Operational Carbon Mitigation Potential of Flexible Multi-Energy Systems: A Case Study

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***Abstract*—We examine the carbon mitigation potential of operational adjustments for a German university campus. To this end, we compare the modeled cost-optimal operation with CO_2-minimizing dispatch plans where different limits for the additional, specific CO_2 mitigation costs are set. At first, the operational mitigation potential of today's combined heat and power (CHP) driven energy system is analyzed. Then we examine the possible effects of increased flexibility of this multi-energy system by adding heat pumps and heat storage. We include a detailed account of today's operational cost structure including taxes and subsidies. To correctly represent the CO_2 footprint of consumed electricity from the grid, we consider the CO_2 intensity of Germany's electricity mix as time-dependent. This is important to correctly honor the impact of the multi-energy system's flexibility. We find that given the current regulatory environment, without considering investment costs, large CO_2 reductions compared to the modeled cost-optimal operation can only be achieved for specific CO_2 mitigation costs above 150€/t. Small reductions can be obtained at much lower cost when a heat pump operates in parallel with the CHP. However, for all scenarios the CO_2 reductions can only be realized by exploiting periods with low CO_2 intensity of the grid's electricity.**

***Index Terms*—CO_2 price, CO_2 emission, electricity market regulation, energy system optimization**

I. Introduction

CO_2 emission reduction is one of the most important challenges of the next decades to limit the global warming below 2.0°C [1]. For a real university campus with electricity, heat, and cold demand, we examine what could be achieved to this end by taking different operational decisions. Such multi-energy systems show high operational flexibility [2, 3, 4]. We examine how the local system can interact with its environment, i.e., the national grid, in order to reduce overall CO_2 emissions. Specifically, we aim at exploiting the strongly time-dependent CO_2 intensity of the national electricity mix. The local system should use electricity from the grid when the CO_2 intensity is lower than the one of the local production.

Operation of multi-energy systems in practice is mostly driven by cost minimization today. To estimate the maximum operational CO_2 reduction potential, one could instead minimize CO_2 emissions during the scheduling process [5, 4]. However, minimization of the emissions only often results in very high costs per tone of reduced CO_2. This would rarely be acceptable to real operators.

To overcome this challenge, we utilize a new two-staged optimization approach in this paper. First, we obtain the cost-optimal dispatch for the modeled system setup. In the second stage, we use the same system model but with the objective of CO_2 emission minimization. At the same time, we constraint the system's operational costs by the cost-optimal benchmark plus allowable CO_2 mitigation costs. These costs are defined by the multiplication of the emission difference between the two stages and a preset specific CO_2 mitigation costs. Since the cost-optimal dispatch is feasible also for the second stage problem, a solution always exists. It will yield reduced CO_2 emissions exactly when the given the cap on specific mitigation costs allows for it.

We apply this method at first to a model of our university campus energy system as it is today, featuring among others a combined heat and power (CHP) plant. Additionally in further scenarios, we extend the system setup with plausible additional technologies, namely heat pumps and heat storage. We examine the first 13 weeks of the year 2021 and obtain the mitigation potential per specific CO_2 price. We only consider variable cost components and do not take any investment costs into account.

II. Methodology of the Two-Stage Optimization

Our energy system model aims to cover system limitations, flexbilities as well as inflexibilities using a mixed-integer linear programming setup. We introduce two different objectives for the two stages, first overall operation costs and second overall CO_2 emissions. The optimization model is equal for both stages, except for the objective function and the cost limitation equation of the second stage.

System components sc consume and produce different energy forms (commodities) c. They consist of different conversion processes cp, where each cp is defined via a triple (c_{in}, sc, c_{out}) of exactly one input commodity c_{in}, the system component sc it belongs to, and one output commodity c_{out}. The input and output power of a conversion process cp at time step t is denoted by $P_{in/out}(c_{in}, sc, c_{out}, t)$.

