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Incorporating flexibility requirements into distribution system expansion planning studies based on regulatory policies

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ABSTRACT

Increasing penetration of renewable energy sources with intermittent generation calls for further flexibility requirements for efficient as well as the safe operation of power systems. Considering the significant growth of distributed energy resources in distribution systems, a promising approach to fulfill such requirements is to deploy local flexibility sources at the distribution level. Nonetheless, due to the monopoly nature of electricity distribution business, effective regulations are required to direct distribution companies toward fulfilling such goals. Accordingly, this paper aims at proposing various policies to motivate distribution companies to enhance the flexibility of their networks. In order to assess the effectiveness of these rules, we present a novel multi-stage distribution expansion planning model considering flexibility requirements. In this model, installation of conventional dispatchable distributed generation units and battery energy storage systems, as well as demand response programs, are considered available flexibility sources for distribution system planners. The proposed framework is applied to a test distribution network with 18 nodes, and the obtained results are thoroughly discussed. Finally, a sensitivity analysis is conducted to assess the effects of the key parameters of the proposed model on expansion planning of the test system.

1. Introduction

Financial regulatory incentives alongside decreasing investment cost in recent years have accelerated integration of renewable energy sources (RES) in power systems. Although high penetration of RES brings some environmental and economic benefits, it may raise new challenges for the power grid operation [1,2]. Intermittent and uncertain power generation of RES, can make the balance of demand and supply harder to achieve [3,4]. As a result, the grid operators must decrease the output power of dispatchable units when RES power generation is high and vice versa. For instance, in a system with high integration of solar units, renewable generation increases dramatically during midday. Thus, the system net load, i.e., the demand supplied by conventional generation units, is pulled down, whereas later on the day, as the solar generation decreases, the system net load ramps up significantly [5]. Studies conducted by the California ISO revealed that as a result of high RES integration, by 2020, the system operator must be able to ramp up the system generation 13,000 MW, all within approximately 3 hours [6]. Such steep ramps featured in the net load of a system with high RES penetration makes it difficult to ensure demand and supply balance. Thus, attempting to smoothen ramps of the system net load, power system operators may resort to curtail RES generation frequently [7]. Although RES power curtailment may help the operators to maintain the balance between demand and supply efficiently, substantial amounts of curtailment decrease project revenues and profitability of RES projects, which, in turn, make achieving RES integration goals unlikely [8]. In order to settle these challenges, energy systems with a higher level of flexibility, i.e., the ability of power systems to efficiently respond to the fluctuations of supply and demand without deteriorating system reliability, are required [9–11].

Accordingly, several studies have been conducted on the flexibility of power systems, the majority of which have been focused on the flexibility of bulk power systems. In [12], the authors provide a systematic method to evaluate the flexibility level in generation planning and market operation. They concluded that market design could be a nontechnical source of flexibility since it reduces the need for investments in additional technical sources of flexibility such as agile generating units and energy storage units. Derived from traditional generation adequacy metrics, a novel metric is proposed in [13] to measure the power system flexibility for purposes of long-term planning studies.

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Nomenclature

Indices

a Index for feeder sections.
d Index for representative days of a year.
e Index for substation expansion options.
h Index for hours of a day.
i Index for conductor types of feeder sections.
l, n, se, ss Indices for nodes.
kb Index for BESS types.
kg Index for dispatchable DG unit types.
ng Index for number of candidate DG units.
t, τ Indices for planning stages.

Sets

$\Omega^{AF}, \Omega^{FF}, \Omega^{RF}$ Sets of addable, fixed, and replaceable feeder sections.
Ω^{B} Set of candidate nodes for installing BESS ($\Omega^{B} \subset \Omega^{L}$).
Ω^{D} Set of representative days of a year.
Ω^{E} Set of substation expansion options.
Ω^{F} Set of all feeder sections ($\Omega^{AF} \cup \Omega^{FF} \cup \Omega^{RF}$).
Ω^{G} Set of candidate nodes for installation of dispatchable DG units ($\Omega^{G} \subset \Omega^{L}$).
Ω^{H} Set of hours of a day.
Ω^{I} Set of conductor types of feeder sections.
Ω^{KB} Set of BESS types.
Ω^{KG} Set of dispatchable DG unit types.
Ω^{L} Set of load nodes ($\Omega^{L} \subset \Omega^{N}$).
Ω^{N} Set of distribution system nodes.
Ω_l^{NG} Set of the number of candidate dispatchable DG units connected to node l.
Ω^{RES} Set of nodes to which renewable DG units are connected ($\Omega^{RES} \subset \Omega^{L}$).
Ω^{S} Set of substation nodes ($\Omega^{S} \subset \Omega^{N}$).
Ω^{SE} Set of candidate nodes for substation construction ($\Omega^{SE} \subset \Omega^{S}$).
Ω^{T} Set of planning stages.

