study that includes hydrogen is presented by Fleschutz et al. [24]. In their utility system model, they consider a natural gas-fueled CHP and boiler, a hydrogen-based system consisting of electrolyser, hydrogen storage, and fuel cell and a heat pump, a solar power plant, a wind turbine and storage units for electricity and thermal energy, including battery electric vehicles. The study shows that the system's flexibility (provided by the storage units and the coupling of the energy system and the mobility demands) leads to significant cost savings for carbon emission-free utility systems. Only some of the presented systems are cost-competitive with their reference system. However, varying prices for purchasing natural gas and ETS emission allowances are not considered, which could lead to increased costs with the inflexible reference system.

To the authors' knowledge, no study has considered using a combination of electric boilers, the generation and use of hydrogen, and storage units to electrify fuel-based utility systems for chemical plants. Therefore, it is still unclear which combinations of those technologies can best enable electrification and how electrified systems would perform in terms of cost and CO_2 emissions compared to utility systems based on fossil sources.

Table B.17
Literature on the design of utility systems for the chemical industry.

Study	Case study	CO_2 emission reduction strategy and/or implemented technologies	Fully decarbonised?
Mitra et al. [63]	Chemical park	None	No
Luo et al. [51]	Petrochemical complex	Optimising exergy efficiency	No
Han and Lee [52]	Petrochemical complex	Increasing efficiency & CCS	No (30 % reduction)
Klasing et al. [8]	No specific process	Electric boilers and heaters and TES	No
Leenders et al. [64]	No specific process	None	No
Hofmann et al. [58]	No specific process	Heat exchanger-network, biomass boiler, electric boiler, and TES	No
Zhang and You [65]	No specific process	None	No
Quian et al. [53]	Petrochemical complex	Wind and PV for power supply, TES and electric chiller	No
Wang et al. [66]	Refinery	Wind and PV integration, electrolyser and energy storage	No
Bauer et al. [9]	No specific process	Electric boiler	No
Ghiasi et al. [54]	Petrochemical complex	Heat exchanger network	No
Hwangbo et al. [55]	Petrochemical clusters	Wind, PV and CCS	No
Kim [67]	Refinery	Full electrification	Yes
Kim [30]	Methyl acetate and ethylbenzene	Full electrification	Yes
Wang et al. [68]	Chemical plant	Wind, solar thermal energy, TES	No
Su et al. [57]	Petrochemical sites	Power from renewable sources, biomass fuels, CCS	No
Li and Zhao [56]	Ethylene plant	None	No
Jimenez-Romero et al. [69]	Chemical plant	None	No

Appendix C. Model formulation

C.1. Nomenclature of parameters and variables

Table C.18

Symbol	Explanation	Unit
Time-dependent variables		
$P_{\mathrm{gr,ElB}}(t)$	Grid power to the electric boiler	MW
$P_{\mathrm{gr,plant}}(t)$	Grid power to the plant	MW
$P_{\mathrm{gr,bat}}(t)$	Grid power to the battery	MW
$P_{\mathrm{gr,H2\,E}}(t)$	Grid power to the electrolyser	MW
$P_{\mathrm{CHP,gr}}(t)$	Power from CHP plant to the grid	MW
$P_{\mathrm{CHP,plant}}(t)$	Power from CHP to the plant	MW
$P_{\mathrm{CHP,bat}}(t)$	Power from CHP to the battery	MW
$P_{\mathrm{bat,plant}}(t)$	Power from battery to the plant	MW
$P_{\mathrm{bat,ElB}}(t)$	Power from battery to the electric boiler	MW
$P_{\mathrm{bat,H2\,E}}(t)$	Power from battery to the electrolyser	MW
$H_{\mathrm{ElB,plant}}(t)$	Heat generated by electric boiler for the plant	MW
$H_{\mathrm{CHP,plant}}(t)$	Heat generated by the CHP for the plant	MW
$H_{\mathrm{TES,plant}}(t)$	Heat from thermal energy storage to the plant	MW
$H_{\mathrm{H2B,plant}}(t)$	Heat from the hydrogen boiler to the plant	MW
$H_{\mathrm{CHP,TES}}(t)$	Heat from CHP to thermal energy storage	MW
$H_{\mathrm{ElB,TES}}(t)$	Heat from electric boiler to thermal energy storage	MW
$H_{\mathrm{GB,plant}}(t)$	Heat from gas boiler to the plant	MW
$H_{\mathrm{GB,TES}}(t)$	Heat from gas boiler to thermal energy storage	MW
$NG_{\mathrm{in}}(t)$	Natural gas input to the utility system	MW
$H_{2,\mathrm{H2\,E,H2B}}(t)$	Hydrogen from electrolyser to the boiler	MW
$H_{2,\mathrm{H2\,E,H2\,S}}(t)$	Hydrogen from electrolyser to storage	MW
$H_{2,\mathrm{H2\,S,H2B}}(t)$	Hydrogen from storage to the boiler	MW
$SOE_{\mathrm{bat}}(t)$	State of energy of the battery	MWh
$SOE_{\mathrm{TES}}(t)$	State of energy in the thermal energy storage	MWh
$SOE_{\mathrm{H2\,S}}(t)$	State of energy in hydrogen storage	kg
$b_1(t)$	Binary variable for battery charging	Binary (0/1)
$b_2(t)$	Binary variable for thermal energy storage charging	Binary (0/1)
$b_3(t)$	Binary variable for hydrogen storage tank	Binary (0/1)
$b_4(t)$	Binary variable for grid connection	Binary (0/1)
Sizing variables		
s_{ElB}	Electric boiler size	MW_{th}
$s_{\mathrm{H2\,E}}$	Electrolyser size	MW_{th}
s_{H2B}	Hydrogen boiler size	MW_{th}
s_{TES}	Thermal energy storage size	MWh
$s_{\mathrm{H2\,S}}$	Hydrogen storage size	MWh
s_{bat}	Battery size	MWh
Time-dependent parameters		
$\mathrm{p}_{\mathrm{el,grid}}(t)$	Electricity price at time t	Eur/MWh
$\mathrm{p}_{\mathrm{NG}}(t)$	Natural gas price at time t	Eur/MWh
$\mathrm{p}_{\mathrm{EUA}}(t)$	CO_2 allowance price at time t	Eur/ton
$H_{\mathrm{dem}}(t)$	(Constant) heat demand of the plant at time t	MW
$P_{\mathrm{dem}}(t)$	(Constant) power demand of the plant at time t	MW
Constants		
s_{CHP}	CHP size	MW
s_{GB}	Gas boiler size	MW
$\mathrm{EF}_{\mathrm{NG}}$	Emission factor for natural gas	kg CO_2/MWh
r_{disc}	Discount rate	%
Δt	Time step duration	h
$\eta_{\mathrm{CHP,el}}$	CHP electric efficiency	—
$\eta_{\mathrm{CHP,th}}$	CHP thermal efficiency	—
η_{GB}	Gas boiler efficiency	—
η_{ElB}	Electric boiler efficiency	—
$\eta_{\mathrm{H2\,E}}$	Hydrogen electrolyser efficiency	—
η_{H2B}	Hydrogen boiler efficiency	—
η_{bat}	Battery charge and discharge efficiency	—
η_{TES}	Thermal energy storage efficiency	—
$\eta_{\mathrm{H2\,S}}$	Hydrogen storage efficiency	—
$\mathrm{MinLoadFactor}_{\mathrm{CHP}}$	Minimum load factor for CHP	% of capacity
$\mathrm{MinLoadFactor}_{\mathrm{GP}}$	Minimum load factor for GB	% of capacity
$\mathrm{crate}_{\mathrm{bat}}$	Charge/discharge rate of battery	MW/MWh
$\mathrm{crate}_{\mathrm{TES}}$	Charge/discharge rate of thermal energy storage	MW/MWh
$\mathrm{cap}_{\mathrm{gr}}$	Grid connection capacity	MW
$\mathrm{area}_{\mathrm{available}}$	Available area for system installation	m^2
c_i	Capital cost of component i	Eur/unit
LT_i	Lifetime of component i	years

