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Risk vs. restriction—An investigation of capacity-limitation based congestion management in electric distribution grids

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ABSTRACT

Electrification of energy end-uses brings an increasing load on electric distribution grids with load peaks that can cause network congestion. However, many new end-uses like electric vehicles, heat pumps, and electrified industrial processes have some flexibility to move their power consumption away from peak times. Congestion management mechanisms can harness this flexibility. This paper investigates congestion management mechanisms based on limited available network capacity for flexible loads during peak times. A case study discusses and investigates real-world examples of such mechanisms from proposals in Germany and the Netherlands. They differ concerning the lead time at which the capacity limitation is announced, with options from near real-time and day-ahead to long-term. These mechanisms are suited to remove network congestion, but there are significant trade-offs concerning the lead time. A shorter lead time leaves more room for using the network during non-congested times but creates a risk of curtailment for end-users, which may come with associated balancing and re-procurement costs. Longer lead times give more certainty on network access conditions but often restrict network usage even when there is no network congestion.

1. Introduction

The energy transition to renewable energy sources brings an increasing electrification of final energy consumption, such as heating, transport, and industrial processes. This increase in electrification can lead to congestion of the electric grid infrastructure, which was not designed with such high loads in mind. In the Netherlands, large parts of the electric grid are already considered to be in danger of congestion.[1] Consequently, some Dutch network operators have a adopted a strategy of refusing new network connections until the problem is resolved.[2] Similar concerns are raised in Germany.[3]

However, many of these new types of electricity consumption are also highly flexible. EVs typically only need to charge a specific minimum demand over the whole night, and heating can also be spread out over a longer time when houses are well insulated. Industrial processes may have flexibility at longer lead times. Thus, excessive load peaks could be avoided by using this flexibility and coordinating loads in a smarter way (Müller et al., 2023; Gowda et al., 2019). This process is also called *congestion management* (Hennig et al., 2023) and many possible methods for this have been proposed in the literature, e.g., market-based methods (Morstyn et al., 2019; Attar et al., 2022; Huang et al., 2015; Ding et al., 2013; Radecke et al., 2019; Esmat et al., 2018), dynamic prices (Shen et al., 2022; MIT Energy Initiative and IIT Comillas, 2016; Verzijlbergh et al., 2014; Alba Rios and O'Brian, 2021), and network reconfiguration (Attar et al., 2022; Shariatkhah and Haghifam, 2012; Huang et al., 2015; Gao et al., 2019). In the long run, network reinforcement (Attar et al., 2022; Pudjianto et al., 2013; Ahmadigorji et al., 2018; Ziari et al., 2013) is also a possible solution, but it takes time, and often, it is not possible to reinforce the network as quickly as flexible loads are increasing.

This special issue is focused on future electricity tariffs that provide solutions to challenges like congestion from high power flexible loads and that help to reduce the need for network expansion. In this article, we take a wider lens than looking only at tariffs by considering a family of congestion management mechanisms that limit end-user network capacity to reduce peak size. Some of these mechanisms can also be considered a network tariff, while others operate in addition to a network tariff but do interact with the design of the tariff. We focus on

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[1] see, e.g., https://capaciteitskaart.netbeheernederland.nl/ (assessed December 2023).
[2] https://www.meterinsight.com/en/blog-and-news/the-electricity-grid-is-full, https://fd.nl/bedrijfsleven/1468954/nog-jarenlang-wachtlijsten-voor-aansluiting-op-het-stroomnet.
[3] https://www.br.de/nachrichten/deutschland-welt/e-autos-und-waermepumpen-mueller-warnt-vor-stromnetz-ueberlastung,TSvmR3C.

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three current proposals from practitioners in regulation and network operation:

- interruptible network connections that can be curtailed by the network operator close to real-time, which has been proposed by the German regulator (Bundesnetzagentur, BNA) (Bundesnetzagentur, 2023a), henceforth called "interruptible connection".
- a day-ahead capacity limitation contract (CLC) proposed by the Dutch regulator ACM (Autoriteit Consument and Markt, 2022). This proposal makes network capacity available without restrictions when no congestion is expected. Still, on the day ahead, the network operator can activate a clause in the contract by which this available capacity is reduced to a pre-contracted value.
- a static capacity subscription network tariff (DNV GL, 2020), which is considered a candidate for a new network tariff for residential consumers in the Netherlands (Overlegtafel Energievoorziening, 2018; CE Delft, 2022).

These proposals are based on a limitation of available capacity for network users. But there are also major differences: one important distinction concerns the lead time at which the capacity limitation is activated and the risk associated with this activation. In interruptible connections, the activation of the limitation happens close to real-time. This leaves network capacity available for use with no restrictions when no congestion occurs, but it does place a risk on the network user because usage can be restricted unexpectedly. The day-ahead capacity limitation is activated the day before real-time, which reduces the risk for the network customers but shifts some risk to the network operator, who now has to anticipate congestion correctly. The static capacity subscription is a long-term contract. Thus, the lead time is typically weeks to months in advance. This eliminates the risk of being curtailed for users and the mis-anticipation risk for network operators. The downside is that it is inflexible and restricts network access when there is no congestion. It is, therefore, less efficient.

Thus, one of the central trade-offs between the approaches appears to be between *risk* of curtailment for the network user and *restriction* of available capacity, especially during non-congested times. Both of these may lead to concerns and even resistance of network user groups to the implementation of these new proposals.[4] In this regard, some critical questions that are not yet well understood are:

1. What are the combined impacts on end users of these mechanisms and electricity market prices?
2. Can the impacts of restricting network capacity and the risk of curtailment be quantified?
3. How can these mechanisms be improved?

The paper describes the three proposals' benefits, drawbacks, and potential costs. We base our analysis on both a qualitative assessment, which is informed by our previous work on congestion management (Hennig et al., 2023) and network tariffs (Hennig et al., 2022a), and a small case study for a residential congested feeder in which all three approaches are simulated and resulting costs and capacity restrictions are estimated.

Section 2 introduces the proposed mechanisms in detail. Section 3 discusses the criteria used for evaluating the approaches in a case study: different kinds of costs and restriction of network capacity. Section 4 describes our modeling setup and shows results for the different mechanisms. Section 5 provides a discussion of the strengths and weaknesses of each proposal that is partially qualitative and partially based on the simulation case study. Section 6 concludes and provides policy advice.

[4] This is shown by the array of responses to the calls for responses on the German and Dutch congestion management strategies.

2. Proposed congestion management mechanisms with capacity limitations

We briefly summarize the proposals that will be investigated in this paper. They can roughly be ordered by the lead time at which the capacity limitation is set: from near real-time in interruptible connections to pre-day-ahead in capacity limitation contracts to long-term static capacity subscriptions.

2.1. Interruptible connections for residential loads

The German Federal Agency proposed this solution for network regulation (BNA) in 2023 (draft proposal Bundesnetzagentur, 2023a and final decision Bundesnetzagentur, 2023b). It envisions a reduced network charge for end-users with high-power flexible loads in return for the ability and authorization of the network operator to exert limited control over the power consumption of these devices. The targeted loads are EVs, electric heating and cooling systems, and batteries. Thus, when congestion occurs in the grid, the network operator can curtail them to a limited capacity to avoid network overload. This proposal extends the idea of non-firm connection agreements, traditionally discussed only for distributed generators and larger industrial consumers (CEER Distribution Systems Working Group, 2023; Anaya and Pollitt, 2017; EUniversal, 2020), to residential loads. In the US, similar schemes have also been employed on a voluntary basis for flexible residential loads in demand response programs (Clean Energy Group, 2021).

The devices covered by the German proposal are non-public electric vehicle chargers, heat pumps, electrical cooling devices, and electrical storage devices; if they have a maximal power consumption of more than 4.2 kW (up from 3.7 kW in the first version of the proposal) and are connected after January 1st 2024. There is an obligation to participate in this model for distribution system operators (DSOs) and customers with newly connected qualifying loads.

In case of congestion, the network operator can curtail participating devices close to real-time down to a minimum of 4.2 kW. If the device cannot reduce power consumption to this level, it is entirely curtailed to a consumption of 0. The proposal also envisions a second variant of control, in which the network operator does not control the individual device but limits the power consumption of the network connection point. In this case, the control is implemented by an intelligent energy management system. This is intended to allow for smarter energy management if the consumer has installed PV panels or batteries, which it can use behind the connection point to keep using the device with a power consumption above 4.2 kW.

Currently, the reduction of network costs is envisioned as a lump-sum payment given to all customers with participating devices. This is irrespective of:

- whether curtailment of these devices is ever activated,
- how much above 4.2 kW (or 5 kW, for the connection point-based variant) their maximal power consumption is,
- how much these devices are used.

An adaption of this cost reduction structure that is more reflective of the power and energy use of the device is considered for the future.

The near real-time curtailment of devices will likely incur additional balancing costs (Section 3.1) for balancing responsible parties who supply the users of these devices. The current version of the proposal explicitly states that the network operator does not have to provide compensation for balancing (2.2. in Bundesnetzagentur, 2023a). This means the balancing responsibility remains entirely with the energy supplier.[5] This contrasts with the situation in the Netherlands, where it is envisioned that the network operator is responsible for preventing the need for any adjustments of balancing responsible parties that occur due to close-to-real-time congestion management actions (Section 2.2).

