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Industrial energy communities: Energy storage investment, grid impact and cost distribution

Kjersti Berg [a,*], Sverre Stefanussen Foslie [a,b], Hossein Farahmand [a]

[a] Norwegian University of Science and Technology (NTNU), Trondheim, Norway
[b] SINTEF Energy Research, Trondheim, Norway

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ABSTRACT

Energy communities are a way for end-users to contribute to the green shift, by installing distributed energy resources such as photovoltaic panels. The focus of energy community studies has mainly been on residential and not industrial consumers. Industrial consumers can be an important key in energy communities, especially with regard to reducing peak demand in the grid. In this article, we use real measurements from a transformer station and an industrial consumer in Norway to find the optimal size of energy storage in two cases: whether the industrial consumer invests independently or collaborates with the local urban area as an energy community. We assess the cost savings of the energy community and the advantages for the distribution system operator, in terms of cost reduction and peak import reduction for the energy community. Ultimately, we investigate the equitable distribution of cost savings from joint investments between the industry and the local urban area. Our results show that thermal energy storage is the most favourable storage option, due to lower investment costs than battery energy storage systems. Furthermore, we find that optimising the storage sizes for the whole energy community leads to both cost reduction for the energy community and a reduction in maximum import for the local grid. The costs are reduced by 1.8%, while the maximum import is reduced by 5%, compared to the reference case where there are no energy storages. Moreover, the economic incentive for industrial consumers to join energy communities is substantially influenced by the selected cost saving redistribution method.

1. Introduction

To reach the European climate goals, there is a need for increased electrification and distributed energy resources. This is causing a strain on the distribution grid, imposing challenges to for instance keep voltages within operating limits in areas with a high number of new photovoltaic (PV) installations [1] or avoiding congestions in areas with high electrification from end-users and industrial processes [2]. As several sectors wish to transition from fossil fuels to electricity, the strain on the grid is increasing rapidly [3]. In Norway, both the national and regional grids are already at their capacity limits in many places [4]. This means that many consumers who wish to connect have to wait until grid reinforcements can be made, which may take up to several years [5]. This causes a delay in the green shift, since many of the new applications for grid connections are related to electrification and decarbonisation of fossil-based industrial processes. The load in the Norwegian grid is at its peak during the coldest period in winter [6]. If we are able to reduce the load in these hours, it could provide more capacity for new consumers or enable existing consumers to increase their electricity use, which again can lead to reduced emissions. Industry consumers play an important role here, as they often have consumption with high peaks [7], and changing their consumption patterns can make a difference both in the local grid where they are connected and the higher voltage levels.

Energy communities can be one way of organising and incentivising peak load reduction in the grid. An energy community is a legal entity that is controlled by its members. The members can be individuals, small- and medium-sized enterprises, or local authorities. Energy communities often include distributed energy resources such as PV generation, and shared assets such as energy storage [8]. Energy communities can provide services to the grid, but it is crucial that it is a *local* energy community, meaning that the members are physically located in the same grid area [8]. Energy communities with energy storage can help the grid, by mitigating voltage issues [9] or reduce congestions [10], and might therefore be a valuable collaboration partner for the distribution system operator (DSO), if the energy storage is sized properly and the economic incentives are present.

* Corresponding author.
E-mail address: kjersti.berg@sintef.no (K. Berg).

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Nomenclature

Indices and sets

i, j	Energy community member
l	Tariff level
m	Month
t	Time step
L	Set of months
T	Set of time steps
W	Set of first hours per week

Parameters

η^{BESS}	Efficiency of BESS [–]
η^{TES}	Efficiency of TES [–]
$\eta^{\text{el. boiler}}$	Efficiency of electric boiler [–]
$\gamma^{\text{TES, sel}}$	Self-discharge of TES [%]
$\overline{\alpha}^{\text{BESS}}$, $\underline{\alpha}^{\text{BESS}}$	Max. and min. SOC for BESS [%]
$\overline{\alpha}^{\text{TES}}$, $\underline{\alpha}^{\text{TES}}$	Max. and min. SOC for TES [%]
$\overline{P}^{\text{el. boiler}}$	Capacity of electric boiler [MWh/h]
C_i^{alone}	Member i's cost when operating alone [€]
$C^{\text{BESS, inv}}$	Investment cost of BESS [€/MWh]
$C^{\text{BESS, op.}}$	Operational cost of BESS [€/MWh/yr]
$C^{\text{BESS,ann}}$	Annualised investment cost for BESS [€/MWh]
$C_l^{\text{grid, p}}$	Cost of grid monthly peak, level l [€/MW]
$C^{\text{grid, vol}}$	Volumetric grid tariff [€/MWh]
C_t^{spot}	Spot market price in hour t [€/MWh]
C^{tax}	Grid consumption tax [€/MWh]
$C^{\text{TES, inv}}$	Investment cost of TES [€/MWh]
$C^{\text{TES, op.}}$	Operational cost of TES [€/MWh/yr]
$C^{\text{TES,ann}}$	Annualised investment cost for TES [€/MWh]
C_i	Distributed, annual operational cost for member i [€]
E_i	Yearly energy consumption for member i [MWh]
G	Maximum import/export allowed [MWh/h]
IR	Interest rate [–]
M	Large number [–]
N^B	Lifetime of BESS [y]
N^T	Lifetime of TES [y]
$P_i^{\text{individual peak}}$	Power peak of member i [MWh/h]
$P_i^{\text{system peak}}$	Power peak of member i during system peak [MWh/h]
P_t^{area}	Area load in hour t [MWh/h]
P_t^{electric}	Electrical demand at industry consumer in hour t [MWh/h]
P_l^{lim}	Limit of grid tariff, level l [MWh/h]
P_t^{other}	Other electrical demand [MWh/h]
$P_t^{\text{steam boiler}}$	Steam boiler electric demand in hour t [MWh/h]
$Q_t^{\text{heat pump}}$	Heat pump thermal production in hour t [MWh/h]
Q_t^{other}	Other thermal demand in hour t [MWh/h]
Q_t^{process}	Process thermal demand [MWh/h]
Q_t^{thermal}	Thermal demand at industry consumer in hour t [MWh/h]
$R^{\text{B, P2E}}$	BESS power-to-energy ratio [MW/MWh]
$R^{\text{T, P2E}}$	TES power-to-energy ratio [MW/MWh]
R^{prod}	Grid remuneration from production [%]
TC	Total, annual operational cost for energy community [€]

Variables

β_t^{impexp}	Binary variable for import and export in hour t
$\beta_{l,m}$	Binary variable for deciding grid tariff level for month m and level l
$c^{\text{grid, peak}}$	Annual cost of monthly peak grid tariff [€]
e^{BESS}	BESS energy capacity [MWh]
e^{TES}	TES energy capacity [MWh]
p_t^{400V}	Electricity consumption at 400 V bus in hour t [MWh/h]
p_t^{690V}	Electricity consumption at 690 V bus in hour t [MWh/h]
$p_t^{\text{BESS,ch}}$	BESS charge in hour t [MWh/h]
$p_t^{\text{BESS,dis}}$	BESS discharge in hour t [MWh/h]
$p_t^{\text{el. boiler}}$	Electric boiler consumption in hour t [MWh/h]
p_t^{exp}	Exported electricity in hour t [MWh/h]
p_t^{imp}	Imported electricity in hour t [MWh/h]
p_t^{industry}	Electricity consumption of industry consumer in hour t [MWh/h]
p_m^{max}	Peak electricity demand of month m [MWh/h]
$q_t^{\text{el. boiler}}$	Electric boiler thermal output in hour t [MWh/h]
$q_t^{\text{hot water}}$	Thermal demand for hot water in hour t [MWh/h]
$q_t^{\text{TES,ch}}$	TES charge in hour t [MWh/h]
$q_t^{\text{TES,dis}}$	TES discharge in hour t [MWh/h]
soc_t^{BESS}	State of charge of BESS in hour t [MWh]
soc_t^{TES}	State of charge of TES in hour t [MWh]

Although the definitions of energy communities [11,12] state that small and medium-sized enterprises can be members, the focus of energy community studies has until now been mainly on households, and industrial consumers are rarely considered [13]. The industrial sector is responsible for over one-third of the energy demand globally [14], and can therefore play a key role in reducing emissions. Some industries have processes with high peak demand and thus have an incentive to install energy storage for peak shaving, especially if they have grid tariffs that are based on peak power. However, it can be challenging for some industries to have enough space to install renewable energy generation to cover their demand [15]. Therefore, it might be beneficial for industry consumers to collaborate with other areas that have more space for, i.e., rooftop PV generation.

This article investigates the economic viability of an industrial consumer with low temperature (<100 °C) process heating demands participating in an energy community. It explores the potential symbiotic relationship between an industrial consumer equipped with energy storage and an urban area with distributed generation. We use real measurements from a transformer station and an industrial consumer in Norway to investigate the optimal size of energy storage in two cases: the industrial consumer invests considering only its own load, or it invests considering the local urban area load and generation, as an energy community. Additionally, we evaluate the cost savings achieved by the energy community in relation to the advantages of the DSO. This assessment includes cost reduction resulting from the energy storage investment and a decrease in peak power import to the community. Finally, we investigate an equitable distribution of cost savings between the industry consumer and the local urban area.

1.1. Related literature

Most studies on energy communities focus on households [16], while only a few involve industrial consumers [13]. Regarding the collaboration between industry and urban areas, several studies investigate "Urban-industrial symbiosis", which is waste management (burning waste and using excess heat for heating the urban area), but very few investigate the potential symbiosis between industrial and urban areas with renewable energy [17,18]. One exception is [17], which looked at an urban-industrial sustainable energy community. The article showed that the industrial sector presents a great opportunity to install renewable energy resources and provide renewable energy to a nearby urban area.

Compared to households, industries have more capital to invest in large central energy storage systems. Also, industry consumers often have multi-energy systems, consisting of for instance both thermal and electrical demand, making it relevant to consider different types of energy storage [19]. As shown in [20], many industries can provide demand response since they already have equipped their facilities with control, measurement and communication infrastructure. The benefit of installing energy storage to enable load shifting is that the industry does not need to change its operation and schedule, which can be difficult due to working hours and manpower. Ref. [21] looked at the sizing of BESS for industrial applications in Germany, for four different industrial profiles. The results showed that it was profitable to install battery energy storage systems (BESS) in most scenarios, due to the peak power grid tariff. In general, however, when comparing BESS and hot water thermal energy storage (TES), studies find that TES is more economical [22,23]. Ref. [23] investigated a hot water TES tailored for an industrial consumer (dairy). The study showed that TES provides cost-effective flexibility, which eliminates the need for BESS, and that the TES contributes to cost reductions and CO_2 emission reduction.