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The objective of the first stage is the minimization of the total costs Γ, defined as

$$\Gamma = \sum_t \sum_{sc} P_{in}(c_{in}, sc, c_{out}, t) OM_{cost}(sc, t). \quad (1)$$

Here, $OM_{cost}(sc, t)$ are the sc-specific operation and maintenance cost including fuel costs at time step t.

The objective of the second stage changes to the minimization of the total emissions E, defined as

$$E = \sum_t \sum_{sc} P_{in}(c_{in}, sc, c_{out}, t) CO_2 I(c_{in}, t). \quad (2)$$

Here, $CO_2I(c_{in}, t)$ is the time-dependent CO_2 intensity of the input commodity. Specifically, we account for the system's CO_2 emissions via the amount of imported natural gas and used electricity from the national grid. The cost limitation of the second stage is defined as

$$\Gamma - \Gamma_{\Gamma_{opt}} \leq \pi_{CO_2}(E_{\Gamma_{opt}} - E) \quad (3)$$

where $\Gamma_{\Gamma_{opt}}$ and $E_{\Gamma_{opt}}$ denote the total costs and emissions from the first stage optimization, respectively.

All other equations describe operational constraints and are valid for both second and first stage. The efficiency of a conversion process cp is defined as

$$P_{in}(c_{in}, sc, c_{out}, t)\eta_{cp} = P_{out}(c_{in}, sc, c_{out}, t) \quad (4)$$

where η_{cp} is the specific efficiency. The power balance per energy commodity c is

$$\sum_{sc, c_{out}} P_{in}(c, sc, c_{out}, t) = \sum_{sc, c_{in}} P_{out}(c_{in}, sc, c, t). \quad (5)$$

Each conversion process cp is limited in power at any time step t,

$$P_{out}(c_{in}, sc, c_{out}, t) \leq u(cp, t)\overline{Cap}(cp) \quad (6)$$

$$P_{out}(c_{in}, sc, c_{out}, t) \geq u(cp, t)\underline{Cap}(cp) \quad (7)$$

Here, $u(cp, t)$ is a binary indicator variable of the on/off state at time t and $\overline{Cap}(cp)$ and $\underline{Cap}(cp)$ the upper and lower power limits in operation mode, respectively. Constraints for minimal up/down times use the indicators $z(cp, t)$ for a start-up time step and $w(cp, t)$ for a shut-down time step. We then use [6]

$$u(cp, t) - u(cp, t-1) = z(cp, t) - w(cp, t), \quad (8)$$

$$z(cp, t) \leq u(cp, t), \quad (9)$$

$$z(cp, t) \geq u(cp, t) - u(cp, t-1), \quad (10)$$

$$z(cp, t) \leq 1 - u(cp, t-1), \quad (11)$$

$$z(cp, t) \leq u(cp, k), \quad k \in [t, t + \sigma_{cp} - 1], \quad (12)$$

$$1 - u(cp, k) \geq w(cp, t), \quad k \in [t, t + \rho_{cp} - 1]. \quad (13)$$

Here, σ_{cp} is the minimal operation period of the conversion process cp after start-up and ρ_{cp} the minimal downtime after a shut-down. For each storage component the storage level $EL_{stor}(cp, t)$ is defined via

$$EL_{stor}(cp, t-1)(1 - \eta_{cp_{SD}} + P_{in}(c_{in}, sc, c_{out}, t)\eta_{cp_{in}} = EL_{stor}(cp, t) + \frac{P_{out}(c_{in}, sc, c_{out}, t)}{\eta_{cp_{out}}}. \quad (14)$$

Here, $\eta_{cp_{in}}$ is the input efficiency, $\eta_{cp_{out}}$ the output efficiency, and $\eta_{cp_{SD}}$ the self-discharge rate assumed as 2% per hour throughout. Storage levels are constrained as

$$0 \leq EL_{stor}(cp, t) \leq \overline{EL}_{stor}(cp). \quad (15)$$

given the maximal storage size $\overline{EL}_{stor}(cp)$.