[5] It is likely assumed that curtailment will not happen too often and, thus, not incur excessive costs. Furthermore, energy suppliers who supply

2.2. Day-ahead capacity limitation contract

A day-ahead capacity limitation contract is currently proposed by the Dutch regulator ACM (Autoriteit Consument and Markt, 2022) with the first deployment planned for the second half of 2023. It envisions a long-term contract between the network operator and network users where the operator can announce a reduction of the capacity of the user's connection on the day-ahead, *before* closing of the day-ahead market. Currently, it is only envisioned as an option for large consumers with connection capacities above $1\,MW$, but it may be extended to smaller connections in the residential section as well. There, the contracts could be either with individual end-users, or with aggregators as proposed in Heinrich et al. (2021).

Specifications in this contract can include the maximal capacity of the connection and maximal allowable reduction, the price per kW of reduction, the number of times it can be activated, and, optionally, for which times the reduction can be activated. It is envisioned that the price per kW of reduction is determined through a market platform where large consumers bid for the smallest required price per kW of flexible capacity. These bids need to include information on the location of the Point of Common Coupling (PCC) of the involved market parties to address the location-specific nature of congestion.

2.3. Static capacity subscription

The capacity subscription is a proposal for a network tariff for residential consumers that performs implicit congestion management (DNV GL, 2020; Hennig et al., 2020; Bjarghov et al., 2022), which has been extensively discussed as a model for the next round of network tariffs in the Netherlands (Overlegtafel Energievoorziening, 2018; CE Delft, 2022). In this mechanism, network users sign up for a fixed amount of network capacity (in kW), within which they can use the network at no or low volumetric charges. A low charge for consumption within the subscribed capacity is used to reflect better the cost of network losses (Bjarghov et al., 2022; Hennig et al., 2022a), which typically have to be recovered by the network operator at market prices.[6] Customers must pay a significantly higher volumetric charge if they exceed their subscribed capacity. For this, an averaging time step over which to compute the exceedance has to be defined: exceeding the capacity for only a few minutes, e.g., due to using a kettle or induction stove on boost function, may not trigger a higher fee if it averages out over the settlement time step, which is typically 15, 30 or 60 min (Hennig et al., 2023). Often, the main problem of network congestion is an overload of the thermal capacity of critical components such as transformers and lines. As these can typically withstand short-duration peaks above their rated capacity, it is reasonable to define the averaging time step slightly longer, such as on the order of one hour.

The subscribed capacity is guaranteed to be available, apart from unforeseen outages which may occur in rare cases. A minimum service level (e.g., 1 or 2 kW) may be mandatory to guarantee basic services. Above that, users can select a capacity level that satisfies their "standard" consumption needs, e.g., lighting, cooking, wet appliances, and entertainment for household consumers. Users with additional high-power flexible loads, such as EVs or heat pumps, may have to choose a higher subscribed capacity to satisfy their needs for these devices without incurring high fees for exceeding the bandwidth.

Note that this proposal integrates capacity limitation into the network tariff. In contrast, the other two proposals described above typically function additionally to an underlying network tariff, but as part of the connection agreement.

multiple service areas may be able to shift energy from one area where devices are curtailed to another where no curtailment takes place or anticipate the statistical occurrence of curtailment in the service areas.

[6] see, e.g., https://www.acm.nl/en/publications/when-setting-2023-tariffs-acm-takes-account-high-costs-connected-grid-losses-due-higher-energy-prices.

Table 1
Comparison of capacity-limitation-based congestion management approaches. **In bold: choices implemented in the case study,** Section 4.

	Interruptible connection	Day-ahead capacity limitation	Static capacity subscription
Lead time for variation announcement	Near real-time	Day-ahead	Contract period
Metering point	Flexible device or **network connection point**	Flexible device or **network connection point**	Network connection point
Relation to network tariff	Additional to default tariff	Additional to or replacing default tariff	Replaces previous tariff
Contracted capacities when not congested	Full technical capacity	Full technical capacity or **subscribed variable capacity** (e.g. 8, 10, 12, … kW	Subscribed fixed capacity (e.g. 2, 3, 4...kW)
Possible variation of contracted capacity when congested	Reduction to fixed value (binary)	**Reduction to fixed value (binary)** or variable	None
Firmness of capacity limit	Hard	**Hard** or soft	Soft

2.4. Comparison

Fig. 1 gives an overview of the timeline in the three approaches. We distinguish between tasks for the network operator (top bar in blue) and for the end-user (bottom bar in orange). As described above, the main difference between the mechanisms concerns the lead time at which the capacity reduction is announced. In the interruptible connection, this happens very close to real-time during the delivery phase of electricity. In contrast, in the day-ahead CLC, it happens shortly before the closing of the day-ahead market, and in the capacity subscription, it is agreed in a long-term contract.

Furthermore, we present additional design choices of the three mechanisms in Table 1. The metering point at which the capacity limitation is applied can be either at a specific device itself or at the overall network connection point of the customer, e.g., a household connection. As discussed, the BNA interruptible connection proposal offers both options. Both options are also possible for a day-ahead variable capacity limitation. The limitation is typically applied to the overall connection in the static subscription, as it is part of the network tariff. The interruptible connection proposed by the BNA is envisioned to be applied in addition to a network tariff, while the capacity subscription replaces the former tariff. The day-ahead CL can be both additional to or replacing the former tariff. The contracted capacity during non-congested times is the full technical capacity of the device or connection in interruptible connection and day-ahead CLs. In the capacity subscription, it is a subscribed capacity, which is typically less than the total technical capacity. When there is congestion, the interruptible connection foresees the reduction of available capacity to a fixed value (e.g. 4.2 kW). The day-ahead CL can also reduce to such a fixed value, but it would also be possible to allow for a variable reduction, based on anticipated network conditions. The capacity subscription has no variation of available capacity based on network conditions. Lastly, "firmness" concerns whether or not the capacity limit is hard, i.e., whether a user can exceed it for a higher price or exceedance is prohibited. In the BNA proposal, the limit during activation of the limitation is hard and can be enforced through a remote switching operation by the network operator. In the capacity subscription, exceeding the subscribed capacity is possible for a higher per-kWh price. In the day-ahead CL both options are possible, based on the contractual specifications. When there are multiple possible choices

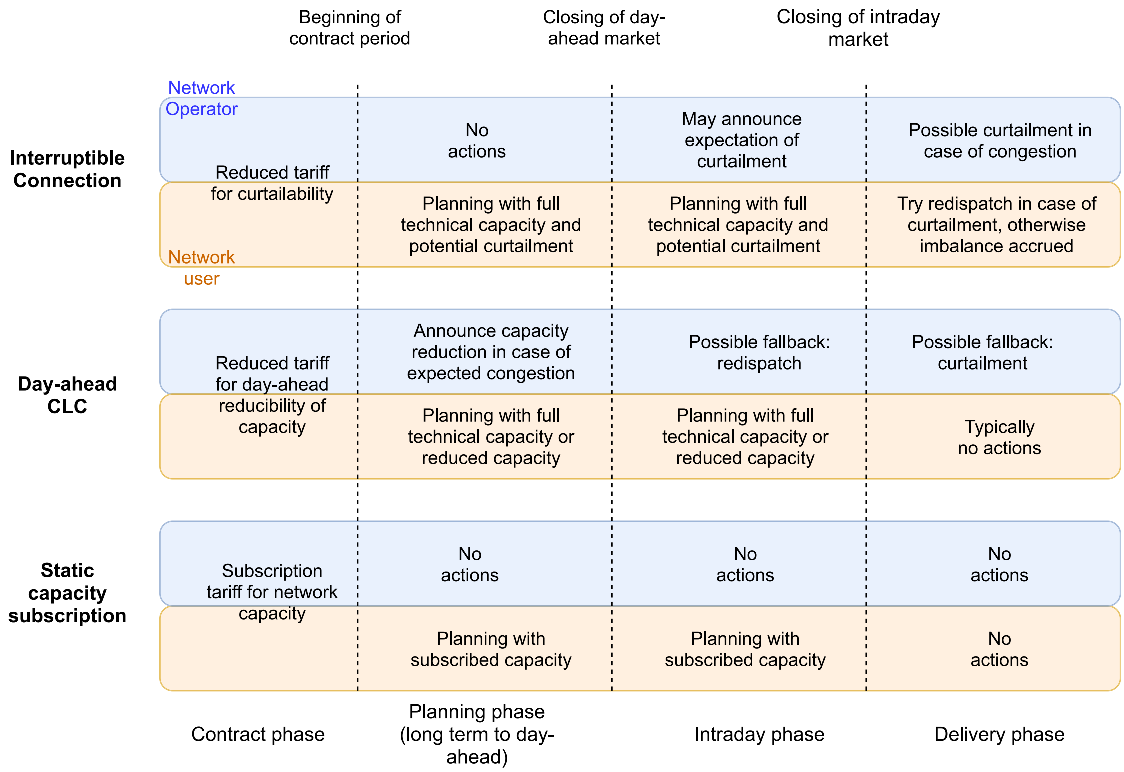

Fig. 1. Timeline of capacity limitation approaches. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

for a mechanism, the boldface option indicates the choice we modeled in the case study, Section 4.

3. Evaluation criteria for case study

We introduced different capacity-based congestion management approaches in the previous section. In the present section, we describe our evaluation criteria for comparing them in a case study (Section 4). These are augmented by a qualitative discussion in Section 5.

