Impact of electricity price policies on optimal district energy system design

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Abstract

A variety of electricity price policies are currently implemented or under consideration in different places around the world. This includes electricity feed-in policies such as feed-in tariffs and net metering, as well as electricity withdrawal price policies such as time-of-use and real-time electricity pricing. Different electricity price policies may influence the economic feasibility and sustainability performance of district energy systems in different ways. However, the precise nature of these relationships is unknown. This paper applies a deterministic mixed-integer linear programming approach to investigate the influence of different electricity price policies on the optimal technical configuration, costs and carbon emissions of a hypothetical district energy system.

The results highlight the potential benefits of a net metering policy to incentivize technical configurations with low carbon emissions, and of a time-of-use pricing policy to incentivize technical configurations with relatively low carbon emissions and low costs. A policy combining net metering and time-of-use pricing is shown to partially realize the combined advantages of these two policies. Furthermore, the results suggest that the precise timing of price variations under dynamic electricity pricing schemes may significantly influence system design incentives and system performance.

Introduction

Distributed energy systems are critical to enabling significant reductions in the carbon footprint of the built environment. *District-scale* energy systems – which enable the exchange of energy amongst buildings in an (urban) district – can, under certain conditions, be an efficient means of facilitating the integration of renewable and low-carbon energy sources. District energy systems have already been realized in a number of cities globally, and their development is foreseen to increase over the coming decades (UNEP, 2015). Both the economic feasibility and the optimal technical composition of district energy systems may be influenced by *electricity price policies* – policies influencing the magnitude and dynamics of prices for electricity feed-in to and withdrawal from the grid.

This, in turn, may influence to what degree and how district energy systems end up being deployed in practice, and ultimately the carbon footprint of the built environment.

The energy policy landscape is highly dynamic, with changes in renewables support policies and electricity pricing structures being considered in Europe, the United States and elsewhere. Policies implemented or under consideration include feed-in tariffs (FITs), feed-in-premiums, net metering, capacity charges, dynamic (e.g. time-of-use or real-time) electricity pricing, network charges, electricity taxes and subsidies for renewable energy installations (e.g. rooftop photovoltaics). These policies may furthermore be implemented in different ways, e.g. different FIT levels, different time-of-use pricing structures. Both *which* policies are implemented and *how* they are implemented may have consequences for the economic feasibility and optimal configuration of district energy systems.

The purpose of this paper is to investigate the influence of different electricity price policies on the optimal technical configuration and overall cost and emissions of a district energy system. The paper describes the implementation and results of a model which calculates the optimal technical configuration and associated costs of a hypothetical district energy system under the influence of different electricity price policies. The developed model is implemented as a mixed-integer linear program, the formulation of which is based on the concept of the energy hub (Geidl and Andersson, 2007).

The paper continues in the following section with an overview of related research, and further specification of the knowledge gap being addressed. After this, the formulation of the model and setup of the experiments are described in some detail, including important assumptions and limitations. Next, key results from the experiments are presented and their implications are discussed. Finally, some conclusions are drawn with respect to the economic feasibility and optimal technical design of district energy systems under different electricity price policies.

Related research

A significant and growing body of research has investigated the influences of electricity price policies on renewable energy investments. Palmer et al. (2015); Zhao et al. (2011); Hsu (2012) used agent-based and system dynamics simulation to study the diffusion of solar photovoltaics under under different policies, such as FITs and capital subsidies. Reuter et al. (2012) used a real options model to investigate the decisions of an electricity producer to invest in renewables under different electricity price policies. Oliveira (2015) applied industrial economics theory to assess the effects of FITs and feed-in-premiums on renewables investments. Couture and Gagnon (2010) assessed the implications of different FIT remuneration models on renewable energy investments.

A smaller body of research has focused on the effects of electricity price policies on district energy systems. Most of this research has addressed the effects of dynamic electricity prices and electricity price uncertainty on the control and scheduling of resources in district energy systems. Kamyab and Bahrami (2016) developed a scheduling algorithm and investigated the influence of time-of-use and dynamic pricing schemes on the operation of a set of interacting energy hubs. The study demonstrates superior performance of dynamic pricing in reducing peak load under specific conditions. Fanti et al. (2015) developed a hierarchical control architecture based on linear programming to identify a control strategy for a district energy system given information about day-ahead electricity prices, and show the efficiency benefits on a real case.