III. The Case Study: A University Campus

The energy system underlying this study is the one of the campus Lichtwiese of the Technical University Darmstadt. Figure 1 depicts all possible energy flows of the system setup as it is today. The annual energy demand is approx. $23GWh$ electricity, $25GWh$ heat, and $8GWh$ cold. On site generation covers also demands for other campuses of the university. A recently built multi-energy monitoring system for electricity, heat and cold provides high resolution energy demand data of the campus. This study uses 15 min aggregated values of the buildings' specific demand trajectories. The demand of the remaining university areas supplied is also monitored with measurements at the system boundary and is included into the demands.

We first investigate the operational CO_2 mitigation potential of the current system setup, the base scenario (BSC). We then extend the basic system by different heat generation and storage technologies, to study the additional benefits of increased sector-coupling and flexibility options. Scenario 1 (SC1) represents an extension by brine-water heat pumps. Scenario 2 (SC2) additionally considers a significantly larger heat storage than the small existing one of the BSC. Scenario 3 (SC3) aims for full electrification of the heat generation by considering an additional, large-scale heat pump. Since the brine-water potential is limited, the large heat pump is modeled as a air-source heat with a lower COP than the small heat pump of SC1&2. Table I summarizes all parameter values of the system components.

The flexibility of the system is the key for being able to exploit periods of low prices and/or low CO_2 intensities of electricity from the the national grid. Local generation may need to be shut down to use more low-carbon electricity from the grid. This is only feasible if the duration of low CO_2 intensity or prices is long enough to outlast the restriction of minimal downtime of local production. Potential ramping restrictions for the local generation also have to allow for flexible adaptions, such that the system can benefit from the short periods of low CO_2 intensity and/or prices. We do not consider the ramp rates, though, since all our system components are flexible enough to perform any adaption within the modeled time resolution of 15 minutes.

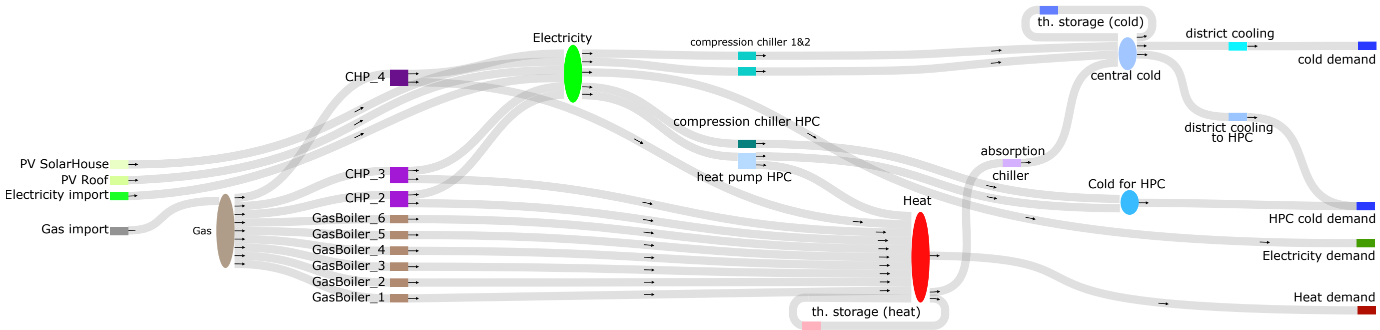

Fig. 1: Modeled energy flows of the campus energy system as it is today (basic system scenario, BSC). The energy system consists of six gas boilers, three CHPs, one absorption chiller, and three compression chillers, where one of these provides cooling explicitly for the high performance computer (HPC). Renewable sources are two small photovoltaic systems ($< 25kWp$). Natural gas and additional electricity are imported into the model regime from the national grid.