3.1. Costs

Congestion management requires shifting or shedding loads, relative to a situation without congestion. Users may incur additional costs due to these adjustments related to the procurement of electricity that depend on user preferences, energy market prices, and how close to real-time the adjustment is required. We can distinguish several kinds of costs:

- Day-ahead market: When users would like to use low prices on the day-ahead electricity market, but cannot due to the congestion management mechanism in place, there is a cost related to purchasing power at higher prices. For this to happen, the mechanism needs to specify network access conditions before the gate closing time of the day-ahead market.
- Intra-day market: In analogy to the first point, costs are also associated with the inability to exploit low intra-day market prices. This is particularly interesting for flexible load types with potential load shifting times of several hours, which residential flexible loads typically have. These load-shifting potentials could be used to exploit price spreads on the intra-day market and price spreads between day-ahead and intra-day markets.
- Balancing costs: in vertically unbundled electricity systems (Brunekreeft and Friedrichsen, 2015) with independent markets, energy suppliers, and network operators, all major network users have a balancing responsibility to the transmission system operator (TSO).[7] When they fail to meet their balancing program they incur balancing costs, which TSO charges for keeping power balance in the system.

All the costs discussed above are related to electricity procurement at wholesale markets and the corresponding balancing responsibility for energy suppliers. In addition to these procurement-related costs, there may be other costs, depending on the congestion management mechanism. In particular, some congestion management mechanisms are based on varying network prices (Hennig et al., 2023). Thus, in those cases, these also need to be considered. In the present paper, however, all of the investigated mechanisms are based on variations of network capacity limitations rather than price variations. Additional costs include taxes, transmission fees, and subsidy schemes. However, these are mostly unrelated to the congestion management method and are not discussed here.

Furthermore, installation costs are associated with implementing a new congestion management mechanism. For example, the interruptible connection requires installing a load-limiting device that the network operator can remotely control. The day-ahead capacity limitation requires the setup of communication channels through which the network operator can send information about expected congestion and available capacity. The day-ahead capacity limitation and the capacity subscription also require installing smart meters. These costs can also be significant and should be considered when a new congestion management mechanism is considered. However, they are not considered in this study.

3.2. Capacity restriction and user discomfort

In addition to the costs of electricity procurement, there may also be discomfort costs for the users from not being able to use the total

[7] see, e.g., https://www.next-kraftwerke.be/en/knowledge-hub/balancing-responsible-party-brp.

technical power capacity of devices, e.g., not being able to charge an EV to the desired amount on time or not being able to heat to the desired comfort level. These are harder to quantify in monetary terms, as they depend on the user's specific willingness to pay (or willingness to accept reduced capacity). However, they can be quantified regarding users' available capacity for using flexible loads, as we will do in the case study (Section 4.3).

4. Case study

In this section, we explain the modeling setup for investigating differences in costs between the different proposals for the case of a residential neighborhood.

4.1. Parameters

General:

$t \in \mathcal{T}$:	Time interval set
$u \in \mathcal{U}$:	User set
$s \in \mathcal{S}$:	Scenario set
Δt_{step}:	power settlement time step in minutes
$P(t)$:	Power over time interval
$\pi^{\text{DA}}(t)$:	day-ahead electricity price at time t
c^{Bal}:	cost assumption for power imbalances
q^{EVUD}:	EV (U)nsatisfied (D)emand
c^{EVUD}:	cost assumption of EV (U)nsatisfied (D)emand
$\lambda^{\text{activation}}(t)$:	activation level of capacity subscriptions at time t

Electric Vehicle Specific quantities:

$t_u^{\text{EV,arr}}$:	Arrival time
$t_u^{\text{EV,dep}}$:	Target departure time
$q_u^{\text{EV,start}}$:	Charge at beginning of simulation in kWh
$q_u^{\text{EV,target}}$:	Target charge at departure time in kWh
$q_u^{\text{EV,daily}}$:	Daily energy demand in kWh
$q_u^{\text{EV,max}}$:	Maximum charge of battery in kWh
$q_u^{\text{EV,min}} = 0$:	Minimum charge of battery in kWh
$P_u^{\text{EV,max}}$:	Maximum rate of charge in kW
$\eta_u^{\text{EV}} \in (0,1]$:	Charging efficiency

4.2. Model design

We use a modification of the Assessment of Network Tariff Systems (ANTS) model, previously used in Hennig et al. (2022a): the ANTS-CS (Capacity Subscription) model,[8] to model a single, potentially congested, residential neighborhood with customer set $u \in \mathcal{U}$. We assume that customers have a certain inflexible power demand $P^{\text{inflex}}(u,t)$ at each time t. In addition, some users have EVs, which can be controlled remotely by an energy supplier (ES). We assume that the ES employs optimization for the scheduling of EV charging based on market electricity prices and that EVs can be continuously controlled. The ES also knows the parameters of the charging constraints of each user: their arrival and departure times, battery size, efficiency, charger capacity, and daily demand for electric energy.[9]

The optimization problem that the ES faces is the following: given expectations about the inflexible demand and the required energy for EV charging, choose the optimal quantity of power purchased at the day-ahead market and optimal dispatch schedules of power to consumers. A complication for this objective is the inherent uncertainty of the problem. The energy supplier does not know how much inflexible load customers will require and how much network capacity they will have available for charging EVs. In the interruptible proposal (Section 2.1), the available network capacity for EVs will be either the total technical capacity or 4.2 kW in case of curtailment. In the day-ahead capacity limitation (Section 2.2), the network operator can set constraints on network usage before the day-ahead planning stage. In the static capacity subscription (Section 2.3), the available network capacity for flexible loads is the subscribed capacity minus whatever inflexible loads a user has at each time (additionally, exceeding the subscribed capacity may be possible for a higher charge during times of no congestion).

As the inflexible loads and resulting available network capacity are not known in advance, we assume that the ES employs a set of potential scenarios for its planning, over which it optimizes jointly. To formalize the optimization problem, we introduce the net power balance of the ES as the difference between purchased power and dispatched power in each scenario s:

$$P^{\text{net}}(s,t) = P^{\text{disp}}(s,t) - P^{\text{pur}}(t), \tag{1}$$

where dispatched power at time t is the sum of all flexible and inflexible loads supplied by the ES:

$$P^{\text{disp}}(s,t) = \sum_{u \in \mathcal{U}} \left(P_u^{\text{flex}}(s,t) + P_u^{\text{inflex}}(s,t) \right) \tag{2}$$

This quantity depends on the specific scenario, while the purchased power in Eq. (1) is scenario-independent. This is because there is only one possible choice for purchasing power on the market, which is optimized across the set of scenarios. In each scenario, the allocation of purchased power to flexible loads is optimized according to the capacity constraints in the given scenario. A resulting net power imbalance, $P^{\text{net}} \neq 0$, incurs an additional balancing cost proportional to the imbalance, where a constant proportionality factor was assumed for simplicity.[10]

Thus, the optimization objective can be stated as:

$$\begin{aligned}\min_{P^{\text{pur}}(t),\, P^{\text{flex}}(u,s,t)} \sum_{t \in \mathcal{T},\, s \in \mathcal{S}} \Big(& \pi^{\text{DA}}(t) \cdot P^{\text{pur}}(t) \\ & + \left(\pi^{\text{DA}}(t) + c^{\text{Bal}}\right) \cdot \theta(P^{\text{net}}(s,t)) \cdot P^{\text{net}}(s,t) \\ & + \left(\pi^{\text{DA}}(t) - c^{\text{Bal}}\right) \cdot \theta(-P^{\text{net}}(s,t)) \cdot P^{\text{net}}(s,t) \Big)\end{aligned} \tag{3}$$

where $\pi^{\text{DA}}(t)$ is the day-ahead price at time t and $\theta(x)$ is the Heaviside theta function that is 0 when $x \leq 0$ and 1 when $x > 0$. We assume that positive imbalance, i.e., requiring more power than purchased on the day-ahead market, has to be procured at a price higher than the day-ahead price with a constant offset for the balancing cost c^{Bal}. Negative imbalance, i.e., excess purchased power, is sold at a symmetrically lower price. What we describe as "balancing costs" here can be seen as a mix of re-trading on the intraday market and remaining portfolio imbalances balanced by the TSO at the applicable balancing prices at each hour. This stylized assumption allows us to include the anticipation of balancing costs for imbalances in a simple way.

[8] available publicly at https://gitlab.tudelft.nl/rhenning/ants-cs.

[9] This assumption of remote controllability is strong and may not currently hold for most loads. In the future, however, we expect these devices to become smarter and more easily controllable, as this will unlock many operational benefits for the power system, which can be translated into financial benefits for their owners.

[10] In reality, balancing costs depend on the total imbalance in the control area and are differentiated between positive and negative imbalances. If a balancing responsible party's imbalance helps resolve the control area imbalance, balancing prices can even be negative (Fransen and Dubbeling, 2019). However, publicly available data at ENTSO-E show a positive price for both imbalances and an equal price for negative and positive imbalance in the vast majority of time steps. This suggests that, on average, imbalances will incur a cost. Furthermore, energy suppliers do not know the exact price of imbalances when purchasing energy. Therefore, we find the assumption of a constant average balancing price sufficient to assess the impact of balancing requirements between the different mechanisms comparatively.