Parameters

α Positive coefficient to calculate price of the electricity power produced by dispatchable DG units.
β_l Cost of deviating power consumption pattern of customer l per unit of energy.
$\acute{\delta}_{n,t}^{G}$ Fictitious demand of DG nodes.
$\eta^{\mathrm{CH}}, \eta^{\mathrm{DCH}}$ BESS charging and discharging efficiencies.
$c_{n,a}$ Incidence matrix element for node n and feeder section a.
D Duration of each planning stage in years.
$\bar{dd}_l$ Amount of elastic load at node l.
$f_{max,i}^{F}$ Current limits of feeder sections.
FC_{kg}^{G}, MC_{kg}^{G} Fuel and maintenance costs for conventional dispatchable DG unit of type kg.
G_{kg}^{G} Generation capacity of dispatchable DG units of type kg.
$G_{l,t,d,h}^{RES}$ Generation of renewable DGs at node l.
$I_{a,i}^{AF}, I_{a,i}^{RF}, I_{kg}^{G}, I_{ss,e}^{S}$ Investment cost of addable feeder sections, replaceable feeder sections, dispatchable DG units, and substations.
$\bar{lc}^{h}, \bar{lc}^{d}$ Upper bounds for hourly and daily system net load variations.
M Sufficiently large number.
$\bar{NB}_l, \bar{NG}_l$ Maximum number of BESS and dispatchable DG units, which can be connected to node l.
$O_{a,i}^{F}$ Operating cost of conductor type i for feeder section a.
p, q Threshold of the first and second steps for the 3-step flexibility cost function.
$\bar{p}_{kb}^{CH}, \bar{p}_{kb}^{DCH}$ Maximum allowable charging or discharging power for BESS of type kb.
r Annual interest rate.
$RC_{d,h}$ Power system ramping cost.
$RP_{d,h}$ Electricity retail price.
$s_{max,ss}$ Initial capacity of existing substations.
$SC_{ss,e}$ Added capacity to substations.
$\bar{soc}_{kb}, \underline{soc}_{kb}$ Maximum and minumum SOC for type kb BESS.
$V^{min}, \bar{V}^{max}$ Lower and upper voltage magnitude limits.
$Z_{a,i}$ Impedance of conductors.

Binary variables

$\theta_{l,kb,t,d,h}^{CH}, \theta_{l,kb,t,d,h}^{DCH}$ Charge and discharge binary indicators.
$an_{l,t}$ Binary variable, which is 1 if load node l is in-service at stage t, being 0 otherwise.
$x_{l,kb,t}^{B}$ Investment variable for installation of BESS.
$x_{a,i,t}^{RF}$ Investment variable for reinforcing replaceable feeder sections.
$x_{a,i,t}^{AF}$ Investment variable for construction of addable feeder sections.
$x_{l,kg,ng,t}^{G}$ Investment variable for installation of dispatchable DG units.
$x_{ss,e,t}^{S}$ Investment variable for construction or expansion of substations.
$y_{a,i,t}^{F}$ Utilization variable for feeder sections.
$y_{l,kg,ng,t}^{G}$ Utilization variable for installed dispatchable DG units.

Continuous variables

$\acute{\delta}_{n,t}^{F}$ Fictitious current flow of feeder sections.
$\acute{\delta}_{n,t}^{S}$ Fictitious current supplied by substations.
$av^{(.)}, pos, av^{(.)}, neg$ Non-negative auxiliary variables for modeling the 3-step flexibility cost function.
C Present value of the total cost.
$C_t^{inv.}$ Total investment cost at stage t.
$C_t^{oper.}$ Total operating cost at stage t.
$cur_{l,t,d,h}^{RES}$ RES curtailed power at node l.
$dd_{l,t,d,h}$ Deviation of power consumption of consumers at node l from their preferred pattern.
$f_{a,t,d,h}^{F}$ Current flow of feeder sections.
FLC_t Flexibility-oriented cost at stage t.
$g_{l,kg,t,d,h}^{G}$ Generation of dispatchable DG units.
$lc_{t,d,h}$ Hourly ramp of the system net load.
$lc_{t,d,h}^{abs}$ Absolute value of the system net load ramp.
$lc_{t,d,h}^{pos}, lc_{t,d,h}^{neg}$ Positive and negative parts of the system net load ramp.
$lc_{t,d,h}^{SS,pos}, lc_{t,d,h}^{SS,neg}$ Positive and negative parts of the second step of the system net load ramp in the 3-step flexibility cost function.
$lc_{t,d,h}^{TS,pos}, lc_{t,d,h}^{TS,neg}$ Positive and negative parts of the third step of the system net load ramp in the 3-step flexibility cost function.
$p_{l,kb,t,d,h}^{CH}, p_{l,kb,t,d,h}^{DCH}$ Charging and discharging power of BESS.
$s_{ss,t,d,h}$ Injected power of the substation ss.
$soc_{l,kb,t,d,h}$ SOC for type kb BESS at node l.
$v_{n,t,d,h}$ Magnitude of nodal voltage.