C.2. Mathematical formulations of the benchmark models

The following equations are used to calculate the performance of the benchmark models.

Objective function.

$$\min \sum_{t=0}^{t=8000} \mathrm{OpEx}(t), \tag{C.1}$$

where

$$\mathrm{OpEx}(t) = \mathrm{p}_{\mathrm{el,grid}}(t) \cdot \Delta t \cdot \left(P_{\mathrm{gr,\,plant}}(t) - P_{\mathrm{CHP,\,gr}}(t) \right) + NG_{\mathrm{in}}(t) \cdot \Delta t \cdot \left(\mathrm{p}_{\mathrm{NG}}(t) + \mathrm{p}_{\mathrm{EUA}}(t) \cdot \mathrm{EF}_{\mathrm{NG}} \right)$$

if the benchmark utility system consists of a CHP and

$$\mathrm{OpEx}(t) = \mathrm{p}_{\mathrm{el,grid}}(t) \cdot \Delta t \cdot P_{\mathrm{gr,\,plant}}(t) + NG_{\mathrm{in}}(t) \cdot \Delta t \cdot \left(\mathrm{p}_{\mathrm{NG}}(t) + \mathrm{p}_{\mathrm{EUA}}(t) \cdot \mathrm{EF}_{\mathrm{NG}} \right)$$

if the benchmark utility system consists of a gas boiler.

Energy balance equality constraints.

Heat balance:

$$H_{\mathrm{dem}} = H_{\mathrm{CHP,plant}}(t), \tag{C.2}$$

or

$$H_{\mathrm{dem}} = H_{\mathrm{GB,plant}}(t), \tag{C.3}$$

Power balance:

$$P_{\mathrm{dem}} = P_{\mathrm{gr,plant}}(t) + P_{\mathrm{CHP,plant}}(t) \tag{C.4}$$

or

$$P_{\mathrm{dem}} = P_{\mathrm{gr,plant}}(t) \tag{C.5}$$

CHP constraints.

Power generation constraint:

$$NG_{\mathrm{in}}(t) = \frac{P_{\mathrm{CHP,plant}}(t) + P_{\mathrm{CHP,excess}}(t) + P_{\mathrm{CHP,gr}}(t)}{\eta_{\mathrm{CHP,el}}} \tag{C.6}$$

Heat generation constraint:

$$NG_{\mathrm{in}}(t) = \frac{H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{CHP,excess}}(t)}{\eta_{\mathrm{CHP,th}}} \tag{C.7}$$

Maximum heat generation:

$$H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{CHP,excess}}(t) \le \mathrm{s}_{\mathrm{CHP}} \cdot \eta_{\mathrm{CHP,th}} \tag{C.8}$$

Minimum heat generation:

$$H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{CHP,excess}}(t) \ge \mathrm{s}_{\mathrm{CHP}} \cdot \eta_{\mathrm{CHP,th}} \cdot \mathrm{MinLoadFactor}_{\mathrm{CHP}} \tag{C.9}$$

Gas boiler constraints.

Heat generation constraint:

$$NG_{\mathrm{GB,in}}(t) = \frac{H_{\mathrm{GB,plant}}(t) + H_{\mathrm{GB,excess}}(t)}{\eta_{\mathrm{GB}}} \tag{C.10}$$

Maximum heat generation:

$$H_{\mathrm{GB,plant}}(t) + H_{\mathrm{GB,excess}}(t) \le \mathrm{s}_{\mathrm{GB}} \cdot \eta_{\mathrm{GB}} \tag{C.11}$$

Minimum heat generation:

$$H_{\mathrm{GB,plant}}(t) + H_{\mathrm{GB,excess}}(t) \ge \mathrm{s}_{\mathrm{GB}} \cdot \eta_{\mathrm{GB}} \cdot \mathrm{MinLoadFactor}_{\mathrm{GB}} \tag{C.12}$$

Grid connection capacity.

Maximum inflow constraint:

$$\mathrm{cap}_{\mathrm{gr}} \cdot b_3(t) \ge P_{\mathrm{gr,plant}}(t) \tag{C.13}$$

Maximum outflow constraint for systems with a CHP:

$$P_{\mathrm{CHP,gr}}(t) \le \mathrm{cap}_{\mathrm{gr}} \cdot (1 - b_3(t)) \tag{C.14}$$

C.3. Mathematical formulations of the model with an existing CHP

The following equations represent the mathematical formulation of the model for the utility system with an existing CHP.

