

# Day-ahead congestion management scheme for distribution networks with dynamic tariff and re-profiling products

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## Abstract

This paper proposes a day-ahead congestion management scheme for distribution networks with the dynamic tariff (DT) and re-profiling products. In the proposed scheme, the DT method is first employed to resolve congestion before the energy bidding process and the re-profiling product is used afterwards to resolve remaining congestion through the flexibility market. Moreover, the original DT model is relaxed to resolve the possible infeasible issue of the DT problem and set a maximum limit for DTs. With the combination of the DT and re-profiling product, the proposed scheme can resolve congestion more effectively while ensuring that the DTs are within an acceptable range. Two case studies were conducted with the Roy Billinton Test System (RBTS) to validate the effectiveness of the proposed scheme.

*Keywords: Congestion management, Distribution network, Dynamic tariff, Re-profiling product.*

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## 1. Introduction

Targets to increase the deployments of distributed energy resources (DERs), such as electrical vehicles (EVs) and heat pumps (HPs), present significant technical challenges to the secure operation of distribution networks. For example, congestion problem could be caused by the simultaneous power consumption of flexible demands. Among various options to deal with congestion problems within distribution networks [1]-[2], demand response (DR) has emerged as a popular approach.

In the existing literature related to the application of DR to congestion management at the distribution level, the DR programs can be categorized into two types, namely the price-based DR programs and incentive-based DR programs. In the price-based DR programs, the flexible demands respond to the changes in electricity prices in order to take advantages of lower price periods. In the dynamic tariff (DT) methods [3]-[4], the final prices (tariffs plus spot prices) at congested hours are higher than those hours without congestion due to the tariffs published by the distribution system operators (DSOs). Therefore, the aggregators, as profit-seeking utilities, will shift flexible demands to off-peak periods to minimize their energy cost and relieve congestion. In [5]-[6], the congestion was also resolved through the tariff scheme but the final tariffs are determined by the distribution grid capacity market scheme through iterative processes. In the incentive-based DR programs, customers receive incentives and change their power consumption patterns accordingly. A coupon incentive-based DR program and a monetary-incentive based DR program were proposed in [7]-[8] to optimally reschedule the flexible demands. In these two methods, the optimal incentives are determined through iterative processes. Another type of incentive-based DR programs is to build a flexibility market, in which aggregators bid flexibility products on behalf of customers and DSOs procure these products to mitigate congestion. A day-ahead flexibility market was established in [9] to trade flexibility products and two types of flexibility products, namely

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scheduled re-profiling products (SRPs) and conditional re-profiling products (CRPs), were defined in [10]. A hierarchy congestion management scheme was designed in [11], in which the DSO purchases SRPs and CRPs to mitigate congestion in the tertiary control layer.

Although the DT method is effective in congestion management, DTs may be very high or even unacceptable to customers when the severe congestion occurs. In addition, the optimization at the DSO side may be infeasible and DTs cannot be obtained, resulting in the failure of the DT method. Therefore, in order to resolve above issues, a two-step congestion management scheme is proposed. In the first step, the DT method is employed to resolve congestion and the original DT model is relaxed in order to deal with the possible infeasible issue and set a maximum limit for the DTs. Due to the relaxation of the DT model, congestion may not be completely mitigated in the first step and is further solved by the re-profiling products in the second step. With the combination of the DT and re-profiling products, the proposed two-step scheme can resolve congestion more effectively and ensure that the published DTs are within an acceptable level.

This paper is organized as follows. Section II describes the DT method, flexibility market and framework of the proposed scheme. Section III provides the mathematical models of the proposed scheme. Case studies are presented and discussed in Section 4, followed by conclusions.

## 2. Proposed Congestion Management Scheme with the Dynamic Tariff and Re-profiling Product

In this section, the procedures of using the DT method and re-profiling products to resolve day-ahead congestion are first described, followed by the illustration of the framework of the proposed scheme.

### 2.1. Dynamic tariff method

The DT method is a decentralized market-based congestion management method and is carried out before the day-ahead energy market clears. According to [3], the procedures of using DTs to solve congestion are as follows. Firstly, the DSO predicts the spot prices and obtains grid model. The DSO also obtains flexible demands data, such as consumption requirements of EVs, from the aggregators or by its own prediction. Secondly, the DSO implements an OPF model considering network constraints to obtain DTs, and sends DTs to the aggregators. Thirdly, after receiving DTs, the aggregators implement their own optimizations based on the predicted spot prices and DTs. Finally, the aggregators submit their optimal energy bids to the day-ahead energy market.