The flexibility of power systems considering limitations of transmission networks is assessed in [14], where a nonlinear relationship is found between the installed renewable generation and the system flexibility. Furthermore, several interventions are compared in [8] to increase the power system flexibility.

Although there are many research studies on the flexibility of bulk power systems, consideration of the flexibility metrics in distribution network studies has attracted less attention. Yet, increasing penetration of intermittent RES together with recent variations in electricity consumption patterns, caused by electrification of transportation, electricity storage integration, home automation, and progresses in information communication technologies, have affected distribution systems. As they are likely to increase more, investing in the local sources of flexibility close to electricity demand becomes inevitable [9]. Moreover, being regarded as essential components of the future power systems, microgrids call for providing more local sources of flexibility at the electricity distribution level [5]. This is essential since, in the islanded mode, microgrids must be capable of balancing their overall demand and generation.

Hence, distribution companies (Discos) must consider investing in local sources of flexibility, e.g., energy storage systems (ESSs), demand-side management, and dispatchable distributed generations (DGs) in their expansion planning studies. Accordingly, the ultimate goal of such planning studies is meeting the growing demand over the planning horizon while providing sufficient flexibility in anticipation of increasing RES generation. Therefore, the planning model should provide an optimal investment plan considering the flexibility requirements of the system.

However, since flexibility enhancement imposes extra costs on Discos, they are not willing to invest in the local sources of flexibility by themselves [5]. Thus, in order to direct Discos to consider the flexibility in their expansion planning and establish sufficient the local sources of flexibility, power system regulators should provide an appropriate framework to make it profitable for Discos to invest in different sources of the flexibility [9].

Given the aforementioned remarks, this paper proposes several novel regulatory policies and evaluates distribution system net load variations as a principal aspect of the flexibility to investigate the effectiveness of the presented policies. In other words, this paper aims at considering a wide range of policies to be imposed on Discos and examining the consequences of each policy on expansion planning of distribution systems and the associated flexibility criteria. The proposed policies are categorized into two groups, namely cost-based rules and policies based on limiting the allowable system net load ramp rates. Afterwards, the proposed policies are incorporated into the expansion planning model of distribution networks to evaluate their effectiveness.

In this respect, a new method is presented for distribution system expansion planning (DSEP) considering the flexibility at the distribution level. The proposed DSEP model is presented in a mixed-integer linear programming (MILP) form and takes into account providing sufficient local sources of the flexibility together with deployment of passive network elements to meet both the growing demand and the increasing RES penetration. In our study, the local sources of flexibility by which Discos can reduce the system net load variations are conventional dispatchable DG units, ESSs, demand-side response programs, and RES generation curtailment. However, the first two can be utilized by the distribution network operator only after the corresponding investment has been made.

The rest of this paper is organized as follows. DSEP problem considering distribution system flexibility is formulated in Section 2. In Section 3, various policies for motivating Discos to provide sufficient flexibility requirements have been proposed and formulated so as to be incorporated into the DSEP model. Section 4 investigates the applicability of the proposed policies by implementing the model on a test distribution network, and Section 5 concludes the paper.

2. Distribution system expansion planning model

The objective of the electricity DSEP problem is to minimize the total investment and operating cost of the network subject to various technical constraints such as equipment capacity limits, nodal voltage limits, demand and supply balance, and radial configuration of the network during its operation [15]. Conventionally, distribution system planners determine the installation time, capacity, and location of new distribution equipment in such a way that minimizes total expansion cost over the planning horizon while ensuring the quality of energy delivery [16].

In the proposed model, it is assumed that the Disco also considers the network flexibility owing to the regulatory policies. Hence, we aim to recast the multi-stage DSEP problem in a new way that the flexibility requirements could also be taken into account. In this regard, it is assumed that the system planners are capable of installing conventional dispatchable DG units and ESSs as candidate options for enhancing the system flexibility. Demand response programs and RES generation curtailment are other local sources of the flexibility, which are considered in this paper. Moreover, in order to capture effects of the various flexibility sources as well as intermittent power generation of RES on the distribution system net load, an hourly load flow is incorporated into the model.