Objective function.

$$\min \sum_{t=0}^{t=8000} \mathrm{OpEx}(t) + \mathrm{CaPex}, \tag{C.15}$$

where

$$\mathrm{OpEx}(t) = \mathrm{p}_{\mathrm{el,grid}}(t) \cdot \Delta t \cdot \left(P_{\mathrm{gr,\,ElB}}(t) + P_{\mathrm{gr,\,plant}}(t) + P_{\mathrm{gr,\,bat}}(t) + P_{\mathrm{gr,\,H2\,E}}(t) - P_{\mathrm{CHP,\,gr}}(t) \right) + NG_{\mathrm{in}}(t) \cdot \Delta t \cdot \left(\mathrm{p}_{\mathrm{NG}}(t) + \mathrm{p}_{\mathrm{EUA}}(t) \cdot \mathrm{EF}_{\mathrm{NG}} \right) \tag{C.16}$$

and

$$\mathrm{CaPex} = \sum_{i \in \{\mathrm{bat,ElB,TES,H2\,E,H2B,H2\,S}\}} \frac{m_i \cdot c_i \cdot r_{\mathrm{disc}}}{1 - (1 + r_{\mathrm{disc}})^{-\mathrm{lt}_i}} \tag{C.17}$$

Energy balance equality constraints.

Heat balance:

$$H_{\mathrm{dem}} = H_{\mathrm{ElB,plant}}(t) + H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{TES,plant}}(t) + H_{\mathrm{H2B,plant}}(t) \tag{C.18}$$

Power balance:

$$P_{\mathrm{dem}} = P_{\mathrm{gr,plant}}(t) + P_{\mathrm{CHP,plant}}(t) + P_{\mathrm{bat,plant}}(t) \tag{C.19}$$

CHP constraints.

Power generation constraint:

$$NG_{\mathrm{in}}(t) = \frac{P_{\mathrm{CHP,plant}}(t) + P_{\mathrm{CHP,excess}}(t) + P_{\mathrm{CHP,bat}}(t) + P_{\mathrm{CHP,gr}}(t)}{\eta_{\mathrm{CHP,el}}} \tag{C.20}$$

Heat generation constraint:

$$NG_{\mathrm{in}}(t) = \frac{H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{CHP,TES}}(t) + H_{\mathrm{CHP,excess}}(t)}{\eta_{\mathrm{CHP,th}}} \tag{C.21}$$

Maximum heat generation:

$$H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{CHP,TES}}(t) + H_{\mathrm{CHP,excess}}(t) \le \mathrm{s}_{\mathrm{CHP}} \cdot \eta_{\mathrm{CHP,th}} \tag{C.22}$$

Minimum heat generation:

$$H_{\mathrm{CHP,plant}}(t) + H_{\mathrm{CHP,TES}}(t) + H_{\mathrm{CHP,excess}}(t) \ge \mathrm{s}_{\mathrm{CHP}} \cdot \eta_{\mathrm{CHP,th}} \cdot \mathrm{MinLoadFactor}_{\mathrm{CHP}} \tag{C.23}$$

Electric boiler.

Heat generation constraint:

$$H_{\mathrm{ElB,plant}}(t) + H_{\mathrm{ElB,TES}}(t) = \left(P_{\mathrm{gr,ElB}}(t) + P_{\mathrm{bat,ElB}}(t) \right) \cdot \eta_{\mathrm{ElB}} \tag{C.24}$$

Sizing constraint:

$$H_{\mathrm{ElB,plant}}(t) + H_{\mathrm{ElB,TES}}(t) \le s_{\mathrm{ElB}} \tag{C.25}$$

Water electrolyser.

Hydrogen production constraint:

$$\left(P_{\mathrm{gr,H2\,E}}(t) + P_{\mathrm{bat,H2\,E}}(t) \right) \cdot \eta_{\mathrm{H2\,E}} = H_{2,\mathrm{H2\,E,H2B}}(t) + H_{2,\mathrm{H2\,E,H2\,S}}(t) \tag{C.26}$$

Sizing constraint:

$$P_{\mathrm{gr,H2\,E}}(t) + P_{\mathrm{bat,H2\,E}}(t) \le s_{\mathrm{H2\,E}} \tag{C.27}$$

Hydrogen boiler.
Heat generation constraint:

$$\left(H_{2,\text{H2 E,H2B}}(t) + H_{2,\text{H2 S,H2B}}(t)\right) \cdot \eta_{\text{H2B}} = H_{\text{H2B,plant}}(t) \tag{C.28}$$

Sizing constraint:

$$H_{\text{H2B,plant}}(t) \le s_{\text{H2B}} \tag{C.29}$$

Battery. State of energy:

$$SOE_{\text{bat}}(t) = \begin{cases} 0, & \text{if } t = 0 \\ SOE_{\text{bat}}(t-1) + \\ \eta_{\text{bat}} \cdot \Delta t \cdot \left(P_{\text{gr,bat}}(t-1) + P_{\text{CHP,bat}}(t-1)\right) - \\ \frac{1}{\eta_{\text{bat}}} \cdot \Delta t \cdot \left(P_{\text{bat,plant}}(t-1) + P_{\text{bat,ElB}}(t-1)\right. \\ \left. + P_{\text{bat,H2 E}}(t-1)\right), & \text{otherwise} \end{cases} \tag{C.30}$$

Maximum charge constraint:

$$P_{\text{gr,bat}}(t) + P_{\text{CHP,bat}}(t) \le \frac{s_{\text{bat}}}{\eta_{\text{bat}}} \cdot \frac{\text{crate}_{\text{bat}}}{\Delta t} \cdot b_1(t) \tag{C.31}$$

Maximum discharge constraint: Discharging for $t = 0$:

$$P_{\text{bat,plant}}(0) + P_{\text{bat,ElB}}(0) + P_{\text{bat,H2 E}}(0) = 0 \tag{C.32}$$

Discharging for $t > 0$:

$$P_{\text{bat,plant}}(t) + P_{\text{bat,ElB}}(t) + P_{\text{bat,H2 E}}(t) \le s_{\text{bat}} \cdot \eta_{\text{bat}} \cdot \frac{\text{crate}_{\text{bat}}}{\Delta t} \cdot (1 - b_1(t)) \tag{C.33}$$