### 2.2. Re-profiling products in the flexibility market

As proposed in [9], the day-ahead flexibility market and day-ahead energy market may coexist in time and space. After the day-ahead energy market clears, the DSO first checks if the proposed energy schedules lead to congestion. If congestion exists, the DSO will purchase flexibility products, namely SRPs in the study, offered by the aggregators in the day-ahead flexibility market to solve it. The SRP means that the aggregator has the obligation to provide a specified demand modification (reduction or increase) during an assigned period. In addition, the market agent was proposed in [11] to help the DSO minimize the cost of the procurement of flexibility products and is also used in this study.

### 2.3. Framework of the proposed congestion management scheme

As mentioned previously, the DT method is carried out before the day-ahead energy market clears while re-profiling products are used after the energy schedules are formulated. Therefore, in the proposed scheme, the DT method is employed in the first step to resolve congestion followed by the procurement of re-profiling products. In the scheme, the aggregators act as mediators among the customers, DSOs and flexibility market and have two main roles: the first role is to determine energy schedules for customers according to DTs; the second role is to gather flexibilities from demand side and trade flexibility products in the day-ahead flexibility market. The framework of the proposed two-step scheme is shown in Fig. 1.

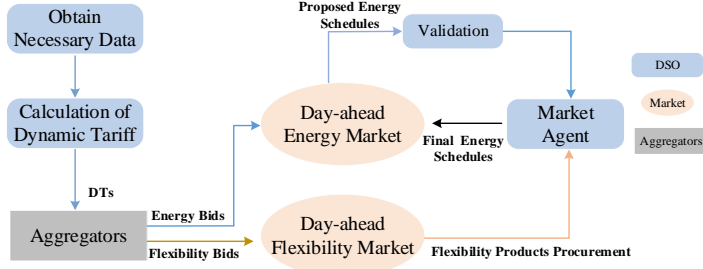


Fig. 1. The framework of the proposed two-step congestion management scheme

As shown in Fig. 1, the procedures of using the proposed scheme to resolve congestion in the day-ahead time frame are described as follows. Firstly, the DSO acquires all necessary data and calculates DTs and publishes them to the aggregators. According to DTs, the aggregators determine energy schedules for those customers who respond to DTs, and submit the energy bids to the day-ahead energy market. At the same time, the aggregators gather flexibilities from the customers who are willing to provide flexibility products, and then offer flexibility products to the day-ahead flexibility market. After the day-ahead energy market clears, the DSO validates if the proposed energy schedules result in congestion. If congestion does not exist, the day-ahead energy market and day-ahead flexibility market are closed. Otherwise, the market agent will help the DSO purchase flexibility products with the minimized cost from the flexibility market to alleviate congestion. After the flexibility market clears, the aggregators are informed about the accepted flexibility products and the final day-ahead energy schedules are determined.

### 3. Mathematical Model of the Proposed Scheme

#### 3.1. Relaxed DT model in the first step

##### 3.1.1. The relaxed DSO optimization

In order to resolve the possible infeasible and high DT issues of the original DT model, the original DSO optimization model [3] is relaxed. The objective of relaxed DSO optimization is to minimize the energy cost and penalty cost, as below.

$$\begin{aligned} \min \quad & \sum_{i \in N_B, t \in N_T} \frac{1}{2} p_{i,t}^T B_{i,t} p_{i,t} + (c_t)^T p_{i,t} \\ & + \frac{1}{2} \tilde{p}_{i,t}^T B_{i,t} \tilde{p}_{i,t} + (c_t)^T \tilde{p}_{i,t} + (w_t^l)^T \alpha_t + (w_t^v)^T \beta_t \end{aligned} \quad (1)$$

where  $N_B$  and  $N_T$  are sets of aggregators and day-ahead planning periods, respectively;  $c_t$  is the spot price in period  $t$ ;  $B_{i,t}$  is the price sensitivity matrix corresponding to aggregator  $i$  in period  $t$ ;  $p_{i,t}$  and  $\tilde{p}_{i,t}$  are power consumption of EVs and HPs of aggregator  $i$  in period  $t$ , respectively;  $\alpha_t$  and  $\beta_t$  are auxiliary variables used to relax the original DSO optimization;  $w_t^l$  and  $w_t^v$  are penalty coefficients.

The relaxed DSO optimization has the following constraints.

- Relaxed line loading constraint

$$D \left( \sum_{i \in N_B} E_i (p_{i,t} + \tilde{p}_{i,t}) + p_t^c \right) \leq f_t^{\max} + \alpha_t, \forall t \in N_T \quad (\lambda_t) \quad (2)$$

where  $D$  is the power transfer distribution factor (PTDF) of the network;  $E_i$  is the customer to load bus mapping matrix;  $p_t^c$  is the conventional active demand in period  $t$ ;  $f_t^{\max}$  is the line limit;  $\alpha_t$  is used to relax the constraint.  $\lambda_t$  is the dual variable of the constraint.