Shared energy storage is considered more economical than individual storage, due to economies of scale and diversity factors [24]. The majority of literature on shared energy storage in energy communities considers households or industry clusters separately. In contrast, this article investigates how energy storage located at an industry consumer can be used in an energy community setting. Concerning shared assets at industrial parks, [25] examined shared energy storage in industrial parks with PV generation. The authors found that shared energy storage increased the local consumption of PV generation. Notably, they did not consider any particular energy storage technology; instead, they used a generic energy storage model in an optimisation model where the objective was to maximise the daily net income from electricity trading. Ref. [26] determined the optimal BESS sharing scheme in an industrial park, by minimising the total operating cost of the industrial park. The authors found that centralised shared energy storage resulted in lower electricity costs and greater utilisation, compared to distributed energy storage at each industry. Energy community studies with energy storage focus mostly on batteries, and only a few works analyse thermal technologies [16], although TES is more cost-competitive than BESS [24]. Ref. [27] looked at peer-to-peer trading in an industrial site in Norway with a community BESS. The objective of the optimisation was to minimise the total cost of electricity for the community. The authors found that peak shaving was the most important factor in cost reduction, due to the monthly peak power grid tariff. Refs. [25–27] provided valuable knowledge on the operation of shared energy storages, however, they did not investigate the optimal size of the storage systems. Ref. [28] investigated the optimal size of BESS for a renewable energy community located in the low-voltage grid. The authors formulated an optimisation model which minimised investment and operational costs of the energy community. The results showed that the optimal BESS size varied significantly depending on whether the energy community consisted of only residential loads or both residential and commercial loads.

The question of how to distribute the costs and benefits within energy communities is still an open question [16,29,30]. Several studies have investigated the topic [25,31,32]. Ref. [31] examined how a grid company could own an energy storage and dynamically allocate shares to prosumers, while resolving overvoltage and congestion issues. The authors formulated an optimisation model that maximised the total export limit of the residential prosumers. The results showed that community energy storage could reduce active power curtailment and increase total generation. Ref. [32] examined household scenarios and proposed a pricing mechanism for energy storage sharing in a market-oriented environment with several communities. The authors formulated a planning model for community energy systems, where the objective was to minimise the total planning and operating costs for each community manager. The results showed that such a storage sharing mechanism could increase the profit of the communities, reduce the interaction with the grid and increase the self-consumption of renewable energy. In [25], which looked at industrial consumers, the authors proposed a reputation factor to reflect the fairness of energy sharing, where the entity that provided more resources received more rewards. The reputation factor was based on the total amount of electricity shared by the user with the energy storage and increased the net present value of the energy storage.

1.2. Contributions

As the related literature reveals, there is a lack of studies on industry consumers in energy communities, and a lack of energy community studies considering energy storage for other types of energy carriers than electricity (i.e. batteries). Considering these gaps, the contributions of this paper are as follows:

- We investigate the storage investment decision of community electrical and thermal energy storage for an energy community with an industrial consumer and an urban area with distributed generation.
- We provide an optimisation model of an industrial consumer participating in an energy community, by using real, hourly measurements for one year from the industrial consumer and the distribution grid.
- We study the incentives for the industrial consumer to participate in the energy community by assessing equitable methods for distributing costs and benefits stemming from investments in distributed generation and energy storage.

1.3. Outline of paper

The outline of the paper is as follows: Section 2 describes the concept of the paper, the optimisation model formulation and the cost allocation methods. Section 3 describes the real-life case study from Trondheim, Norway and assumptions regarding energy storages. Section 4 presents the results from the optimisation model, cost distribution and sensitivity analysis. Finally, Section 5 gives the concluding remarks.

2. Method

Fig. 1 shows the concept of the paper: An industry consumer is considering an investment in energy storage to minimise its own energy costs. The industrial consumer has the option to invest in a BESS and/or a hot water TES on the thermal side of the system, offering flexibility in electricity consumption while ensuring the seamless operation of

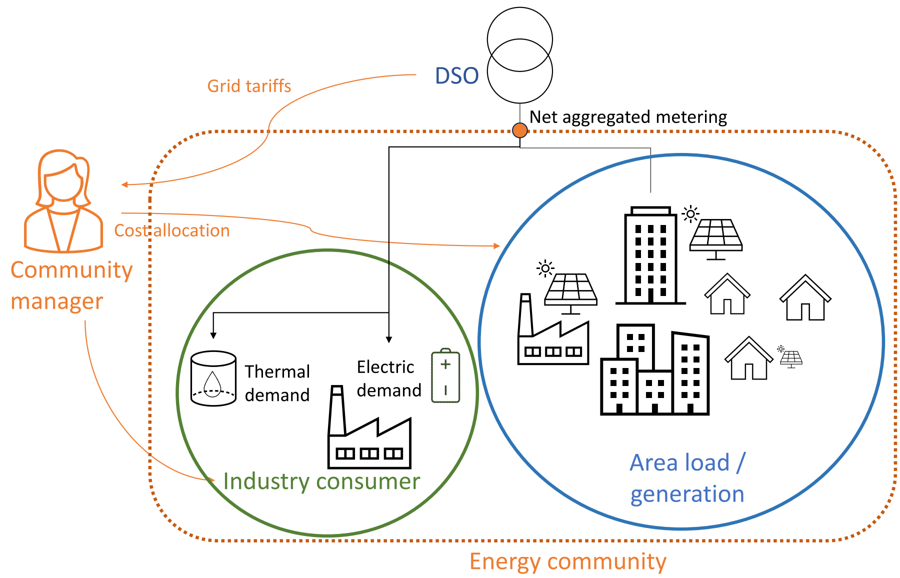

Fig. 1. Paper concept.

the facility's processes. The industry receives its electricity supply from a transformer that also serves the local urban area. The DSO aims to reduce peak imports to the region. We investigate two cases for storage investment: the industry optimises for itself, or the industry and local urban area form a collaborative energy community that optimises together with aggregated net metering. If the energy community is formed, it receives a common grid tariff from the DSO based on the aggregated net metering. The different energy storage technologies are optimised based on this common grid tariff, and the final costs are redistributed to the members by the community manager subsequently.

2.1. Optimisation model formulation

The optimisation model is a deterministic, mixed integer non-linear optimisation program (MINLP) that determines the sizes of BESS and TES. Subsequently, the investment costs, operational costs, storage operation and import/export are outputs of the optimisation model.

The objective of the optimisation model is to minimise annualised capital and operational costs, as given in (1).

$$\begin{aligned} \min \quad & C^{\text{BESS,ann}} e^{\text{BESS}} + C^{\text{TES,ann}} e^{\text{TES}} \\ & + C^{\text{BESS, op.}} e^{\text{BESS}} + C^{\text{TES, op.}} e^{\text{TES}} \\ & + c^{\text{grid,peak}} \\ & + \sum_{t \in T} \Big[(C_t^{\text{spot}} + C^{\text{grid, vol}} + C^{\text{tax}}) p_t^{\text{imp}} - C_t^{\text{spot}} (1 + R^{\text{prod}}) p_t^{\text{exp}} \Big] \end{aligned} \tag{1}$$

The different parts of the objective function are as follows. Annualised investment costs for BESS and TES, $C^{\text{BESS,ann}}$ and $C^{\text{TES,ann}}$, and energy storage sizes of BESS and TES, e^{BESS} and e^{TES}. Operational costs for BESS and TES, $C^{\text{BESS, op.}}$ and $C^{\text{TES, op.}}$. Annual costs for monthly peak grid tariff, $c^{\text{grid,peak}}$. Annual costs of buying electricity from the spot market, C_t^{spot}, volumetric grid tariff, $C^{\text{grid, vol}}$, and taxes, C^{tax}, all dependent on the electricity import, p_t^{imp}. Annual revenue for selling electricity to the grid, consisting of the spot market price and compensation from the DSO for reducing losses in the grid, R^{prod}, dependent on the electricity export, p_t^{exp}.

The calculation of the monthly peak grid tariff requires binary variables $\beta_{1,m}$ and $\beta_{2,m}$ to decide the cost level for each month m in the set of months L, as given in (2). This grid tariff is based on a stepwise cost structure, where the consumer pays depending on which step the monthly peak load falls within.

$$\begin{aligned} c^{\text{grid,peak}} = \sum_{m \in L} \Big[& C_1^{\text{grid, p}} p_m^{\max} (1 - \beta_{1,m}) + C_1^{\text{grid, p}} P_1^{\lim} \beta_{1,m} \\ & + C_2^{\text{grid, p}} (p_m^{\max} - P_1^{\lim})(1 - \beta_{2,m}) \\ & + C_2^{\text{grid, p}} (P_2^{\lim} - P_1^{\lim}) \beta_{2,m} \\ & + C_3^{\text{grid, p}} (p_m^{\max} - P_2^{\lim}) \beta_{2,m} \Big] \end{aligned} \tag{2}$$

Here, $C_1^{\text{grid, p}}$-$C_3^{\text{grid, p}}$ are the costs of level 1–3 and $p_m^{\max}$ is the peak load of month m. $\beta_{1,m}$ and $\beta_{2,m}$ take the value of 1 if the monthly peak load is above the limit of $P_1^{\lim}$ or $P_2^{\lim}$, respectively.

The annualised investment costs for BESS and TES are calculated as follows:

$$C^{\text{BESS,ann}} = \frac{IR(1+IR)^{N^B}}{(1+IR)^{N^B} - 1} \cdot C^{\text{BESS, inv}} \tag{3}$$

$$C^{\text{TES,ann}} = \frac{IR(1+IR)^{N^T}}{(1+IR)^{N^T} - 1} \cdot C^{\text{TES, inv}} \tag{4}$$

where IR is the investment rate, N^B and N^T are the lifetimes of BESS and TES, and $C^{\text{BESS, inv}}$ and $C^{\text{TES, inv}}$ are the investment costs of BESS and TES, respectively.