Sizing constraint:

$$SOE_{\text{bat}}(t) \le s_{\text{bat}} \tag{C.34}$$

Thermal energy storage.
State of energy (SOE):

$$SOE_{\text{TES}}(t) = \begin{cases} 0, & \text{if } t = 0 \\ SOE_{\text{TES}}(t-1) + \\ \left(H_{\text{CHP,TES}}(t-1) + H_{\text{ElB,TES}}(t-1)\right) \cdot \Delta t - \\ \frac{H_{\text{TES,plant}}(t-1)}{\eta_{\text{TES}}} \cdot \Delta t, & \text{otherwise} \end{cases} \tag{C.35}$$

Maximum charge constraint

$$H_{\text{CHP,TES}}(t) + H_{\text{ElB,TES}}(t) \le \frac{s_{\text{TES}} \cdot \text{crate}_{\text{TES}}}{\Delta t} \cdot b_2(t) \tag{C.36}$$

Maximum discharge constraint: Discharging for $t = 0$:

$$H_{\text{TES,plant}}(0) = 0 \tag{C.37}$$

Discharging for $t > 0$:

$$H_{\text{TES,plant}}(t) \le \frac{s_{\text{TES}} \cdot \eta_{\text{TES}} \cdot \text{crate}_{\text{TES}}}{\Delta t} \cdot (1 - b_2(t)) \tag{C.38}$$

Sizing constraint:

$$SOE_{\text{TES}}(t) \le s_{\text{TES}} \tag{C.39}$$

Hydrogen storage.
State of energy:

$$SOE_{\text{H2 S}}(t) = \begin{cases} 0, & \text{if } t = 0 \\ SOE_{\text{H2 S}}(t-1) + \left(H_{2,\text{H2 E,H2 S}}(t-1)\right. \\ \left. - \frac{H_{2,\text{H2 S,H2B}}(t-1)}{\eta_{\text{H2 S}}}\right) \cdot \Delta t, & \text{otherwise} \end{cases} \tag{C.40}$$

Charge constraint

$$H_{2,\text{H2 E,H2 S}}(t) \le s_{\text{H2 S}} \cdot b_3(t) \tag{C.41}$$

Discharge constraint: Discharging for $t = 0$:

$$H_{2,\text{H2 S,H2B}}(0) = 0 \tag{C.42}$$

Discharging for $t > 0$:

$$H_{2,\text{H2 S,H2B}}(t) \le \frac{s_{\text{H2 S}} \cdot \eta_{\text{H2 S}}}{\Delta t} \cdot (1 - b_3(t)) \tag{C.43}$$

Sizing constraint:

$$SOE_{\text{H2 S}}(t) \le s_{\text{H2 S}} \tag{C.44}$$

Grid connection capacity.
Maximum inflow constraint:

$$\text{cap}_{\text{gr}} \cdot b_4(t) \ge P_{\text{gr,plant}}(t) + P_{\text{gr,ElB}}(t) + P_{\text{gr,bat}}(t) + P_{\text{gr,H2 E}}(t) \tag{C.45}$$

Maximum outflow constraint:

$$P_{\text{CHP,gr}}(t) \le \text{cap}_{\text{gr}} \cdot (1 - b_4(t)) \tag{C.46}$$

C.4. Constraints in model with an existing gas boiler

The following equations represent the mathematical formulation of the model for the utility system with an existing gas boiler.

Objective function.

$$\min \sum_{t=0}^{t=8000} \text{OpEx}(t) + \text{CaPex}, \tag{C.47}$$

where

$$\begin{aligned} \text{OpEx}(t) = {} & \text{p}_{\text{el,grid}}(t) \cdot \Delta t \cdot \Big(P_{\text{gr, ElB}}(t) + P_{\text{gr, plant}}(t) + P_{\text{gr, bat}}(t) + P_{\text{gr, H2 E}}(t)\Big) \\ & + NG_{\text{in}}(t) \cdot \Delta t \cdot \left(\text{p}_{\text{NG}}(t) + \text{p}_{\text{EUA}}(t) \cdot \text{EF}_{\text{NG}}\right) \end{aligned} \tag{C.48}$$

and

$$\text{CaPex} = \sum_{i \in \{\text{bat,ElB,TES,H2E,H2B,H2S}\}} \frac{m_i \cdot c_i \cdot r_{\text{disc}}}{1 - (1 + r_{\text{disc}})^{-\text{lt}_i}} \tag{C.49}$$

Energy balance equality constraints.
Heat balance:

$$H_{\text{dem}} = H_{\text{ElB,plant}}(t) + H_{\text{GB,plant}}(t) + H_{\text{TES,plant}}(t) + H_{\text{H2B,plant}}(t) \tag{C.50}$$

Power balance:

$$P_{\text{dem}} = P_{\text{gr,plant}}(t) + P_{\text{bat,plant}}(t) \tag{C.51}$$

Gas boiler constraints.
Heat generation constraint:

$$NG_{\text{GB,in}}(t) = \frac{H_{\text{GB,plant}}(t) + H_{\text{GB,TES}}(t) + H_{\text{GB,excess}}(t)}{\eta_{\text{GB}}} \tag{C.52}$$

Maximum heat generation:

$$H_{\text{GB,plant}}(t) + H_{\text{GB,TES}}(t) + H_{\text{GB,excess}}(t) \le \text{s}_{\text{GB}} \cdot \eta_{\text{GB}} \tag{C.53}$$

Minimum heat generation:

$$H_{\text{GB,plant}}(t) + H_{\text{GB,TES}}(t) + H_{\text{GB,excess}}(t) \ge \text{s}_{\text{GB}} \cdot \eta_{\text{GB}} \cdot \text{MinLoadFactor}_{\text{GB}} \tag{C.54}$$

Electric boiler.

Same as in Appendix C.3.

Water electrolyser.

Hydrogen production constraint: Same as in Appendix C.3.

Hydrogen boiler.

Same as in Appendix C.3.

Battery. State of energy:

$$SOE_{\text{bat}}(t) = \begin{cases} 0, & \text{if } t = 0 \\ SOE_{\text{bat}}(t-1)+ & \\ \eta_{\text{bat}} \cdot \Delta t \cdot P_{\text{gr,bat}}(t-1) - \frac{1}{\eta_{\text{bat}}} \cdot \Delta t \cdot \big(P_{\text{bat,plant}}(t-1) & \\ +P_{\text{bat,ElB}}(t-1) + P_{\text{bat,H2 E}}(t-1)\big)\,, & \text{otherwise} \end{cases} \tag{C.55}$$

Maximum charge constraint:

$$P_{\text{gr,bat}}(t) \leq \frac{bat_{\text{cap}}}{\eta_{\text{bat}}} \cdot \frac{crate_{\text{bat}}}{\Delta t} \cdot b_1(t) \tag{C.56}$$

Maximum discharge constraint: Same as in Appendix C.3.