TABLE I: List of all system components including the extensions of the scenarios

System component sc	fuel η	Power/Energy limit (Cap/EL_{stor}) Upper	Lower	Minimal Up-/Down-time
Base scenario				
Gas Boiler 1-6	0.91	9.3 MW_{th}	0.93 MW_{th}	-/-
Th. storage cold	-	1.7 MWh 1.6 MW_{th}		-
Th. storage heat	-	8.3 MWh 5 MW_{th}		-
CHP 2&3	0.87	$2.0 MW_{el}$ $2.0 MW_{th}$	$1.0 MW_{el}$ $1.0 MW_{th}$	2h/2h
CHP 4	0.88	3.3 MW_{el} 3.0 MW_{th}	1.6 MW_{el} 1.5 MW_{th}	2h/2h
Abs. chiller	0.74	1 MW_{th}	0 MW_{th}	-/-
Compr. chillers	2.70	0.5 MW_{th}	0 MW_{th}	-/-
Scenario 1 extension: heat pump				
Heat pump	4.00	3 MW_{th}	0.3 MW_{th}	2h/2h
Scenario 2 extension: heat pump and additional larger storage				
Heat pump	4.00	3 MW_{th}	0.3 MW_{th}	2h/2h
Th. Storage heat	-	120 MWh 5 MW_{th}		-/-
Scenario 3 extension: huge heat pump and additional larger storage				
Heat pump	3.00	10 MW_{th}	0.5 MW_{th}	2h/2h
Th. Storage heat	-	120 MWh 5 MW_{th}		-/-

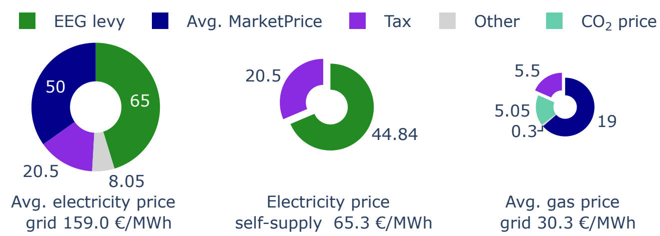

Fig. 2: Composition of the relevant energy costs. The shown market price is the average over the first 13 weeks of 2021.

IV. Energy Costs and CO_2 Intensities

An overview of the composition of the energy costs is shown in figure 2. The costs for electricity from the grid are based on the German hourly day-ahead spot market price. We also include the currently applicable regulatory costs. For electricity from the grid, EEG levy, grid fees, electricity tax and a few other fees apply. For self-consumed own generation, the EEG levy and the electricity tax have to be considered. The EEG levy is reduced in this case and we calculate it assuming 6750 full load hours for the CHPs. The electricity tax has to be paid for self-consumed electricity generation from the large CHP, but not for the small ones which are below the threshold of greater than 2 MW_{el}. The gas cost calculation is based on the TTF gas neutral price. Applicable taxes are the energy tax, grid fees and a concession fee. Additionally, we consider the novel CO_2 price for gas introduced in Germany at the beginning of 2021.

While energy prices are commonly considered as time-dependent, we claim that this should also apply to the CO_2 intensities of imported electricity. Note that this is not the case given Germany's current regulatory framework for assessing local CO_2 emissions. Local energy systems only then could benefit through its flexibility from temporally low CO_2 intensities in the grid and avoid using electricity when its production is mainly from fossil sources. We calculate the CO_2 intensity of the German national electricity mix as a supply weighted average for each time step, using the historical supply data (production per type) from the ENTSO-E transparency platform. We do not take cross border energy flows into account and assume Germany to be a copper plate. The CO_2 intensity of gas is $0.202t/MWh$ throughout.

V. Results for Operational CO_2 Mitigation Potential

Figure 3 shows the main results of our analysis. It covers the first 13 calendar weeks of the year 2021. Each week is

