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Assessing customer engagement in electricity distribution-level flexibility product provision: The Norwegian case

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ABSTRACT

Procurement of demand-side flexibility at the distribution network level, as a cost-efficient alternative to traditional network reinforcement, requires customer engagement in the long-term. Potential limitations and benefits of alternative flexibility instruments (flexibility contracts, local flexibility markets, and dynamic network tariffs) for procuring such flexibility service are presented first. Secondly, a methodology is proposed to assess customer engagement and its effect on network reinforcement requirements and total system costs. An explicit flexibility instrument (a demand response program compensating customer for reductions in network withdrawals) is considered under two scenarios, one with a standard distribution network tariff (fixed and volumetric charges), and one with a dynamic distribution network tariff (fixed and critical peak charges). Rational customers' responses are simulated, under both scenarios, using parameters and actual 2019 data for the Skagerak pilot project in Norway. Results confirm that flexibility instruments interact with one another, shaping customer engagement. Specifically for the observed case, the efficacy of the demand response program was found to be significantly enhanced by the simultaneous implementation of a dynamic distribution network tariff, leading to deferred network reinforcements, and higher system-wide economic efficiency.

1. Introduction

The ongoing transformation of electricity Distribution Networks (DNs), fostered by decarbonisation, decentralisation and digitalisation, creates both challenges and opportunities for Distribution System Operators (DSOs). The increasing deployment of Distributed Energy Resources (DERs) such as small-scale generation, storage, and electric vehicles may congest network assets and drive network expansion. The same technologies, however, can become a source of flexibility and assist DSOs in congestion management and reinforcement deferral. The procurement of flexibility by DSOs, as a potentially cost-efficient alternative to traditional network management and reinforcement, has full support from the Council of European Energy Regulators [1,2], and aligns with the Clean Energy Package - Article 32 of the EU Directive 2019/944 [3]. The latter requires that DN development plans ensure transparency on the flexibility products that can act as an alternative to, or reduce the size of, network expansions.

DNs substantially differ from one another depending on grid topology, location, and type of customers, thus requiring, in practice, different flexibility products but also different instruments to access flexibility [2]. Matching flexibility products to suitable flexibility instruments is, indeed, crucial to ensure that customer reactions are effectively triggered in the desired direction. Economic signals have been shown to have a critical role in this regard [4], although *customer engagement* can be influenced by other factors, such as comfort and personal preference, or societal and ecological awareness [5]. Focusing specifically on demand-side DN customers, another crucial but underexplored issue concerns the assessment of customer engagement in contexts where more than one flexibility instrument is in place.

While DN customers have been traditionally exposed to static (volumetric) DN tariffs, increasingly this is no longer the case, or tariffs are soon expected to change. A relatively large number of studies have recently looked at the problem of re-designing DN tariffs (e.g., [6–11]) and most of these proposals include time-varying or critical peak charges. In other words, these tariffs are already designed to implicitly convey economic signals eliciting customer engagement in the provision of flexibility services. When an explicit flexibility instrument is added (e.g., a Demand Response program or a Flexibility Market), the interplay between the two instruments will affect customer engagement, and ultimately the efficacy and cost-effectiveness of flexibility procurement.

To shed light on this issue, this paper models and compares the economic signals transmitted by an explicit demand-side

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Nomenclature

Sets:

C	Customers
H	Hours
S	Seasons
v	Events

Parameters:

AR	Annual reward (€)
D_h	Demand at each load level for each customer (kW)
FC_{grid_c}	Fixed grid charge for each customer (€/customer)
FC_{DER}	Fixed cost of DER (€/kW)
FH_c	Flexibility hours (hrs)
I_{DR}	Demand response incentive (€/kWh curtailed)
$PCNC$	Peak Coincidence Network Charge (€/kW)
RC_{DER_s}	Running cost of DER for each season (€/kWh)
RD	Rate of discharge (%)
T	Threshold at which PCNC is applied (kW)
$\mathrm{VC}_{grid_{c,s}}$	Variable grid charge for energy withdrawn from the grid (€/kWh)

Variables:

C_{DER_c}	Installed capacity of DER for each customer (kW)
$\mathrm{E}_{DER_{h,c,s}}$	Energy produced by DER during each hour of each season by each customer (kWh)
$\mathrm{E}_{DR_{h,c,s}}$	Energy reduced through DR program participation (kWh)
$\mathrm{E}_{grid_{h,c,s}}$	Energy withdrawn from the grid during each hour of each season by each customer (kWh)
$\mathrm{E}_{grid_{th1c}}$	Energy withdrawn from the grid that exceeds threshold by each customer (kWh)
u	Binary variable to indicate DR hours
x	Binary variable to activate DR annual reward constraint

flexibility instrument – a Demand Response program offering a fixed incentive per kWh of voluntarily curtailed energy — when combined with two alternative DN tariffs, a static and a dynamic one. The latter includes a Peak Coincidence Network Charge linked to the customer's contribution to the network peak utilisation [7]. Customers providing flexibility for network capacity management are only partially flexible (i.e., available to curtail only part of their demand under the DR program) and can always invest in Distributed Energy Resources (e.g., a battery system), on top of taking part in the DR program. The objective of the study is to assess whether the two alternative combinations of instruments (a DR program and a static DN tariff vs a DR program and a dynamic DN tariff) are effective and cost-efficient drivers of customer engagement in the provision of flexibility — so that network reinforcements can be avoided or, at least, deferred.

Other technical papers analysing flexibility procurement from demand-side DN customers have found that demand curtailment has, indeed, the ability to defer or avoid network expansions at the distribution level [12–14]. The present work expands on these engineering studies by including the role of the DN tariff as an implicit economic signal for flexibility procurement. In doing so, the present study is closely related only to a recent working paper that also focuses on the interaction between a demand curtailment program (involving mandatory curtailments by the DSO, for a fixed remuneration) and a cost-reflective DN tariff (including only capacity-based charges) [15].

To simulate customers' responses, an *ad hoc* optimisation model is developed, where customers seek to minimise network-related costs under a set of technical constraints (i.e., only the DN components of the customer's bill are included in the optimisation, as in [7]). This methodology differs from the one employed by [14,15], which is based on a bi-level structure which includes the decision of the DSO in the upper level and the customers' response in the lower one. It is worth noticing that in the context of existing studies about the drivers of customer engagement in flexibility provision, modelling and simulation approaches are, indeed, quite rare. Preference has been given in the past to pilot projects[1] and surveys.[2]

The proposed optimisation model is run using the parameters and actual data of a pilot site located in Norway, owned by the DSO Skagerak Energi, and part of the E-Regio project [27]. The Nordic Council of Ministers [28] has remarked that Scandinavian DSOs and their customers would economically benefit from postponing distribution network upgrades as long as possible. When demand exceeds the existing network capacity, network expansion often involves both new investment and early refurbishment before the average expected lifetime of existing assets. Hence, flexibility provisions that postpone DN investments would be of significant value [29]. The present work provides new evidence in this regard using a simple optimisation model that could be a useful tool for regulators and policy makers. Note that [15] runs simulations using synthetic data instead.

Before entering the details of the study, an organised overview of the main flexibility products and instruments is presented, focusing on the ones employed for network capacity management. The goal is to discuss their potential limitations and benefits concerning customer engagement. While this is the first contribution of this study, the other include: an optimisation model, suitable for simulating rational customers' response to a variety of incentives; simulation results, from a pilot site, on the combined effect of DR programs and network tariffs on long-term flexibility procurement from demand-side customers; and recommendations for distribution network operators on cost-effective alternatives to grid expansion.

[1] The pilot project LINEAR - Local Intelligent Networks for Energy Active Regions [16], in Belgium, showed that a flexibility instrument that appeals to comfort, societal, ecological and financial awareness of customers results in a stronger engagement. The French project Nice Grid [17,18], has also showed that sustainability and ecology are triggers that keep customers involved. The PowerMatching City pilot project in the Netherlands [19], showed that acknowledging customer preference by guaranteeing comfort and reducing energy costs was the key to customer engagement. Three pilot projects: Inovgrid in Portugal [20], EcoGrid in Denmark [21,22], and the Pacific Gas & Electric's (PG&E) Green Button in the USA [23], showed that raising awareness and providing user-friendly platforms that enable customers to interact and give them greater control over their energy use promoted their engagement.