- Relaxed voltage magnitude constraint

$$V_0 \left( 1 - \frac{1}{V_0^2} (R(p_i^c + \sum_{i \in N_B} E_i(p_{i,t} + \tilde{p}_{i,t})) + Xq_i^c) \right) \geq V^{\min} - \beta_i, \forall t \in N_T \quad (\gamma_i) \quad (3)$$

The left side of constraint (3) calculates the voltage magnitude according to an approximation method proposed in [12].  $V_0$  is the voltage magnitude at the substation node;  $V^{\min}$  is the lower limit of the voltage magnitude;  $q_i^c$  is the conventional reactive demand;  $\beta_i$  is used to relax the constraint;  $R$  and  $X$  are real and imagine parts of the inverse matrix of the partial nodal admittance  $Y_{LL}$ , respectively, which is the a submatrix of the admittance matrix  $Y$ :

$$Y = \begin{bmatrix} Y_{00} & Y_{0L} \\ Y_{L0} & Y_{LL} \end{bmatrix}.$$

- State of charge (SOC) level constraint of EV

$$e_{i,t}^{\min} \leq \sum_{t_- \leq t} (p_{i,t_-} - d_{i,t_-}) + e_{i,0} \leq e_{i,t}^{\max}, \forall i \in N_B, t \in N_T \quad (\mu_{i,t}^-, \mu_{i,t}^+) \quad (4)$$

where  $e_{i,t}^{\min}$  and  $e_{i,t}^{\max}$  are the lower and upper limits of the SOC level of EV, respectively;  $e_{i,0}$  is the initial SOC level;  $d_{i,t}$  is the discharging power of EV due to driving.

- Household temperature constraint

$$K_{i,t}^{a,\min} \leq \sum_{t_- \leq t} A_{i,t,t_-} \tilde{p}_{i,t_-} + K_{i,0}^a \leq K_{i,t}^{a,\max}, \forall i \in N_B, t \in N_T \quad (\tilde{\mu}_{i,t}^-, \tilde{\mu}_{i,t}^+) \quad (5)$$

where  $A_{i,t,t_-}$  is the power to temperature matrix;  $K_{i,t}^{a,\min}$  and  $K_{i,t}^{a,\max}$  are the lower and upper limits of household temperature, respectively;  $K_{i,0}^a$  is the initial household temperature.

- Power consumption limits of EV and HP

$$p_{i,t}^{\min} \leq p_{i,t} \leq p_{i,t}^{\max}, \forall i \in N_B, t \in N_T \quad (\sigma_{i,t}^-, \sigma_{i,t}^+) \quad (6)$$

$$\tilde{p}_{i,t}^{\min} \leq \tilde{p}_{i,t} \leq \tilde{p}_{i,t}^{\max}, \forall i \in N_B, t \in N_T \quad (\tilde{\sigma}_{i,t}^-, \tilde{\sigma}_{i,t}^+) \quad (7)$$

where  $p_{i,t}^{\min}$  and  $p_{i,t}^{\max}$  are the lower and upper limits of charging power of EVs, respectively;  $\tilde{p}_{i,t}^{\min}$  and  $\tilde{p}_{i,t}^{\max}$  are the lower and upper limits of power consumption of HPs, respectively.

- Limits of the auxiliary variables

$$\begin{cases} \alpha_i \geq 0, \forall t \in N_T & (\xi_i) \\ \beta_i \geq 0, \forall t \in N_T & (\chi_i) \end{cases} \quad (8)$$

Compared with the original DSO optimization in [3], the auxiliary variables  $(\alpha_i, \beta_i)$  are introduced in (2) and (3) to relax constraints and ensure that feasible solutions can be found. After the DSO solves the relaxed DSO optimization, the derived DT, defined by  $\rho_i$ , is calculated as,

$$\rho_i = D^T \lambda_i + \frac{R^T \gamma_i}{V_0} \quad (9)$$

According to (9), the DT has two parts that are associated with constraints (2) and (3), respectively. If either of constraints (2) and (3) does not bind, the corresponding part of DT is zero.