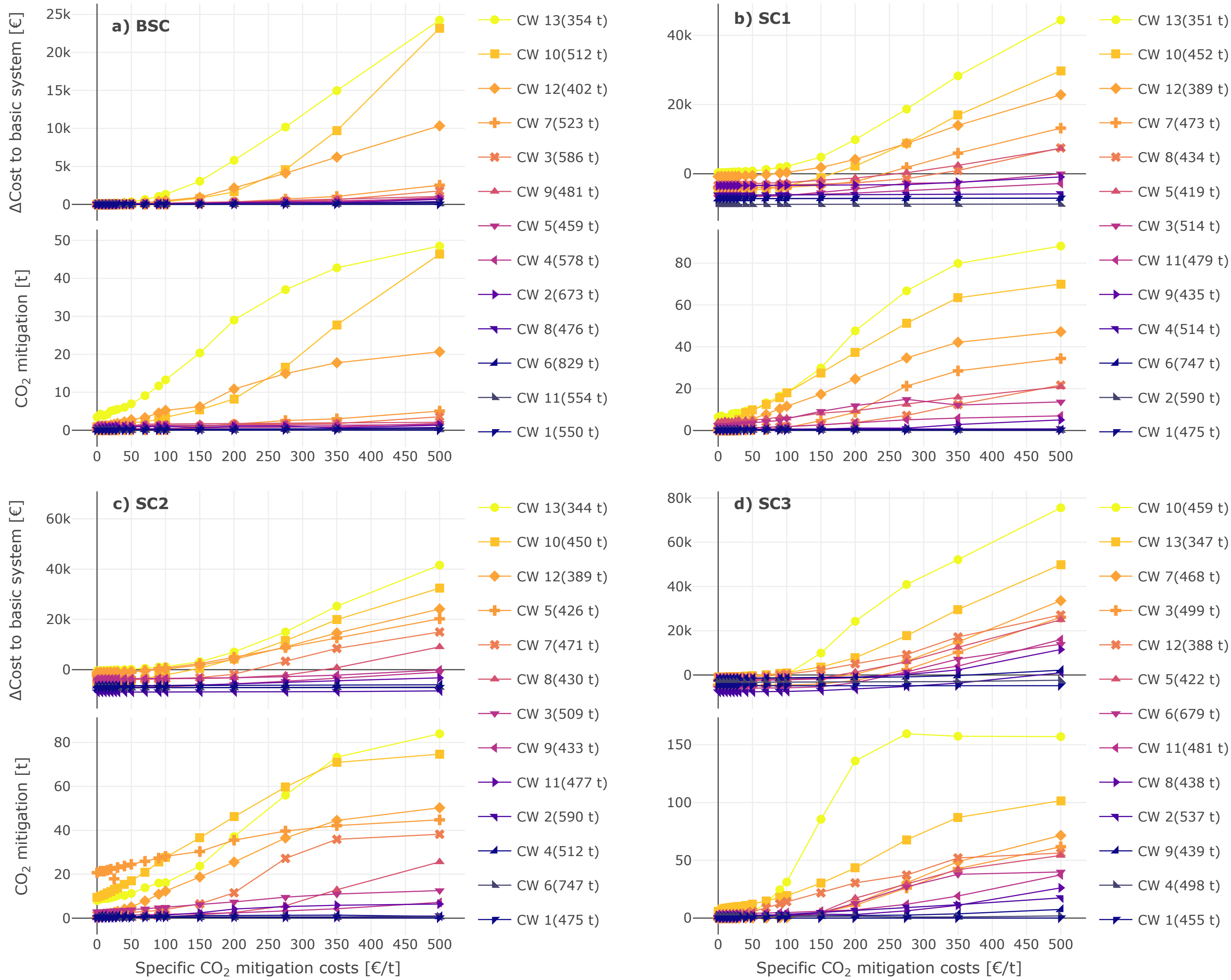

Fig. 3: CO_2 mitigation potential depending on the allowed specific CO_2 mitigation price compared to the modeled cost-optimal system operation, for the first 13 weeks of 2021. Subfigures a)-d) show the results for the different considered system setups. In each subfigure the top plot shows the cost difference in comparison to cost-optimal operation of the BSC system. The bottom plot gives the total CO_2 emission reduction compared to the cost-optimal operation of the same system. Each legend additionally states the CO_2 emissions of the cost-optimal operation of the subfigure's scenario for each calender week. Note that the scaling and the color-coding is different in each plot. Significant CO_2 emission reductions can be achieved in weeks when the CO_2 intensity of electricity from the national grid is low.

analyzed separately and perfect foresight for demands and prices is assumed. The first optimization stage is solved once per calendar week for the basic system and each scenario. The second stage, emission objective optimization is solved with a pre-defined specific CO_2 mitigation price limit from 0 to 500 €/t.