[2] Residential customer elasticity for incentive-based Demand Response programs is evaluated in [24], where data from two nationwide surveys are integrated within a detailed residential load model to calculate incentive-based elasticity at the individual appliance level. Through trials, programs and surveys, motivations, enablers and barriers for consumer engagement are discussed and reviewed in [24–26].

The rest of the paper is organised as follows. Flexibility products and instruments are introduced in Section 2. The optimisation methodology is presented in Section 3. Section 4 introduces the Case Study, illustrates the results of the simulation, and discusses them. Conclusions and policy implications are summarised in Section 5.

2. Procurement of flexibility at the distribution network level

Matching flexibility products with adequate flexibility instruments is an important element in designing an effective procedure to procure flexibility for the DSO. This section introduces first the main flexibility products and instruments found in the literature or the practice (Section 2.1). Then, it discusses how they can be mapped together to guarantee customer engagement in the long-term (Section 2.2) – the focus is on the provision of long-term flexibility products.

2.1. Flexibility products

Flexibility products at the DN level can be provided by demand- and supply-side network customers and are used to support the DSO to operate the network efficiently. The most common ones include network capacity management, congestion management, and network reserves.

(i) Network Capacity Management

A capacity management product specifically targets network peaks triggered by load or generation and resulting in incidental or recurring congestions. These peaks may undermine the network's reliability and ultimately drive network reinforcements. Thus, this product aims to reduce coincident peaks and defer or avoid reinforcements [2]. Network capacity management takes place during the DSO's planning phase, where potential (future) congestions are assessed within a long-term horizon (potential congestions normally result from diminished transfer capabilities due to an increase in generation or load [30]). In short, network capacity management is a long-term capacity product that aims to prevent potential network congestions.

(ii) Congestion Management

Congestion management consists in activating a remedial action to respect operational security limits — thermal, voltage, and stability limits restricting physical power flows through the network according to the characteristics of the physical assets (cables and transformers) [31]. Congestion management is performed to provide a short-term solution to relieve constrained parts of the network. First, DSOs activate their flexible grid assets, including topology changes, tap changers, voltage boosters, etc. If networks assets are insufficient to eliminate the congestion, the DSOs may either invest in new assets or procure and utilise customer flexibility. These congestions might not have been anticipated during the long-term network planning process or are due to situations where network reinforcements cannot cope with the load/ generation increase [2]. In short, congestion management is a short-term energy product aiming to relieve temporary congestions.

(iii) Network Reserves

Network reserves are used to provide redundancy or system reliability in the form of physical capacity reserves — capacity that is made available in case of a potential outage in the system, creating alternative routing possibilities [28]. This product is critical in areas exposed to extreme weather conditions, such as the Nordic countries, where repairing faulted equipment may take much longer than usual. In those cases, standby capacity can be used in the meantime. Hence, customers providing this flexibility product act as distribution network reserves through load shedding and generation injections. Also, they must be able to provide ancillary services such as voltage control and power quality support, within their technical limits. In short, network reserves are a long-term capacity product, like network capacity management, with the difference that customers will respond only during emergency events.

2.2. Flexibility instruments

The procurement by the DSO of the flexibility products described above requires adequate instruments that guarantee customer engagement and higher cost-efficiency in the operation and planning of the distribution network. The categories of instruments most often employed with demand-side customers include DR programs, flexibility markets, and dynamic DN tariffs. The first two are considered explicit flexibility instrument, while the last one is an implicit one.

(i) DR Programs (Flexibility Contracts)

DR programs involve flexibility contracts that govern the relationship between the demand-side customer and the DSO or its intermediaries. These contracts include a financial reward that customers receive when providing a load profile's modification. DR programs pay customers in different ways, through bill credits or a discount rate, or via an activation fee and, sometimes, an availability fee, both administratively determined [32,33]. DR programs may include different provisions, such as a pre-defined percentage of load reduction during certain hours, a fixed load capping, or a dynamic load capping [34], and they might give access to customers' appliances through direct load control [35,36].[3] Reviews of DR programs are presented in [39–43]. Although they are often criticised because of the difficulty in setting the baseline, these types of contracts can reduce uncertainty regarding customers' flexibility in the planning phase. For instance, well-designed contracts with a penalty component can guarantee customer engagement, particularly in long-term flexibility products.

(ii) Flexibility Markets

Flexibility Markets are designed to procure flexibility in an organised marketplace, where customers or service providers acting on their behalf, exchange flexibility for a certain product and a defined period of time. The main difference with respect to flexibility contracts, is that compensations for providers are market-based. In practice, the two instruments can co-exist when DR programs are entered via a competitive process or when individual obligations are further negotiated, among flexibility providers, using a trading platform (run by a market operator). Different designs have been proposed for flexibility markets with a variety of clearing methods, approaches to establish baselines, temporal scopes (e.g., real-time, *a priori*), and coordination schemes [58,59]. Most importantly, flexibility markets are thought to provide flexibility to the DSO at the least cost, as free price formation is driven by competition, and the procured flexibility amounts are better calibrated to the DSO's and participants' needs. In fact, procurement is cost-efficient only when markets are sufficiently liquid [1]. The latter can be difficult to achieve, particularly when the geographical areas from which the flexibility is procured is small, or when flexibility is procured with short advance notice. In practice, DSOs appear to have concerns also regarding the ability of flexibility markets to effectively engage customers in the

[3] Flexibility can be contracted also at the connection stage, via so called "constrained connections" (a connection with a possibility of curtailment), although this is more common for supply-side network customers [37,38].

Table 1
Flexibility products and flexibility instruments. Examples from the literature and the practice.

Flexibility product	Flexibility instrument	Examples of implementation: Paper's title or name and country of the project	Ref.
Network capacity management	DR program (Flexibility contract)	Firming renewable power with demand response: an end-to-end aggregator business model	[44]
		End-user flexibility in the local electricity grid-blurring the vertical separation of market and monopoly?	[4]
	Dynamic DN tariffs	Designing efficient distribution network charges in the context of active customers	[7]
		Introducing a demand-based electricity distribution tariff in the residential sector: demand response and customer perception	[26]
	Flexibility market	FlexNett project, Norway	[45]
		Grid capacity management for peer-to-peer local energy communities	[46]
		Local flexibility market design for aggregators providing multiple flexibility services at distribution network level	[47]
Congestion management	Flexibility market	iPower project, Flexibility Clearing House (FLECH), Denmark	[48]
		EcoGrid 2.0 project, Denmark	[21]
		Interflex project, The Netherlands	[49]
		United-Grid project, Sweden	[50]
		Distribution-level flexibility market for congestion management	[51]
		Demand response: for congestion management or for grid balancing?	[52]
	Dynamic DN tariffs	Dynamic tariff for day-ahead congestion management in agent-based LV distribution networks	[53]
		Capacity subscription tariffs for electricity distribution networks: design choices and congestion management.	[54]
		Day-ahead tariffs for the alleviation of distribution grid congestion from electric vehicles	[55]
Network reserves	DR program (Flexibility contract)	Contract design for demand response	[35]
		A nascent market for contingency reserve services using demand response	[56]
		Reliability and risk assessment of post-contingency demand response in smart distribution networks	[57]

provision of long-term products [50]. This is the view adopted for the present paper as well.[4]

(iii) Dynamic Distribution Network Tariffs

Dynamic DN tariffs are those that vary over time to convey economic signals regarding the network's status and needs. They normally present time-of-use and critical-peak pricing structures, designed to incentivise customers to change their behaviour in different ways. The former structure influences customers to shift their time of withdrawal away from high- and towards low-price periods. The latter structure identifies specific time periods when restricting network usage would be more cost-effective for the DSO (and for the customers). For instance, Peak Coincidence Network Charges (PCNC) incentivise customers to reduce their network withdrawals during hours when network usage exceeds an administratively pre-defined threshold [7]. As network usage at peak times is one of the main drivers of investment costs, dynamic DN tariffs are considered a useful instrument to minimise network costs via the postponement or avoidance of network upgrades [60]. One of their main drawbacks, however, is the lack of sufficient granularity to signal local flexibility needs. In those cases, DSOs might complement them with flexibility procurement via additional (explicit) instruments [1].