### 3.1.2. Optimization at the aggregator side

After receiving DTs, each aggregator determines its own energy planning using the following optimization problem. For aggregator  $i$ ,

$$\begin{aligned} \min \quad & \sum_{t \in N_T} \frac{1}{2} p_{i,t}^T B_{i,t} p_{i,t} + (c_i 1 + E_i^T \rho)^T p_{i,t} \\ & + \frac{1}{2} \tilde{p}_{i,t}^T B_{i,t} \tilde{p}_{i,t} + (c_i 1 + E_i^T \rho)^T \tilde{p}_{i,t} \end{aligned} \quad (10)$$

subject to (4)-(7).

The objective of the aggregator optimization is to minimize the energy cost based on the spot prices and DTs, and the optimization subjects to constraints (4)-(7).

### 3.2. Existence of upper limit of DTs

A part of KKT conditions of the relaxed DSO optimization is,

$$w_t^l 1 - \lambda_t + \xi_t = 0 \quad (11)$$

$$w_t^v 1 - \gamma_t + \chi_t = 0 \quad (12)$$

$$\xi_t \leq 0 \perp \alpha_t \geq 0 \quad (13)$$

$$\chi_t \leq 0 \perp \beta_t \geq 0 \quad (14)$$

Combining (11), (12), (13) and (14) yields,

$$\begin{cases} \lambda_t \leq w_t^l 1 \\ \gamma_t \leq w_t^v 1 \end{cases} \quad (15)$$

Thus, the derived DTs satisfy the following inequality,

$$\rho_t \leq D^T (w_t^l 1) + \frac{R^T (w_t^v 1)}{V_0} \quad (16)$$

Equation (16) gives an upper bound to DTs. Since  $D$ ,  $R$  and  $V_0$  are given parameters associated with the network, the upper limit of DTs can be regulated by the penalty coefficients ( $w_t^l$ ,  $w_t^v$ ). Therefore, the DSO can set a maximum limit for DTs by presetting suitable penalty coefficients. Moreover, according to (15) and (16), the maximum limits for two parts of the DT can be regulated separately. If two parts of the DT are smaller than their preset maximum limits, all the elements of  $\xi_t$  and  $\chi_t$  are negative and all the elements of  $\alpha_t$  and  $\beta_t$  are zero. In such a case, the relaxed DSO optimization is the same as the original one. The detailed proof of the equivalence between the DSO side optimization and the distributed optimizations at the aggregator side can be found in [3].

### 3.3. Market agent model in the second step

After receiving a request from the DSO, the market agent helps the DSO procure SRPs with the minimized cost in the day-ahead flexibility market. It is assumed that the SRP is characterized by time of service, location (node) of service, type of service, volume of service and price. The market agent optimization model is as follows.

$$\min \sum_{t \in N_T} \sum_{i \in N_B} \sum_{g \in N_d} \sum_{f \in P_t^{(i,g)}} \pi_f^f p_f^f z_f^{pur} \quad (17)$$

subject to

$$D \left( \sum_{t \in N_T} E_i (p_{i,t}^s + \tilde{p}_{i,t}^s) + p_i^c \right) \leq f_t^{\max} \quad \forall t \in \bar{N}_T \quad (18)$$

$$z_f^{pur} \in \{0, 1\} \quad \forall f \in P_t^{(i,g)}, i \in N_B, g \in N_d, t \in \bar{N}_T \quad (19)$$

$$\sum_{f \in P_t^{(i,g)}} z_f^{pur} \leq 1, \forall i \in N_B, g \in N_d, t \in \bar{N}_t \quad (20)$$

The objective function (17) is to minimize the procurement cost of flexibility products.  $\bar{N}_t$  is the set of day-head planning periods in which SRPs are used to resolve congestion;  $N_d$  is the set of electric nodes except for the substation node;  $P_t^{(i,g)}$  is the set of offered SRPs of aggregator  $i$  at node  $g$  in period  $t$ ;  $\pi_f^f$  represents the price of  $f$ -th SRP;  $p_f^f$  represents the volume of  $f$ -th SRP;  $z_f^{pur}$  is the binary variable representing the purchasing status of  $f$ -th SRP,  $z_f^{pur}$  is one if  $f$ -th SRP is purchased; otherwise,  $z_f^{pur}$  is zero. Constraint (18) represents that the line loading limits are not violated after implementing the purchased SRPs.  $p_{i,t}^s$  and  $\tilde{p}_{i,t}^s$  are, respectively, power consumption of EVs and HPs of aggregator  $i$  at period  $t$  after implementing purchased SRPs. Constraint (19) defines the binary nature of the variable  $z_f^{pur}$ . Constraint (20) means that the number of purchased SRPs of each aggregator at each node in each period should be no more than one.