Batteries are one of the most widely used ESSs in power networks due to their various benefits, such as peak load shaving, power quality improvement, load control, system balancing, and congestion management. Moreover, since they can be installed in small scales and have a fast-acting response, they can be leveraged as the local sources of flexibility at the distribution level. In this regard, investing in battery energy storage systems (BESS) is considered the alternative option for increasing the network flexibility in our study.

2.1. Objective function

As previously mentioned, the main goal of the optimal planning problem is to minimize the present value of the total network expansion cost. Therefore, the objective function is formulated as follows:

$$C = \sum_{t\in\Omega^T}\left(\frac{1}{(1+r)^{(t-1)D}}C_t^{inv.}\right) + \sum_{t\in\Omega^T}\left(\frac{(1+r)^D-1}{r(1+r)^D(1+r)^{(t-1)D}}C_t^{oper.}\right) \tag{1}$$

$$\begin{aligned} C_t^{inv}= &\sum_{a\in\Omega^{RF}}\sum_{i\in\Omega^I} I_{a,i}^{RF}x_{a,i,t}^{RF} + \sum_{a\in\Omega^{AF}}\sum_{i\in\Omega^I} I_{a,i}^{AF}x_{a,i,t}^{AF} \\ &+ \sum_{ss\in\Omega^S}\sum_{e\in\Omega^E} I_{ss,e}^{S}x_{ss,e,t}^{S} + \sum_{l\in\Omega^B}\sum_{kb\in\Omega^{KB}} I_{kb}^{B}x_{l,kb,t}^{B} \\ &+ \sum_{l\in\Omega^G}\sum_{kg\in\Omega^{KG}}\sum_{ng\in\Omega_l^{NG}} I_{kg}^{G}x_{l,kg,ng,t}^{G} \end{aligned} \tag{2}$$

$$\begin{aligned} C_t^{oper.}= &\sum_{a\in\Omega^F}\sum_{i\in\Omega^I} O_{a,i}^{F}y_{a,i,t}^{F} \\ &+ \sum_{l\in\Omega^G}\sum_{kg\in\Omega^{KG}}\sum_{d\in\Omega^D}\sum_{h\in\Omega^H}(FC_{kg}^G-\alpha RP_{d,h})g_{l,kg,t,d,h}^G \\ &+ \sum_{l\in\Omega^G}\sum_{kg\in\Omega^{KG}}\sum_{ng\in\Omega_l^{NG}} MC_{kg}^G y_{l,kg,ng,t}^G \\ &+ \sum_{l\in\Omega^B}\sum_{kb\in\Omega^{KB}}\sum_{d\in\Omega^D}\sum_{h\in\Omega^H}\alpha RP_{d,h}(p_{l,kb,t,d,h}^{CH}-p_{l,kb,t,d,h}^{DCH}) \\ &+ \sum_{l\in\Omega^{RES}}\sum_{d\in\Omega^D}\sum_{h\in\Omega^H} RP_{d,h}cur_{l,t,d,h}^{RES} \\ &+ \sum_{l\in\Omega^L}\sum_{d\in\Omega^D}\sum_{h\in\Omega^H}\beta_l\ |dd_{l,t,d,h}| + FLC_t \end{aligned} \tag{3}$$

The objective function (1) comprises investment and operating costs. Formulated in (2), the investment cost at each stage includes installation cost of new feeder sections, reinforcement cost of replaceable feeder sections, and investment cost of substations, as well as installation cost of BESS and dispatchable DG units. The operating cost of each planning stage is modelled by (3), where operating cost of feeders, maintenance and fuel cost of the conventional dispatchable DG units, operating cost of BESS, RES power curtailment cost, cost of demand response plans, and flexibility-oriented cost (FLC_t) are considered.

Detailed discussion on FLC_t, which is the penalty paid by the Disco due to excessive variations in the system net load, is deferred to Section 3.

It is worth emphasizing that only by paying the economic loss to the RES investors, the Disco can curtail the generation of these units. Moreover, it is assumed that the Disco sells electrical power produced by dispatchable DG units at a price of $\alpha RP_{d,h}$, where α is a positive coefficient less than unity to account for the network charges. Thus, according to this expression, network charges for one unit of electrical energy produced by DG units is assumed to be $(1-\alpha)RP_{d,h}$. The same price is considered in selling discharging energy of BESS or buying their charging energy.

Demand-side response refers to the customer actions which can be equivalently modelled as a virtual power source in balancing demand–supply of the system [17]. Hence, it can be considered as a source of the flexibility for distribution system operators [18]. The proposed demand response model is built on the model developed in [19], where deviating the scheduled consumption pattern of consumers is considered to affect their comfort for which the Disco must compensate consumers.