Several further papers investigate the effects of market-based electricity price variations and uncertainty on the planning and business case of district energy systems. Pazouki and Haghifam (2016) used a two-stage stochastic mixed-integer linear programming approach to identify the optimal set of technologies and associated capacities under conditions of electricity price, wind and demand uncertainty. Good and Mancarella (2016) used stochastic mixed-integer linear programming to investigate the business case for multi-energy districts, and demonstrated the potential value of optimizing a district virtual power plant with respect to price signals from various markets.

While previous research has assessed the influence of electricity price uncertainty on district energy system design and control, it has not directly investigated the effects of different electricity price policies. In particular, it is not known how different electricity price policies may influence the feasibility and optimal technical configuration of district energy systems, and in turn possibilities for carbon reductions. The aim of this paper is to address this knowledge gap.

Methodology

The present study applies a deterministic mixed-integer linear programming (MILP) approach to investigate the effects of different electricity price policies on the optimal technical configuration and economic performance of a district energy system. The formulation of the developed MILP model is based on the *energy hub* concept – a conceptual model of multi-carrier energy systems used to represent the interactions of multiple energy conversion and storage technologies Geidl and Andersson (2007).

The modelled system includes a set of 50 identical multi-family residential buildings in a hypothetical urban district in Switzerland, with given demands for electricity and heat and given roof areas usable for installation of solar photovoltaic and/or solar thermal panels. The design of the buildings is assumed to be fixed, with the exception of the technologies for provision of heat and electricity. In the course of optimization, a diverse set of energy conversion and storage technologies are evaluated for installation and sizing. Considered energy conversion technologies include gas boilers, gas-driven combined-heat-and-power (CHP) plants, ground-source heat pumps (GSHP), solar photovoltaic panels and solar thermal panels. Considered energy storage technologies include hot water tanks and batteries. Table 1 lists the relevant technical and economic properties of the technologies considered in the optimization.

Both an electrical network and a district heating network are assumed to be installed, allowing for heat and electricity exchange between buildings. However, the system is modelled as a single node, meaning that the demands for all buildings are aggregated and the electrical/thermal networks are not explicitly represented. As such, no distinction is made between centralized (district level) vs. decentralized (building level) solutions for energy conversion and storage. The aggregated system is assumed to have a single connection to the electricity grid, but no connection to any external heating network.

The technical configuration of the system is optimized under a number of different electricity price policy scenarios. Analyzed policies include (1) *electricity feed-in price policies*, including feed-in tariffs, feed-in premiums and net metering; and (2) *electricity withdrawal price policies*, including real-time electricity pricing, time-of-use electricity pricing and flat-rate electricity pricing. Electricity feed-in price policies are assumed to apply only to electricity generated using renewable sources, in this case solar photovoltaics. Grid feed-in of non-renewable energy is compensated at a price of zero. Electricity price data is based on Swiss data from the canton of Zurich[1] and the European Power Exchange[2].

Table 2 provides an overview of the assessed policy

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[1]https://www.ewz.ch/
[2]https://www.epexspot.com

Table 1: Technical and economic properties of the considered technologies.

	GSHP	Gas boiler	Gas CHP	Solar PV	Solar thermal	Battery	Heat tank
Lifetime (years)	20	30	20	25	25	20	20
Capital cost (CHF per kW or m2)	2270	730	2870	325	1350	-	-
Capital cost (CHF per kWh)	-	-	-	-	-	430	40
OM cost (CHF per kWh)	0.1	0.01	0.021	0.06	0.12	-	-
Efficiency	3.2	0.94	0.3	0.17	0.75	-	-
(Dis)charging efficiency						0.9	0.9
Heat to power ratio	-	-	1.73	-	-	-	-
Standing losses (fraction per hr)	-	-	-	-	-	0.001	0.001
Max (dis)charging rate (fraction per hr)	-	-	-	-	-	0.30	0.25

scenarios. For testing the different feed-in price policies, a flat price for electricity withdrawal is assumed. For testing of the different electricity withdrawal price policies, a FIT of CHF 0.19 per kWh is assumed for renewables-based electricity feed-in, which corresponds to the current FIT level in Switzerland. Under TOU pricing, the hours for daytime prices are 6:00-22:00 Monday to Saturday; all other periods are covered by nighttime prices.