Sizing constraint: Same as in Appendix C.3.

Thermal energy storage.

State of energy (SOE):

$$SOE_{\text{TES}}(t) = \begin{cases} 0, & \text{if } t = 0 \\ SOE_{\text{TES}}(t-1)+ & \\ \big(H_{\text{GB,TES}}(t-1) + H_{\text{ElB,TES}}(t-1)\big) \cdot \Delta t - & \\ \frac{H_{\text{TES,plant}}(t-1)}{\eta_{\text{TES}}} \cdot \Delta t, & \text{otherwise} \end{cases} \tag{C.57}$$

Maximum charge constraint

$$H_{\text{GB,TES}}(t) + H_{\text{ElB,TES}}(t) \leq \frac{s_{\text{TES}} \cdot \text{crate}_{\text{TES}}}{\Delta t} \cdot b_2(t) \tag{C.58}$$

Maximum discharge constraint: Same as in Appendix C.3.

Sizing constraint: Same as in Appendix C.3.

Hydrogen storage.

Same as in Appendix C.3.

Grid connection capacity.

Maximum inflow constraint: Same as in C.3. Maximum outflow constraint: Not required because no electricity can be sold to the grid.

Appendix D. Remaining results

D.1. Cost-optimal utility systems for different opex scenarios

Table D.19
Additionally installed utility technologies for cost-optimal utility system for an ethylene oxide plant for six different years and a grid connection capacity of 97.4 MW.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	15.0	0.0	0.0	0.0	0.0	0.0
2021	15.0	0.0	0.0	0.0	0.0	0.0
2022	70.0	84.9	420.2	0.0	0.0	0.0
2023	76.5	0.0	307.3	0.0	0.0	0.0

Table D.20
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the ethylene oxide plant for distinct years and a grid connection capacity of 97.4 MW.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	14.1	14.1	0.0	120.3	120.3	0.0
2019	11.1	11.1	0.0	120.3	120.3	0.0
2020	7.6	7.6	0.0	113.8	120.3	5.4
2021	27.9	28.8	3.1	109.7	120.3	8.8
2022	76.5	85.5	10.5	91.2	120.3	24.2
2023	30.7	33.6	8.6	93.3	120.3	22.3

Table D.21
Additionally installed utility technologies for cost-optimal utility system for an ethylene glycol plant for six different years and a grid connection capacity of 90.2 MW.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	22.2	0.0	0.0	0.0	0.0	0.0
2022	85.2	9.3	393.9	0.0	0.0	0.0
2023	87.1	0.0	369.3	0.0	0.0	0.0

Table D.22
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the ethylene glycol plant for distinct years and a grid connection capacity of 90.2 MW.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	10.8	10.8	0.0	78.8	78.8	0.0
2019	8.5	8.5	0.0	78.8	78.8	0.0
2020	5.9	5.9	0.0	78.8	78.8	0.0
2021	21.4	21.6	1.1	75.1	78.8	4.7
2022	59.2	63.3	6.4	64.0	78.8	18.7
2023	23.0	25.0	8.2	64.0	78.8	18.7

Table D.23
Additionally installed utility technologies for the cost-optimal utility system for a PET plant for six different years and a grid connection capacity of 49.7 MW.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	12.2	0.0	0.0	0.0	0.0	0.0
2022	47.1	4.9	217.7	0.0	0.0	0.0
2023	48.1	0.0	204.1	0.0	0.0	0.0

Table D.24
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the PET plant for distinct years and a grid connection capacity of 49.7 MW.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	6.0	6.0	0.0	43.5	43.5	0.0
2019	4.7	4.7	0.0	43.5	43.5	0.0
2020	3.3	3.3	0.0	43.5	43.5	0.0
2021	11.8	11.9	1.1	41.5	43.5	4.7
2022	32.6	34.8	6.4	35.4	43.5	18.7
2023	12.7	13.8	8.2	35.4	43.5	18.7

D.2. Grid connection capacity

Table D.25
Newly installed capacity for the olefins plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
50 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	157.4	524.4	602.8	0.0	0.0	0.0
	F	235.5	0.0	870.3	0.0	0.0	0.0
60 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	221.2	556.3	1046.3	0.0	0.0	0.0
	F	304.0	0.0	1281.6	0.0	0.0	0.0
70 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	275.9	556.3	1484.2	0.0	0.0	0.0

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Table D.25 *(continued)*

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
	F	372.6	0.0	1607.5	0.0	0.0	0.0
80 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	336.1	604.7	1908.9	0.0	0.0	0.0
	F	432.0	0.0	1708.0	0.0	0.0	0.0
90 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	364.0	698.7	2188.9	0.0	0.0	0.0
	F	447.7	0.0	1786.1	0.0	0.0	0.0
110 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	492.2	741.7	3011.8	0.0	0.0	0.0
	F	570.4	0	2277.3	0.0	0.0	0.0
120 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	90.4	0.0	0.0	0.0	0.0	0.0
	D	90.4	0.0	0.0	0.0	0.0	0.0
	E	560.7	741.7	3396.7	0.0	0.0	0.0
	F	648.2	0.0	2788.6	0.0	0.0	0.0

Table D.26
Newly installed capacity for the ethylene oxide plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
50 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	38.0	63.7	133.6	0.0	0.0	0.0
	F	49.1	0.0	146.3	0.0	0.0	0.0
60 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	29.9	63.7	183.8	0.0	0.0	0.0
	F	39.4	0.0	204.2	0.0	0.0	0.0
70 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	47.7	63.7	261.0	0.0	0.0	0.0
	F	58.7	0.0	262.1	0.0	0.0	0.0
80 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	54.0	82.9	307.4	0.0	0.0	0.0
	F	68.4	0.0	284.0	0.0	0.0	0.0
90 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	60.3	84.9	362.2	0.0	0.0	0.0
	F	71.8	0.0	284.0	0.0	0.0	0.0
110 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	79.6	84.9	478.6	0.0	0.0	0.0