The objective expression can be rewritten as indicated in Appendix B. Furthermore, it is possible to leave part of the required EV demand unsatisfied due to tight network constraints or high prices. EV demand is likely not as cost-inelastic as traditional demand, though this depends on user preferences. Assuming that it is possible to have a certain q^{EVUD} (EV Unsatisfied Demand) at discomfort cost c^{EVUD} per kWh, we can add a term to the objective function that reflects this. Together with the aforementioned transformation, the objective then becomes:

$$\min_{P^{\mathrm{pur}}(t),\, P^{\mathrm{flex}}(u,s,t)} \sum_{s \in S} \Big(\sum_{t \in \mathcal{T}} \left(\pi^{\mathrm{DA}}(t) \cdot P^{\mathrm{disp}}(s,t) + c^{\mathrm{Bal}} \cdot |P^{\mathrm{net}}(s,t)| \right) + c^{\mathrm{EVUD}} \cdot q^{\mathrm{EVUD}}_{\mathrm{total}}(s) \Big) \tag{4}$$

The unsatisfied EV demand is not dependent on time, as it is expressed as an energy difference between the desired battery charge and the actual battery charge at the departure times of the EVs. The treatment of the absolute value in the objective function of Eq. (4) is explained in Appendix C.

The charge constraint for each EV at its departure time is then:

$$q^{\mathrm{EV}}_u(s, t^{\mathrm{EV,dep}}_u) \geq q^{\mathrm{EV,target}}_u - q^{\mathrm{EVUD}}_u(s) \tag{5}$$

And $q^{\mathrm{EVUD}}_{\mathrm{total}}$ is the sum of all individual unsatisfied demands. Assigning individual discomfort costs for each user based on their preferences in a real-world implementation would also be possible.

Additionally, there are the following constraints: The rate of charge of an EV is bound by the maximal throughput of the charger, which is what we call the "technical capacity" of the device connection in Section 2:

$$P^{\mathrm{EV}}_u(t) \leq P^{\mathrm{EV,max}}_u \tag{6}$$

The size of the battery binds the charge of the EV battery:

$$q^{\mathrm{EV,min}}_u \leq q^{\mathrm{EV}}_u(t) \leq q^{\mathrm{EV,max}}_u \tag{7}$$

EVs can only charge when they are parked at home, from arrival time to departure time:

$$P^{\mathrm{EV}}_u(t) = 0, \text{ if } t \notin [t^{\mathrm{EV,arr}}_u, t^{\mathrm{EV,dep}}_u] \tag{8}$$

The battery charge of an EV is initialized to the starting charge at $t = 0$. Afterward, it is updated based on how much was charged in the previous period, taking into account the charging efficiency of the EV. Before the EV arrives at home, its charge is reduced by the daily driving demand.[11]

$$q^{\mathrm{EV}}_u(t) = \begin{cases} q^{\mathrm{EV,start}}_u, & \text{if } t = 0 \\ q^{\mathrm{EV}}_u(t-1) & \\ \quad + \eta^{\mathrm{EV}}_u \cdot P^{\mathrm{EV}}_u(t-1) \cdot \Delta t_{\mathrm{step}}, & \text{if } t \in [t^{\mathrm{EV,arr}}_u, t^{\mathrm{EV,dep}}_u] \\ q^{\mathrm{EV}}_u(t^{\mathrm{EV,dep}}_u) - q^{\mathrm{EV,daily}}_u & \text{if } t = t^{\mathrm{EV,arr}}_u - 1 \end{cases} \tag{9}$$

In addition to these constraints, a further tightening of the available network capacity may occur due to the congestion management method. In static capacity subscriptions, the charging power of an EV is limited to the subscribed capacity of the customer minus the inflexible load that this customer has at a given time (or to zero, in case the inflexible load already exceeds the subscription):

$$P^{\mathrm{EV}}_u(s,t) \leq \max\left(P^{\mathrm{subscribed}}_u - P^{\mathrm{inflex}}_u(s,t), 0 \right) \tag{10}$$

This is typically not a hard constraint. As discussed in Section 2.3, the user may be able to exceed the subscribed capacity in exchange for a higher volumetric charge. But for the modeling, we assume that this higher charge is always higher than wholesale price differences, so users would not intentionally choose to exceed their subscribed capacity. Note that the inflexible load of the user at time t is not known to the energy supplier when making the day-ahead purchasing decision, Eq. (4). This is why we introduced different load scenarios, s, over which the energy supplier optimizes jointly. For assigning static subscriptions, we use the cost assumptions presented in Table 2. We compute the best-subscribed capacity for each household based on their inflexible loads over a year. Additionally, for EV owners, we add a capacity of 0.5 kW per each 2.5 kWh of daily demand to reflect the higher capacity needs of these users.[12]

For modeling the day-ahead CLC, we assigned each user a variable subscribed capacity of 11.5 kW. This is sufficient to charge an EV at the full charger capacity of 11 kW during the night.[13] In analogy to Eq. (10), the limitation becomes:

$$P^{\mathrm{EV}}_u(s,t) \leq \lambda^{\mathrm{activation}}(t) \cdot P^{\mathrm{sub.variable}}_u \tag{11}$$

where $\lambda^{\mathrm{activation}}(t)$ is a time-dependent activation factor of the variable subscription level. On the day ahead, the DSO announces the activation factors for the next day. When it expects no congestion, this factor is equal to 1. When it does expect congestion, this factor is set to below 1. We use only a single activation level to better compare the interruptible connection strategy, which sets the available capacity to 5 kW, the same value used for interruptible connections.

In interruptible connections as proposed by the BNA (Section 2.1), the network capacity can be limited specifically for the flexible device to a pre-defined value p^{limited}, e.g. 4.2 kW, during times of congestion:

$$P^{\mathrm{EV}}_u(t) \leq p^{\mathrm{limited}} \quad \forall t \in \mathcal{T}^{\mathrm{cong}}(c),\ u \in \mathcal{U}^{\mathrm{curt}}(c,t), \tag{12}$$

where $\mathcal{T}^{\mathrm{cong}}$ is the set of all time intervals with congestion and $\mathcal{U}^{\mathrm{curt}}(t)$ is the set of users selected for curtailment. Alternatively, the constraint can be applied at the connection level, in which case a higher p^{limited}, e.g. 5 kW is used:

$$P^{\mathrm{EV}}_u(t) + P^{\mathrm{inflex}}_u(t) \leq p^{\mathrm{limited}} \quad \forall t \in \mathcal{T}^{\mathrm{cong}}(c),\ u \in \mathcal{U}^{\mathrm{curt}}(c,t), \tag{13}$$

We implemented this version in the case study to better compare with the day-ahead variable limitation.

This constraint is difficult because neither the congested times nor the set of curtailed users is known to the energy supplier when making the day-ahead purchasing decision, Eq. (4). Thus, we introduce an additional set of curtailment scenarios c in this method, which describes the degree of congestion at each time. For ease of modeling, the energy supplier assumes only three different curtailment scenarios for each time step: 1. no curtailment, 2. 50% of devices curtailed, and 3. 100% of devices curtailed. Each scenario occurs with a certain time-dependent probability. The curtailment probability will typically be higher when the network is highly loaded. In residential areas, the traditional peak hours are during the evenings when many people come home from work. However, we assume that most users use smart EV charging, which uses low wholesale prices. In such a case, the network peak may be moved to the times of lowest wholesale prices (Hennig et al., 2020). Thus, we assume that the energy supplier assumes there is a chance of curtailment during the two lowest-wholesale-price hours each night.

[11] We assume that arrival and departure times are the same time of day each day for simplicity. They are different for different users though.

[12] This simple heuristic is typically not too far off from the optimal result. We do this because, in real situations, customers will likely not know their exact daily demand, and it also varies over time, so finding an optimal solution here seems overly ambitious. We have also studied the impact of varying the assigned subscription to the next higher or lower level (+/− 0.5 kW), and it did not change results significantly.

[13] Note that this is somewhat different than the setup currently envisioned by ACM in Section 2.2, where participants bid for the lowest price reduction for a variable capacity. This is because the latter concept is envisioned mostly for industrial customers. In our setup, it would be difficult to model a bidding process for every EV, as it requires a lot of assumptions on the individual valuations of the network capacity of the users.

Table 2
Parameter values for simulation case study.

Parameter	Values
General	
Number of households	50
Number of EVs	25
Time step	60 min
Imbalance cost assumption	20 ct/kWh
Unsatisfied EV load value	40 ct/kWh
Static capacity subscription	
Cost of the subscribed cap.	80 Eur/kW
Cost below subscribed cap.	3 ct/kWh
Cost above subscribed cap.	30 ct/kWh
Day-ahead CL and interruptible connection	
Capacity during congestion	5 kW
Scenario generation method	
Number of scenarios	10
Relative std. deviation	2%
Decay parameter	0.9
Simulation dates	02/01/2021–16/01/2021

The objective function Eq. (4) can then be amended to include this curtailment assumption:

$$\min_{P^{\mathrm{pur}}(t),\, P^{\mathrm{flex}}(u,s,c,t)} \frac{1}{\#\mathcal{S}} \sum_{s\in\mathcal{S}} \Big(\sum_{t\in\mathcal{T}} \sum_{c\in[0,50,100]} \rho(t,c) \cdot \big(\pi^{\mathrm{DA}}(t) \cdot P^{\mathrm{disp}}(s,c,t) + c^{\mathrm{Bal}} \cdot |P^{\mathrm{net}}(s,c,t)|\big) + c^{\mathrm{EVUD}} \cdot q^{\mathrm{EVUD}}_{\mathrm{total}}(s) \Big) \tag{14}$$

where $\rho(t,c)$ is the probability of $c\%$ of curtailment at time t. It is usually 0% curtailment with probability 1 and 0 otherwise. We assume a non-zero probability of curtailment events only for the two lowest wholesale-price hours.