We extract four major observations and findings:

1) Significant CO_2 emission reductions of up to 30% (CW10, setup SC3) are possible via operational measures, even with today's electricity mix in the national grid. Across all scenarios the weeks with the highest mitigation potential are CW 10 & 13. These weeks are the ones with longer periods of low CO_2 intensity for electricity from the grid. Flexible multi-energy systems are thus shown to be able to exploit these periods, yielding lower local CO_2 emission balances.
2) The specific CO_2 mitigation costs for which significant emission reductions can be achieved by taking operational measures are in the range above 150 €/t for most setups. During week CW13 one could reduce the systems' CO_2 emissions by approx. 6% for 150 €/t or up to approx. 14% for 500€/t. The highest absolute CO_2 mitigation potential of about 30% is observed for CW10 and system setup SC3 at 275€/t.

The observed specific mitigation costs are very high compared to the trading price for EU-ETS emission allowances of approx. 40 €/t (April 2021) or the recently introduced German CO_2 tax of 25€/t.

3) Smaller CO_2 emission reductions can be achieved operationally at lower specific costs. Specifically for scenario 2 with a small heat pump and a significant heat storage a CO_2 reduction in the range of 5-25t can be saved per week at almost no additional costs compared to the modeled cost-optimal operation. This is because low-CO_2 electricity from the grid can immediately be converted into heat yielding lower specific emissions per heat unit than heat from the CHP or the gas boilers. The storage additionally allows to shift significant energy amounts to times of high heat demand. Still, the savings depend on how well the time periods of demand and low CO_2 fit together in a specific week.
The basic system could also save approx. 9t for 75€/t in CW 13 with low CO_2 intensity of the grid. Then the grid covers the full electricity demand and only boilers supply the heat.
4) System setups including heat pumps allow for reduced CO_2 emissions even if only cost-optimal operation is assumed. The emissions for setup SC1 are on average over all considered weeks 9.6% lower than for the basic setup. Moreover, the integration of heat pumps into a CHP-driven system reduces the operational costs in all weeks – without considering investment costs. This is achieved by using the electricity generated by the local CHPs for the heat pumps which are more efficient than the gas boilers.

VI. Conclusion

This case study confirms that realistic multi-energy systems allow to exploit periods when the CO_2 intensity of electricity from the national grid is low. Their operational flexibility can thus be explicitly valued in terms of possible CO_2 emission reductions. In our case study, up to 30% of emission reductions can be achieved for some weeks given the most flexible setup.

However, the computed specific mitigation costs, above 150 €/t for significant savings, are rather high compared to different current CO_2 prices, e.g., the EU-ETS price of approx. 40 €/t (April 2021) or the currently introduced CO_2 tax in Germany of 25 €/t. The obtained specific mitigation costs thus probably surpass plausible levels of goodwill and the necessary operational adjustments to realize these emission savings may thus not be practically acceptable for real operators.

However, the required specific mitigation costs for significant CO_2 emission reductions will decline in the future. When the CO_2 intensity of the national energy mix decreases with increasing share of renewable energies, the spread of the CO intensities (local vs. grid electricity generation) will increase, and consequently the potential for CO_2 mitigation by using electricity from the grid will rise and the specific costs will drop.

Germany's currently high subsidies for CHP self-supply in terms of gas tax refund and significantly lower fees and levies of electricity for self-consumption, on the other hand, counteract this potential by overly prioritizing the CHP option. This will remain true even if one day the electricity from the grid will be highly renewable and show a low CO_2 intensity.

As a result, we propose two necessary adaptions of the regulatory framework to realize the potential of the proposed operational CO_2 mitigation. First, the legal framework should account for time-dependent CO_2 intensity which, currently, it does not. Second, with increasing renewables, the subsidies for CHP self-supply and consumption should be lowered not to counteract the proposed CO_2 mitigation potential.

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