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Table D.26 *(continued)*

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
	F	86.1	0	355.5	0.0	0.0	0.0
120 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	15.0	0.0	0.0	0.0	0.0	0.0
	D	15.0	0.0	0.0	0.0	0.0	0.0
	E	89.2	84.9	532.3	0.0	0.0	0.0
	F	95.8	0.0	403.7	0.0	0.0	0.0

Table D.27
Newly installed capacity for the ethylbenzene plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
50 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	41.6	3.1	144.5	0.0	0.0	0.0
	F	41.6	0.0	119.5	0.0	0.0	0.0
60 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	49.4	3.8	194.3	0.0	0.0	0.0
	F	50.1	0.0	170.5	0.0	0.0	0.0
70 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	57.9	3.8	253.8	0.0	0.0	0.0
	F	58.6	0.0	221.5	0.0	0.0	0.0
80 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	66.3	3.8	312.4	0.0	0.0	0.0
	F	432.0	0.0	272.5	0.0	0.0	0.0
90 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	67.1	3.8	371.9	0.0	0.0	0.0
	F	447.7	0.0	323.4	0.0	0.0	0.0
110 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	91.8	3.8	420.7	0.0	0.0	0.0
	F	92.6	0.0	385.4	0.0	0.0	0.0
120 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	21.7	0.0	0.0	0.0	0.0	0.0
	E	100.3	3.8	481.8	0.0	0.0	0.0
	F	101.1	0.0	397.0	0.0	0.0	0.0

Table D.28
Newly installed capacity for the ethylene glycol plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
50 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	40.9	9.3	144.8	0.0	0.0	0.0
	F	42.5	0.0	121.9	0.0	0.0	0.0

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Table D.28 *(continued)*

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
60 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	49.8	9.3	193.5	0.0	0.0	0.0
	F	51.4	0.0	175.5	0.0	0.0	0.0
70 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	58.7	9.3	256.0	0.0	0.0	0.0
	F	60.3	0.0	229.1	0.0	0.0	0.0
80 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	67.7	9.3	318.5	0.0	0.0	0.0
	F	69.3	0.0	282.7	0.0	0.0	0.0
90 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	76.3	9.3	378.8	0.0	0.0	0.0
	F	78.2	0.0	336.3	0.0	0.0	0.0
110 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	94.1	9.3	431.8	0.0	0.0	0.0
	F	96.1	0.0	393.9	0.0	0.0	0.0
120 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	22.2	0.0	0.0	0.0	0.0	0.0
	E	103.1	9.3	492.4	0.0	0.0	0.0
	F	105.0	0.0	414.2	0.0	0.0	0.0

Table D.29
Newly installed capacity for the PET plant under different grid connection capacity values. f_{grcap} is the percentage of the connection capacity required for a fully electrified utility supply.

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
50 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	22.6	4.9	80.3	0.0	0.0	0.0
	F	23.5	0.0	67.4	0.0	0.0	0.0
60 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	27.6	4.9	107.2	0.0	0.0	0.0
	F	28.4	0.0	96.9	0.0	0.0	0.0
70 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	32.5	4.9	141.6	0.0	0.0	0.0
	F	33.3	0.0	126.5	0.0	0.0	0.0
80 %	A	0.0	0.0	0.0	0.0	0.0	0.0

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Table D.29 *(continued)*

f_{grcap}	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 Boiler [MW]	H2 storage [MWh]
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	37.4	4.9	176.1	0.0	0.0	0.0
	F	38.2	0.0	156.0	0.0	0.0	0.0
90 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	42.2	4.9	209.4	0.0	0.0	0.0
	F	43.2	0.0	185.5	0.0	0.0	0.0
110 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	52.0	4.9	238.5	0.0	0.0	0.0
	F	53.0	0.0	217.7	0.0	0.0	0.0
120 %	A	0.0	0.0	0.0	0.0	0.0	0.0
	B	0.0	0.0	0.0	0.0	0.0	0.0
	C	0.0	0.0	0.0	0.0	0.0	0.0
	D	12.2	0.0	0.0	0.0	0.0	0.0
	E	56.9	4.9	268.1	0.0	0.0	0.0
	F	57.9	0.0	228.5	0.0	0.0	0.0

D.3. Impact of the minimal load of the legacy technology

Table D.30
Additionally installed utility technologies for the cost-optimal utility system for an Olefins plant for six years, a grid connection capacity of 692.4 MW and the lower minimal load of the CHP.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	126.6	0.0	0.0	0.0	0.0	0.0
2021	126.6	0.0	0.0	0.0	0.0	0.0
2022	445.4	609.8	2531.9	0.0	0.0	0.0
2023	551.3	0.0	2391.2	0.0	0.0	0.0

Table D.31
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the Olefins plant for distinct years, a grid connection capacity of 692.4 MW and a lower minimal load of the CHP.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	107.8	107.8	0.0	723.4	723.4	0.0
2019	84.7	84.7	0.0	723.4	723.4	0.0
2020	59.4	58.7	1.2	723.4	668.6	7.8
2021	212.9	205.3	3.6	723.4	634.1	12.3
2022	619.5	547.8	11.6	723.4	496.1	31.4
2023	245.0	219.0	10.6	723.4	501.7	30.7

Table D.32
Additionally installed utility technologies for the cost-optimal utility system for an ethylene oxide plant for six different years, a grid connection capacity of 97.4 MW and the lower minimal load of the CHP.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	21.1	0.0	0.0	0.0	0.0	0.0
2021	21.0	0.0	0.0	0.0	0.0	0.0
2022	69.7	77.8	389.0	0.0	0.0	0.0
2023	83.2	0.0	372.8	0.0	0.0	0.0

Table D.33
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the ethylene oxide plant for six different years, a grid connection capacity of 97.4 MW and a lower minimal load of the CHP.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	14.1	14.1	0.0	120.3	120.3	0.0
2019	11.1	11.1	0.0	120.3	120.3	0.0
2020	7.5	7.6	1.3	111.2	120.3	7.6
2021	27.6	28.8	4.2	105.4	120.3	12.4
2022	74.4	85.5	13.0	82.9	120.3	31.1
2023	29.4	33.6	12.5	84.4	120.3	29.8

Table D.34
Additionally installed utility technologies for the cost-optimal utility system for an ethylbenzene plant for six different years, a grid connection capacity of 85.8 MW and a minimal load of the GB of 30 % of its capacity.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	30.4	0.0	0.0	0.0	0.0	0.0
2022	83.4	3.8	371.5	0.0	0.0	0.0
2023	84.1	0.0	322.4	0.0	0.0	0.0