2.3. Mapping flexibility products and instruments

Several examples are found in the literature and practice (research or pilot projects) of matches between flexibility products and instruments. Table 1 provides an organised overview of common matching sets. Focusing on long-term certainty of (demand-side) customer engagement, the highest requirements are those associated with the product 'network reserves', used in emergency (critical) situations. As expected, this product is preferably paired with flexibility contracts. The product 'network capacity management' needs customer engagement to postpone or avoid network reinforcements. Hence, certainty over the long-term is also key but it can be achieved in different ways. One possibility is through flexibility contracts – preferably imposing penalties for non-delivery; another is via (strong) economic signals transmitted by dynamic DN tariffs — the latter may drive customers to invest in DERs, that consequently guarantee customer engagement in the long-term. Flexibility markets are also an option, but they have been preferably proposed as a flexibility instrument for 'congestion management'.[5] Dynamic DN tariffs can also transmit economic signals for congestion management, making it a feasible, but less attractive approach.

While Fig. 1 serves as a summary, highlighting whether each product–instrument pair can, indeed, guarantee customer engagement, it is relevant to note that in order to improve customer engagement a DSO might also procure more than one flexibility product. For example, a DSO requesting both network reserves and network capacity management would give stronger signals to customers regarding the need for flexibility in the long-term. As a result, customers might be more likely to make long-term investment decisions such as DER purchases. In a similar manner, a DSO might combine different flexibility instruments for the procurement of the same product (for example, flexibility markets could complement flexibility contracts). This is the strategy

[4] Interestingly, a couple of commercial flexibility platforms (https://nodesmarket.com and https://piclo.energy) are starting to challenge this view by trading long-term flexibility products.

[5] A recent report summarising flexibility initiatives in Europe, confirms that, in practice, flexibility markets are preferentially employed to procure congestion management products [61].

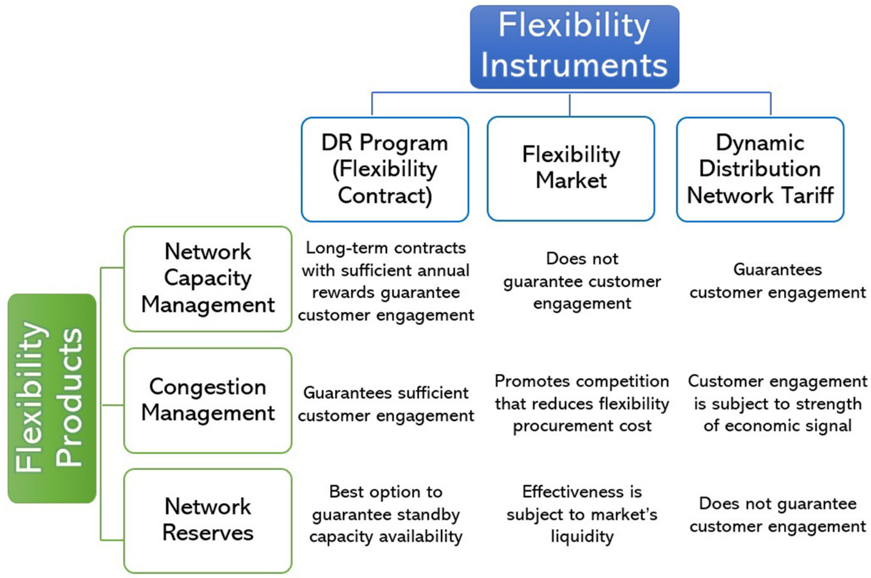

Fig. 1. Mapping flexibility products and flexibility instruments. Remarks focus on the expected ability of the flexibility instruments to guarantee customer engagement (or to lower procurement costs) in the provision of the corresponding flexibility product.

explored in this work. The focus is on the combination of an explicit and an implicit flexibility instrument in the procurement of network capacity management, an area where the academic literature is scarce, except for [15].

The Norwegian pilot site chosen for the Case Study presents an actual need for product 'network capacity management' and, in this sense, is representative of the distribution sector in Scandinavian countries [29]. The chosen explicit flexibility instrument is a DR program with an administratively determined activation fee — an instrument that the local DSO already employs and consider valuable. The focus on procurement from demand-side customers is in line with an estimated high technical potential for end-user flexibility in Norway [4]. The implicit flexibility instrument is a dynamic DN tariff with a critical-peak structure. Dynamic DN tariffs are the other preferred instrument to procure network capacity management (see Table 1) and are expected to become more prominent as DNs continue to evolve under the energy transition (see Section 1).

3. Assessment of customer engagement

Customer engagement is challenging to assess since a customer's response to a flexibility instrument may be influenced by several factors, including the combination of instruments in place. This Section presents the research framework (Section 3.1) and the proposed assessment methodology (Section 3.2). One of the main assumptions is that customers are rational, so that customer engagement is subject, among other things, to the price signals they receive. Their responses have consequences on their bills and the need to meet future load growth through wiring or non-wiring solutions. Hence, the methodology's output indicators will capture system costs, network peak reduction, and related necessary network reinforcements (see Section 4).

3.1. The framework

The research framework is as follows: as electricity demand grows, flows on the distribution network also grow and may exceed its current capacity, thus requiring network reinforcements. To avoid potential network congestions, the DSO plans the necessary investments and when to carry them out. The costs of these investments are then incorporated into the DN tariff paid by the customers. To avoid or defer these investments, the DSO can elicit customer engagement via one or more flexibility instruments.

Rational customers react to economic signals so that their electricity demand is satisfied at the lowest (distribution network-related) cost. Thus, based on the price signals they receive, they seek opportunities to reduce their DN bills. Their options include entering a DR program, investing in DERs, or doing both. The DR program remunerates customers via an administratively determined activation fee (paid on the energy voluntarily curtailed by the customer). As for the DN tariff, two alternatives are considered. In the first one, customers are exposed to a traditional (static) DN tariff; in the second one, to a dynamic DN tariff. The static DN tariff comprises a fixed (€/cust. per year) and a variable charge (€/kWh). The dynamic DN tariff includes a fixed charge and a Peak Coincidence Network Charge (PCNC) related to the consumer's contribution to the network peaks (€/kW) [7]. The focus is on comparing customer engagement under these two alternative pricing structures. Hence, other components of the electricity bill, such as energy prices, taxes, and transmission network tariffs, which play an important role in real-life decisions to become active customers, are purposely neglected.

As discussed in [7] and [62], PCNC is the forward-looking component of the tariff and, as illustrated in Fig. 2, is only applied when the network's utilisation level exceeds a pre-defined threshold (i.e., during peak hours). This threshold is designed to reflect the investment capacity required by the expected generation/load growth and signal customers to reduce their network usage. The network reinforcement cost is, indeed, allocated in the forward-looking component of the tariff (PCNC), and the fixed charge recovers the remaining portion of the network costs (for an application see Section 4). Hence, at the beginning of the billing period (typically of one year), the DSO announces an initial value of the fixed charge, the PCNC, and the expected peak hours (updates on the expected peak hours are given closer to real-time). At the end of the billing period, the DSO knows the actual peak hours and the network costs recovered through the PCNC. The outstanding network costs are then recovered through an updated fixed charge. Fixed charges can be designed using different methodologies, for example, Ramsey-pricing principles [63,64].

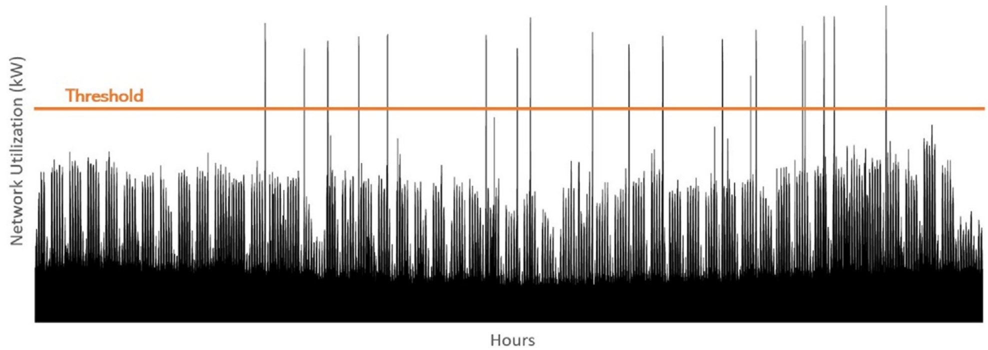

Fig. 2. Illustration of the dynamic DN tariff: when the network's utilisation level (kW) exceeds a pre-defined threshold (in orange) consumers are charged a Peak Coincidence Network Charge (€/kW); during the rest of the hours, a fixed charge (€/customer) is applied.