Fig. 2 shows a visualisation of a general industrial energy community, including the variable names used in the following equations. The electricity balance constraint for grid exchange is given in (5). The import and export are decided from the industry load, p_t^{industry}, and the load and generation in the urban area, P_t^{area}. When the industry is optimising only for itself, P_t^{area} is set to zero.

$$p_t^{\text{industry}} + P_t^{\text{area}} = p_t^{\text{imp}} - p_t^{\text{exp}} \qquad t \in T \tag{5}$$

In general, the import to the industry consumer can be described as the electric demand at the industry, P_t^{electric}, the BESS charge/discharge power, $p_t^{\text{BESS, ch}}$ and $p_t^{\text{BESS, dis}}$, and the power consumed by the electric boiler which converts electricity into heat, $p_t^{\text{el. boiler}}$:

$$p_t^{\text{industry}} = P_t^{\text{electric}} + p_t^{\text{BESS, ch}} - p_t^{\text{BESS, dis}} + p_t^{\text{el. boiler}} \qquad t \in T \tag{6}$$

The electric boiler converts electricity to heat, $q_t^{\text{el. boiler}}$, with an efficiency, $\eta^{\text{el. boiler}}$. This heat is then connected to the thermal demand, Q_t^{thermal} and the TES charge/discharge, $q_t^{\text{TES, ch}}$ and $q_t^{\text{TES, dis}}$:

$$p_t^{\text{el. boiler}} \eta^{\text{el. boiler}} = q_t^{\text{el. boiler}} \qquad t \in T \tag{7}$$

$$q_t^{\text{el. boiler}} = Q_t^{\text{thermal}} + q_t^{\text{TES, ch}} - q_t^{\text{TES, dis}} \qquad t \in T \tag{8}$$

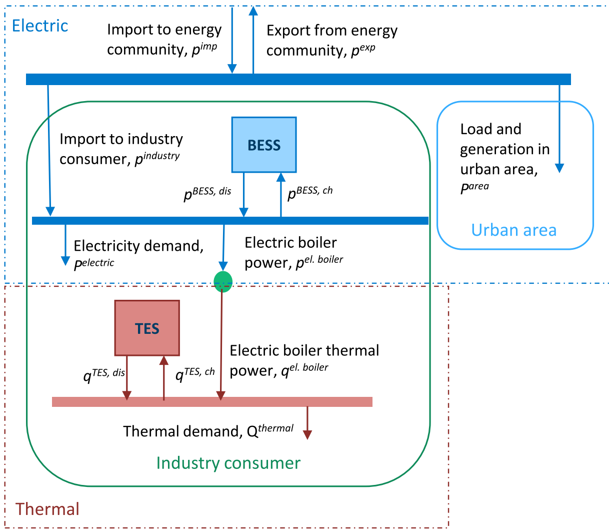

Fig. 2. General overview of the energy flows in the energy community. The urban area is modelled as a parameter representing load and generation, while the industry consumer consists of an electric and a thermal part, where BESS and TES can be invested in.

To avoid import and export at the same time, a binary variable, β_t^{impexp}, is added in the following restrictions, where G is the maximum limit for import and export from/to the grid:

$$p_t^{\text{imp}} \leq \beta_t^{\text{impexp}} \cdot G \qquad t \in T \quad (9)$$

$$p_t^{\text{exp}} \leq (1 - \beta_t^{\text{impexp}}) \cdot G \qquad t \in T \quad (10)$$

Eq. (11) keeps track of the highest hourly consumption of month m, while (12)–(15) use binary variables $\beta_{1,m}$ and $\beta_{2,m}$ to determine which level the peak power falls within for month m, using the large number M.

$$p_t^{\text{imp}} \leq p_m^{\text{max}} \qquad t \in T \quad (11)$$

$$p_m^{\text{max}} - P_1^{\text{lim}} \leq \beta_{1,m} M \qquad m \in L \quad (12)$$

$$P_1^{\text{lim}} - p_m^{\text{max}} \leq (1 - \beta_{1,m}) M \qquad m \in L \quad (13)$$

$$p_m^{\text{max}} - P_2^{\text{lim}} \leq \beta_{2,m} M \qquad m \in L \quad (14)$$

$$P_2^{\text{lim}} - p_m^{\text{max}} \leq (1 - \beta_{2,m}) M \qquad m \in L \quad (15)$$

The industry consumer has the possibility to invest in a BESS and/or a hot water TES. The constraints for the BESS are given in (16)–(22), where η^{BESS} denotes the charge/discharge efficiency of the BESS. Eq. (20) ensures that the state of charge (SOC) of the battery, soc_t^{BESS} is the same at the beginning of every week, to avoid long-term scheduling of the battery system in the optimisation model. This constraint is therefore only valid for hours in set W, which is the set of the first hour of each week. The SOC is restricted to maximum and minimum levels, $\underline{\alpha^{\text{BESS}}}$ and $\overline{\alpha^{\text{BESS}}}$, to limit degradation in (18)–(19). The discharge and charge variables are further restricted by the energy capacity times the power-to-energy ratio, $R^{\text{B, P2E}}$, representing the inverter size of the battery system.

$$\begin{aligned} soc_t^{\text{BESS}} = {} & soc_{t-1}^{\text{BESS}} + \eta^{\text{BESS}} p_t^{\text{BESS, ch}} \Delta t \\ & - \frac{1}{\eta^{\text{BESS}}} p_t^{\text{BESS},dis} \Delta t \end{aligned} \qquad t \in T \backslash \{1\} \quad (16)$$

$$\begin{aligned} soc_t^{\text{BESS}} = {} & soc_T^{\text{BESS}} + \eta^{\text{BESS}} p_t^{\text{BESS, ch}} \Delta t \\ & - \frac{1}{\eta^{\text{BESS}}} p_t^{\text{BESS, dis}} \Delta t \end{aligned} \qquad t = 1 \quad (17)$$

$$soc_t^{\text{BESS}} \leq \overline{\alpha^{\text{BESS}}} e^{\text{BESS}} \qquad t \in T \quad (18)$$

$$soc_t^{\text{BESS}} \geq \underline{\alpha^{\text{BESS}}} e^{\text{BESS}} \qquad t \in T \quad (19)$$

$$soc_t^{\text{BESS}} = soc_{t+1}^{\text{BESS}} \qquad t \in W \quad (20)$$

$$p_t^{\text{BESS, ch}} \leq R^{\text{B, P2E}} e^{\text{BESS}} \qquad t \in T \quad (21)$$

$$p_t^{\text{BESS, dis}} \leq R^{\text{B, P2E}} e^{\text{BESS}} \qquad t \in T \quad (22)$$

The TES is modelled similar to the BESS, except a self-discharge parameter, $\gamma^{\text{TES},sel}$, which is added to represent heat leakage:

$$\begin{aligned} soc_t^{\text{TES}} = {} & soc_{t-1}^{\text{TES}} + \eta^{\text{TES}} q_t^{\text{TES, ch}} \Delta t \\ & - \frac{1}{\eta^{\text{TES}}} q_t^{\text{TES, dis}} \Delta t - soc_{t-1}^{\text{TES}} \gamma^{\text{TES, sel}} \end{aligned} \qquad t \in T \backslash \{1\} \quad (23)$$

$$\begin{aligned} soc_t^{\text{TES}} = {} & soc_T^{\text{TES}} + \eta^{\text{TES}} q_t^{\text{TES, ch}} \Delta t \\ & - \frac{1}{\eta^{\text{TES}}} q_t^{\text{TES, dis}} \Delta t - soc_T^{\text{TES}} \gamma^{\text{TES, sel}} \end{aligned} \qquad t = 1 \quad (24)$$

$$soc_t^{\text{TES}} \leq \overline{\alpha^{\text{TES}}} e^{\text{TES}} \qquad t \in T \quad (25)$$

$$soc_t^{\text{TES}} \geq \underline{\alpha^{\text{TES}}} e^{\text{TES}} \qquad t \in T \quad (26)$$

$$q_t^{\text{TES, ch}} \leq R^{\text{T, P2E}} e^{\text{TES}} \qquad t \in T \quad (27)$$

$$q_t^{\text{TES, dis}} \leq R^{\text{T, P2E}} e^{\text{TES}} \qquad t \in T \quad (28)$$

Here, soc_t^{TES} denotes the SOC of the TES, η^{TES} is the charge/discharge efficiency, $\underline{\alpha^{\text{TES}}}$ and $\overline{\alpha^{\text{TES}}}$ are the minimum and maximum SOC limits, and $R^{\text{T, P2E}}$ is the power-to-energy ratio of the TES.

Eqs. (29) and (30) ensure that variables are non-negative. Eqs. (31)–(32) define the binary variables.

$$\begin{aligned} & e^{\text{BESS}}, e^{\text{TES}}, p_t^{\text{exp}}, p_t^{\text{imp}}, p_t^{\text{industry}}, p_t^{\text{BESS, ch}}, \\ & \quad p_t^{\text{BESS, dis}}, soc_t^{\text{BESS}}, q_t^{\text{TES,ch}}, q_t^{\text{TES,dis}}, soc_t^{\text{TES}}, \\ & \quad q_t^{\text{TES, sel}}, p_t^{\text{el. boiler}}, q_t^{\text{el. boiler}} \geq 0 \end{aligned} \qquad t \in T \quad (29)$$

$$p_m^{\text{max}} \geq 0 \qquad m \in L \quad (30)$$

$$\beta_{1,m}, \beta_{2,m}, \beta_{2,m} \in \{0, 1\} \qquad m \in L \quad (31)$$

$$\beta_t^{\text{impexp}} \in \{0, 1\} \qquad t \in T \quad (32)$$

2.2. Cost distribution methods

After running the optimisation model, we compare different ways of distributing the operational costs to the industry consumer and the urban area.

The first method is the flat energy pricing [29], where the cost for each member i, C_i, is calculated from the total costs, TC, and the yearly energy consumption of each member i, E_i:

$$C_i = \frac{TC}{\sum_i E_i} \cdot E_i \quad (33)$$

The second method is the coincident peak [29], where the cost is calculated on the basis of each member's power consumption in the hour of the system peak, $P_i^{\text{system peak}}$:

$$C_i = \frac{TC}{\sum_i P_i^{\text{system peak}}} \cdot P_i^{\text{system peak}} \quad (34)$$

The third method is the non-coincident peak [29], where the cost is calculated similarly to the previous method, but the individual peak of each member, $P_i^{\text{individual peak}}$, is used instead of the power consumption at the system hour:

$$C_i = \frac{TC}{\sum_i P_i^{\text{individual peak}}} \cdot P_i^{\text{individual peak}} \quad (35)$$

The fourth method is based on the Shapley value [30], where the costs are distributed among members depending on their contribution to the total cost. The Shapley value is a concept from cooperative game theory, where the payoffs are distributed among players in a coalitional game [33]. When there are two actors in the energy community, the cost is calculated as follows for member i:

$$C_i = \frac{(TC - C_i^{\text{alone}}) + C_j^{\text{alone}}}{2} \tag{36}$$

where C_i^{alone} is member i's cost when operating alone, hence before joining the energy community. C_j^{alone} is the cost before joining the energy community for the other actor, j.