2.2. Operational constraints

In the presented model, linear approximations of Kirchhoff's voltage law (KVL) and Kirchhoff's current law (KCL) are considered, as introduced in [20]. However, in order to underline hourly variations of the system net load, unlike [20], an hourly load flow is incorporated into the model. Thus, the rest of the operational constraints, including voltage, current, and substation capacity limits, should also be satisfied in each hour. Constraint (4) applies KVL to each feeder section, which is in use. Constraints (5) and (6) represent KCL applied at each system node. Constraints (7), (8), and (9) express limits on nodal voltage magnitudes, feeder section currents, and substation capacities, respectively.

$$|Z_{a,i}f^F_{a,t,d,h} + \sum_{n\in\Omega^N} c_{n,a}v_{n,t,d,h}| \leqslant M(1-y^F_{a,i,t}); \quad \forall\, a\in\Omega^F, \forall\, i\in\Omega^I, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{4}$$

$$\sum_{a\in\Omega^F} c_{l,a}f_{a,t,d,h} + G^{RES}_{l,t,d,h} + \sum_{kg\in\Omega^{KG}} g^G_{l,kg,t,d,h} = d_{l,t,d,h} + dd_{l,t,d,h} + cur^{RES}_{l,t,d,h} + \sum_{kb\in\Omega^{KB}}(p^{CH}_{l,kb,t,d,h} - p^{DCH}_{l,kb,t,d,h}); \quad \forall\, l\in\Omega^L, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{5}$$

$$\sum_{a\in\Omega^F} c_{ss,a}f_{a,t,d,h} + s_{ss,t,d,h} = 0; \ \forall\, ss\in\Omega^S, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{6}$$

$$V^{min} \leqslant v_{n,t,d,h} \leqslant V^{max}; \quad \forall\, n\in\Omega^N, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{7}$$

$$|f^F_{a,t,d,h}| \leqslant \sum_{i\in\Omega^I} y^F_{a,i,t} f^F_{\max,i}; \ \forall\, a\in\Omega^F, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{8}$$

$$0 \leqslant s_{ss,t,d,h} \leqslant s_{\max,ss} + \sum_{e\in\Omega^E}\left(\sum_{\tau=1}^{t} x^S_{ss,e,\tau}\right)SC_{ss,e}; \quad \forall\, ss\in\Omega^S, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{9}$$

Limits on the generation of dispatchable DG units and RES power curtailment are formulated in (10) and (11), respectively.

$$0 \leqslant g^G_{l,kg,t,d,h} \leqslant \sum_{ng\in\Omega^{NG}_l} G^G_{kg} y^G_{l,kg,ng}; \quad \forall\, l\in\Omega^G, \forall\, kg\in\Omega^{KG}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{10}$$

$$0 \leqslant cur^{RES}_{l,t,d,h} \leqslant G^{RES}_{l,t,d,h}; \quad \forall\, l\in\Omega^{RES}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{11}$$

Based on the demand response model proposed in [19], demand of each load node is categorized into two types: elastic and inelastic. The elastic demands allow the system operator to modify their scheduled consumption pattern during a day. However, the total daily required energy of such demands have to be entirely supplied, i.e., the sum of hourly power consumption deviations over a day must be zero. In other words, the operator can only shift the energy consumption from a preferred time to another by paying the so-called *discomfort cost* to the consumer. Thus, the demand response model is subjected to the following constraints:

$$|dd_{l,t,d,h}| \leqslant \bar{dd}_l; \quad \forall\, l\in\Omega^L, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{12}$$

$$\sum_{h\in\Omega^H} dd_{l,t,d,h} = 0; \quad \forall\, l\in\Omega^L, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D \tag{13}$$

The BESS model used in this paper is based on the MILP formulation that is presented in [21]. In this respect, constraints (14) and (15) specify allowable charging and discharging power limits. In (16), the operational limits of the state of charge (SOC) are formulated. Equation (17) calculates SOC of BESS in each hour based on the SOC, and charging and discharging powers in the previous hour. As a logical constraint, expression (18) avoids simultaneous charging and discharging of BESS.