A dynamic DN tariff of the type described here has not been implemented in real life yet. However, a similar approach is used in Australia, where DN tariffs include a Peak Demand Charge based on the highest 30-minute consumed power during peak periods (3 pm to 9 pm weekdays). The approach is forward-looking and the Peak Demand Charge recovers part of the network costs based on the Long-Run Marginal Cost (LRMC), and the rest is recovered through fixed and variable charges [65,66].

3.2. The methodology: formulation of customers' response

It is assumed that customers react rationally to the economic signals they receive, i.e., minimise distribution network-related costs while satisfying their electricity demand. As shown in Eq. (1) distribution network-related costs include three elements: *Grid costs*, *DR Reward*, and *DER cost*. The *Grid Cost* depends on the DN tariff (typically composed of a fixed and a variable charge — respectively, FC_{grid} and VC_{grid}). As an alternative to fully satisfy their demand from the grid, customers can:

– participate in DR programs, earning an incentive, I_{DR}, per kWh curtailed (*DR Reward*);
– invest in DERs, where FC_{DER} and RC_{DER} respectively represent the fixed and running costs of the DER (*DER cost*).

$$\text{Min} \sum_{c=1}^{C} \sum_{h=1}^{H} \left[(\mathit{Grid\ Cost}) + (\mathit{DER\ Cost}) - (\mathit{DR\ Reward}) \right] \tag{1}$$

It is assumed that, if possible, the DERs and DR programs are activated during peak hours (groups of consecutive peak hours are referred to as 'events'). Depending on whether the chosen DER is controllable or not, the available capacity during peak hours differs. Hence, uncontrollable DER types, such as solar PV, do not serve as network reinforcement substitutes as efficiently as storage.

Going into more details, Eq. (2) shows that the decision variables are:

– the amount of energy withdrawn from the grid (E_{grid});
– the investment capacity in DER (C_{DER}) and the energy withdrawn from it (E_{DER});
– the curtailed energy through the DR program (E_{DR}).

It important to note that while E_{DR} generates revenues for the customer, it is also technically limited (by the flexible portion of the load for each customer and by a given number of consecutive hours of flexibility provision — see also below). Consequently, also *DR Reward* has an upper limit. Customers can further reduce their *Grid Costs* by employing a DER, i.e., by using E_{DER} to serve the load (also within technical limits). The option to earn revenues from the DER, e.g., by injecting energy into the network or earning DR rewards is neglected here. The motivation for the latter is that savings obtained from reducing network costs are assumed to be significantly greater than the DR rewards (see Section 4). Nevertheless, from the viewpoint of the DSO, lowering grid utilisation via load shedding or employing a DER makes no difference and including in the model the DER as a DR provider could be done without loss of generality.

The optimisation occurs over all the hours ($h = 1, \ldots, H_s$) in a season, over all the seasons ($s = 1, \ldots, S$) and customers ($c = 1, \ldots, C$), and it is subject to:

– an equality constraint, Eq. (3), ensuring that customer demand is met in each hour;
– the boundaries in Eqs. (4)–(7), limiting the decision variables within permissible limits:

- in Eq. (4) the hourly E_{grid} of each customer is limited by their grid capacity (C_{grid});
- in Eq. (5) the invested DER capacity per customer is limited by the minimum and maximum capacities available on the market for the corresponding technology;
- in Eq. (6) the DER's hourly energy production is subject to the technology's rate of discharge (RD);
- in Eq. (7) the DER's total energy production during a set of consecutive hours, i.e., during an event (v), is limited by the DER capacity (for simplification, the efficiency conversion for DERs is neglected in this formulation).

$$\begin{aligned} \underset{E_{grid}, E_{DER}, C_{DER}, E_{DR}}{\text{Min}} \sum_{s=1}^{S} \sum_{c=1}^{C} \sum_{h=1}^{H_s} \Big[\big(& FC_{grid_c} + VC_{grid_{c,s}} E_{grid_{h,c,s}} \big) \\ & + (FC_{DER} C_{DER_c} \\ & + RC_{DER_s} E_{DER_{h,c,s}}) - (I_{DR} E_{DR_{h,c}}) \Big] \end{aligned} \tag{2}$$

$$\sum_{c=1}^{C} E_{grid_{h,c}} + \sum_{c=1}^{C} E_{DER_{h,c}} + \sum_{c=1}^{C} E_{DR_{h,c}} = D_h \qquad c \in C, h \in H \tag{3}$$

$$0 \le E_{grid_{h,c}} \le C_{grid_c} \qquad c \in C, h \in H \tag{4}$$

$$C_{DER_c}{}^{min} \le C_{DER_c} \le C_{DER_c}{}^{max} \qquad c \in C \tag{5}$$

$$0 \le E_{DER_{h,c}} \le RD * C_{DER_c} \qquad c \in C, h \in H \tag{6}$$

$$\sum_{h=1}^{H_{s,v}} E_{DER_{h,c}} \le C_{DER_c} \qquad c \in C, v \in V \tag{7}$$

Two aspects of the above optimisation problem require further specification: the DR program and the DN tariff. As for the first, a traditional DR program is considered here, compensating customers according to voluntary load reductions during peak hours (it is assumed that customers that enrol in the DR program are always available to provide flexibility). To realistically account for this DR program, three constraints are introduced:

– the energy curtailed per hour during an event is subject to the flexible capacity made available by the customer for the DR program (C_{DR}), as indicated in Eq. (8), where u is a binary variable assuming the value of 1 during peak hours and zero otherwise; note that the hourly C_{DR} of each customer is calculated based on their flexibility percentage (f_c) and hourly demand, as indicated in Eq. (9) – the flexibility percentage may differ across customers based on their type (e.g., residential or industrial) and elasticity to prices;
– customers (particularly residential ones) can only provide demand-side flexibility for a limited number of consecutive hours, FH, per event, as shown in Eq. (10);
– customers will participate in DR programs if a minimum Annual Reward (AR) is met as represented in Eqs. (11)–(13) – x is a binary variable taking the value of 1 when demand-side flexibility is used (hence, the annual reward constraint is activated) and zero otherwise.

$$0 \le E_{DR_{h,c}} \le u_{h,c} * C_{DR_{h,c}} \qquad h \in H, c \in C \tag{8}$$

$$C_{DR_{h,c}} = f_c * D_{h,c} \qquad h \in H, c \in C \tag{9}$$

$$\sum_{h=1}^{H_{s,v}} u_{h,c} \le FH_c \qquad c \in C, v \in V \tag{10}$$

$$\sum_{h=1}^{H} I_{DR} E_{DR_{h,c}} \ge AR * x_c \qquad h \in H, c \in C \tag{11}$$

$$\sum_{h=1}^{H} u_{h,c} \ge x_c \qquad h \in H, c \in C \tag{12}$$

$$u_{h,c} \le x_c \qquad h \in H, c \in C \tag{13}$$

As for the second aspect, the introduction of a dynamic DN tariff requires:

– a calculation of the *Grid Costs* which includes that PCNC, leading to the objective function in Eq. (14);
– the constraints in Eqs. (15)–(16), where E_{gridT_h} (bounded between zero and a maximum value) represents the energy that exceeds the network's threshold (T).

$$\begin{aligned} \underset{E_{grid}, E_{DER}, C_{DER}, E_{DR}}{\text{Min}} \sum_{s=1}^{S} \sum_{c=1}^{C} \sum_{h=1}^{H_s} \Big[\big(& FC_{grid_c} + PCNC * E_{gridT_{h,s}} \big) \\ & + (FC_{DER} C_{DER_c} \\ & + RC_{DER_s} E_{DER_{h,c,s}}) - (I_{DR} E_{DR_{h,c}}) \Big] \end{aligned} \tag{14}$$

$$E_{gridT_h} = \sum_{h=1}^{H} \sum_{c=1}^{C} E_{grid_{h,c}} - T \qquad h \in H, c \in C \tag{15}$$

$$0 \le E_{gridT_h} \le E_{gridT_h}{}^{max} \qquad h \in H, c \in C \tag{16}$$

4. Case study, results and discussion

The Case Study used in this work and the corresponding parameters (described in Section 4.1) are based on the Skagerak pilot site (*Skagerak EnergiLab*) belonging to Skagerak Energi, one of the largest distribution network owners in Norway. Skagerak Energi has a partnership with Odds Ballklubb, Norway's oldest and most environmentally friendly soccer club. Their home stadium, the Skagerak Arena, is often used to test new and innovative energy solutions [67]. The results of the analysis of this Case Study are presented in Section 4.3 and then discussed in Section 4.3.