Table D.35
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the ethylbenzene plant for six different years, a grid connection capacity of 85.8 MW and a lower minimal load of the GB.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	10.1	10.1	0.0	77.1	77.1	0.0
2019	7.9	7.9	0.0	77.1	77.1	0.0
2020	5.5	5.5	0.0	77.1	77.1	0.0
2021	20.2	19.9	1.5	77.1	72.1	6.5
2022	59.5	54.9	7.7	77.1	59.6	22.7
2023	23.5	21.1	10.2	77.1	60.6	21.4

Table D.36
Additionally installed utility technologies for the cost-optimal utility system for an ethylene glycol plant for six different years, a grid connection capacity of 90.2 MW and the lower minimal load of the GB.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	31.1	0.0	0.0	0.0	0.0	0.0
2022	85.5	9.3	381.5	0.0	0.0	0.0
2023	87.1	0.0	336.7	0.0	0.0	0.0

Table D.37
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the ethylene glycol plant for six different years, a grid connection capacity of 90.2 MW and a lower minimal load of the GB.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	10.8	10.8	0.0	78.8	78.8	0.0
2019	8.5	8.5	0.0	78.8	78.8	0.0
2020	5.9	5.9	0.0	78.8	78.8	0.0
2021	21.6	21.3	1.4	78.8	73.6	6.6
2022	63.3	58.5	7.6	78.8	60.9	22.7
2023	25.0	22.6	9.6	78.8	61.7	21.7

Table D.38
Additionally installed utility technologies for the cost-optimal utility system for a PET plant for six different years, a grid connection capacity of 49.7 MW and the lower minimal load of the GB.

Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	17.1	0.0	0.0	0.0	0.0	0.0
2022	47.2	4.9	210.7	0.0	0.0	0.0
2023	48.1	0.0	185.7	0.0	0.0	0.0

Table D.39
Total cost and scope 1 CO_2 emissions of benchmark and new utility system for the PET plant for six different years, a grid connection capacity of 49.7 MW and a lower minimal load of the GB.

	Total cost [million euro]			Scope 1 CO_2 emissions [kiloton]		
Year	CHP-based system	New system	Reduction [%]	CHP-based system	New system	Reduction [%]
2018	6.0	6.0	0.0	43.5	43.5	0.0
2019	4.7	4.7	0.0	43.5	43.5	0.0
2020	3.3	3.3	0.0	43.5	43.5	0.0
2021	11.9	11.7	1.7	43.5	40.7	6.4
2022	34.8	32.2	7.5	43.5	33.7	22.5
2023	13.8	12.4	10.1	43.5	34.1	21.6

D.4. Impact of different technology cost scenarios

Table D.40
Additionally installed utility technologies for the cost-optimal utility system for an Olefins plant for six capex scenarios and six different years. The grid connection capacity is 692.4 MW. Bold values indicate changes compared to previous results.

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
Bat-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2020	90.4	0.0	0.0	0.0	0.0	0.0
Bat-High	2021	90.4	0.0	0.0	0.0	0.0	0.0
Bat-High	2022	**462.3**	**556.3**	**2813.2**	0.0	0.0	0.0
Bat-High	2023	511.1	0.0	2103.2	0.0	0.0	0.0
Bat-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2020	90.4	0.0	0.0	0.0	0.0	0.0
Bat-Low	2021	90.4	0.0	0.0	0.0	0.0	0.0
Bat-Low	2022	**385.0**	**927.1**	**2342.6**	0.0	0.0	0.0
Bat-Low	2023	**433.8**	**370.8**	**1716.7**	0.0	0.0	0.0
TES-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2020	90.4	0.0	0.0	0.0	0.0	0.0
TES-High	2021	90.4	0.0	0.0	0.0	0.0	0.0
TES-High	2022	423.6	741.7	**1999.1**	0.0	0.0	0.0
TES-High	2023	511.1	0.0	**1682.5**	0.0	0.0	0.0
TES-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2020	90.4	0.0	0.0	0.0	0.0	0.0
TES-Low	2021	**130.6**	0.0	**200.9**	0.0	0.0	0.0
TES-Low	2022	**449.4**	741.7	**3417.8**	0.0	0.0	0.0
TES-Low	2023	**542.5**	0.0	**2712.7**	0.0	0.0	0.0
H2E-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2020	90.4	0.0	0.0	0.0	0.0	0.0
H2E-High	2021	90.4	0.0	0.0	0.0	0.0	0.0
H2E-High	2022	423.6	741.7	2591.7	0.0	0.0	0.0
H2E-High	2023	511.1	0.0	2103.2	0.0	0.0	0.0
H2E-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2020	90.4	0.0	0.0	0.0	0.0	0.0
H2E-Low	2021	90.4	0.0	0.0	0.0	0.0	0.0
H2E-Low	2022	423.6	741.7	2591.7	0.0	0.0	0.0
H2E-Low	2023	511.1	0.0	2103.2	0.0	0.0	0.0

Table D.41
Additionally installed utility technologies for the cost-optimal utility system for an ethylene oxide plant for six capex scenarios and six different years. The grid connection capacity is 97.4 MW. Bold values indicate changes compared to previous results.

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
Bat-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2020	15.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2021	15.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2022	**74.4**	**63.7**	**444.9**	0.0	0.0	0.0
Bat-High	2023	76.5	0.0	307.3	0.0	0.0	0.0
Bat-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2020	15.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2021	15.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2022	**65.5**	**106.1**	**399.7**	0.0	0.0	0.0
Bat-Low	2023	**69.1**	**42.5**	**284.0**	0.0	0.0	0.0
TES-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2020	15.0	0.0	0.0	0.0	0.0	0.0
TES-High	2021	15.0	0.0	0.0	0.0	0.0	0.0
TES-High	2022	70.0	84.9	**329.5**	0.0	0.0	0.0
TES-High	2023	76.5	0.0	**278.5**	0.0	0.0	0.0
TES-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2020	15.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2021	**21.7**	0.0	**33.4**	0.0	0.0	0.0
TES-Low	2022	**72.9**	84.9	**544.8**	0.0	0.0	0.0
TES-Low	2023	**87.4**	0.0	**434.3**	0.0	0.0	0.0
H2E-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2020	15.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2021	15.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2022	70.0	84.9	423.7	0.0	0.0	0.0
H2E-High	2023	76.5	0.0	307.3	0.0	0.0	0.0
H2E-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2020	15.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2021	15.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2022	70.0	84.9	423.7	0.0	0.0	0.0
H2E-Low	2023	76.5	0.0	307.3	0.0	0.0	0.0

Table D.42
Additionally installed utility technologies for the cost-optimal utility system for an ethylbenzene plant for six capex scenarios and six different years. The grid connection capacity is 85.8 MW. Bold values indicate changes compared to previous results.