The model is run for a time period of one year at one hour resolution, with the objective of minimizing total costs. Both the operation of the system (dispatch schedule of technologies) and the design of the system (technology capacities) are optimized. For each policy scenario, a single optimization is carried out and a cost optimal solution is sought – a solution which minimizes the sum of capital and operational costs over the lifetime of the system, including rebates from electricity feed-in.

The model is developed using the *Ehub Modeling Tool*[3], an open source tool for modeling and optimization of building and district multi-energy systems. The model represents a first application of this new tool for the study of district energy system design and operation. Inputs to the Ehub Tool include: (1) building energy demand profiles, (2) solar radiation time series and estimated usable roof areas for solar generation technologies, (3) electricity price time series, and (4) technical and economic properties of energy conversion, storage and network technologies considered for installation. Building energy demand profiles for the given case are based on typical demand profiles for multi-family residences in Switzerland. Solar radiation time series are based on historical weather data for the canton of Zurich. Given these

inputs, the tool generates and executes MILP model code for optimizing the technological composition of the defined system.

A full detailing of the variables and equations in the model is not provided here, but can be found on the Web[4]. Key equations equations in the model include: (1) a load balance constraint which ensures that the balance between supply and demand of each energy carrier is maintained during each timestep (hour); (2) an equation for calculating the total net cost of the system, including capital costs, operational costs, maintenance costs and income from exports to the grid; and (3) an equation for calculating total net carbon emissions of the system, including both emissions from within the system as well as emissions incurred or avoided by energy imported from or exported to the electricity grid. These equations are formulated as follows:

$$\sum_{c=1}^{n} E_{gen}(c) + \sum_{s=1}^{n} \left(E_{out}(s) - E_{in}(s) \right) \\ = E_{demand} + E_{exp} - E_{imp} \quad (1)$$

$$C_{tot} = C_{cap} + C_{oper} + C_{maint} + C_{imp} - I_{exp} \quad (2)$$

$$Emiss_{CO_2} = \sum_{c=1}^{n} \left(CF(c) \cdot \sum_{t=1}^{n} E(c,t) \right) \quad (3)$$

where c refers to the energy conversion technologies in the system (including the electricity grid), s refers to the energy storage technologies in the system, E

Table 2: *Overview of the analyzed policy scenarios.*

Policy type	Policy scenario	Explanation
Electricity feed-in price policies	Feed-in tariff (FIT)	Fixed compensation for solar feed-in to the electricity grid at CHF 0.19 per kWh.
	Feed-in-premium (FIP)	Variable compensation for solar feed-in to the electricity grid in the form of a fixed premium on top of the electricity spot price, which varies in hourly increments. The FIP is scaled such that the annual average feed-in price is equal to the feed-in tariff above (CHF 0.19 CHF / kWh)
	Net metering (NM)	Solar feed-in to the grid may be drawn back for free at future points in time (no direct financial compensation for solar feed-in)
	None	No monetary or energetic compensation for renewables-based electricity feed-in to the grid.
Electricity withdrawal price policies	Real-time pricing (RTP)	Electricity prices based on electricity spot market prices plus tax and network surcharges. The real-time price is scaled such that the annual average electricity price is equal to that under TOU pricing.
	Time-of-use (TOU) pricing	Electricity prices based on a 2-tier time-of-use pricing scheme (day tariff: 0.27 CHF/kWh, night tariff: 0.14 CHF/kWh)
	Flat pricing	Flat rate electricity price of 0.214 CHF/kWh. This scenario is identical to the FIT scenario.

the energy output/input associated with a technology, storage or load, CF the carbon factor of a given technology (including the grid), and t the timestep.

These key equations are complemented by a number of other equations governing various aspects of system operation and technology capacity determination. Each of the tested policy scenarios corresponds to a modified model formulation and a modified set of equations, which is necessary to capture the effects of the respective policy.

Underlying this model formulation are several important simplifications and assumptions. With regard to generation and storage technologies, investment costs are considered to scale linearly with technology capacity. This ignores potential economies of scale and capacity independent (fixed) costs, such as installation and balance of system costs. Additionally, minimum and maximum capacities for generation and storage technologies are not defined, and part-load efficiencies and minimum part-load constraints for energy conversion technologies are not considered. This means that certain configurations identified by the optimization may not be feasible or economical in practice. Finally, it is assumed that building electricity demand does not respond to changes in electricity price within the tested ranges – electricity demand is inelastic. The implications of these simplifications and assumptions will be discussed in more detail below.