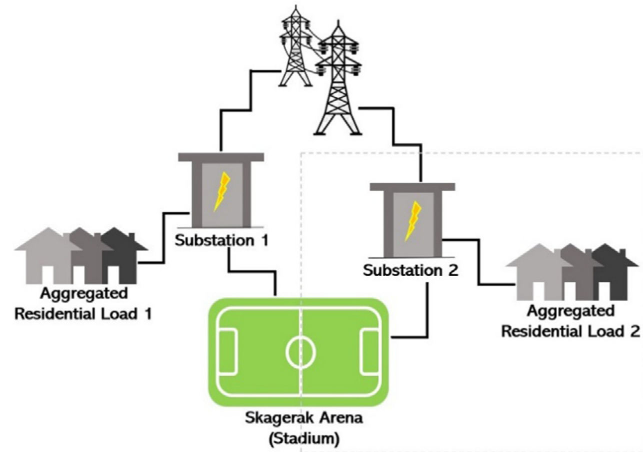

Fig. 3. Illustration of the Skagerak Distribution Network — the portion of interest for the Case Study is inside the dotted line.

4.1. Case study

As shown in Fig. 3, the Case Study focuses on a portion of the Skagerak Distribution Network (the one within the dotted box). With a capacity of 750 kW, this includes Substation 2, which is connected to the higher voltage grid and serves two 'customers': customer C1 is part of the stadium, and customer C2 is an aggregated residential load. The load duration curve of the two customers is shown in Fig. 4 and is based on actual data measured in 2019. It presents a network peak consumption of 746 kW and an individual peak consumption of 501.20 kW and 302.14 kW for customers C1 and C2, respectively.

It is assumed that in the current year the DSO incurs a total network cost of € 710,000. Also, a load increase of 100 kW is expected for the following years. Due to discrete network investments, the least network reinforcement that could be carried out amounts to 250 kW. It is also assumed that the network reinforcement cost is equal to € 213,000 (calculated as 30% of total network cost). As an alternative to grid expansion, the DSO could rely on demand-side flexibility. Hence, the Case Study simulates and compares customer engagement in flexibility provision under two DN tariffs, a static (Tariff 1) and a dynamic one (Tariff 2). The parameters of the two tariffs are described below.

(i) Tariff 1: Fixed Charge + Variable Charge

As for Tariff 1, actual values from Skagerak Energi are used. Considering the fixed charge first, customer C1 (the stadium) pays, as a commercial user, an FC_{grid} of 33,641 €/cust. on an annual basis. Customer C2, instead, is a group of 100 residential customers, with a total FC_{grid} of 34,500 €/cust. per year.

The variable charge amounts to 0.2711 €/kWh and 0.4714 €/kWh for C1 and C2, respectively, during the winter months (September–April) and to 0.2561 €/kWh and 0.3856 €/kWh for C1 and C2, respectively, during the summer months (May–August) [68].

(ii) Tariff 2: Fixed Charge + PCNC

The fixed charge in Tariff 2 is calculated from the total network cost minus the network reinforcement cost (€ 497,000 = €

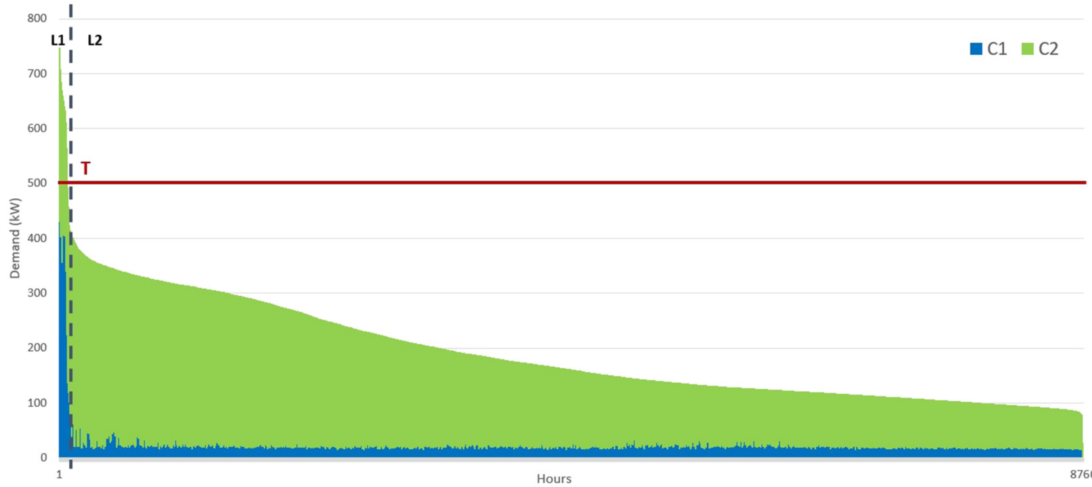

Fig. 4. Actual load duration curve for 2019: customer C1 (green) is a portion of a stadium, and customer C2 (blue) is an aggregated residential load. The threshold, T, for the dynamic DN tariff is illustrated in red. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

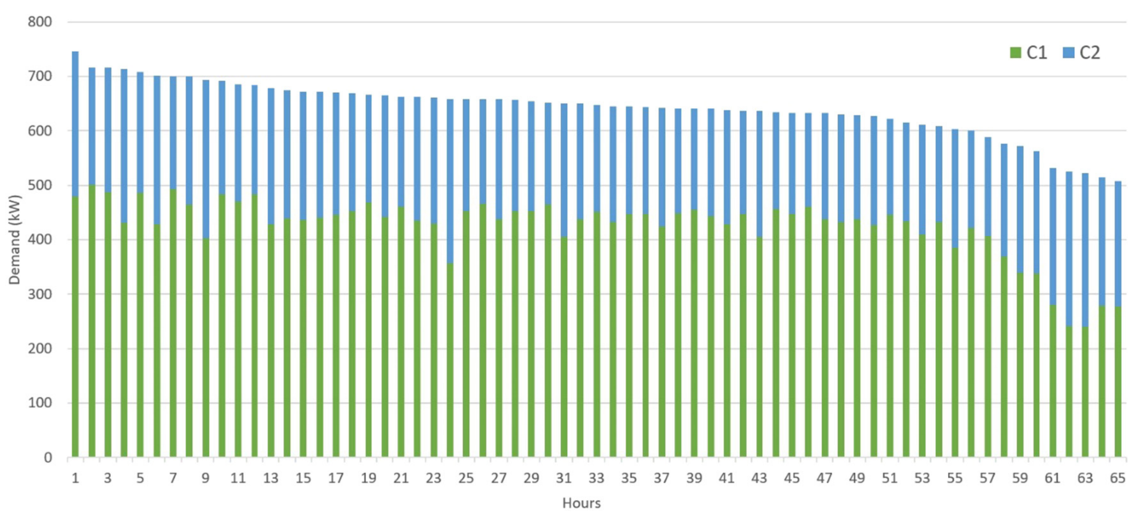

Fig. 5. Load duration curve for load level 1 (load above the threshold of 500 kW).

710,000 - € 213,000) and is allocated to the two customers using the same ratio as in Tariff 1. Hence, customer C1 and customer C2 respectively pay an annual FC_{grid} of 245,367 €/cust. and 251,633 €/cust.