3. Case study

The presented model is applied to a case study in Trondheim, Norway. The industry consumer is a real-life dairy producing around 75 million litres of dairy products yearly. Processing of dairy products includes both heating and cooling demands, for processes such as pasteurising, cleaning, storage, and product cooling etc. [34]. We focus on the process heating demands of the investigated dairy in this work, which require hot water slightly below 100 °C. The dairy therefore requires both thermal and electrical energy and is connected to a transformer that also supplies an urban area of diverse consumers. The dairy and the DSO of the area have provided hourly measurements for one year, 2022. The available space for accommodating energy storage solutions is a critical consideration for industrial consumers. In our case study, the industrial site is able to fit a large hot water tank and/or a battery container, and there are therefore no size limitations on the energy storages.

More details on the specific constraints for the industry consumer can be found in Appendix A. All measurements from the industry consumer are from 2022, and specifications regarding the data handling can be found in Appendix B.

3.1. Load and generation

Fig. 3 shows the annual load of the industry consumer (dairy), and the urban area load with and without PV generation. The urban area load is taken from measurements at the transformer station in 2022, provided by the DSO in the area, where the industry load is subtracted. The increase in load at the end of the year is attributed to the decrease in temperatures in December. Figs. 4 and 5 show the yearly consumption and the number of consumers connected to the transformer station. Note that "Industry" in these figures denotes the total amount of industry consumers in the area, not only the dairy. The majority of the load comes from households, both in terms of number of customers and their yearly consumption (35%). Commercial buildings and services also contribute significantly to the yearly consumption (31%), although there are only 223 of them, compared to 2452 households. 33 industries stand for 31% of the yearly consumption in the area, and this includes the industrial consumer (dairy).

In this case study, we assume that the urban area has installed PV generation. The PV is sized based on the urban area load shown in Fig. 5. There are 2452 households, and the average PV size in Norway is 9 kWp for households [35]. We assume that 50% of the households install PV panels, which amounts to $2452 \cdot 9 \cdot 50\%$ kWp $\approx$ 11 MWp. This PV generation could in theory be located anywhere in the urban area, as the load profile is aggregated. The PV profile is generated from Renewables Ninja [36] for the location of Trondheim, Norway.

The characteristics of the industry consumer (dairy) load and urban area load are presented in Table 1. The term "Area" represents the urban area load data measured at the transformer (with the industry load subtracted), while "Area w/ PV" denotes the urban area load when the synthetic PV generation is subtracted. The coincidence factor[1] of the urban area and the industry consumer is 0.93, and does not change when we add the PV generation, since the PV generation is zero at the peak load hour. We see that the dairy consumes 22% of the annual load in total. When we add PV generation to the urban area load, the annual load is reduced by 9991 MWh.

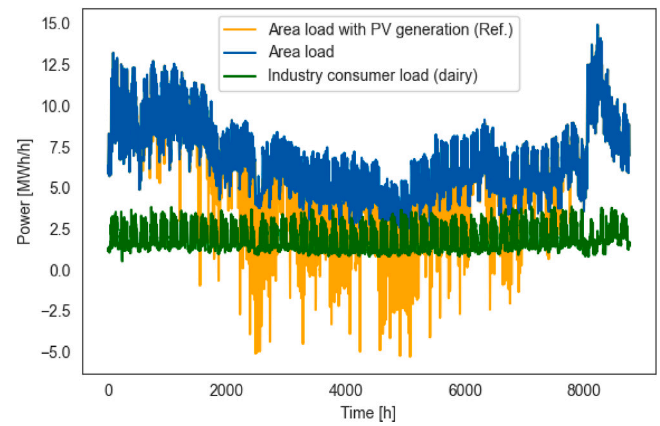

Fig. 3. Annual load and PV generation for industry consumer and urban area for year 2022. Net demand is positive for load and negative for generation.

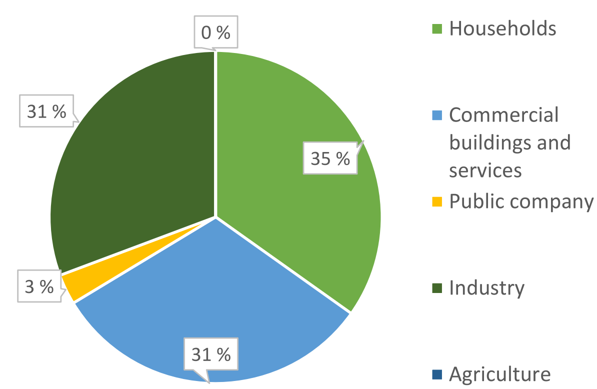

Fig. 4. Yearly consumption at transformer station divided into customer group. "Industry" denotes the total amount of industry consumers in the area, not only the dairy.

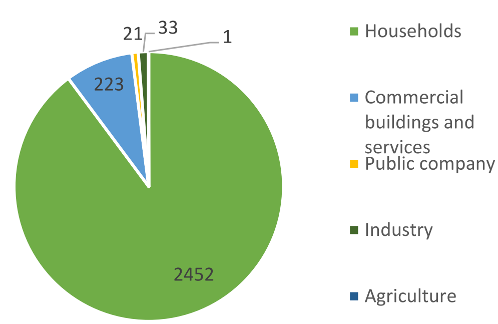

Fig. 5. Number of consumers at transformer station divided into customer groups. "Industry" denotes the total amount of industry consumers in the area, not only the dairy.

Table 1
Load characteristics. "Industry" refers to the dairy.

	Industry	Area	Area w/PV
Peak load [MWh/h]	4.00	14.94	14.94
Annual load [MWh]	17,241	59,729	49,738

[1] Coincidence factor is calculated as the maximum total load divided by the sum of individual maximum load: 17.69/(4.00 + 14.94).

Table 2
Monthly peak grid tariff [37].

p_m^{max}	Winter [€/kW]	Summer [€/kW]
<100	4.6	3.0
>100 and <500	3.8	2.6
>500	3.0	2.1

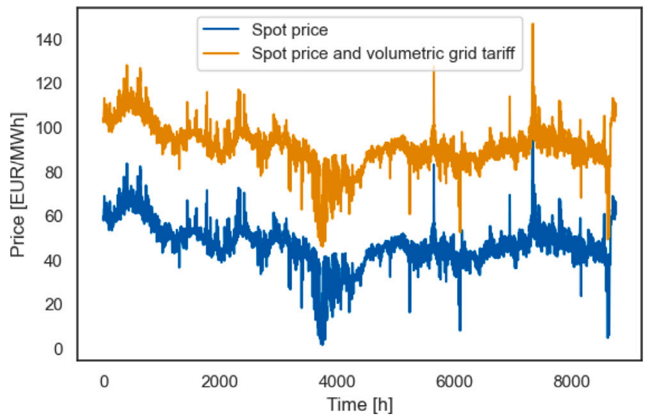

Fig. 6. Spot price for the year 2019 and volumetric grid tariff, including consumption tax and VAT.

3.2. Grid tariff and spot price

The industry consumer has a volumetric grid tariff and a monthly peak grid tariff. The volumetric tariff is 0.39 ¢/kWh, and the consumption tax is 0.055 ¢/kWh [37]. The monthly peak grid tariff for the industry consumer is shown in Table 2 for winter (November-April) and summer (May-October) [37]. The industry pays for each step of the tariff. For instance, if the monthly peak consumption in January is 650 kWh/h, the cost would be $100 \cdot 4.6 + 400 \cdot 3.8 + 150 \cdot 3.0$ €= 2430 €.

Fig. 6 shows the spot price from 2019 used as input, both with and without the volumetric grid tariff and consumption tax (excluding the monthly peak grid tariff). The spot prices are skewed to match the weekdays of 2022.

3.3. Thermal energy storage

The TES is assumed to be a hot water tank TES, with the hot water outlet near the top of the tank, and the cold water return near the bottom of the tank. In an idealised storage, perfect thermal stratification can be assumed, meaning that there is no mixing of hot and cold water within the tank, and the temperature increases from the bottom to the top [38]. To account for imperfections in the stratification, as well as the requirement for a sufficiently high temperature difference between the TES outlet and the process demands, we assume that the upper and lower SOC limits of the thermal storage are 75% and 25%, respectively. The cost of a TES is highly subjected to economies of scale [39], but in the capacity range pertinent to this study, we assume a linear cost per energy unit of 25 €/kWh [40].

3.4. Battery energy storage system

The BESS is assumed to be a lithium-ion battery, and is modelled with an investment cost dependent on battery energy capacity of 200 €/kWh [41]. According to [41], this investment cost is assumed to be reached within 2030 for nickel manganese cobalt oxide (NMC), lithium manganese oxide (LMO) and nickel cobalt aluminium (NCA) technologies. Furthermore, the battery SOC is restricted to be between 10% and 90%.

Table 3
Input parameters for optimisation.

Parameter	Value
Investment cost BESS, $C^{\text{BESS, inv}}$	200 €/kWh [41]
OPEX BESS, $C^{\text{BESS, op.}}$	0.57 €/MW/yr [42]
Investment cost TES, $C^{\text{TES, inv}}$	25 €/kWh [40]
OPEX TES, $C^{\text{TES, op.}}$	8.8 €/MWh [42]
Efficiency BESS, η^{BESS}	0.98 [41]
Efficiency TES, η^{TES}	0.9 [40]
Lifetime BESS, N^{B}	15 y [41]
Lifetime TES, N^{T}	20 y [40]
TES discharge, $\gamma^{\text{TES,sel}}$	0.2%
Interest rate, IR	0.051
Capacity electric boiler, $\overline{P^{\text{electric boiler}}}$	2500 kW
Efficiency electric boiler, $\eta^{\text{electric boiler}}$	0.99
Power-to-energy ratio BESS, $R^{\text{B, P2E}}$	1
Power-to-energy ratio TES, $R^{\text{T, P2E}}$	1
BESS SOC upper and lower limits	90%, 10%
TES SOC upper and lower limits	75%, 25%

3.5. Technical input parameters to optimisation model

Table 3 shows the input parameters for the optimisation model.

4. Results and discussion

This section shows the results from running the optimisation model for the different cases. We investigate three cases:

- Reference (Ref.): No storage investment.
- Industry: We investigate the sizing of energy storage when the industry consumer optimises its own investment and operational costs without considering the urban area. The optimisation model exclusively considers the industry consumer's energy demand.
- Energy Community (EC): We investigate the sizing of energy storage when the industry consumer collaborates with the area. The optimisation model is executed to account for both the industrial and urban energy demand, alongside PV generation.

The model is formulated as a MINLP, and is implemented in Pyomo/Python [43], using Gurobi [44] as an optimisation solver. The model was run for hourly values of one year, which took approximately 84 s on a Dell PC with an Intel Core i5-1145G7 @ 2.60 GHz, 16 GB RAM.