Results

Certain aspects of the results are consistent across all scenarios. For heat production, a gas boiler and CHP unit are installed in all cases, and the majority of heat demand is met by the gas boiler. Heat production via ground-source heat pump is not utilized in any of the scenarios due to the relatively high capital cost and the relatively low price of natural gas (0.09 CHF/kWh). A heat storage is also installed under all scenarios, and is used primarily to meet peak demand. For electricity production, solar photovoltaic (PV) panels and the installed CHP unit complement grid electricity under all scenarios. Battery storage is not utilized under any of the scenarios, due to the relatively high associated capital costs.

Analysis of electricity feed-in price policies

Key results of the electricity feed-in price policy scenarios are illustrated in Figures 1 and 2. As these figures show, the results are quite similar under the *FIT* and *FIP* scenarios, suggesting that a dynamically varying feed-in price exerts only little influence on the optimal configuration of the technical system. In comparison to the *FIT* and *FIP* scenarios, the *Net Metering (NM)* scenario results in a considerably larger PV installation and a slightly larger CHP unit. Although PV production is not financially compensated under a net metering policy, electricity fed to the grid may be freely withdrawn at a future point in time, reducing expenditures for grid electricity. This may be particularly advantageous under situations in which grid electricity constitutes a major expense – either due to large demand or high prices – which is the case with the modelled system. As may be expected, the *None* scenario – in which no compensation for renewables-based electricity feed-in is offered – results in significantly lower PV investment compensated by greater utilization of grid electricity and a larger CHP unit.

Net system costs – which reflect capital and operational expenses, as well as income from grid feed-in – are highest under the *None* scenario, somewhat lower under the *NM* scenario, and lowest under the *FIT* and *FIP* scenarios. The high cost of the *None* scenario is driven by higher operational expenditures for
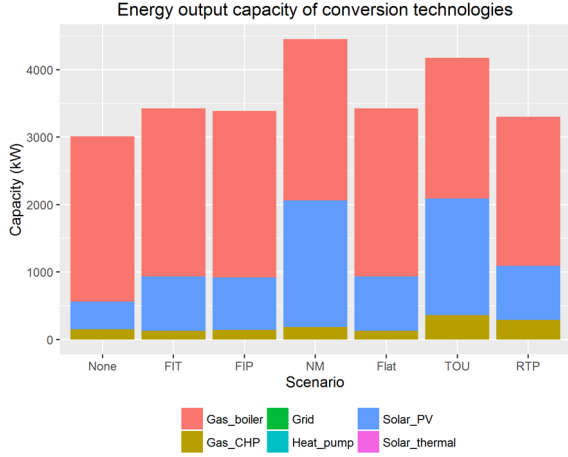
Figure 1: Capacities of heat and electricity conversion technologies under the different electricity price policies. None, FIT, FIP and NM denote the electricity feed-in price policies. Flat, RTP and TOU denote the electricity withdrawal price policies.

Figure 2: Net system costs and emissions under the different electricity price policies.

grid electricity and lower (zero) income for grid feed-in. While income from grid feed-in under the *NM* scenario is also zero, operational expenditures for grid electricity are significantly lower due to greater utilization of PV electricity and of compensating power from the grid. Net system emissions – which reflect system-internal emissions, incited emissions for grid electricity production and avoided emissions due to grid feed-in of renewable energy – are, by far, lowest under the *NM* scenario, and highest under the *None* scenario. Lower emissions under the *NM* scenario may be attributed to greater production of PV electricity, some of which is fed to the grid, and some of which is directly utilized to satisfy system demand.