As for the PCNC, the threshold, T, is selected first and set at 500 kW (network investments will add 250 kW extra capacity). Then, the PCNC is calculated using the following equation:

$$PCNC = \frac{Network\ Reinforcement\ Cost}{Power\ exceeding\ threshold\ during\ peak\ hours} \tag{17}$$

To compute the denominator in Eq. (17), the annual load duration curve in Fig. 4 is divided into two Load Levels. The first one, L1, represents the network peak hours, i.e., those when the load exceeds the threshold T. The rest of the hours belong to the second Load Level, L2. The load duration curve for Load Level 1 is illustrated in Fig. 5. During L1, several events (sets of consecutive hours when the network's utilisation level exceeds the threshold) take place, as shown in Table 2. In 2019 a total of 65 peak hours were registered. They occurred during 19 events, mainly during football games – 11 in the winter (for a total of 38 h) and 8 in the summer (for a total of 27 h). The total power exceeding the threshold during peak hours in the same year was 8831 kW. Hence, the PCNC is set at 24.12 €/kW.

Table 2
Load Level 1: Events during the winter and summer season.

Winter events		Summer events	
Event number	Duration (h)	Event number	Duration (h)
1	4	1	3
2	3	2	3
3	3	3	3
4	4	4	3
5	1	5	3
6	4	6	3
7	3	7	4
8	1	8	5
9	5		
10	5		
11	5		
Tot.	38	Tot.	27

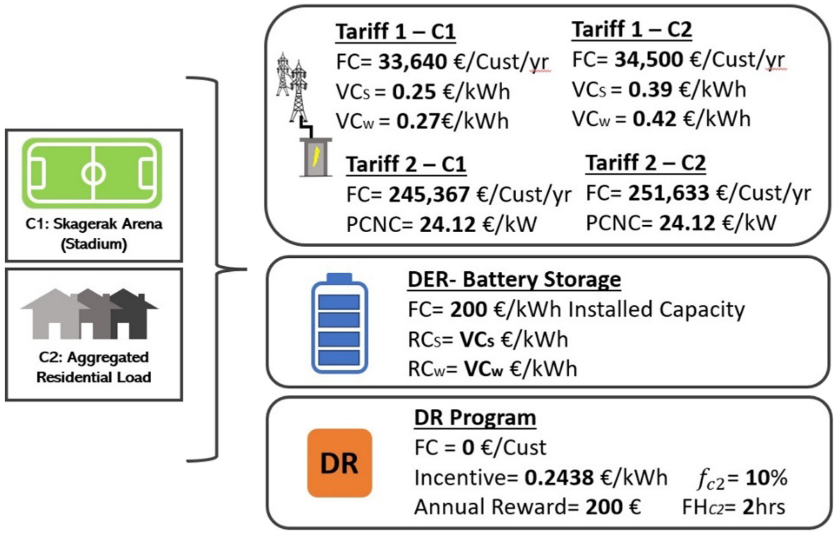

Fig. 6. Main parameters for the Case Study.

Under both DN tariffs, customers can provide demand-side flexibility by entering a DR program, investing in DER, or combining the two. The relevant parameters for the customers' options are given below.

(i) DR program

As for the incentive, I_{DR}, an actual value of € 0.2438 per kWh curtailed, is used. This parameter is taken from the DR program run by Skagerak Energi in 2019 [68]. While this reference might not be a perfect fit for a single household (the DR program was designed for large customers willingly to disconnect during emergency events that may extend to days), customer C2 represents an aggregated residential load administrated by an aggregator. Customer C2 is assumed to consist of flexible and inflexible households that together can provide a flexibility percentage of 10%, i.e. they can reduce 10% of their hourly demand for 2 h during each event, given that their annual aggregated reward is at least € 200 [69]. Differently, since most events occur during football games, customer C1 is considered entirely inflexible.

(ii) DER — Battery Storage

To provide network capacity management, consumers might consider the installation of battery storage. The investment cost for this form of DER (FC_{DER}) is set at € 200 per kWh of installed capacity [70,71]. The battery is of type 1/2C, i.e., it can fully discharge within 2 h. The battery is used for self-consumption, not for network injections, and there are no revenues associated with discharging it. Under the assumption to neglect energy and transmission network costs, the distribution-network related costs of charging the battery are represented using the volumetric charge of the current distribution network tariff. Therefore, the costs associated with charging the battery are set to be equivalent to the variable charge of Tariff 1 (VCgrid), thus accounting for the customer (C1 or C2) and the season (winter or summer).

The main parameters for the Case Study are summarised in Fig. 6. Customers' responses are modelled via Eqs. (1)–(16) and computed using a MILP optimisation method implemented in Matlab. Since the network is highly utilised only in Load Level 1, customers' responses to the provided price signals are also expected to occur in the same hours. Thus, the optimisation focuses only on Load Level 1, but total system costs are calculated for the entire year.

4.2. Results

Results are presented with reference to two alternative scenarios: Scenario 1 implementing Tariff 1 and Scenario 2 implementing Tariff 2. A Reference Scenario is also defined, representing network utilisation in 2019. This latter scenario implements Tariff 1, but customers are not offered the opportunity to enter a DR program and no DERs were installed in 2019.

The first set of results for Scenario 1 and Scenario 2 are presented in Figs. 7 and 8, respectively, for both winter (left inside) and summer (right inside). Graphs represent, for each customer (C1 and C2) and peak hour (38 in the winter and 27 in the summer), the following variables:

- the amount of energy withdrawn from the grid (*Grid* labelled graphs);
- the energy curtailed via the DR program (*DR* labelled graphs);
- the amount of energy withdrawn from DER (*DER* labelled graphs);
- the total energy withdrawn from the grid (by C1 and C2 together) which exceeds the 500-kW threshold set for Tariff 2 (*Threshold Exceeding Capacity* labelled graphs).

Results for Scenario 1 show that under Tariff 1, customer C1 (the stadium) satisfies its load fully from the grid and does not take part in the DR program nor installs DER. Customer C2, instead, participates in the DR program, reducing its contribution during peak hours by 837.46 kWh.

Results for Scenario 2 show that under Tariff 2, both customers reduce their network usage. Customer C1 invests in a 445-kWh battery, and customer C2 participates in the DR program. Customers' responses to the flexibility instruments lead to an overall reduced network usage, which remains below the 500-kW threshold during most (although not all) of the observed hours (55 h out of 65). In this regard, Fig. 9 compares the network's utilisation level in Scenario 1 and Scenario 2 to the Reference Scenario. While minor changes with respect to the current network utilisation (as measured in 2019) can be detected under Scenario 1, significant peak reductions are visible under Scenario 2.

A second set of results for Scenario 1 and Scenario 2 is reported in Table 3, showing, the annual distribution network-related costs for customers C1 and C2 in Scenario 1 and 2. *Grid Costs* are shown

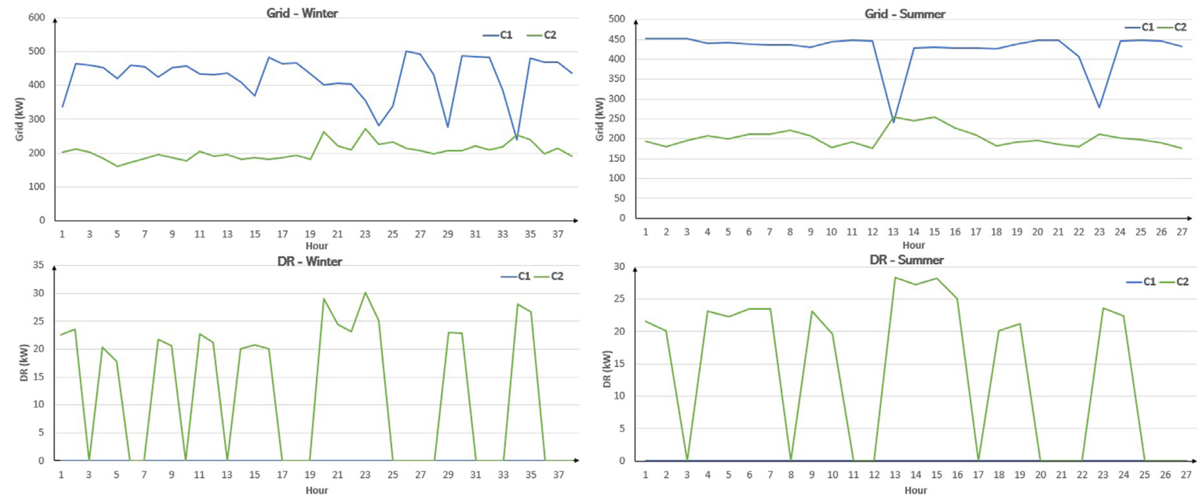

Fig. 7. Case Study results for Scenario 1. The graphs compare the choices made by customer C1 (blue) and C2 (green) during peak hours in winter (left) and summer (right). **Grid** | Energy withdrawn from the grid. **DR** | Curtailed energy through DR participation. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