First, we display the results from the optimisation model in two reference weeks. Next, we compare the annual costs and maximum import for the cases. After this, we investigate different methods for distributing the costs between the industrial consumer and the urban area. Finally, a sensitivity analysis is carried out to investigate the impact of several input parameters.

4.1. Summer and winter reference weeks

Two reference weeks for winter and summer are based on the maximum transformer load (12–19 December) and minimum transformer load (01–08 August). Here, the results are presented for these reference weeks for Case Industry and Case Energy community.

4.1.1. Case industry

Fig. 7 shows the import to the industry consumer for the winter week, divided into the two buses where the energy storages can be placed, BESS can be placed at the electrical bus (blue) and TES can be installed at the thermal bus (green). The optimal TES size is found to be 4.69 MWh, and the model does not invest in a BESS. The original import to the industry is shown in a dashed line, and it is clear that the TES is operating to reduce the peak demand, due to the monthly peak grid tariff. In this week, the peak is reduced from 3.87 MWh/h to 3.23 MWh/h.

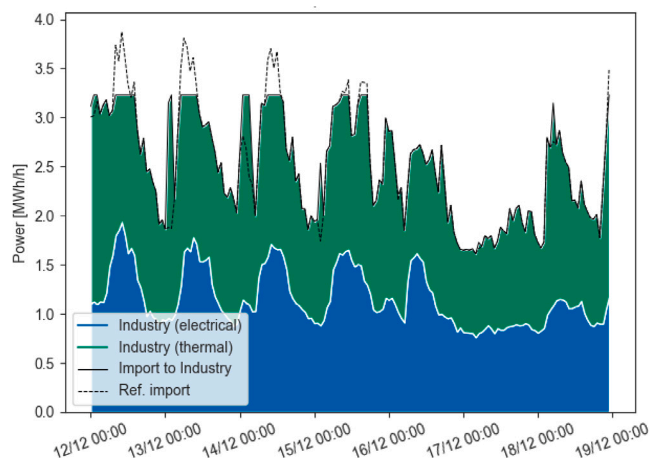

Fig. 7. Import to industry consumer in Case Industry, winter week. The industrial consumer has both electrical and thermal consumption, and the difference between the original and the new import is due to the TES operation.

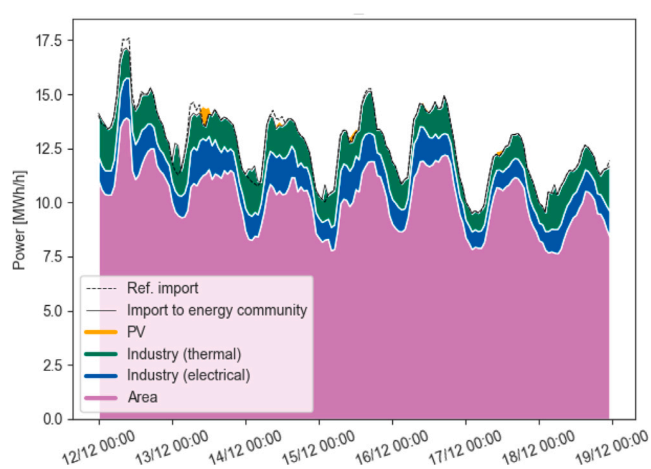

Fig. 8. Import to energy community in Case Industry, winter week. The import to the energy community is divided into the electrical and thermal demand of the industrial consumer, and the load and PV generation of the urban area. The difference between the ref. import and the new import is due to the TES operation.

Fig. 8 shows the import to the energy community for the winter week. The total import is due to electrical and thermal load at the industry consumer, and load and PV generation of the urban area. At hour 8290, the peak load is 17.15 MWh/h, where the urban area (purple) has the highest share of the load, with 13.82 MWh/h. The change between the original import (stippled line) and the import when storage is included (black line) is due to the change in operation from the electric boiler together with the TES. Although the objective in this case is to reduce the peak load for the industry, not the whole urban area, the import to the energy community is in fact reduced from 17.69 MWh/h to 17.15 MWh/h, a reduction of 3.1%.

4.1.2. Case energy community

When the optimisation model is run for Case EC, which accounts for both the industry load and the urban area load and PV generation, the model invests in a larger TES of 5.46 MWh. BESS is still not profitable to invest in. Fig. 9 compares the import to the energy community for the winter week for all cases. It can be seen that the maximum import, which originally occurred at hour 8290, is lowered even further in Case EC, compared to Case Industry, to 16.78 MWh/h.

In the summer, the PV generation of the urban area affects the import/export a lot more than in winter, and the load is much lower

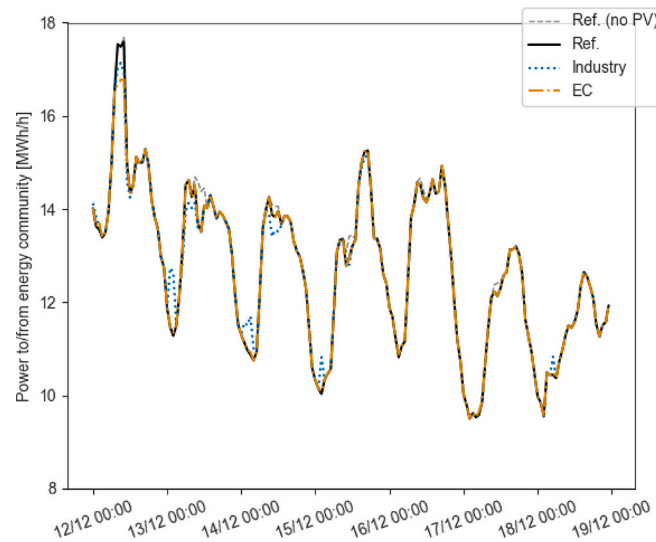

Fig. 9. Import to energy community for all cases, winter week. Ref. (no PV) represents the load in the reference case without PV generation, and is included to illustrate the low effect of PV generation in winter. The peak import is reduced in Case Industry and Case EC due to the TES operation.

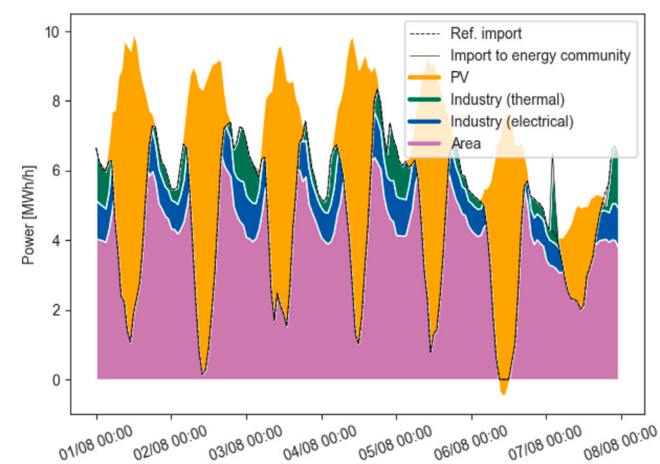

Fig. 10. Import (positive) and export (negative) to/from energy community in Case EC, summer week. The import/export is divided into the electrical and thermal demand of the industrial consumer, and the load and PV generation of the urban area. The peak import is reduced compared to the reference case, due to the TES operation.

than in winter. Fig. 10 shows the import to the energy community for Case EC in the summer week. As in Fig. 8, the import consists of the industry electrical and thermal load, and the urban area load and PV generation. The peak demand in this week originally occurred at hour 5100 with 9.98 MWh/h, without PV generation. The highest peak in the summer week now occurs in hour 5178, and is 8.35 MWh/h. Interestingly, the TES is only operating in the last two days of the summer week, as shown in Fig. 11. The figure compares the TES operation in Case EC and Case Industry for the summer week, and it is clear that the TES charges and discharges more often in Case Industry. In fact, the annual TES use in Case Industry is 2818 h, while in Case EC it is 2224 h.

When comparing the import to the energy community for all three cases for the summer week, we see that PV has a large significance, as shown in Fig. 12, creating valleys (low demand) at new times of the day. The valleys now occur around noon, instead of during the night/early morning, which originally happened in Case Ref. (no PV).

Fig. 13 shows a violin plot of the import/export to/from the energy community per month for all cases. The figure illustrates a substantial

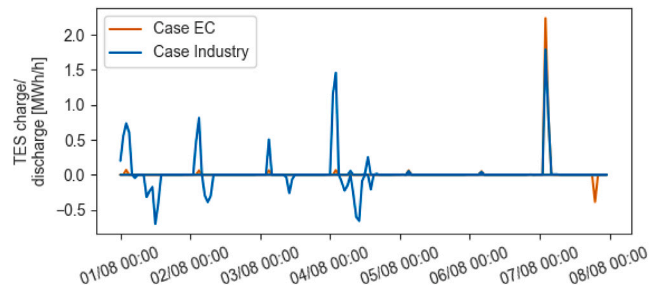

Fig. 11. TES charge (positive) and discharge (negative) for Case Industry and Case EC, summer week.

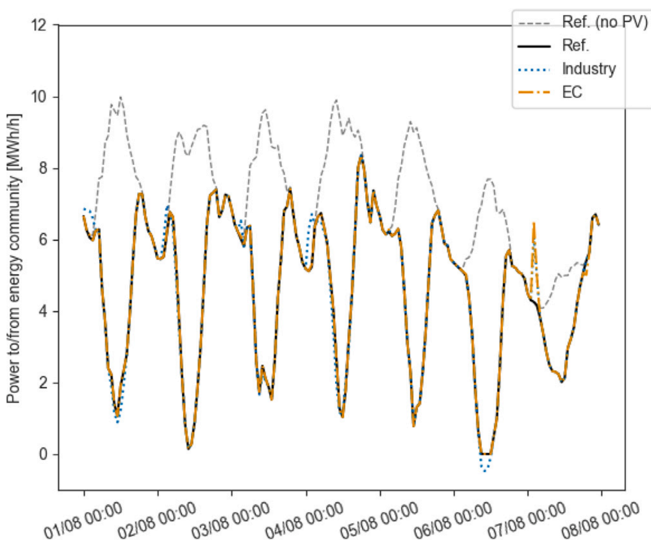

Fig. 12. Import (positive) and export (negative) to/from energy community for all cases, summer week. Ref. (no PV) represents the load in the reference case without PV generation, and is included to demonstrate the effect of PV generation in summer.

occurrence of hours with high demand in December, and import fluctuations throughout the year. January and February are also months with high peak demands. It is observed that the peak demand during December and January exhibit a decrease in Case Industry, and to a greater extent in Case EC, compared to the reference case. Case Industry yields a lower peak demand compared to Case Ref. in nine out of twelve months. Consequently, the entire area accrues benefits from the independent optimisation efforts of the industrial consumer. The peak load is, however, always reduced even further when the whole energy community optimises together. It can also be seen that there is an export indicated by negative values from April to October, which never exceeds 5 MWh/h. The storage is only used to reduce peak demand and never used to reduce export in the summer months.