#### 4. Case Studies

Two case studies were carried out with the Roy Billinton Test System (RBTS) [13] to validate the effectiveness of the proposed scheme for congestion management of distribution networks. Fig. 2 shows the single line diagram of the Bus 4 distribution network. The study focuses on feeder 1 and line segments of feeder1 are labelled as L1-L12 and load points are labelled as LP1-LP7. The detailed data of load points and line segments can be found in [13]. Fig. 3 shows the spot prices during the day-head planning period (24 hours). Table 1 lists the key parameters of simulations [3]. It is assumed that there are two aggregators in the study, aggregator 1 has contracts with 80 customers per load point; aggregator 2 has contracts with 120 customers per load point. Moreover, 80 percent of EVs and HPs of each aggregator at each load point react to DTs, and the rest of them provide flexibility products.

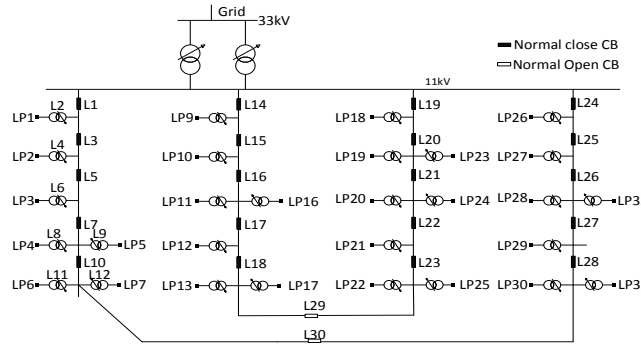


Fig. 2. Single line diagram of Bus 4 distribution network

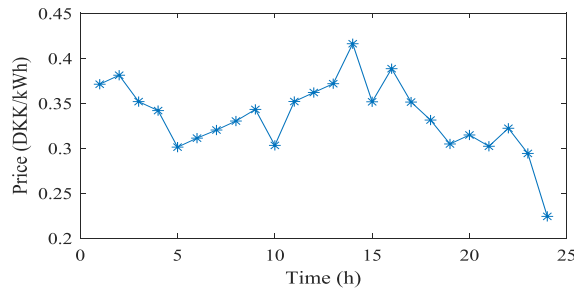


Fig. 3. Day-head spot prices

Table 1. Key parameters of simulations [3]

Parameters	Value
EV battery size	25 kWh
Peak charging power	11 kW (3 phase)
Min. /Max. SOC	20/85%
Average driving distance	40 km
COP of HP	2.3
Min. /Max. temperature of house	20/24 °C
Active power limit of L2	case1: 1350 kW case2:1350 kW
Active power limit of L3	case1: 6200 kW case2: 6020 kW
Resistance/reactance	0.26/0.027 ohm/km
Min. limit of voltage	0.948 p.u.

#### 4.1. Case studies

The effectiveness of the proposed scheme is verified in the following two cases. In case1, the congestion can be mitigated by the DT method with the original unrelaxed model, but with very high DTs. In case2, the congestion is more severe and results in the infeasibility of the unrelaxed DT model.

##### 4.1.1. Case 1

After preforming the unrelaxed DSO optimization (removing auxiliary variables from the relaxed DSO optimization) and aggregator optimization, the resulting line loadings (only critical hours are shown) of L2 and L3 are shown in Fig. 4 (a) and (b), ( $d_{ev}$  and  $d_{hp}$  are EVs and HPs that react to DTs,  $f_{loads}$  are EVs and HPs that provide flexibility products,  $c_{loads}$  are conventional active demands). It can be seen that the resulting line loadings at the aggregator side are the same as the ones at the DSO side, which demonstrates the decentralized nature of the DT method. The derive DTs are listed in Table 2, from which it can be seen that a very high DT (7.227 DKK/kWh) occurs at LP1 at “t19”. In addition, the voltage profile of the critical bus (LP7), as shown in Fig. 5, is above the minimal limit and the maximum error between the approximated voltage magnitude and accurate one is around 10%.

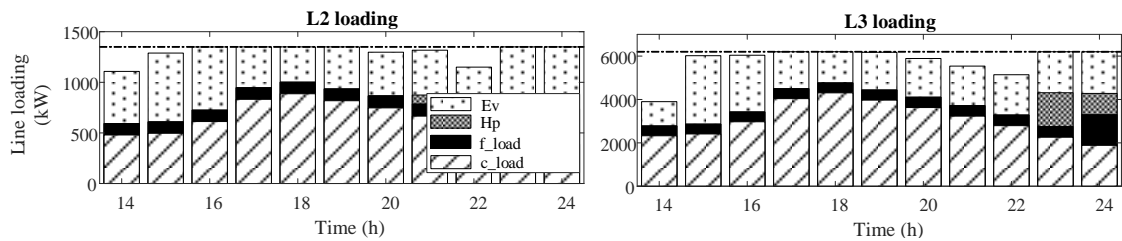


Fig. 4. (a) Line loadings of L2 and L3 at the DSO side.