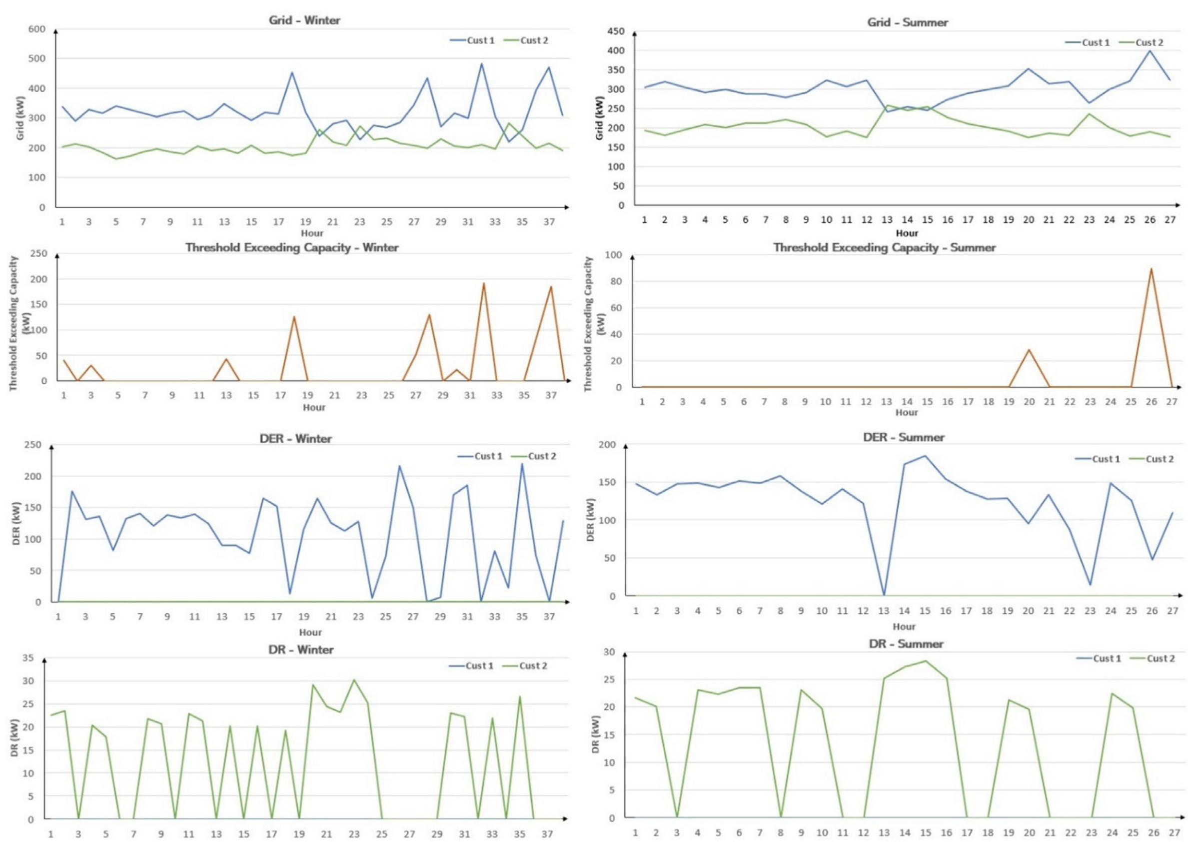

Fig. 8. Case Study results for Scenario 2. The graphs compare the choices made by customer C1 (blue) and C2 (green) during peak hours in winter (left) and summer (right). **Grid** | Energy withdrawn from the grid. **Threshold Exceeding Capacity** | Total energy withdrawn from the grid (orange) which exceeds the 500-kW threshold set for *Tariff 2*. **DER** | Energy withdrawn from DER. **DR** | Curtailed energy through DR participation. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

in columns 2–4 and include either the fixed and variable charges paid under Tariff 1, during peak hours (L1) and in non-peak hours (L2), or the fixed and PCNC charges paid ex-ante or ex-post under Tariff 2. *DER costs,* including both investment and running costs, are in column 5. *DR Rewards* are reported in column 6.

A few remarks are in order. First, results from the two scenarios differ in terms of cost-reflectiveness of the DN tariff. In Scenario 1 customer C2's annual total costs (i.e., the customer's contribution to the recovery of the total network costs) are much higher than customer C1's. However, because the network peaks are associated with the football games, it is customer C1 who is driving total network cost in a forward-looking perspective. In other words, the volumetric component of a DN tariff is not cost-reflective and does not allocate costs efficiently. In Scenario

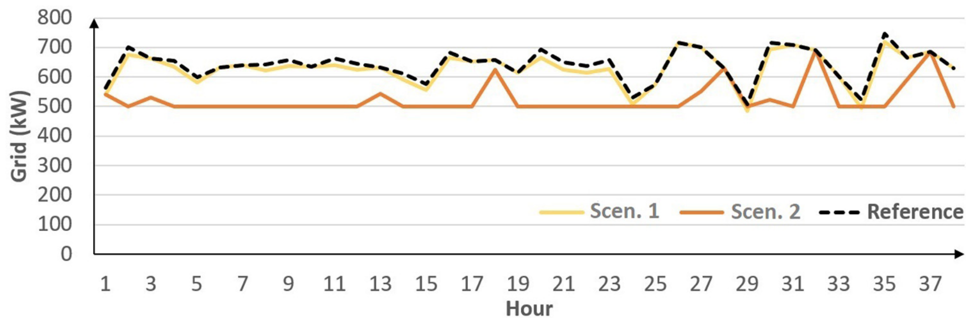

Fig. 9. Case Study results. Network utilisation during Winter peak hours under Scenario 1 (yellow), Scenario 2 (orange), and Reference Scenario (dotted black). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 3
Case Study results. Distribution network-related costs for customers C1 and C2.

Scenario 1						
Distribution network-related costs	FC (€)	VC-L1 (€)	VC-L2 (€)	DER (€)	DR (€)	Annual total (€)
Customer C1	33,641	7207	94,946	–	–	135,794
Customer C2	34,500	5358	533,779	–	(204.17)	573,433
Total	709,431			–	(204.17)	709,227
Scenario 2						
Distribution network-related costs	FC (€)	PCNC-L1 Ex-ante (€)	FC Ex-post (€)	DER (€)	DR (€)	Annual total (€)
Customer C1	245,367	16,840	92,906	90,769	–	445,883
Customer C2	251,633	7974	95,279	–	(200.24)	354,685
Total	521,814		188,185	90,769	(200.24)	**800,569**

2 the forward-looking PCNC allocates the costs associated with network reinforcement in a cost-reflective way, i.e., based on each customer contribution to the network peaks. This allocation occurs by design, as PCNC is paid by customers based on their contribution to peak hours, when network utilisation is above the threshold. Differently, the fixed charges of Tariff 2 (both *ex-ante* and *ex-post*) result in similar costs for customers C1 and C2.

Second, as for consumers' contribution to peak reduction, the DN tariff in Scenario 1 clearly fails to convey the network's utilisation level and does not encourage customer engagement during peak hours. By contrast, Tariff 2 encourages customers to be reactive during peak hours, and peak reduction is significant. Customer C1's large contribution to peak hours means a high payment via the PCNC in Scenario 2; hence, the investment in DER (by contrast, customer C1 does not contribute flexibility in Scenario 1). The choice of consumer C2 is to enter a DR program in both scenarios. While the compensations paid to consumer C2 under the DR program in Scenario 1 and Scenario 2 are quite similar (around €200), this mostly derives from the choice of the incentive, I_{DR}, which is not large. In fact, the response of customer C2 is quite different under the two scenarios. Specifically, results reveal how the goal of customer C2 changes from maximising load reductions under Scenario 1 to avoidance of PCNC in Scenario 2.