$$0 \leqslant p^{CH}_{l,kb,t,d,h} \leqslant \theta^{CH}_{l,kb,t,d,h}\bar{P}^{CH}_{kb}; \quad \forall\, l\in\Omega^B, \forall\, kb\in\Omega^{KB}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{14}$$

$$0 \leqslant p^{DCH}_{l,kb,t,d,h} \leqslant \theta^{DCH}_{l,kb,t,d,h}\bar{P}^{DCH}_{kb}; \quad \forall\, l\in\Omega^B, \forall\, kb\in\Omega^{KB}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{15}$$

$$\sum_{\tau=1}^{t} x^B_{l,kb,\tau}\underline{soc}_{kb} \leqslant soc_{l,kb,t,d,h} \leqslant \sum_{\tau=1}^{t} x^B_{l,kb,\tau}\bar{soc}_{kb}; \quad \forall\, l\in\Omega^B, \forall\, kb\in\Omega^{KB}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{16}$$

$$soc_{l,kb,t,d,h+1} = soc_{l,kb,t,d,h} + (p^{CH}_{l,kb,t,d,h}\eta^{CH} - p^{DCH}_{l,kb,t,d,h}/\eta^{DCH}); \quad \forall\, l\in\Omega^B, \forall\, kb\in\Omega^{KB}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{17}$$

$$\theta^{CH}_{l,kb,t,d,h} + \theta^{DCH}_{l,kb,t,d,h} \leqslant 1; \quad \forall\, l\in\Omega^B, \forall\, kb\in\Omega^{KB}, \forall\, t\in\Omega^T, \forall\, d\in\Omega^D, \forall\, h\in\Omega^H \tag{18}$$

2.3. Investment and utilization constraints

As a common assumption in DSEP models [11,20,22,23], it is assumed that only one investment action, e.g., reinforcement or addition, is allowed to be performed on each network asset, i.e., feeder section, substation, dispatchable DG unit, and BESS over the planning horizon:

$$\sum_{t\in\Omega^T}\sum_{i\in\Omega^I} x^{RF}_{a,i,t} \leqslant 1; \ \forall\, a\in\Omega^{RF} \tag{19}$$

$$\sum_{t\in\Omega^T}\sum_{i\in\Omega^I} x^{AF}_{a,i,t} \leqslant 1; \ \forall\, a\in\Omega^{AF} \tag{20}$$

$$\sum_{t\in\Omega^T}\sum_{e\in\Omega^E} x^{S}_{ss,e,t} \leqslant 1; \ \forall\, ss\in\Omega^{S} \tag{21}$$

$$\sum_{t\in\Omega^T} x^G_{l,kg,ng,t} \leqslant 1; \ \forall\, l\in\Omega^G, \forall\, kg\in\Omega^{KG}, \forall\, ng\in\Omega^{NG}_l \tag{22}$$

$$\sum_{t\in\Omega^T} x^B_{l,kb,t} \leqslant 1; \ \forall\, l\in\Omega^B, \forall\, kb\in\Omega^{KB} \tag{23}$$

Furthermore, (24)–(26) ensure that each alternative of the distribution assets is utilized only after the corresponding investment has been made. Constraint (27) and (28) limit the number of installed conventional DG units and BESS in each candidate node. These constraints reflect practical limitations such as space availability at each location.

$$y^F_{a,i,t} \leqslant \sum_{\tau=1}^{t} x^{RF}_{a,i,\tau}; \ \forall\, a\in\Omega^{RF}, \forall\, i\in\Omega^I, \forall\, t\in\Omega^T \tag{24}$$

$$y^F_{a,i,t} \leqslant \sum_{\tau=1}^{t} x^{AF}_{a,i,\tau}; \ \forall\, a\in\Omega^{AF}, \forall\, i\in\Omega^I, \forall\, t\in\Omega^T \tag{25}$$

$$y^G_{l,kg,ng,t} \leqslant \sum_{\tau=1}^{t} x^G_{l,kg,ng,\tau}; \ \forall\, l\in\Omega^G, ng\in\Omega^{NG}, kg\in\Omega^{KG}, \forall\, t\in\Omega^T \tag{26}$$

$$\sum_{t\in\Omega^T}\sum_{kg\in\Omega^{KG}}\sum_{ng\in\Omega^{NG}_l} x^G_{l,kg,ng,t} \leqslant \bar{NG}_l; \ \forall\, l\in\Omega^G \tag{27}$$

$$\sum_{t\in\Omega^T}\sum_{kb\in\Omega^{KB}} x^B_{l,kb,t} \leqslant \bar{NB}_l; \ \forall\, l\in\Omega^B \tag{28}$$

2.4. Radiality constraints

Maximum number of feeder sections in a radial distribution network with N nodes from which S nodes are substation nodes is $N-S$ [24]. However, at each stage of the planning horizon, the number of *in-service nodes*, including load nodes, DG nodes, and so-called *transfer nodes*, depends on the decision variables of the model and is not specified priori [25]. Thus, in order to ensure radial operation of the network, (29) and (30) are considered in the model. By imposing these radiality constraints, binary variables $an_{l,t}$ of in-service nodes are set to 1, and the maximum number of utilized branches is also limited to the total number of in-service nodes so as to ensure the radial network operation.