In addition to day-ahead planning, there are two more phases (see Fig. 1): 1:. updates on the intraday market and 2:. the dispatch stage or delivery phase. The intraday stage is largely analogous to the day-ahead trading stage. In it, energy suppliers can adjust their planning and use price spreads between different intra-day time steps and between the power purchased on the day-ahead market and the intraday. However, this only results in adjusting the day-ahead schedule; thus, we do not model this stage explicitly. Thus, for modeling simplicity, we fuse the intraday and dispatch stages into a single modeling stage.

In this intraday balancing and dispatch stage, the energy suppliers' main objective is to minimize imbalance costs, given a fee for portfolio imbalances and the option to re-trade energy in the intraday market. Here, the inflexible loads of users and the activation of curtailment of interruptible connections are known. I.e., all the previously unknown capacity limitation constraints have now been revealed. Thus, the objective can be stated as:

$$\min_{P^{\mathrm{flex}}(u,t,s^*)} \sum_{t\in\mathcal{T}} \pi^{\mathrm{DA}}(t) \cdot P^{\mathrm{net}}(t,s^*) + c^{\mathrm{Bal}} \cdot |P^{\mathrm{net}}(t,s^*)| + c^{\mathrm{EVUD}} \cdot q^{\mathrm{EVUD}}_{\mathrm{total}} \tag{15}$$

where s^* denotes the scenario of inflexible load and curtailment decisions that is realized in real-time (which is in general different from any of the projected scenarios $s \in \mathcal{S}$ of the day-ahead problem), and we use the same cost assumptions as in Eq. (4) to be consistent with the day-ahead stage.

The energy supplier can adjust the dispatch of flexible demand $P^{\mathrm{flex}}(u,t)$. For example, if some users are curtailed in the interruptible proposal but others are not, it can redirect power flows from the curtailed users to the non-curtailed ones. Moreover, it can re-trade power in the market at a price correlated to the day-ahead price (we assume perfect correlation here for simplicity), but again with a penalty c^{Bal}. Lastly, we add a term that reflects the possibility of leaving EV demand unsatisfied for a specific discomfort cost.

We use a rolling time horizon of 48 h for the day-ahead optimization problem to capture saving opportunities that result from pre-/postponing charging due to expected higher/lower prices on the next day. We assume that the day-ahead planning is done at noon for the times starting from 12 p.m. The dispatch stage is done simultaneously for all 24 h starting at midnight, to simplify fulfilling the intertemporal constraints of EV charging.[14] At this stage, we assume that all relevant parameters of the capacity constraint are known for the next 24 h, while for the following 24 h after that, we use the same projection as in the day-ahead model (again to capture the intertemporal constraints over multiple days).

The relevant parameters of the model are summarized in Table 2. We use power prices from EPEX-NL[15] for January 2021 and household load profiles generated with the Load Profile Generator[16] by Pflugradt (2016). The electric vehicle charging profiles are taken from Verzijlbergh (2013).

4.3. Results

We begin by discussing the purchased power of the energy supplier for all flexible and inflexible loads in the different strategies in Fig. 2. For the interruptible connection proposal, we distinguish between a naive and an anticipating implementation: in the naive version, the energy supplier does not account for the possibility of curtailment in its day-ahead planning. Thus, this implementation leads to the highest spikes of flexible loads in the planning, as the energy supplier assumes that the full technical capacity will always be available. In the anticipating mode, the energy supplier considers the possibility of curtailment in their day-ahead purchasing decision. Thus, they already reduce the highest load peaks for the next day to reduce the risk of curtailment.

Similarly, in the day-ahead variable CLC, during the periods with the highest expected loads (i.e., the times with the lowest prices), the available capacities for variable contracts are reduced by the network operator. This has a similar effect as the downward adjustment of purchased loads in the anticipating version of the interruptible connection implementation and spreads out flexible loads over a longer time. Lastly, in the static capacity subscription version, the spikes in flexible loads are reduced even more and spread out over an even longer time. This is due to the higher capacity restrictions (see Fig. 6), which limits EV charging (or other flexible loads) to the subscribed capacity at all times. In summary, all three proposals reduce peaks of flexible loads.[17]

We now review some results of individual users to understand how the different proposals work. For this, we distinguish between light and heavy EV users, as it is interesting to see how the mechanism affects different user groups differentially. Heavy users are defined as those with a daily demand of 11 kWh or more, medium users with a demand of 6 to 11 kWh, and light users below 6 kWh daily. In Figs. 3, 4 and 5 we show the three mechanisms for a randomly chosen light and heavy user for the same example day as Fig. 2 (with the same users in each graph). In the interruptible connection on this day, Fig. 3, the network operator implemented curtailment at 3:00 am. We can see how the heavy EV user can use the total network capacity without congestion.

[14] Note that in reality, this optimization would have to be performed on a rolling basis as more information becomes available with an updated set of scenarios for expected future inflexible demand in the following hours, as in the day-ahead objective. However, we reduced this problem by integrating all 24 dispatch decisions into one optimization problem for modeling simplicity. In this balancing stage, purchasing day-ahead electricity (at a lower cost) is no longer possible, and the problem is only about how to dispatch the already purchased load among the different EVs. Thus, the resulting differences do not change the results significantly.

[15] https://www.epexspot.com/en/market-data, complete historical data was generously made available by EPEX for academic usage.

[16] https://www.loadprofilegenerator.de/.

[17] In the naive implementation of the interruptible proposal, the large peaks are curtailed in real-time, which incurs large balancing costs. Thus, the energy supplier presumably would start anticipating curtailment to reduce costs.

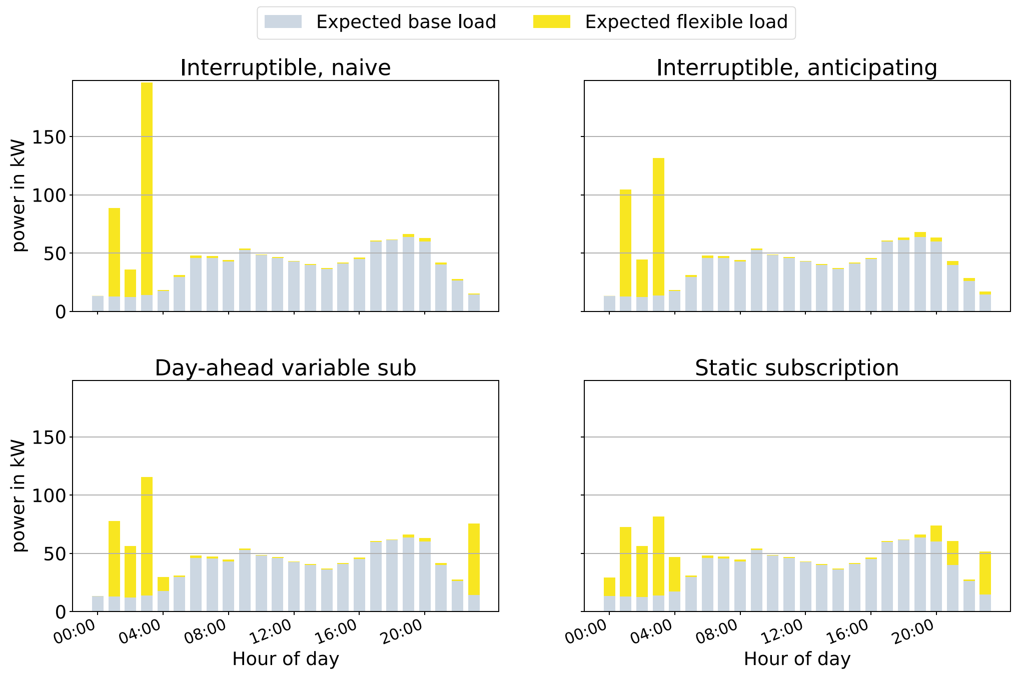

Fig. 2. Purchase decisions for flexible loads day-ahead under different congestion management methods on an exemplary day during the optimization time period.

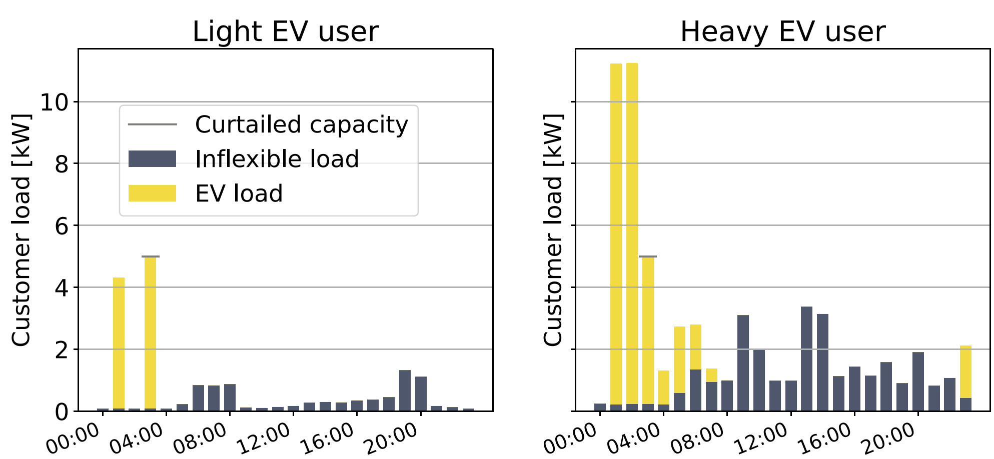

Fig. 3. Interruptible connection in example day. Same users as in Figs. 4 and 5.