4.2. Comparing costs and maximum import

Table 4 shows a summary of the storage investment and maximum import for the different cases. As already mentioned, there is no BESS investment in any of the cases. When comparing Case Industry and Case EC, the size of the TES is increased by 770 kWh.

The DSO is interested in whether the maximum import to the whole area, and therefore the stress on the transformer, is lowered. For Case Industry, we can see that the maximum import to the area is reduced by 3.1%, from 17.69 MWh/h to 17.14 MWh/h. For Case EC, the maximum import to the urban area is reduced even further, with 5.1%, to 16.78 MWh/h. Hence, optimising for the whole urban area reduces the peak

Table 4
Yearly results - technical.

	Case		
	Ref.	Industry	EC
Size BESS [MWh]	0	0	0
Size TES [MWh]	0	4.69	5.46
Max. imp. industry [MWh/h]	4.00	3.34	4.22
Max. imp. EC [MWh/h]	17.69	17.14	16.78

Table 5
Yearly results - costs [€].

Cost	Case		
	Ref.	Industry	EC
Ann. inv. cost BESS [k€]	0	0	0
Ann. inv. cost TES [k€]	0	9.48	11.04
Op. cost BESS [k€]	0	0	0
Op. cost TES [k€]	0	0.041	0.048
Op. cost industry [k€]	1030	999	?
Op. cost urban area [k€]	3009	3009	?
Total op. cost [k€]	4039	4007	3968

load more than optimising for the Industry alone, which is expected due to the increased investment in energy storage. At the same time, it is noteworthy that optimising for the industry consumer alone reduced the peak import to the energy community significantly. Note also that the maximum import to the industry consumer increases in Case EC, compared to both Case Ref. and Case Industry, due to charging of energy storage, which is more beneficial for the peak load of the energy community as a whole.

Table 5 shows the costs for each case, split into annualised investment costs for the energy storage technologies and operational costs for the energy storages, the industry consumer and the urban area. We see that the total operational costs are reduced by 0.8% in Case Industry, and 1.8% in Case EC. For the industry consumer, the operational costs are reduced by 3.0% in Case Industry.

It is intuitive that an energy community with aggregated net metering will experience a cost reduction, compared to the case where it does not have aggregated metering. For the DSO to allow this, the question remaining is whether this gives a benefit to the grid, in terms of a reduction of peak import. This case study shows that both peak import and costs in fact are reduced. Hence, both the energy community and the DSO are better off in this case.

4.3. Equitable distribution of costs within EC

In this energy community, the industry consumer is contributing with energy storage, while the urban area is contributing with PV generation. The total reference operational costs were 4039 k€, as shown in Table 5, and have been lowered to 3968 k€ from the aggregated net metering. As described in Section 2.2, we investigate four ways of distributing the costs: flat energy pricing, coincident peak, non-coincident peak and Shapley value.

In the flat energy pricing method, the cost is divided based on yearly consumption. In Case EC, the industry consumer has a yearly consumption of 17,642 MWh and the urban area has a yearly consumption of 49,738 MWh:

$$C_I = \frac{3968}{17,642 + 49,738} \cdot 17,644 = 1039 \tag{37}$$

$$C_A = \frac{3968}{17,642 + 49,738} \cdot 49,738 = 2929 \tag{38}$$

We see that the industry cost, C_I, is 9 k€ higher than in the reference case. The urban area cost is lower than in the reference case.

In the coincident peak method, the costs are divided depending on how much each member contributes to the system peak. The system

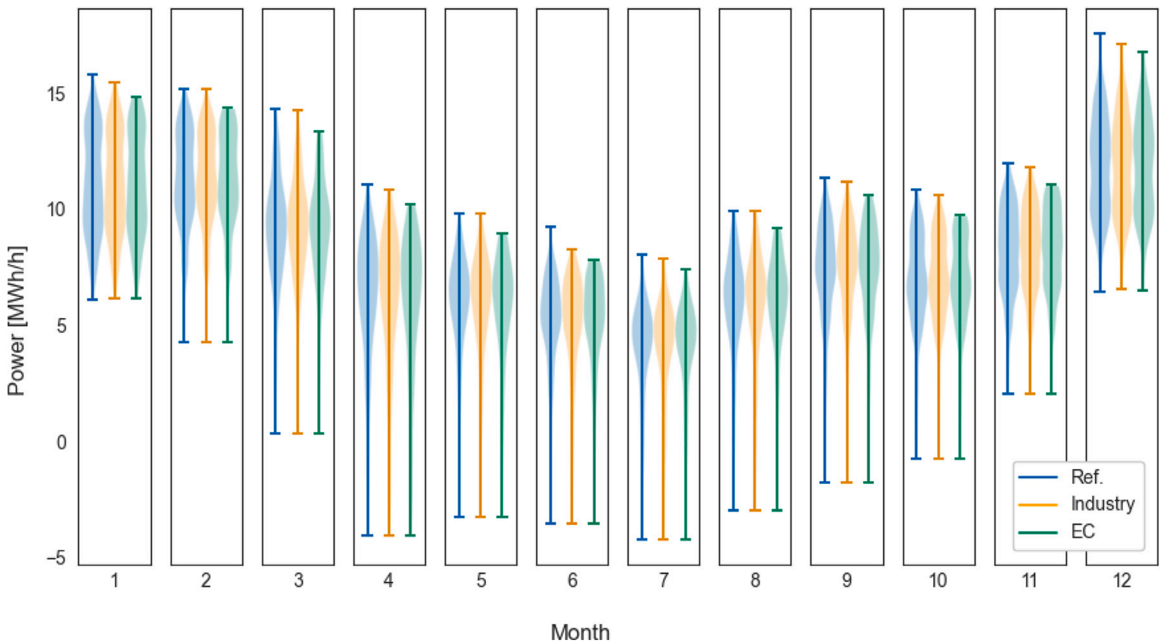

Fig. 13. Violin plot of import (positive) and export (negative) to/from energy community for all cases across different months.

peak occurs in hour 8223 for Case EC, where the industry consumer has a consumption of 2.17 MWh/h and the urban area has a consumption of 14.61 MWh/h:

$$C_I = \frac{3968}{(2.17 + 14.61)} \cdot 2.17 = 513 \tag{39}$$

$$C_A = \frac{3968}{(2.17 + 14.61)} \cdot 14.61 = 3454 \tag{40}$$

Here, the industry cost is 517 k€ lower than in the reference case, and also lower than the cost obtained in Case Industry. The urban area cost is higher than in the reference case.

In the non-coincident peak method, the costs are divided depending on each member's individual peak. In Case EC, the peak of the industry consumer is 5.29 MWh/h, while the peak of the urban area is 14.94 MWh/h:

$$C_I = \frac{3968}{(5.29 + 14.94)} \cdot 5.29 = 1037 \tag{41}$$

$$C_A = \frac{3968}{(5.29 + 14.94)} \cdot 14.94 = 2931 \tag{42}$$

Here, the industry operational cost is 7 k€ higher than in the reference case. The urban area cost is lower than in the reference case.

With the Shapley value, the costs are divided depending on each member's contribution to the cost reduction. In this case, we only have two actors since the urban area is aggregated into one:

$$C_I = \frac{(3968 - 3009) + 999}{2} = 979 \tag{43}$$

$$C_A = \frac{(3968 - 999) + 3009}{2} = 2989 \tag{44}$$

Here, both actors save 20 k€ by joining the energy community. Calculating the cost reduction for each member in the urban area is out of the scope of this paper, since we only have aggregated data. One might argue that it is unfair that the industry receives half of the cost reduction, since the urban area consists of many members. At the same time, it is the industry that is investing in energy storage that makes it possible to reduce the peak load in such a manner that the costs are reduced.

Comparing the different cost distribution methods, it is only the Shapley value method that reduces costs for both the industrial consumer and the urban area. In Case Industry, the total costs for the industry are operating costs of 999 k€ and annual investment costs of TES of 9.48 k€, a total cost of 1008 k€. If the industry consumer joins the energy community, and invests in a larger storage, its costs increase if flat energy pricing or non-coincident peak is used as a cost distribution method. If the cost distribution method is the coincident peak, the industry is rewarded for lowering its individual peak (using storage) when the system peak is occurring, and it, therefore, reduces its costs. The downside of using the coincident peak is that the urban area experiences increased costs compared to the reference case, since it is not rewarded for what the storages are doing as they are located at the industry consumer. Therefore, it seems like the Shapley value is the fairest cost distribution method. The drawback of this method is that the cost for the industry consumer and the urban area if they did not join the energy community, needs to be known, while the other methods only rely on smart meter data.

4.4. Sensitivity analysis

Two types of sensitivity analysis have been carried out: first, we stepwise change the investment costs of TES and BESS, to see how this impacts the storage sizes, total costs and maximum import from the grid. Second, the levels of spot price, grid tariff, interest rate and PV size are changed one-at-a-time, to see how this impacts the main results.

4.4.1. Sensitivity of storage capital expenditures

Figs. 14 and 15 show the results of the sensitivity analysis on TES and BESS capital expenditures, for Case Industry and Case EC, respectively. The heatmaps show the stepwise results of running the optimisation model 6 × 7 times, with varying investment costs for BESS and TES. The value ranges are equal in both figures, so the colours can be compared.