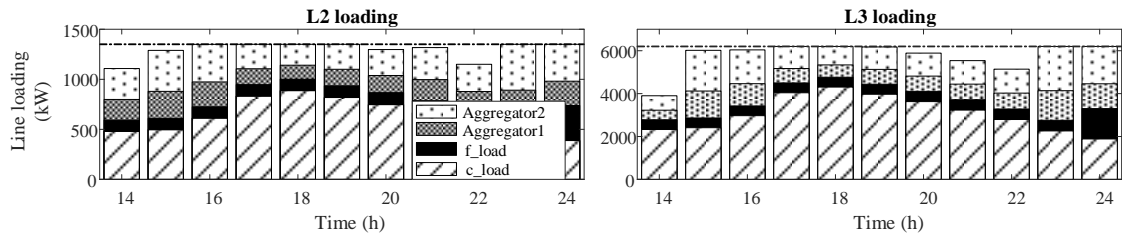


Fig. 4. (b) Line loadings of L2 and L3 at the aggregator side.

Table 2. Derived DTs in two cases

unit (DKK/kWh)		time	t5	t8	t10	t15	t16	t17	t18	t19	t21	t23	t24
case1	original DT model	LP1	-	0.002	0.034	-	-	1.304	3.002	<b>7.227</b>	-	0.008	0.078
		LP2	-	-	-	-	-	2.433	6.000	-	-	0.007	0.078
		LP3	-	-	-	-	-	2.433	6.000	-	-	0.007	0.077
		LP4	-	-	-	-	-	2.433	6.000	-	-	0.007	0.077
		LP5	-	-	-	-	-	2.433	6.000	-	-	0.007	0.077
	relaxed DT model	LP1	0.009	-	0.0138	0.139	0.450	1.203	<b>3.000</b>	<b>3.000</b>	-	0.016	0.089
		LP2	-	-	-	-	-	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
		LP3	-	-	-	-	-	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
		LP4	-	-	-	-	-	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
		LP5	-	-	-	-	-	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
case2	relaxed DT model	LP1	0.009	-	0.014	0.139	0.450	1.203	<b>3.000</b>	<b>3.000</b>	0.009	0.016	0.087
		LP2	-	-	0.013	0.121	0.450	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
		LP3	-	-	0.013	0.121	0.450	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
		LP4	-	-	0.013	0.121	0.450	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077
		LP5	-	-	0.013	0.121	0.450	1.202	<b>3.000</b>	<b>3.000</b>	-	0.007	0.077

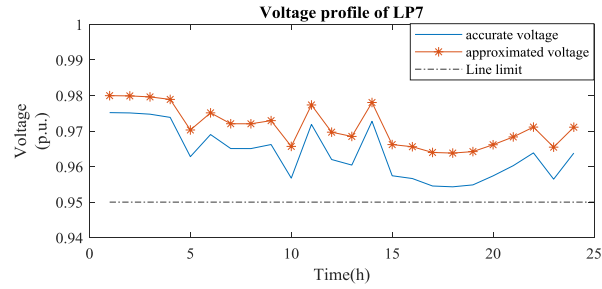


Fig. 5. Voltage profile of LP7

In order to resolve the high DT issue, the relaxed DSO optimization is implemented. As shown in Fig. 5, since voltage constraints are not violated, high DT issue is caused by the line loading constraints. According to the given matrix  $D$ , we choose  $w_l^y$  as 3 to set a maximum limit 3 DKK/kWh to DTs, and we set  $w_l^x$  as a very large number, e.g.,  $1e5$ , because there is no need to relax voltage constraints. The derived DTs are listed in Table 2, it can be seen that the maximum value of DT is 3 DKK/kWh that is restricted by the preset limit. Resulting line loadings of L2 and L3 exceed line limits, as shown in Fig. 6, and corresponding loading values exceeding line limits are listed in Table 3. In such a case, the market agent optimization is performed to purchase SRPs to resolve the remaining unsolved congestion. Take “t18” as an example, the selected SRPs and corresponding prices are highlighted in Table 4. The resulting line loadings after implementing selected SRPs are shown in Fig. 7. It can be seen that the resulting line loadings are below the line limits. The above results validate that the proposed two-step scheme can effectively solve congestion and at the same time ensure that the DTs are below a preset threshold.