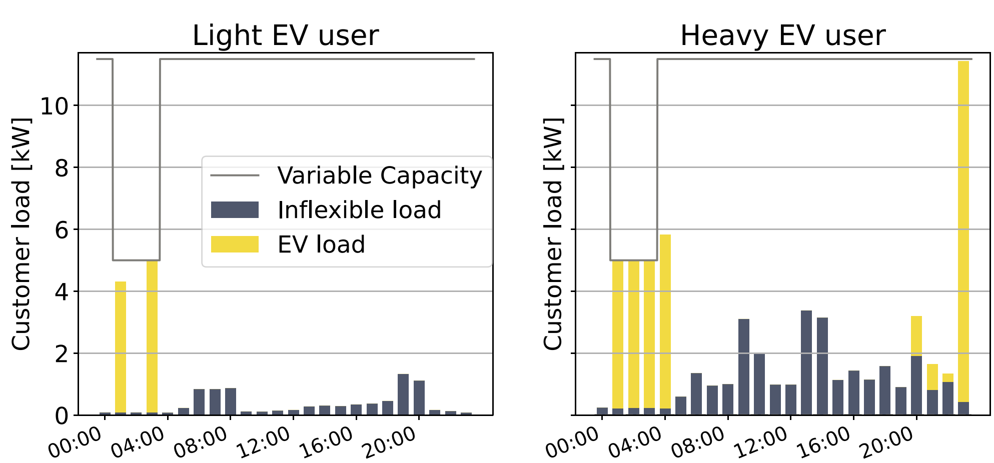

Fig. 4. Day-ahead variable capacity limitation for flexible load in example day.

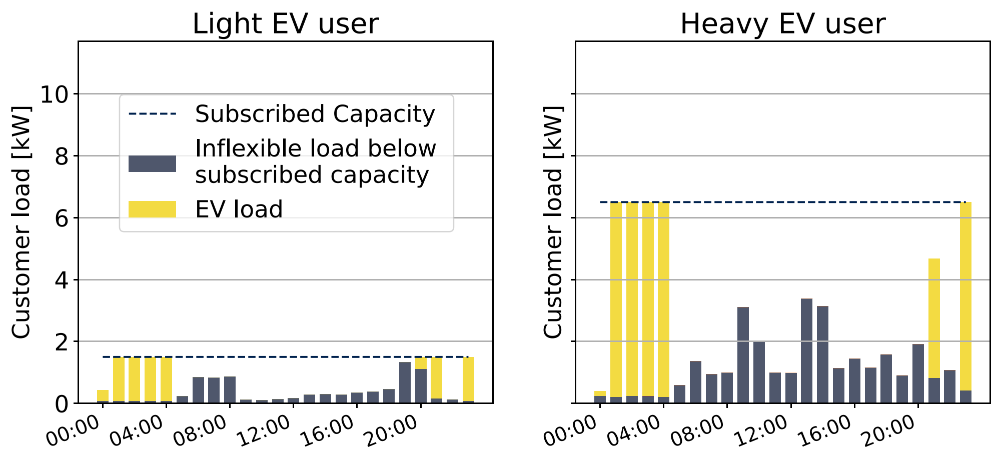

Fig. 5. Static capacity subscription in example day.

Table 3
Day-ahead purchasing costs and balancing energy requirements in different congestion management methods.

	Interruptible, naive	Interruptible, anticipating	Day-ahead CLC	Static cap. subscription
Total day-ahead market costs [Euro]	922	920	931	933
EV charging day-ahead market costs [Euro]	97.3	95.1	105	108
Pos. imbalance [kWh]	280	260	108	118
Neg. imbalance [kWh]	2.5	0	0	2.1
Imbalance costs [Euro]	56.4	51.8	21.6	23.7

This contrasts with the day-ahead variable capacity limitation implementation, Fig. 4. Here, in the chosen example day, the network operator has announced a reduction of available capacity for all hours from 1:00 to 3:00 am, as congestion was anticipated to be likely during these hours. Thus, the network capacity is considerably reduced for the heavy EV user, compared to the interruptible connection. On the other hand, since the reduction was announced on the day ahead already, it gave more planning certainty to the energy supplier, which will become apparent when we look at balancing requirements (Table 3).

In the static capacity subscription, Fig. 5, the available capacity for flexible devices is determined solely based on the subscribed capacity and the inflexible load of a user at each time. The light EV user here has a 1.5 kW subscription while the heavy user has 6.5 kW subscription. They use their total subscribed capacity for multiple hours to fulfill their charging needs. As we can see from this and from Fig. 2, the static subscription spreads out flexible loads more than the other strategies and prevents users from using the total technical capacity of their devices and the entire available network capacity during all times.

Now, we focus on the impacts on the energy supplier in terms of total costs and required balancing. Table 3 shows the total day-ahead wholesale price cost and balancing energy requirements in the different strategies. It is noticeable that the differences in wholesale electricity costs for charging the whole EV fleet are not that large: in our data set, it is at most 9.2 Euros over the chosen 2-week time span. This is because the price differences between the cheapest and 2nd, 3rd, and 4th-cheapest times are not that large. We would also expect this effect to continue when there will be many more flexible loads: these will usually bid up the prices at the cheapest hours to the level of the next cheapest hours.

Concerning the required balancing energy, we find significant differences. We distinguish between a positive balancing requirement, which occurs when too much power has been procured, and a negative balancing requirement, which results from too little power procurement. Negative balancing occurs when the charge requirements of EVs cannot be fulfilled due to previous curtailment or due to the realization of a different load scenario, and power has to be procured at the balancing market as a last resort.

The naive implementation of an interruptible connection that ignores the possibility of being curtailed leads to large balancing requirements when curtailment occurs. The anticipating implementation reduces the required curtailment and never leads to harmful imbalances in our simulation. This could be improved even further if the network operator would update the energy suppliers with more information about expected congestion, such that they could improve their purchasing decisions. Day ahead variable capacity limitations and static capacity subscriptions incur much lower balancing requirements. The reason for this is, that in these cases the only source of uncertainty on the day-ahead is the inflexible load of customers, which determines how much capacity is available for the EV charging.

Note: With current cost assumptions, none of the strategies incur unsatisfied EV demand. We can push the model towards that situation when we set the cost of unsatisfied EV demand close to the balancing cost. In reality, balancing prices vary over time, and when they are very high the model would choose to leave EV demand unsatisfied instead.

Lastly, we discuss the impacts of the different strategies on the capacity that users have available for charging their EVs. Fig. 6 shows the distribution of available capacities over all simulated time steps separated by user types.[18] Note that the violin plot appears to be a continuous distribution, even though the underlying data is discrete.[19]

In the static capacity subscription, the available capacity for EVs is given by the subscribed capacity minus whatever inflexible loads the user uses. Thus, the distribution spreads across the range of possible capacities from 0 to the subscribed capacity of the respective EVs. We assume that heavy users tend to sign up for higher subscribed capacities, so the maximal available capacities tend to get bigger for heavier users. In the day-ahead variable subscription, the distribution mirrors our input assumptions. As explained above Eq. (11), users sign up for a variable subscription of 11.5 kW here. Thus, most of the time

[18] We consider only time steps where the vehicle is parked at home and available for charging for these calculations.

[19] E.g., in the interruptible connection, the upper value is always fixed to the full charging capacity of 11 kW, even though it appears from the plot as though there are capacities just below 11 kW, which is not true. This is a shortcoming of this type of plot, but we nevertheless found it more intuitive to grasp than other types of plots.

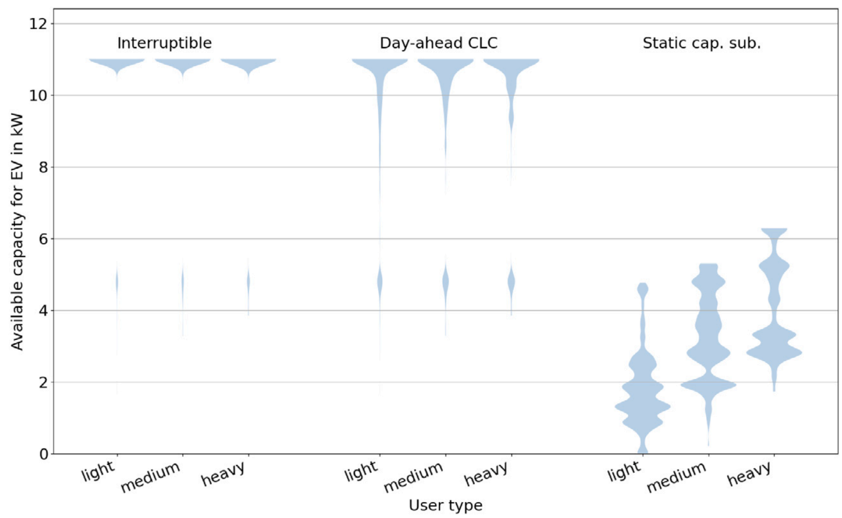

Fig. 6. Available capacity for EVs with different congestion management methods.

they have almost the full technical capacity of 11 kW available for charging. The times when capacity is limited on the day ahead are visible as a smaller cluster around 5 kW, the available capacity when limitations are announced. In the interruptible connection proposal, the limitation occurs more rarely than the day-ahead limitation. This is because the network operator can wait and see until near real-time to observe whether congestion is actually happening, while the day-ahead activations are based purely on anticipation and therefore have to occur more frequently.