Fig. 14(a) and (b) show the sizes of the BESS and TES, (c) shows the reduction in total costs of the industry consumer, and (d) shows the reduction in maximum import to the energy community. The capital expenditure for BESS is in the range of 100–200 €/kWh, and for TES it is in the range of 10–100 €/kWh. The white colour in the plot indicates no storage investment. It becomes evident that the model only invests in a BESS when the BESS investment cost is 160 €/kWh or lower, and the TES cost is 55 €/kWh or higher. For these cases, the BESS size ranges from 402 kWh to 1.3 MWh. The model invests in a TES for all costs, except when the TES investment cost is above 70 €/kWh

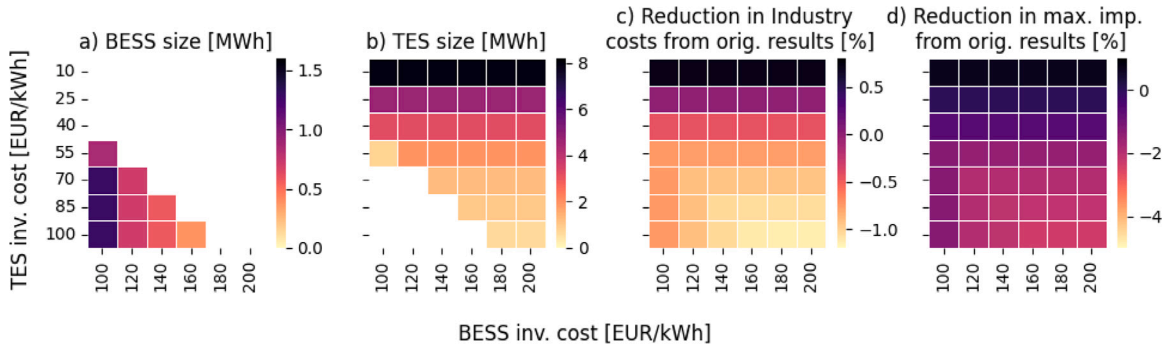

Fig. 14. Heatmap of (a) BESS size, (b) TES size, (c) reduction in total costs for the industry consumer and (d) reduction in maximum import to energy community as the function of TES and BESS investment costs for Case Industry. White colour means no storage investment. A positive reduction in costs means lower costs than the original result. A positive reduction in maximum import means a lower maximum import than the original result.

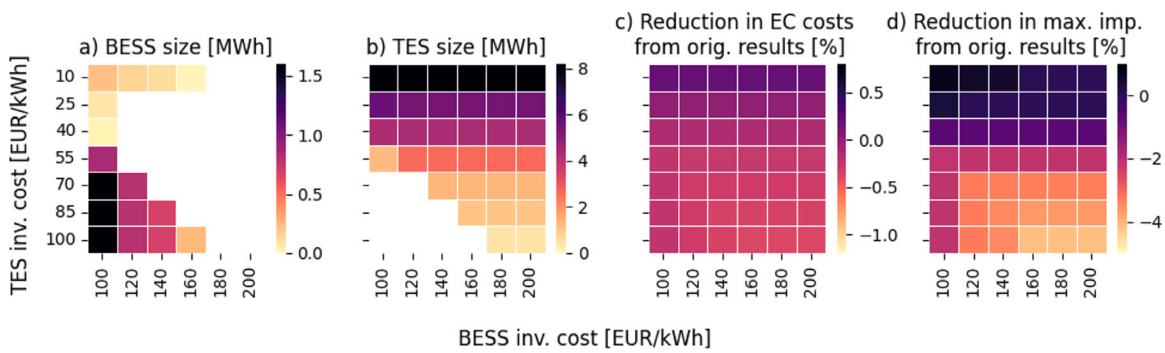

Fig. 15. Heatmap of (a) BESS size, (b) TES size, (c) reduction in total costs for the energy community and (d) reduction in maximum import to energy community as the function of TES and BESS investment costs for Case EC. White colour means no storage investment. A positive reduction in costs means lower costs than the original result. A positive reduction in maximum import means a lower maximum import than the original result.

and the BESS investment cost is 160 €/kWh or lower. The TESS size ranges from 0.6 MWh to 8.0 MWh, which is quite a large spread. The total cost for the industry consumer and the maximum import, on the other hand, vary very little. The reduction in cost ranges from −1.2% to 0.8%, indicating that the results are robust. The maximum import does not change significantly from the original results, with a reduction in the range of −2.4% to 0.7%. We see that the highest reduction in cost occurs when we have the largest investment in TES. Similarly, the reduction of maximum import follows the increasing investment in TES capacity (note that a negative reduction of maximum import corresponds to an increase in import).

Fig. 15 shows the same heatmap, but for Case EC. Comparing with Fig. 14, we see that there is more investment in BESS for lower TES investment costs. When the TES investment cost is 10 €/kWh, the model invests in a TES with a capacity of 8.2 MWh. Additionally, when BESS investment costs are also low, it is profitable to install a small BESS to reduce the peak import. However, when the TES investment cost rises to 25 €/kWh, the optimal TES size decreases to 5.6 MWh. In this scenario, the model does not find it profitable to combine TES with a BESS for peak import reduction when BESS investment costs exceed 100 €/kWh. Overall, the TES sizes range from 0.4 MWh to 8.2 MWh, and the BESS sizes range from 70 kWh to 1.6 MWh, both larger ranges than for Case Industry. The reduction in total cost ranges from −0.4% to 0.2%, hence a very little change. Maximum import varies more than it did in Case Industry. The reduction is now in the range of −4.2% to 0.7%. Hence, high investment costs for TES lead to smaller TES sizes and therefore an increase in maximum import.

To summarise, we see that the results for total costs are quite robust, as the sensitivity analysis shows only a slight difference in values. There is a larger spread in the storage investment decision, and overall we see that lower storage cost leads to larger storage sizes, lower total costs, and lower maximum import.

4.4.2. Sensitivity of spot price, grid tariff, interest rate and PV size

Table 6 shows the sensitivity analysis of spot price level, grid tariff level, interest rate and PV size for Case EC. The spot price level and grid tariff level are given as factors that are multiplied by the original input. Both the volumetric and the monthly peak grid tariff are adjusted. The interest rate and PV size are given in [%] and [MWp], respectively. Original inputs are given in bold. The overall picture is that the results are quite robust, since they do not change significantly for the different inputs. Two exceptions can be seen: the operational cost is clearly sensitive to the spot price level, and the optimal TES size is clearly sensitive to the grid tariff level.

The TES size increases when the grid tariff level increases, and decreases when the interest rate increases. BESS is only invested in when spot price levels and grid tariff levels are high. Overall, The TES size is in all cases a minimum of 16 times larger than the BESS.

For varying spot price levels, the TES size only varies slightly, ranging from 5.30 to 5.51 MWh. Interestingly, the TES size does not follow the spot price level linearly. For a spot price level of 2, the model invests in a slightly larger storage to be able to reduce the monthly peaks, and thereby the monthly peak grid tariff cost. When the spot price level further increases, however, it outcompetes the price signal from the monthly peak grid tariff, and the model has a higher priority of responding to high/low spot prices, which requires a smaller TES. When the spot price increases to even higher levels, and thereby higher fluctuations, the model finds it profitable to invest in more storage that can be used to lower the cost from importing electricity, and this storage is also used to reduce the monthly peaks. In other words, there is a constant trade-off between the different costs in the objective function: the energy storage investment costs, the spot price and energy grid tariff costs, the monthly peak grid tariff costs and the remuneration from feed-in. The monthly peak grid tariff price signal is dominant until a certain point, but when the spot price gets higher, these two

Table 6
Sensitivity analysis on the spot price level, grid tariff level, interest rate and PV size for Case EC. Spot price level and grid tariff level are multiplication factors of the original input. Numbers in bold correspond to the original assumption.

		e^{BESS} [MWh]	e^{TES} [MWh]	Op. costs [k€]	Max. imp. [MWh/h]
Spot price level	**1**	**0**	**5.46**	**3 968**	**16.78**
	2	0.02	5.51	7 277	16.77
	3	0	5.30	10,587	16.78
	4	0.07	5.30	13,894	16.72
	5	0.30	5.51	17,198	16.63
Grid tariff level	**1**	**0**	**5.46**	**3 968**	**16.78**
	1.5	0.05	6.22	4 265	16.74
	2	0.19	7.38	4 565	16.68
	2.5	0.29	8.22	4 866	16.64
	3	0.59	10.21	5 159	16.52
Interest rate [%]	3	0	5.73	3 968	16.78
	4	0	5.54	3 968	16.78
	5.1	**0**	**5.46**	**3 968**	**16.78**
	6	0	5.27	3 968	16.78
	7	0	5.06	3 969	16.78
PV size [MWp]	**11**	**0**	**5.46**	**3 968**	**16.78**
	14	0	5.00	3 831	16.78
	17	0	5.52	3 693	16.78
	20	0	4.86	3 558	16.78
	23	0	4.80	3 424	16.78

price-signals become conflicting as the optimisation model needs to decide what the optimal monthly peak is, which energy storage size is required to reach this peak, and whether it is more important to charge/discharge the TES when the prices are low/high.

The TES size generally decreases for higher PV sizes, except for a PV size of 17 MWp where the model finds it profitable to invest in a slightly larger TES (5.52 MWh) to reduce the monthly peak power grid tariff. When the PV size increases further, however, the increased generation leads to higher cost savings from electricity import, remuneration from feed-in, and monthly peak power grid tariff during the summer months, and therefore the TES size is reduced.

The total operating cost is highly sensitive to the spot price level, increasing to over 17 M€ for a spot price level increase of 5. The grid tariff level also increases the overall costs. For a change in interest rate, the cost remains in the same range as before, as it mainly impacts the investment decision in energy storage.

The lowest maximum import obtained is 16.52 MWh/h, which is a reduction of 1.5% from the original optimisation result. This result is obtained for the highest grid tariff level. In general, we can see that the maximum import follows the grid tariff level, which is due to the monthly peak grid tariff. Maximum import is also reduced if the spot price level is 4 or 5 times higher, since there are more hours with high spot price at the same time as high demand. Interest rate and PV size do not affect the maximum import.

4.5. Discussion

With regard to comparing the different storage types in the energy community, our results have shown that the optimisation model favours TES, compared to BESS, due to lower investment costs. When we compare Case EC with Case Industry, we see that the storage sizes are increased, while maximum import and total costs are reduced.

When investigating the different cost distribution methods, we see that only the Shapley value lowers the costs for both the industry consumer and the urban area. We also see that the other cost distribution methods give very different results, and that cost recovery with regard to the investment costs might not occur. This leads to a greater discussion on energy community equity, which might also affect the interest in joining the community. The energy community is assumed to be collaborative, since the optimisation is done centrally, but the cost distribution method strongly affects which member receives the most benefit out of joining the energy community. In this case study, it is the industry consumer that invests in the energy storage. The urban area, on the other hand, contributes with PV generation, which is a reason for why a larger energy storage size is optimal. The cost distribution methods that focus on peak load of the grid clearly do not compensate the urban area, since the PV is not contributing to reducing the peak load effectively in this Norwegian energy community.

We performed a sensitivity analysis to investigate how the results change with different assumptions for input parameters. When we altered the storage investment costs, we found that they highly impacted the optimal size of the storages. It was also more likely that BESS was invested in when optimising for the whole energy community, than for the industry consumer alone. The costs, however, only varied slightly, leading to the conclusion that our results are robust. When we altered the spot price level, grid tariff level, interest rate and PV size, we also found that our results did not change much. There were two exceptions: the costs, which were highly sensitive to the spot price level, and the TES sizes, which were highly sensitive to the grid tariff level. We also saw that the optimal TES size did not follow a linear trend for higher spot price levels and PV sizes. This emphasises the complex nature of optimisation models with many different price-signals, especially with a monthly peak grid tariff. Although the sensitivity analysis showed only minor changes in the optimal TES size for the different spot price levels and PV sizes, the operation of the TES varied depending on whether it was profitable to use the TES for storing surplus PV generation, doing energy arbitrage, or peak shaving.