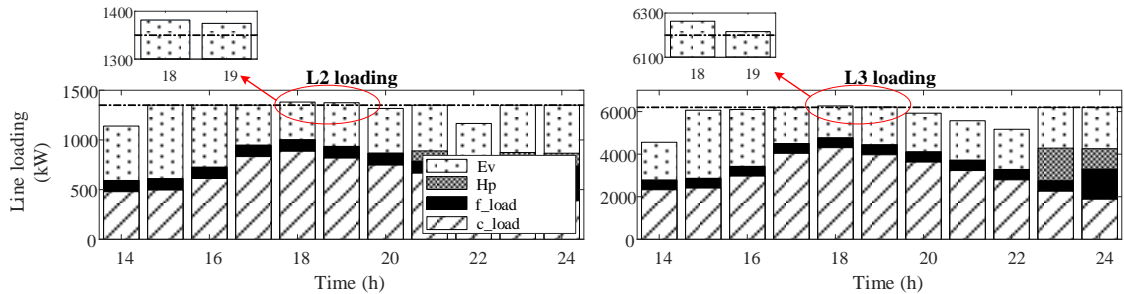


Fig. 6. Line loadings of L2 and L3 of the relaxed DT model



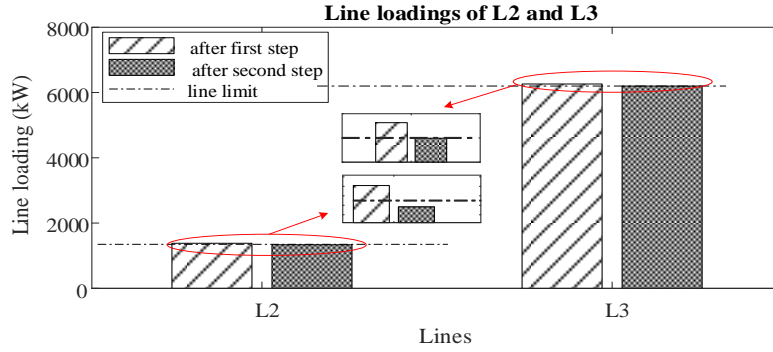


Fig. 7. Line loadings of L2 and L3 at “t18” after implementing selected SRPs

Table 3. Loading values of L2 and L3 exceeding limits

unit (kW)	lines	Loading value exceeding limit	
		t18	t19
<b>case1</b>	L2	31.64	24.66
	L3	63.14	16.18
<b>case2</b>	L2	31.64	24.66
	L3	296.26	182.97

Table 4. Offered scheduled re-profiling products at “t18”

	case1					case2				
	aggregator1		aggregator2			aggregator1		aggregator2		
	volume (kW)	price (DKK/kW)	volume (kW)	price (DKK/kW)		volume (kW)	price (DKK/kW)	volume (kW)	price (DKK/kW)	
<b>LP1</b>	<b>20</b>	<b>0.44</b>	<b>25</b>	<b>0.46</b>		<b>20</b>	<b>0.44</b>	<b>25</b>	<b>0.46</b>	
<b>LP2</b>	<b>12</b>	<b>0.35</b>	<b>18</b>	<b>0.38</b>		<b>12</b>	<b>0.35</b>	<b>18</b>	<b>0.38</b>	
<b>LP3</b>	<b>16</b>	<b>0.38</b>	<b>20</b>	<b>0.43</b>		<b>16</b>	<b>0.38</b>	<b>20</b>	<b>0.43</b>	
<b>LP4</b>	<b>15</b>	<b>0.37</b>	<b>18</b>	<b>0.40</b>		<b>15</b>	<b>0.37</b>	<b>18</b>	<b>0.40</b>	
<b>LP5</b>	<b>20</b>	<b>0.45</b>	<b>20</b>	<b>0.44</b>		<b>20</b>	<b>0.45</b>	<b>20</b>	<b>0.44</b>	

#### 4.1.2. Case 2

In this case, more severe congestion occurs and the unrelaxed DSO optimization is infeasible. However, the relaxed DT model in the proposed scheme ensures that feasible solutions can be found and the DT and re-profiling products are combined to resolve congestion.

In this case, we choose  $w_i^v$  and  $w_i^p$  as 3 and 55, respectively, in order to set a maximum limit 4 DKK/kWh to DTs. After solving the relaxed DSO optimization, the DTs are listed in Table 2 and the voltage profile of the critical bus (LP7) is shown in Fig. 8. It can be seen that the maximum value of DTs is 3 DKK/kWh because the voltage constraints are not violated and DTs are restricted by  $D^T(w_i^v, 1)$  only. As observed in Fig. 9, there is remaining unsolved congestion in L2 and L3 at “t18” and “t19”, and loading values exceeding limits are listed in Table 3. In such a case, the DSO purchases re-profiling products to solve congestion. The selected SRPs and corresponding prices are highlighted in Table 4 and the final line loadings of L2 and L3 are shown in Fig. 10. Although the congestion in L3 cannot be completely solved due to the limited volume of SRPs, the proposed scheme can deal with the possible infeasible issue and utilize DTs and re-profiling products to solve as much congestion as possible.