Although these constraints are sufficient conditions for radiality of passive networks, they are only necessary conditions for that of active grids, since they do not prevent isolated sections supplied by DG units. Thus, (31)–(36) should be considered in the model to prevent isolated sections supplied by DG units [25]. These constraints together with (29) and (30) guarantee the radiality of an active distribution system. These equations prevent isolated sections supplied by DG units by assigning fictitious current demands to the candidate nodes for installation of dispatchable DG units. As a result, these nodes maintain their connection to substation nodes since substation nodes should supply the fictitious current demands.

$$\sum_{a\in\Omega^F}\left[|c_{l,a}|\sum_{i\in\Omega^I} y^F_{a,i,t}\right] \geqslant an_{l,t};\ \forall\ l\in\Omega^L,\ \forall\ t\in\Omega^T \tag{29}$$

$$\sum_{a\in\Omega^F}\sum_{i\in\Omega^I} y^F_{a,i,t} \leqslant \sum_{l\in\Omega^L} an_{l,t};\ \forall\ t\in\Omega^T \tag{30}$$

$$\sum_{a\in\Omega^F} c_{n,a}\delta^F_{a,t} = \delta^G_{n,t}-\delta^S_{n,t};\ \forall\ n\in\Omega^N,\ \forall\ t\in\Omega^T \tag{31}$$

$$0\leqslant\delta^F_{a,t}\leqslant|\Omega^G|\sum_{i\in\Omega^I} y^F_{a,i,t};\ \forall\ a\in\Omega^F,\ \forall\ t\in\Omega^T \tag{32}$$

$$0\leqslant\delta^S_{n,t}\leqslant|\Omega^G|;\ \forall\ n\in(\Omega^S\backslash\Omega^{SE}),\ \forall\ t\in\Omega^T \tag{33}$$

$$0\leqslant\delta^S_{n,t}\leqslant|\Omega^G|\sum_{e\in\Omega^E}\sum_{\tau=1}^{t} x^S_{n,e,\tau};\ \forall\ n\in\Omega^{SE},\ \forall\ t\in\Omega^T \tag{34}$$

$$\delta^S_{n,t}=0;\ \forall\ n\in(\Omega^N\backslash\Omega^S),\ \forall\ t\in\Omega^T \tag{35}$$

$$\delta^G_{n,t}=\begin{cases}1;\ \forall\ n\in\Omega^G,\ \forall\ t\in\Omega^T\\ 0;\ \forall\ n\in(\Omega^N\backslash\Omega^G),\ \forall\ t\in\Omega^T\end{cases} \tag{36}$$

2.5. Flexibility measure

As mentioned before, this paper aims to provide a regulatory framework that motivates Discos to enhance the flexibility of their networks. Thus, a quantitative measure is required to assess the flexibility of distribution systems, which can be reflected in system net load variations or hourly net load ramp rates. To this end, the hourly net load ramps are firstly formulated as follows:

$$lc^{abs}_{t,d,h}=\left|\sum_{ss\in\Omega^S}(s_{ss,t,d,h}-s_{ss,t,d,h-1})\right|;\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{37}$$

Nonlinear absolute value operator in (37) makes the model nonlinear. Thus, we use linear equivalent expressions (38)–(40), where two non-negative auxiliary variables $lc^{pos}_{t,d,h}$ and $lc^{neg}_{t,d,h}$ are introduced to model the absolute value of $lc_{t,d,h}$. Logically, only one of these two variables can be non-zero at the same time. However, there is no need to explicitly incorporate such constraint into the model, since the FLC_t (as formulated later in Section 3) and, hence, the objective function is monotonically increasing with respect to the summation of $lc^{pos}_{t,d,h}$ and $lc^{neg}_{t,d,h}$. Thus, the optimization algorithm set one of them to 0.

$$lc_{t,d,h}=\sum_{ss\in\Omega^S}(s_{ss,t,d,h}-s_{ss,t,d,h-1});\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{38}$$

$$lc^{pos}_{t,d,h}-lc^{neg}_{t,d,h}=lc_{t,d,h};\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{39}$$

$$lc^{abs}_{t,d,h}=lc^{pos}_{t,d,h}+lc^{neg}_{t,d,h};\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{40}$$

In the following section, these variables are employed to model flexibility-oriented costs.

3. Proposed flexibility-enhancing policies

In this section, various policies are presented with the ultimate goal of leading Discos into decreasing daily variations in their system net load. These policies can be divided into two categories: financial penalization and net load ramp limits. A combination of both policies can also be adopted.