Analysis of electricity withdrawal price policies

Key results of the electricity withdrawal price policy scenarios are illustrated in Figures 1 and 2. The results vary considerably across the different electricity withdrawal price policy scenarios. With regard to heat production, the *RTP* and *TOU* scenarios include larger CHP capacities (and correspondingly lower boiler capacities) compared to the Flat scenario. Installed PV capacity is relatively equivalent under the *RTP* and *Flat* scenarios, and significantly larger under the *TOU* scenario. These patterns may be explained by the time-varying character of electricity prices under the *RTP* and *TOU* scenarios. Under both of these scenarios, grid electricity prices are significantly higher during times of peak electricity demand, which occur in the morning and the evening. Larger CHP capacity allows for more self-generation of electricity during these peak times, reducing the need for purchase of expensive grid electricity. Under the *TOU* scenario, high grid electricity prices cor-
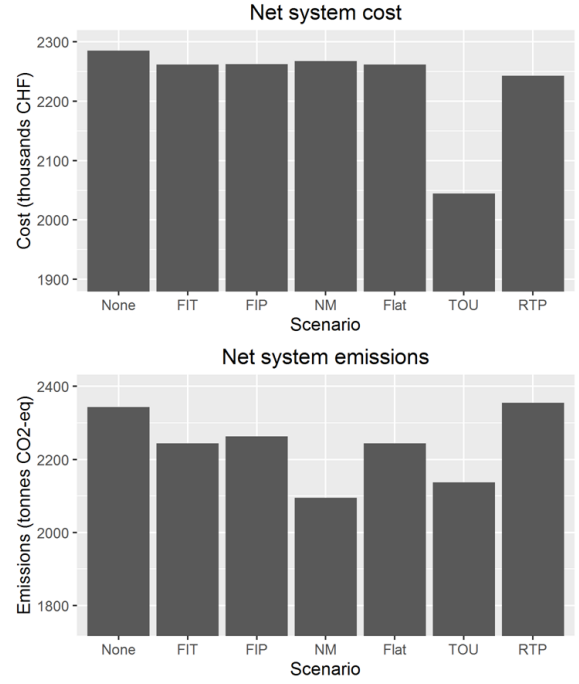
respond temporally with solar radiation availability, which incentivizes a large PV installation as a way to offset grid electricity purchases. Under the *RTP* scenario, peak grid electricity prices – which are highest at times of peak demand – do not correspond as fully with solar radiation availability as under the *TOU* scenario, resulting in relatively lower levels of PV installation.

Figure 3 illustrates the operational consequences of the different grid electricity pricing policies during a randomly selected week in the Spring. Under the Flat scenario, CHP production is essentially constant throughout the duration of the selected week. Under the *TOU* scenario, the CHP unit is generally only operational during times of high grid electricity prices. It is shut down during the nighttime hours, favouring the utilization of cheaper grid electricity. Further analysis shows that inputs to the heat storage under a *TOU* scenario occur exclusively when the CHP unit is operational. In other words, the excess heat produced by the CHP unit during peak electricity price hours is fed to the heat storage. The contents of the heat storage are then deployed during heat demand peaks to reduce boiler load (Figure 4).