It should be noted that we have not included a detailed battery degradation model, meaning that the battery may be even less profitable than these results depict. The investment cost for TES has been modelled linearly, which might lead to unrealistically low costs for small sizes of TES. Another point which is important to mention is the space limitations of the energy storages. In this work, we have assumed that the dairy has no space limitations for installing hot water tanks or battery containers. This could certainly play an important role in other case studies where the industry consumer has less space available. In such scenarios, this could potentially bias the outcomes in favour of BESS, given that batteries exhibit a higher density compared to hot water tanks.

This research investigates two perspectives at once: the members of the energy community and the DSO. For the members, the objective of creating the energy community is to lower the costs. This cost reduction, however, occurs because the energy community is assumed to have aggregated net metering. But for the DSO to allow this kind of metering, it needs to be evident that the peak load of the grid is also lowered, so that the energy community also brings benefits to the local grid. The results show that this does in fact happen: When the industry optimises on its own (Case Industry), the maximum peak is reduced to 17.14 MWh/h. When the energy community optimises together (Case EC), the maximum peak is reduced to 16.78 MWh/h. This reduction in maximum import happens since the monthly peak grid tariff is the most important cost driver.

Some results of this study can be compared to existing literature. Refs. [45,46] both concluded that a hybrid solution with BESS and TES was the most economical option. Ref. [45] found that the optimal system was 71% TES and 29% BESS. The authors assumed that the TES had a capital cost 6x lower than the battery, and investigated one commercial building with PV generation and electric vehicle charging. Similarly, [46] found that a hybrid energy storage system with TES and BESS was more cost-effective than single energy storages. The energy storage technologies investigated were different from the ones in this study: a molten salt TES and a lead–acid BESS. Moreover, only electrical demand was included, and therefore no thermal demand. Our finding is in line with [23], which also concluded that it was optimal to invest in TES, and no BESS, for a dairy. The discrepancies between the results are likely related to the thermal share of the demand profile used, where our study and [23] involves an industrial consumer with a significant thermal demand, emphasising the benefit of a TES.

As argued in the introduction, many energy community studies mainly investigate households and disregard industrial consumers. Our findings indicate that industrial consumers constitute a significant part of a local urban area's load, and therefore they are able to make a larger contribution to the local urban area by reducing the peak load. Our findings also indicate that this is in fact profitable for both the industrial consumer and the urban area if an equitable cost distribution method is used. The peak load of this case study is reduced by approximately 0.9 MW, which accounts for 5% of the transformer load. As explained in the introduction, we need to free up as much space in the grid as possible by reducing the peak load. In this particular case, an investment in shared energy storage in an industrial energy community is profitable for the members and contributes to 0.9 MW of new capacity in the grid. As Fig. 5 showed, there are more commercial and industrial consumers in this urban area. If more of these have thermal demand, the peak load might be reduced even further by investing in more or larger TES.

5. Conclusion

In this article, we aimed to quantify the benefits of investing in thermal and electrical energy storage in an industrial energy community, for an industry consumer and the energy community as a whole. We investigated a real-life case study in Trondheim, Norway, using measurements from the local transformer and the industrial consumer.

The results showed that in an industrial energy community with thermal demand, hot water TES was the most favourable storage option, due to lower investment costs than BESS. Furthermore, we found that optimising the storage sizes for the whole energy community leads to both cost reduction for the energy community and a reduction in maximum import for the local grid. The costs were reduced by 1.8%, while the maximum import was reduced by 5%, compared to the reference case. The optimal TES size when optimising for the energy community was 16% higher than the optimal TES size when optimising for the industrial consumer alone. BESS was only economically viable in the sensitivity analysis, for a significant reduction in BESS investment cost, or a significant increase in spot price or grid tariff levels. In this particular case study, an investment in shared energy storage at an industrial energy community is profitable for the actors included, and contributes to 0.9 MW of new capacity in the grid.

When investigating the cost distribution between the industrial consumer and the urban area, we found that the cost distribution method heavily impacts whether it is economically attractive for the industry consumer to join the energy community. Only the coincident peak-method and the Shapley value lead to a reduction in electricity costs for the industrial consumer. Future work should investigate how to divide these costs fairly, ensuring that members who invest in capital-intensive technologies, such as energy storage, can recover their costs.

The sensitivity analysis showed that BESS investment costs must decline significantly for it to be a competitive option compared to TES. Therefore, in industrial energy communities, these results support that TES should be invested in where possible before considering investing in BESS. The sensitivity analyses also showed that an increase in PV generation leads to a reduction in TES size. These results show that forming energy communities with the inclusion of industry actors with thermal demand may be profitable and should be given attention in future energy community studies.

CRediT authorship contribution statement

Kjersti Berg: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Sverre Stefanussen Foslie:** Writing – review & editing, Writing – original draft, Validation, Methodology, Investigation, Data curation, Conceptualization. **Hossein Farahmand:** Writing – review & editing, Supervision, Funding acquisition, Conceptualisation.

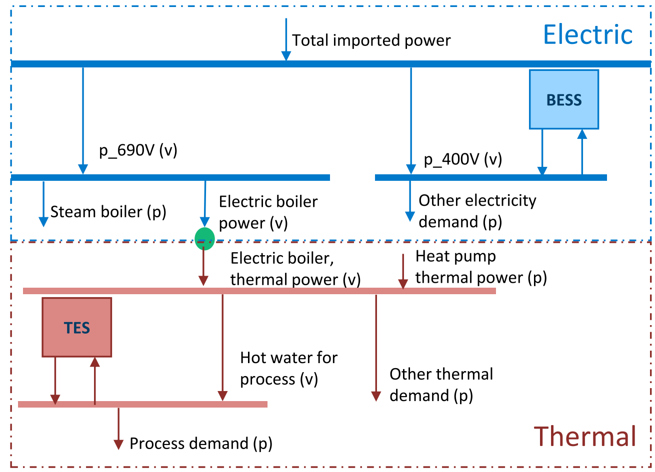

Fig. A.16. Overview of the electrical and thermal energy flows at the industry consumer investigated in this particular case study. (p) denotes parameters and (v) denotes variables in the optimisation model.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Kjersti Berg reports administrative support and statistical analysis were provided by Tensio TS. Kjersti Berg reports administrative support and statistical analysis were provided by Tine SA. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The authors do not have permission to share data.

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Appendix A. Constraints for industry consumer

Fig. A.16 shows an overview of the electrical (blue) and thermal (red) systems at the industry consumer site. The 400 V bus supplies electrical demand and the 690 V bus supplies an electric boiler that provides thermal energy. The optimisation model has the option to install a BESS at the 400 V bus and a TES further downstream from the 690 V bus as shown in the figure.

The energy balance constraints for electricity and heat at the industry facility are given in (A.1)–(A.8).

$$p_t^{\text{industry}} = p_t^{400\text{V}} + p_t^{690\text{V}} \qquad t \in T \quad \text{(A.1)}$$

$$p_t^{690\text{V}} = P_t^{\text{steam boiler}} + p_t^{\text{el. boiler}} \qquad t \in T \quad \text{(A.2)}$$

$$q_t^{\text{el. boiler}} + Q_t^{\text{heat pump}} = q_t^{\text{hot water}} + Q_t^{\text{other}} \qquad t \in T \quad \text{(A.3)}$$

$$p_t^{\text{el. boiler}} \leq \overline{P^{\text{el. boiler}}} \qquad t \in T \quad \text{(A.4)}$$

$$p_t^{\text{el. boiler}} \eta^{\text{el. boiler}} = q_t^{\text{el. boiler}} \qquad t \in T \quad \text{(A.5)}$$

$$q_t^{\text{hot water}} = Q_t^{\text{process}} + q_t^{\text{TES,ch}} - q_t^{\text{TES,dis}} \qquad t \in T \quad (A.6)$$

$$p_t^{400\text{V}} = P_t^{\text{other}} + p_t^{\text{BESS,ch}} - p_t^{\text{BESS,dis}} \qquad t \in T \quad (A.7)$$

$$p_t^{690V}, p_t^{400V}, p_t^{\text{el. boiler}}, q_t^{\text{el. boiler}}, q_t^{\text{hot water}} \geq 0 \qquad t \in T \quad (A.8)$$

Appendix B. Data handling

The data from the dairy is gathered from the energy monitoring system of the dairy, covering both electric and thermal systems. The measurements are hourly for 2022. As there were some errors in the data monitoring system during some periods, some data had to be approximated. Following is an explanation of the changes.

B.1. Thermal measurements

The data management system logging the thermal side had some errors from January to mid-February of 2022. Due to this, the measurements on the thermal side for this period could not be used. New data for this period was generated, replacing weeks 1 to 7 with week 8. There is a slight temperature dependence in the demand for thermal energy from the boilers and heat pump, however the temperatures in January and February 2022 at the location of the dairy were fairly equal. We therefore consider this approximation acceptable.

Furthermore, in 42 h, the heat pump thermal energy output was higher than the measured thermal demand, leading to an infeasible optimisation problem when running for Case Ref. Therefore, in these hours, the heat pump thermal power output was set equal to the demand.

B.2. Electricity measurements

During some periods, the measurement values for the electricity consumption of the steam boiler were missing. Some of these are single missing values, while the main part are continuous missing values in the periods: April 12–April 20, April 30 (6 h), May 28–June 03, June 26–June 27, August 05–August 22. In total, approx. 12.5% of the values are missing. In these periods, the gap has been filled using either data from the day before, or the weeks before or after. The steam boiler has a small electricity consumption compared to the electric boiler, so any small error here would not affect the overall results significantly.

B.3. Peaks

Some outliers have been identified in the measurements of the thermal energy demand, which are obviously outside the operational range of the system. The measurements which are negative, or above 2.5 MW (other thermal demand) and 2 MW (process demand) have been adjusted to comply with the hour before the misreading. In total, 23 values were modified this way.

The measurements from the transformer station had two days of extraordinary measurements with a very high peak (18 MW) on June 22 and zero consumption on June 23, due to maintenance work. These days have been set equal to the day before and after, June 21 and June 24, respectively.

B.4. Daylight saving time

In the hour of switching from daylight saving time in October, the measurements of the two consecutive hours of 02:00 were merged. To correct this, they were divided into two equal parts in the consecutive hours.

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