5. Discussion

As shown in Section 4, each of the presented congestion management mechanisms can reliably resolve congestion. However, they each come with particular benefits and drawbacks. In this section, we discuss the performance of the mechanisms based on both qualitative evaluation and our case study results.

5.1. BNA proposal and interruptible connections in general

The main strength of interruptible connections is that it does not restrict network access when there is no congestion, as can also be seen from Fig. 6. This means that users of flexible loads can use the full technical capacities of their devices most of the time and consequently use low wholesale prices (Table 3), as well as charge EVs or heat their homes with heat pumps quickly when desired. This allows for efficient network loading during these times.

However, users run the risk of being curtailed in near real-time. Our case study shows this leads to higher balancing costs in this approach (Table 3). This may result in risks for aggregators who manage multiple connections: a near real-time curtailment may lead to an energy imbalance in their portfolio. If they cannot spread this energy imbalance over other flexible loads, they are liable for the resulting imbalance costs and re-procurement of electricity (see Section 3.1). This typically leads to balancing costs, and the electricity that could not be delivered needs to be re-procured at market prices. This also suggests that this proposal may not be viable for individual critical loads such as large industrial consumers for whom an unforeseen outage of equipment due to reduced capacity would incur prohibitively high losses in production lines.

Furthermore, interruptible connections may be better suited for situations with low frequency and congestion depth, where curtailment remains an exception. When congestion occurs very frequently and at high levels, the activation of curtailment may become so frequent that a strategy with more security (like static capacity subscriptions) may become preferable.

Another drawback of this mechanism is that in its current form, it is not cost-reflective, as the tariff reduction does not depend on usage. For example, a user with a heat pump with a technical capacity of 4 kW who rarely uses this total technical capacity and is rarely curtailed receives the same lump-sum rebate as a user with an 11 kW EV charger in a congested area who may be curtailed often. Furthermore, the mechanism is somewhat discriminating: users in congested areas are curtailed more often than those in non-congested areas, even though they get the same rebate. However, this is a general feature of dynamic congestion management mechanisms, as network congestion is spread unevenly throughout the network (Hennig et al., 2020). Lastly, implementing this mechanism requires the installation of load-limiting devices that the network operator can control, a cost factor that we did not consider in our case study.

5.2. ACM proposal and day-ahead variable capacity in general

In principle, a limitation of variable capacity announced before the day-ahead market closes could efficiently resolve congestion. It does not limit network capacity when congestion can be ruled out with certainty. Also, it gives users (or aggregators) more planning certainty for scheduling flexible loads, as they can include the network capacity constraint in their trading decisions on the day-ahead and intraday markets. Moreover, regarding cost-reflectiveness, this class of proposals is a step ahead of the BNA proposal: users pay (or get a rebate, depending on the mechanism design) explicitly based on how much of their capacity is variable.

Our simulation results show that the day-ahead announcement significantly reduced the balancing requirements for the energy-supplying party Table 3. Moreover, the required restriction of network capacity is far below that of the static capacity subscription (Fig. 6). However, at the same time, the restriction is also significantly more frequent than in interruptible connections. This is also reflected in slightly higher charging costs for EVs (Table 3). These costs affect heavy EV users more than light EV users, for whom even the reduced capacity is still sufficient to mostly charge their EV at the lowest wholesale prices (Fig. 4).

It is also important to note that this mechanism still requires a fallback option like redispatch or curtailing connections when unforeseen congestion occurs, which we did not explicitly model here. If congestion occurs that was not anticipated on the day ahead, e.g., due to wrong estimations by the network operator or exploitation of spreads on the intraday market by aggregators and other large customers, it is the network operator's responsibility to become active and remove this congestion, e.g., through re-dispatch markets.[20] This may pose a risk, as re-dispatch markets can be costly and are known to be vulnerable to strategic behavior (inc-dec gaming), as market participants may artificially create problems to be paid by the network operator to remove them again (Hirth et al., 2019; Hennig et al., 2022b). In the residential sector, an alternative to market-based redispatch could be the curtailment of connections like in the BNA proposal as a fallback.

Depending on the fallback mechanism, risks are distributed differently: redispatch places a financial risk on the network operator and may not be suitable for LV feeders due to strategic behavior. Furthermore, because of the added costs in case the network operator underestimates congestion, they may tend to overestimate it to protect against these costs. This would reduce the mechanism's efficiency as the capacity limitation would become activated more frequently, even when unnecessary. On the other hand, curtailing connections again leads to a residual risk of curtailment for users (albeit likely lower than in a mechanism based solely on interruptible connections). Curtailment may thus not be suitable for many industrial customers.

Lastly, the current ACM proposal envisions selling capacity limitations on a market where customers bid for the lowest required price per kW reduction to contracted capacity. This may work well in a liquid market with a large pool of bidders where strategic behavior and collusion can be ruled out. However, it might not work well for small feeders, where a single aggregator could control a large part of the flexible loads and charge exaggerated prices.

5.3. Static capacity subscription

The most significant benefit of the static capacity subscription is the (near-)absolute planning certainty, as it guarantees the available capacity long-term. After the finalization of the contracts, users know exactly how much capacity they have for the contract phase (notwithstanding unforeseen power outages). This also means that this mechanism requires no additional tasks from the network operator, in contrast to the other two approaches (see Fig. 1).[21] Moreover, this mechanism performs well regarding cost-reflectiveness (Hennig et al., 2022a), and it lets users decide their capacity level considering their utility, e.g., from high-capacity EV charging, rather than an externally imposed restriction like in the BNA proposal. Lastly, further benefits are that this mechanism introduces no spatial discrimination based on congestion and is relatively simple, without the need to communicate available capacity or install load-limiting devices.

The main problem with this mechanism is that it restricts users to their subscribed capacity, even though their devices can draw much more power. For example, EV chargers are often available at 11 or 22 kW and heat pump power consumption is similarly in the order of 1 – 10 kW (Georges et al., 2017). Thus, users of these devices can either spend more money on procuring a higher capacity (or paying the higher charge for exceeding capacity) or use their devices more often at a power consumption rate much lower than what would be technically possible.

As our results indicate (Table 3), the impact may be small regarding the costs required to charge a typical daily demand of most EV users, as most users do not require large amounts of energy on most nights. However, the user discomfort may be relatively high, as it may be frustrating to have only the low subscribed capacity available for their devices (at low per kWh-prices) when the technical capacity of these devices is much higher, see also Fig. 6. This becomes important when users require a higher capacity, e.g., to charge a vehicle quickly or heat a home faster.

5.4. Limitations of the case study

Due to resource and data availability constraints, our case study provides only a limited proof-of-concept of the proposed mechanisms rather than a real network simulation. The most consequential limitations are:

- The neighborhood is small, with only 50 households and up to 25 EVs.
- We did not consider distributed generation (DG) like solar PV panels, which brings additional uncertainty for inflexible loads and may sometimes be used to reduce load at the network connection point to below the capacity limitation required by the mechanism.
- We considered only smart charging, not vehicle-to-grid/vehicle-to-home or the operation of batteries, which can further aid in respecting the required capacity limitations.
- We neglected power flow constraints and only modeled a single network constraint at the LV transformer, ignoring reactive power and voltage concerns.
- We assumed all flexible loads in the area are managed by the same supplier. In reality, multiple suppliers will be active in a given region and compete with each other.
- We also assume the supplier is only active in a single neighborhood. In reality, they will be active in multiple neighborhoods. This could make it easier to avoid balancing costs by shifting energy flows from congested to non-congested areas.
- We use a 60-min time step in our modeling. On the day-ahead market, it is already possible to trade in 15-min time steps. Therefore, overloads may occur at this resolution.[22] Therefore, in an improved simulation or implementation in reality, the settlement time step for the capacity limitation should perhaps align with the smallest trading time steps of the electricity market in a given location.

However, we believe the main conclusions drawn in the preceding chapters are valid, as they are based on the general properties of the proposed mechanisms not affected by any of these limitations.

6. Conclusion and policy implications

We investigated network congestion management mechanisms based on network capacity limitations for flexible loads, currently discussed in the Netherlands and Germany. The mechanisms we have analyzed can be sorted by the lead time at which reductions of available

[20] In the Netherlands, for example, the GOPACS platform is intended to be used for this purpose.

[21] However, this only holds if sufficiently many customers are induced to stay below the subscribed capacity, as otherwise, a violation of network bounds may still occur. In this respect, one potential shortcoming of the mechanism is that it triggers no additional demand response once the load exceeds the subscribed level. Customers are not incentivized to spread out an exceedance of the subscribed level over multiple timesteps rather than having it all in a single time step. This may be resolved already by the relatively low likelihood of many customers coincidentally exceeding their subscribed load at high levels. Still additionally, it should be ensured that all customers have automated management of their flexible device, which prevents exceedance of subscribed load as much as possible. Furthermore, the cost of exceedance could also be designed in an escalating way, such that exceeding the subscribed level by higher margins becomes more expensive Li et al. (2023).