Net system costs are lowest, by far, under the *TOU* scenario. This is driven by significantly lower grid electricity expenditures and greater income from renewable energy exports relative to the *Flat* and *RTP* scenarios. The reduced operational expenditures and greater export income in the *TOU* scenario more than offset the additional capital costs for a larger PV system and CHP unit. Net system emissions are also
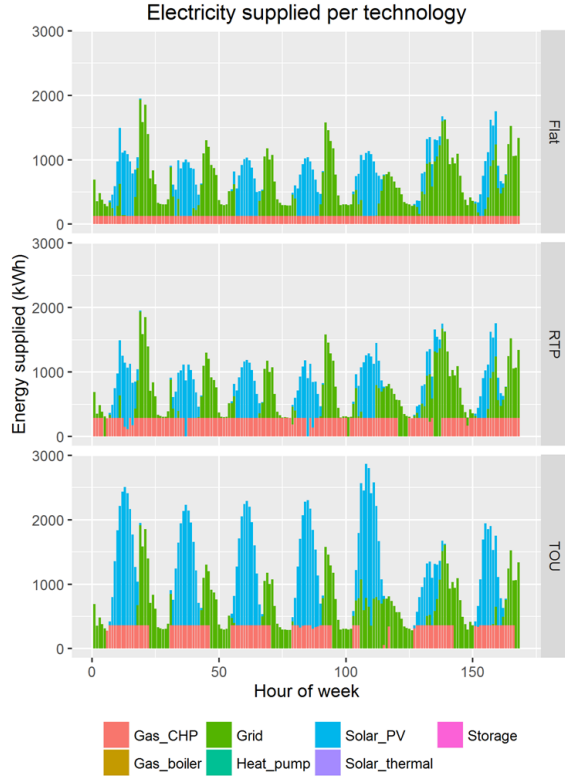
Figure 3: Electricity production per technology during a randomly selected week in Spring under the different electricity withdrawal price policies.
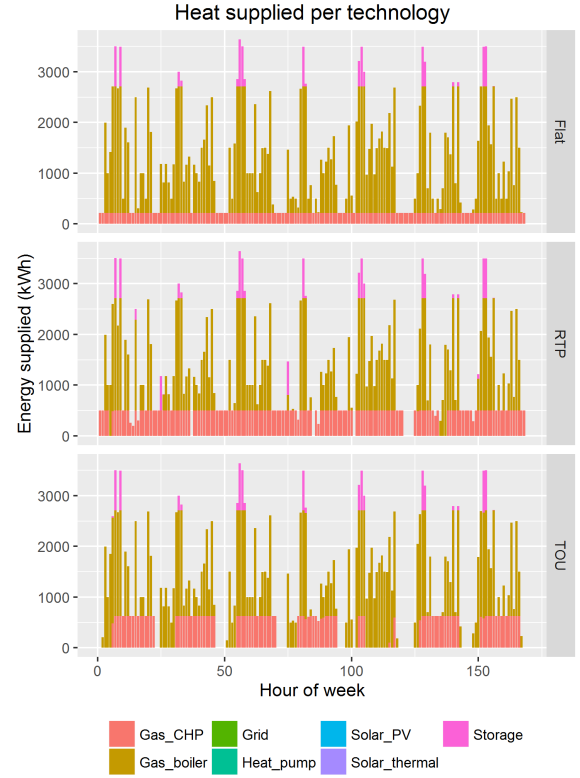

Figure 4: Heat production per technology during a randomly selected week in Spring under the different electricity withdrawal price policies. The heat storage is primarily used to reduce boiler load during times of peak heat demand.

lowest under the *TOU* scenario compared with the other electricity withdrawal price policies, a product of the comparatively larger PV installation. Interestingly, the *RTP* scenario results in the highest level of emissions, driven by a smaller PV installation relative to the *TOU* scenario and a larger CHP unit relative to both the *TOU* and *Flat* scenarios.

Discussion

The results described above shed light on the effects of different electricity price policies on the optimal technical configuration and operational characteristics of a district energy system. Specifically, the results highlight the potential benefits of a net metering policy to incentivize a technical configuration with low carbon emissions, and of a time-of-use pricing policy to incentivize a technical configuration with both low carbon emissions and low costs.

In terms of electricity feed-in price policies, feed-in tariffs and feed-in premiums also offer some benefits (relative to no policy) in terms of incentivizing technology configurations with improved emissions profiles. Moreover, the seeming ability of net metering to incentivize technical configurations with comparatively very low emissions suggests a potentially important future role for electricity storage in district energy systems. While battery storage was not selected for installation under any policy scenario (due

to high associated capital costs), it is clear that the capital costs and efficiency of batteries are rapidly decreasing. Insofar as net metering acts as a "virtual storage" for renewables-based electricity, it is possible that cheaper batteries may assume this role in the future and, to a degree at least, reduce the need for (and benefits of) net metering.

In terms of electricity withdrawal price policies, the results suggest that real-time electricity pricing offers little to no benefit relative to flat or time-of-use pricing, with regard to both emissions and cost savings. It is a somewhat counterintuitive result that real-time and time-of-use pricing policies – which are similar in their dynamic variation of electricity prices – result in very different system performance. This difference is due to the coincidence of peak grid electricity price times with peak solar availability under a time-of-use policy, but not under a real-time pricing policy. This suggests that the specific *timing* of price variations under different dynamic electricity pricing schemes may play an important role in determining the sustainability and cost performance of district energy systems.