Finally, as customers decide to satisfy their demand mostly through the grid in Scenario 1, the DSO achieves, as expected, cost recovery of the total network cost. The sum of the revenues from the DN tariff, minus the payment made to consumers in the DR program, provide a total annual balance of € 709,227 against a total network cost of € 710,000 (the small difference will be recovered on the following year's tariffs). However, lacking customer engagement, network reinforcements are needed to accommodate the expected load growth. Thus, total system costs (sum of the customer costs plus the network reinforcement costs) in Scenario 1 are € 922,227 (€ 709,227 + € 213,000). Notably, cost recovery is also ensured in Scenario 2, but now 70% of total network costs are recovered through an ex-ante fixed charge, 3% through the PCNC, and 27% via an ex-post fixed charge. Thus, assuming that the network reinforcement can be delayed, total system costs in Scenario 2 amounts to € 800,569, which is 13% lower than in Scenario 1.

4.3. Discussion

The findings of the Case Study should be interpreted in light of a few observations. A first set of comments derive from the fact that, while higher system-wide economic efficiency is achieved in Scenario 2, network utilisation remains above the threshold for 10 h per year. This means that the PCNC for the next year will increase significantly (the *Network investment cost* in Eq. (17) remains the same but the *Power exceeding threshold during peak hours* is significantly lower). As a result, the economic signal associated with this part of the DN tariff becomes stronger and network reinforcements can continue to be postponed.

Further actions to strengthen customer engagement include the design of a DR program which is better calibrated on the residential sector, on the one hand, and the commercial user, on the other hand. Results from a sensitivity analysis on the incentive, I_{DR}, the flexibility percentage, and the Annual Reward show that these parameters have a significant effect on customer engagement. The flexibility percentage limits the E_{DR} capacity, and without sufficient I_{DR} an acceptable annual reward may not be reached. In other words, the administratively set incentive should be well aligned with the sector the DR program is to be implemented in. Alternatively, to strengthen customer engagement it might be worth considering a market-based allocation of the flexibility contracts, or the simultaneous procurement of another flexibility product (e.g., network reserves). These alternative proposals might encourage higher participation from customer C2 and induce customer C1 to make at least part of its load flexible. However, the total system cost and benefits of such solutions should be carefully assessed. As known, the interaction of different flexibility instruments (or products) might have negative effects not only on customer engagement. Particular attention should be given to avoiding known drawbacks such as: *(i)* double charging of compensations (or penalties), via connection, access, and use of system charges [72]; *(ii)* procuring products from local flexibility markets with low liquidity [50]; or *(iii)* ignoring that most critical peak pricing charges in DN tariffs have insufficient granularity to send price signals to the exact location where flexibility is needed [73].

A second set of observations regards the issues of predictability and fairness. The main concern regarding PCNC is the predictability of the peak hours during which it will be applied. In the above Case Study, most peak hours can be anticipated since they are linked to football games which are always announced in advance. However, in other cases where it is difficult to predict when peak hours will occur, other flexibility instruments might be preferable — for instance, Local Flexibility Mechanisms, as proposed in [74–76]). As for fairness, the question regards customer C1 individually bearing the DER investment cost. This issue is controversial and complex because DERs are often the source of multiple revenue streams (e.g., through network injections during off-peak hours or the provision of other flexibility products such as network reserves and congestion management). Both are left for further research.

Lastly, the proposed methodology has known limitations. For instance, the assumption made to look only at distribution-network related cost, while instrumental in highlighting the incentives that derive from the choices made at the DN level, might be removed. Future developments of the methodological framework should also allow the use the battery for network injections, thus adding to the realism of the Study Case.

5. Conclusion

This work has focused on the procurement of demand-side flexibility at the distribution network level. Among the flexibility products currently proposed in the literature or being tested in practice, the interest was on the procurement of flexibility to defer or avoid network reinforcement, i.e., on network capacity management. Given the long-term nature of this flexibility product and the lumpiness of network investments, the instrument(s) used to procure this product should not only be cost efficient, but also ensure a sufficient level of customer engagement in the long-term. Consistently, a DR program (an explicit flexibility instrument) is studied, in combination with an implicit one, a dynamic DN tariff. Both chosen for their ability to guarantee customer engagement in the long-term. A methodology was built to test the properties of these instruments against an alternative scenario where the DR program is combined with a static DN tariff. The method finds the optimal response of customers aiming at minimising network-related costs while satisfying their electricity demand.

The analysis was conducted using actual parameters from Skagerak EnergiLab, a Norwegian pilot project, and actual consumption data from 2019. The results from the Case Study showed that customer engagement (measured in terms of network utilisation levels during peak hours) is significantly higher when the DR program is combined with a dynamic DN tariff. The (partially flexible) customer finds it optimal to engage in the DR program under both scenarios but prefers to be curtailed during peak hours only when PCNC are imposed. Similarly, the inflexible customer remains passive under a static DN tariff but invests in DERs (to avoid using the network during peak hours) when PCNC are collected. These results indicate that the static DN tariff currently used by Skagerak Energi can still ensure some customer engagement when an explicit flexibility instrument (a DR program) is introduced. However, the same flexibility instrument would be used more efficiently (from a network reinforcement's perspective) when coupled with a cost reflective dynamic DN tariff (the latter was found to be instrumental in eliciting a response also from the inflexible customer).

From a cost efficiency's perspective, the results of the Case Study showed that total system costs are lower when the DR program is used together with dynamic DN tariffs, i.e., when the level of customer engagement is higher. Although customer engagement comes at a cost (the DSO pays compensations for curtailment under the DR program and inflexible customer pay for investment in DERs), this cost was lower than the network reinforcement cost.

Overall, the above results confirm that the instruments used to procure demand-side flexibility at the distribution level interact with one another (similar conclusions were reached in [15], using synthetic load profiles instead of real-life data). For this reason, they should be designed and assessed as a portfolio. Specifically, using such an integrated assessment, the present work suggests that when procuring demand-side flexibility for network capacity management, the efficacy of a DR program can be significantly enhanced by the simultaneous implementation of a dynamic DN tariff.

An additional relevant aspect that emerges from the Case Study is that customer engagement is ultimately bounded by the amount of flexibility that customers can provide, based on technical and individual preferences. For instance, customers driving network reinforcements were, in the present case, the least flexible ones. These customers might be unresponsive to the available DR program but prone to adopt a technological solution (i.e., battery storage) under a dynamic DN tariff. This choice, in turn, ensures that flexibility can be provided in the long-term and therefore counted upon to avoid network reinforcements. Further work will investigate the combination of flexibility instruments that would lead also the partially flexible customers to invest in DERs. In this regard, other DER technologies can be considered, in addition to storage, as they could equally or better support customer engagement. A methodological extension would be needed in case a flexibility market is also considered.

Finally, the Case Study suggests that the compensations paid (per kWh and annually) under the DR program would play an important role in the level and type of customer engagement. While the incentive (I_{DR}) considered here was relatively low, higher values will unlock further demand-side flexibility. The issue is complicated by the possibility that some consumers might game the system [15], and by the option, already considered in other jurisdictions (e.g., Great Britain [72]), to introduce an availability fee, in addition to an activation fee. Nevertheless, the question of the level of compensation that might conduce to higher levels of customer engagement at an efficient system cost certainly deserves further investigation.

CRediT authorship contribution statement

Ibtihal Abdelmotteleb: Conceptualization, Methodology, Investigation, Software, Writing- original draft, Writing - review & editing, Providing critical feedback and helping to shape the research, analysis and manuscript. **Elena Fumagalli:** Conceptualization, Resources, Validation, Formal analysis, Writing - review & editing, Providing critical feedback and helping to shape the research, analysis and manuscript. **Madeleine Gibescu:** Conceptualization, Supervision, Funding acquisition, Writing - review & editing, Providing critical feedback and helping to shape the research, analysis and manuscript.

Declaration of competing interest

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

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