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
Bat-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2021	21.7	0.0	0.0	0.0	0.0	0.0
Bat-High	2022	**83.5**	**2.8**	385.4	0.0	0.0	0.0
Bat-High	2023	84.1	0.0	361.3	0.0	0.0	0.0
Bat-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2021	21.7	0.0	0.0	0.0	0.0	0.0
Bat-Low	2022	**83.1**	**4.7**	385.4	0.0	0.0	0.0
Bat-Low	2023	**83.6**	**1.9**	361.3	0.0	0.0	0.0

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Table D.42 *(continued)*

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
TES-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2021	21.7	0.0	0.0	0.0	0.0	0.0
TES-High	2022	**83.1**	3.8	**368.5**	0.0	0.0	0.0
TES-High	2023	84.1	0.0	**312.0**	0.0	0.0	0.0
TES-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2021	21.7	0.0	**33.4**	0.0	0.0	0.0
TES-Low	2022	**83.4**	3.8	**494.0**	0.0	0.0	0.0
TES-Low	2023	84.1	0.0	**374.4**	0.0	0.0	0.0
H2E-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2021	21.7	0.0	0.0	0.0	0.0	0.0
H2E-High	2022	83.3	3.8	385.4	0.0	0.0	0.0
H2E-High	2023	84.1	0.0	361.3	0.0	0.0	0.0
H2E-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2021	21.7	0.0	0.0	0.0	0.0	0.0
H2E-Low	2022	83.3	3.8	385.4	0.0	0.0	0.0
H2E-Low	2023	84.1	0.0	361.3	0.0	0.0	0.0

Table D.43
Additionally installed utility technologies for the cost-optimal utility system for an ethylene glycol plant for six capex scenarios and six different years. The grid connection capacity is 90.2 MW. Bold values indicate changes compared to previous results.

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
Bat-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2021	22.2	0.0	0.0	0.0	0.0	0.0
Bat-High	2022	**85.7**	**6.9**	393.9	0.0	0.0	0.0
Bat-High	2023	87.1	0.0	369.3	0.0	0.0	0.0
Bat-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2021	22.2	0.0	0.0	0.0	0.0	0.0
Bat-Low	2022	**84.7**	**11.6**	393.9	0.0	0.0	0.0
Bat-Low	2023	**85.9**	**4.6**	369.3	0.0	0.0	0.0
TES-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2021	22.2	0.0	0.0	0.0	0.0	0.0
TES-High	2022	**84.7**	9.3	**375.4**	0.0	0.0	0.0
TES-High	2023	87.1	0.0	**324.9**	0.0	0.0	0.0
TES-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2021	22.2	0.0	**33.4**	0.0	0.0	0.0
TES-Low	2022	**85.5**	9.3	**506.9**	0.0	0.0	0.0
TES-Low	2023	87.1	0.0	**389.8**	0.0	0.0	0.0

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Table D.43 *(continued)*

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
H2E-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2021	22.2	0.0	0.0	0.0	0.0	0.0
H2E-High	2022	85.2	9.3	393.9	0.0	0.0	0.0
H2E-High	2023	87.1	0.0	369.3	0.0	0.0	0.0
H2E-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2021	22.2	0.0	0.0	0.0	0.0	0.0
H2E-Low	2022	85.2	9.3	393.9	0.0	0.0	0.0
H2E-Low	2023	87.1	0.0	369.3	0.0	0.0	0.0

Table D.44
Additionally installed utility technologies for the cost-optimal utility system for a PET plant for six capex scenarios and six different years. The grid connection capacity is 49.7 MW. Bold values indicate changes compared to previous results.

TC scenario	Year	Electric boiler [MW]	Battery [MWh]	TES [MWh]	Electrolyser [MW]	H2 boiler [MW]	H2 storage [MWh]
Bat-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
Bat-High	2021	12.2	0.0	0.0	0.0	0.0	0.0
Bat-High	2022	**47.3**	**3.7**	217.7	0.0	0.0	0.0
Bat-High	2023	48.1	0.0	204.1	0.0	0.0	0.0
Bat-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
Bat-Low	2021	12.2	0.0	0.0	0.0	0.0	0.0
Bat-Low	2022	**46.8**	**6.1**	217.7	0.0	0.0	0.0
Bat-Low	2023	**47.5**	**2.4**	204.1	0.0	0.0	0.0
TES-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
TES-High	2021	12.2	0.0	0.0	0.0	0.0	0.0
TES-High	2022	47.1	4.9	**209.0**	0.0	0.0	0.0
TES-High	2023	48.1	0.0	**179.2**	0.0	0.0	0.0
TES-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
TES-Low	2021	12.2	0.0	**33.4**	0.0	0.0	0.0
TES-Low	2022	**47.2**	4.9	**280.0**	0.0	0.0	0.0
TES-Low	2023	48.1	0.0	**215.1**	0.0	0.0	0.0
H2E-High	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2020	0.0	0.0	0.0	0.0	0.0	0.0
H2E-High	2021	12.2	0.0	0.0	0.0	0.0	0.0
H2E-High	2022	47.1	4.9	217.7	0.0	0.0	0.0
H2E-High	2023	48.1	0.0	204.1	0.0	0.0	0.0
H2E-Low	2018	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2019	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2020	0.0	0.0	0.0	0.0	0.0	0.0
H2E-Low	2021	12.2	0.0	0.0	0.0	0.0	0.0
H2E-Low	2022	47.1	4.9	217.7	0.0	0.0	0.0
H2E-Low	2023	48.1	0.0	204.1	0.0	0.0	0.0

Data availability

The code, selected input data, and all results are available in a 4TU repository with https://doi.org/10.4121/a78d852f-b103-4651-8dba-a1148eac7c58. The code is also publicly available on GitHub (SvenjaBie/ElectrUtilEtyhlInd_Open).

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