Moreover, the direct congestion management methods, e.g., network reconfiguration, can also be integrated in the proposed scheme to act as an option to further solve congestion. For example, as shown Fig. 2, the DSO may close the tie-switch on L30 and open the sectionalizing switch on L10 to transfer loads of LP6 and LP7 to feeder 4 to mitigate the remaining congestion in L3. How to combine the direct congestion management methods with the proposed scheme in an optimal manner will be studied in our future work.

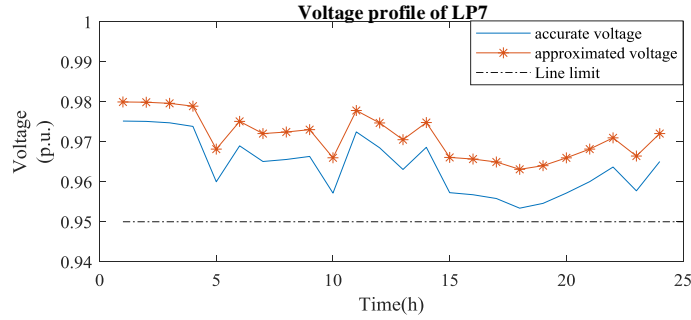


Fig. 8. Voltage profile of critical bus LP7

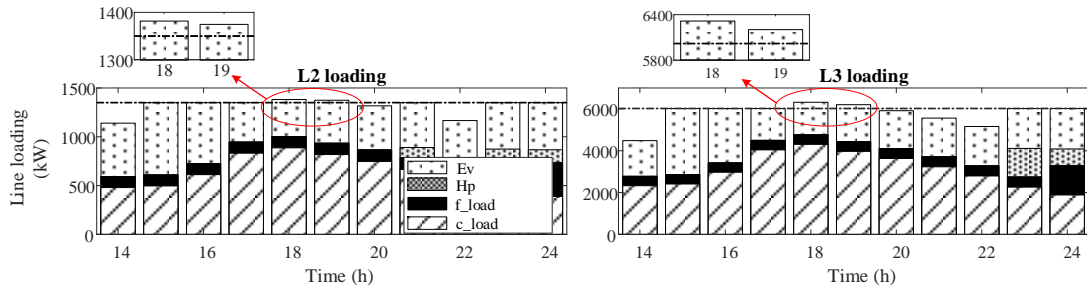


Fig. 9. Resulting line loadings of L2 and L3 of the relaxed DSO optimization in Case 2

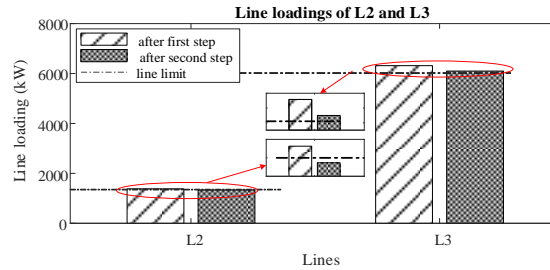


Fig. 10. Line loadings of L2 and L3 at “t18” after implementing selected SRPs

## 5. Conclusions

This paper proposes a day-ahead congestion management scheme for distribution networks with DTs and re-profiling products. In the proposed scheme, the DT method is employed in the first step to mitigate congestion and the re-profiling product is used in the second step to resolve remaining congestion. In particular, the original DT model is relaxed in order to deal with the possible infeasibility of the DT problem and set a maximum limit for DTs. The simulation results in case 1 demonstrate that the proposed scheme can resolve congestion effectively and at the same time maintain DTs within an acceptable range. However, the original DT method requires very high DTs to resolve congestion. In case 2, the original DT method fails to resolve congestion while the proposed scheme can resolve as much as congestion as possible with acceptable DTs. Although the congestion is not completely mitigated by the proposed scheme, the direct congestion methods, such as network reconfiguration and load shedding, can be used by the DSOs to resolve remaining congestion and avoid negative effects on the network. In a summary, the proposed scheme can resolve congestion more effectively and ensure that the published DTs are below a preset threshold.

## Conflict of Interest

The authors declare no conflict of interest.

## Author Contributions

The authors contribute equally to the work in this paper. All authors had approved the final version.

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