[22] If the price spread of several 15-min time steps within the same hour is large enough on the intraday market, it would make sense for an energy supplier to buy a lot of power in one-time step and very little or none in another, such that their average load over the whole hour is below the subscribed capacity for their users, but that at 15-min level overloads occur which may damage the network infrastructure.

network capacity are announced: near real-time interruptible connections, day-ahead variable capacity limitation contracts, or long-term static capacity subscriptions.

In principle, all these solutions can help resolve network congestion, but each proposal has some drawbacks in its current form. The interruptible connection of the BNA proposal allows users to make full use of their capacity when there is no congestion but can introduce unexpected balancing requirements. The day-ahead capacity limitation removes congestion efficiently and with planning certainty when it is anticipated correctly by the network operator. However, if the congestion forecast is wrong, it can lead to excessive restrictions or a need for an emergency fallback mechanism. Long-term capacity subscription provides complete planning certainty but always restricts users to the subscribed capacity, even when network conditions do not require this. In the following paragraphs, we advise on possible improvements based on our analysis.

The BNA proposal and interruptible connections in general

The cost-reflectiveness of this proposal can be improved. As discussed in Section 2.1, currently, a network tariff reduction is given to any user with a device with a power capacity higher than 4.2 kW, independent of the usage of this device and of whether there is congestion in the area (in case of multiple devices for the same user, the network operator has to decide on whether the mechanism is applied on a per-device basis or for the connection as a whole with a higher minimum capacity). In line with tariff-setting regulatory principles and previous research (Hennig et al., 2022a), we recommend making the proposal more cost-reflective by charging heavier users more than light users while accounting for the expected depth and duration of interruptions. This might require changes to how financial remuneration for this proposal is implemented. Rather than giving a discount for making the connection interruptible, a charge could be associated with installing a flexible device above 4.2 kW. This charge should be higher, the more capacity is desired for the device, and the fewer interruptions are tolerated. Note that this requires the network operator to be informed about all the high-power devices installed in their network. This means that there needs to be a binding obligation for users to register these devices, and possibly also a penalty for failure to do so.

Furthermore, the network operator should strive to limit unplanned interruptions as much as possible to reduce balancing requirements. As we showed in Table 3, balancing requirements can be reduced when the energy supplier anticipates possible curtailments. To aid this process, the network operator could send information on the day ahead on expected congestion, with updates during the intraday timeframe. Information on the frequency and location of curtailment events per area should be made available by the network operator.

The ACM proposal on day-ahead capacity limitation contracts

As discussed in Section 5, a potential problem is that the network operator does not anticipate congestion sufficiently and requires a fallback option when additional congestion occurs unexpectedly. To limit the requirement for this emergency fallback as much as possible, it could be helpful to require customers to send their intended schedules after the day-ahead market closes to confirm that congestion based on day-ahead schedules does not occur. In cases where customers intend to make large upward modifications of their day-ahead schedules in intraday markets, they might be required to check with the network operator whether this is still possible.[23]

Furthermore, the proposal envisions end-users to bid for reductions in network price that they require to make their capacity flexible. As dominant players like aggregators who control a large share of flexible loads on residential feeders could abuse this bidding process, making the contracts only with individual end users might be better and, additionally, to turn around the buy/sell positions: the users could pay the network operator a higher price for fixed capacity and a low price for network capacity that can be reduced. This reduces the financial risks for the network operator.

Static capacity subscription

The main problem of the capacity subscription is the permanent incentive to restrict consumption to the subscribed capacity, even when there is no congestion. Several strategies could alleviate this. Firstly, one possibility is to activate the capacity reduction incentive only when there *is* network congestion. This would require setting up additional communication channels to communicate to users when this is the case. Secondly, it could be an option to implement a two-part subscription. This is explained further under the following recommendation.

Recommended solution: two-part subscription for flexible and variable capacity

Based on our analysis, we propose a new mechanism combining the static subscription's advantages with the more dynamic solutions: a two-part capacity subscription. One part is a base capacity subscription for network capacity guaranteed to be available as in the normal capacity subscription. The part has a relatively high price per kw of subscribed capacity. In addition, customers can choose to add a variable subscription. The variable subscription is significantly cheaper per network capacity per kW. In return, the network operator can reduce it on the day ahead or close to real-time, depending on the congestion situation in the network. This approach would combine the cost-reflectiveness and planning certainty of a capacity subscription with the ability of an interruptible connection to make the best use of available capacity. Furthermore, it would avoid the potential for market power abuses when users are asked to bid for a required reduction in network prices. Customers who do sign up for a variable subscription will need to install additional control devices, as in the interruptible connection, with which the network operator can limit the available variable capacity. Due to the limited scope of this article, which was focused on investigating current proposals, we did not explicitly simulate this proposal in our case study. However, we recommend it to be studied in depth in future work.

CRediT authorship contribution statement

Roman J. Hennig: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Software, Visualization, Writing – original draft, Writing – review & editing. **Laurens J. de Vries:** Conceptualization, Funding acquisition, Project administration, Supervision, Writing – review & editing. **Simon H. Tindemans:** Funding acquisition, Project administration, Supervision, Validation, Writing – review & editing, Conceptualization.

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.

Data availability

The authors do not have permission to share data.

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[23] Note that this might give an incentive to aggregators to exaggerate their day-ahead schedules, as that gives them more flexibility to adjust upwards on the intraday. One solution could be requiring them to prove their intended schedules by showing the corresponding trade receipts of the day-ahead market. These should sum up to all of their intended local schedules.

Appendix A. Scenario generation

We use a simple auto-regressive model of the first order, i.e., an AR(1) model for generating scenarios of inflexible loads and prices for Eq. (4). The scenario generation is based on a given set of input data for inflexible loads and day-ahead prices. We assume that the day-ahead planning process is done at noon of the preceding day, as this is the gate closure time of the day-ahead market in the Netherlands. We further assume that the network operator can observe the aggregate load at the transformer level and share this information with the energy supplier to make forecasts for purchasing decisions. Though this is not always the case, we expect measuring devices at LV transformers to become more common.

Based on the last observed load time step at noon, we forecast an ensemble of scenarios centered around the supplied input data set. In the simple AR(1) model, we draw the errors for each time step independently from a Gaussian distribution centered at 0 with an inferred standard deviation based on the variability observed in the input data set:

$$\xi(t) = \phi \cdot \xi(t-1) + \epsilon(t) \tag{16}$$

where $\xi(t)$ are the errors relative to the input data set, ϕ is called the *decay parameter* and $\epsilon \sim \mathcal{N}(0, \sigma^2)$ is random white noise. We sample a number n_S of scenarios that the supplier and network operator use to solve their stochastic optimization problem. By the same process, we generate a scenario for the realized values of inflexible load in the intra-day problem Eq. (15). This guarantees that the scenarios used for planning have the same statistical properties as the finally realized scenarios and that sometimes extreme scenarios are also realized. If we simply took the given input data to be the actually realized values, this would not be true.

Appendix B. Optimization objective transformation

The first part of the optimization objective Eq. (3) involving the theta functions can be transformed as follows:

$$\begin{aligned}
&\pi^{\mathrm{DA}}(t) \cdot P^{\mathrm{pur}}(t) \\
&+ \left(\pi^{\mathrm{DA}}(t) + c^{\mathrm{Bal}}\right) \cdot \theta(P^{\mathrm{net}}(s,t)) \cdot P^{\mathrm{net}}(s,t) \\
&+ \left(\pi^{\mathrm{DA}}(t) - c^{\mathrm{Bal}}\right) \cdot \theta(-P^{\mathrm{net}}(s,t)) \cdot P^{\mathrm{net}}(s,t) \\
&= \pi^{\mathrm{DA}}(t) \cdot P^{\mathrm{pur}}(t) + \left(2 \cdot c^{\mathrm{Bal}} \cdot \theta(P^{\mathrm{net}}(s,t)) + \pi^{\mathrm{DA}}(t) - c^{\mathrm{Bal}}\right) \cdot P^{\mathrm{net}}(s,t) \\
&= \pi^{\mathrm{DA}}(t) \cdot P^{\mathrm{disp}}(s,t) + c^{\mathrm{Bal}} \cdot |P^{\mathrm{net}}(s,t)|
\end{aligned}$$

where we used $\theta(-x) = 1 - \theta(x)$ in the first equation and $2 \cdot \theta(x) - 1 = \mathrm{sign}(x)$, as well as the definition of net power, $P^{\mathrm{net}} = P^{\mathrm{disp}} - P^{\mathrm{pur}}$.

Appendix C. Absolute value variable transformation

To transform the absolute value function in the day-ahead optimization objective, Eq. (4), we express this value as the difference of its positive and negative parts:

$$P^{\mathrm{net}}(s,t) = P^{\mathrm{net},+}(s,t) - P^{\mathrm{net},-}(s,t) \tag{17}$$

Where we require both of these quantities to be non-negative:

$$P^{\mathrm{net},+}(s,t),\ P^{\mathrm{net},-}(s,t) \geq 0 \quad \forall\, s,t \tag{18}$$

The absolute value can then be expressed as the sum of these two linear parts:

$$|P^{\mathrm{net}}(s,t)| = P^{\mathrm{net},+}(s,t) + P^{\mathrm{net},-}(s,t) \tag{19}$$

Theoretically, we also require that only one of the parts in Eq. (17) can be non-zero, as the net power can be either positive or negative (or zero), but not both at the same time. In practice however, this is not necessary. The optimization objective Eq. (4) is minimal when only one of them is non-zero, otherwise we could always remove the non-zero common part to achieve a lower value. Thus, the solver will always set one of them to zero.

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