The favourable performance of net metering and time-of-use pricing policies would seem to indicate towards the benefits of a policy approach combining

these two policies. Further experiments with the developed model suggest that such an approach is indeed advantageous, but does not fully leverage the combined benefits of these policies. Specifically, the combination of the *TOU* and *NM* scenarios does indeed incentivize the installation of large quantities of solar PV, similar to under the *NM* scenario (with flat electricity pricing) presented in the previous section. This translates into a net system emissions level comparable to that under the *NM* scenario (Figure 5). In terms of net system costs, the results of a combined policy lie essentially halfway between those of a pure *NM* and pure *TOU* scenario. The reason for this is that, under a combined policy, sale of excess PV production to the grid does not yield a direct financial benefit in the form of a feed-in-tariff, which is the case in the *TOU* scenario.
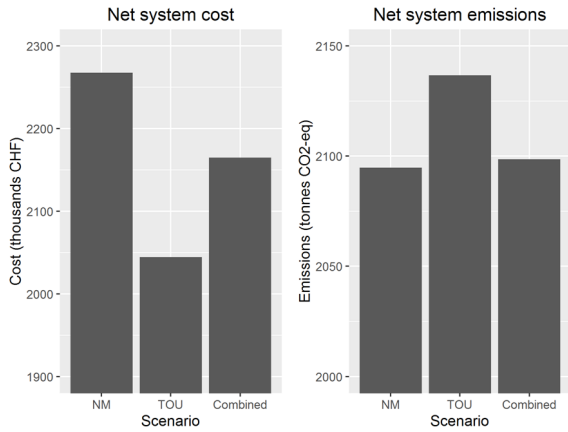

Figure 5: Results from a policy scenario combining time-of-use pricing with net metering.

These results may be indicative to policy makers and/or district energy system developers, in terms of understanding how different electricity price policies may influence the economic feasibility and environmental profile of district energy systems. However, it is important to point out that the presented results rest on a number of important assumptions, the validity of which has not yet been fully explored. First, the results may be considered valid only for the chosen case, which features a specific energy demand profile and solar radiation time series. Energy demand profiles and solar radiation availability may vary widely across different geographical contexts, which suggests that the results may look very different in different locations. For instance, a warmer, sunnier climate with more cooling demand and less heating demand may feature higher electricity loads for cooling and greater coincidence between peak energy demand and peak solar availability. Both of these factors would likely favour the installation of larger PV arrays independent of the chosen policy.

Furthermore, the representation of energy conversion and storage technologies in the model leaves out po-

tentially relevant aspects such as part-load operational constraints, part-load efficiencies and nonlinear capital investment curves, which may skew the results. The model also excludes a number of technology options, such as wind turbines, air-source heat pumps, fuel cells, hydrogen storage and different types of thermal networks. Finally, only a handful of possible policies have been examined. Also worth considering, for instance, would be capital subsidies, capacity charges and different FIT or FIP levels. Studying combinations of policies applicable to different types or sizes of systems may also be relevant.

As a first step for future research, a full assessment of these assumptions and limitations is pertinent. In particular, this should include applying the model to a broader range of cases, technology possibilities and policy scenarios. Next to this, an important outstanding research gap has to do with the externalized costs of different electricity price policies. While this research has quantified the net system costs of several policies, it has not considered the costs that these different policies may incur on grid operators or other actors external to the system. For instance, net metering requires that grid operators be capable of accommodating (potentially large levels of) solar feed-in, and feed-in-tariffs require direct payments that are usually passed on to consumers. For policy makers, it is important to understand not just the influences of a policy on the feasibility and performance of district energy systems, but also its broader societal costs.

Conclusions

This paper has applied a deterministic mixed-integer linear programming approach to investigate the influence of different electricity price feed-in and withdrawal policies on the optimal technical configuration, net costs and net carbon emissions of a hypothetical district energy system. The results have highlighted the potential benefits of a net metering policy to incentivize a technical configuration with low carbon emissions, and of a time-of-use pricing policy to incentivize a technical configuration with both low carbon emissions and low costs. A policy combining net metering and time-of-use pricing was shown to partially leverage the combined advantages of these two policies. Furthermore, the results suggest that the precise timing of price variations under dynamic electricity pricing schemes may significantly influence system design incentives and system performance.

The results of this paper may be indicative to policy makers and/or district energy system developers in terms of understanding how different electricity price policies may influence the economic feasibility and environmental profile of district energy systems. However, the presented results rest on a number of important assumptions and case-specific features which must be considered in applying these conclusions to

other cases. Future research should focus on testing and validating the utilized approach to a broader range of cases, technology possibilities and policy scenarios.

Acknowledgement

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