3.1. Financial penalization

A potential approach for motivating Discos to enhance the flexibility is to penalize them for variations in the system net load. Under such policies, distribution system planners are required to consider the penalty as an operational cost in the optimization model and try to provide sufficient sources of the flexibility to minimize the total expansion cost. Various forms of financial penalization policies are as follows:

(1) Linear flexibility cost function

In this type, the penalty cost associated with each hour has a linear relation with the corresponding system net load ramp, and the flexibility cost is formulated as follows:

$$FLC_t=\sum_{d\in\Omega^D}\sum_{h\in\Omega^H} RC_{d,h}lc^{abs}_{t,d,h};\ \forall\ t\in\Omega^T \tag{41}$$

(2) Multi-step flexibility cost function

Slight ramps do not result in penalties, under this policy. However, the ramping cost is higher for steeper hourly ramps. Therefore, the operators prefer slight system net load ramps in consecutive hours instead of a steep ramp in one hour. As an example, a three-step flexibility cost function can be formulated in a linear form as follows:

$$lc^{SS,pos}_{t,d,h}+p-av^{SS,neg}=lc_{t,d,h};\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{42}$$

$$av^{SS,pos}-lc^{SS,neg}_{t,d,h}-p=lc_{t,d,h};\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{43}$$

$$lc^{TS,pos}_{t,d,h}+q-av^{TS,neg}=lc_{t,d,h};\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{44}$$

$$av^{TS,pos}-lc^{TS,neg}_{t,d,h}-q=lc_{t,d,h};\ \forall\ t\in\Omega^T,\ \forall\ d\in\Omega^D,\ \forall\ h\in\Omega^H \tag{45}$$

$$\begin{aligned}FLC_t=&\sum_{d\in\Omega^D}\sum_{h\in\Omega^H}[RC^{SS}_{d,h}(lc^{SS,pos}_{t,d,h}+lc^{SS,neg}_{t,d,h})\\&+RC^{TS}_{d,h}(lc^{TS,pos}_{t,d,h}+lc^{TS,neg}_{t,d,h})];\ \forall\ t\in\Omega^T\end{aligned} \tag{46}$$

In (42)–(46), av^{SS} and av^{TS} are non-negative auxiliary variables for second and third steps, respectively. According to this model, the hourly system net load ramps lower than p are penalty-free. Hourly variations between p and q, denoted by $lc^{SS}_{t,d,h}$, are penalized with a lower cost coefficient $RC^{SS}_{d,h}$, and hourly variations higher than q ($lc^{TS}_{t,d,h}$) are penalized with a higher penalty rate $RC^{TS}_{d,h}$.

3.2. Net load ramp constraint

Another approach to motivating Discos to invest in local flexibility sources is to limit the allowable system net load variations. Thus, the distribution system planner would provide sufficient sources of the flexibility to meet the constraint in the optimization. Various policies based on net load ramp limits are as follows:

(1) Constraint on hourly ramps

The constraint determines that hourly net load ramps of distribution system must not exceed a specific limit determined by the regulator. This constraint is formulated as follows:

$$lc^{abs}_{t,d,h} \leqslant \bar{lc}^{h};\ \forall\ t \in \Omega^{T},\ \forall\ d \in \Omega^{D},\ \forall\ h \in \Omega^{H} \tag{47}$$

(2) Constraint on total ramps during each day

In this case, the regulator limits the summation of the hourly system net load variations during each day. This constraint is expressed as follows:

$$\sum\nolimits_{h\in\Omega^{H}} lc^{abs}_{t,d,h} \leqslant \bar{lc}^{d};\ \forall\ t \in \Omega^{T},\ \forall\ d \in \Omega^{D} \tag{48}$$

4. Numerical results

In order to illustrate the effectiveness of the proposed policies, the presented DSEP model is implemented on a modified version of the 18-node distribution test network introduced in [26]. This network consists of 2 substation nodes, 16 load nodes, and 24 feeder sections. These feeder sections are classified into three categories: fixed, replaceable, and addable feeder sections. The following considerations have been taken into account in the simulations:

- The planning horizon consists of three stages, each of which is two-year-long, considering a 10% annual interest rate.
- Two alternatives for reinforcing each replaceable feeder section and two for installing each addable feeder section are considered. Also, two options for installing a dispatchable DG unit and two for investing in BESS are taken into account. Data used for feeder sections and conventional DG units are borrowed from [23].
- The BESS considered in the simulations are Lithium-Ion, and the prices of BESS investment are taken from [27].
- Two types of RES generation are considered: solar photovoltaic and wind turbine. Profiles of solar and wind generation are based on the data from [28] and [29], respectively. Per-unit RES generation patterns are illustrated in Fig. 1, where the daily maximum generation is considered the base value for calculation of the per-unit figures.
- In terms of load type, three categories, namely commercial, industrial, and residential, are considered. Moreover, four representative days are considered in each year: summer working day, summer non-working day, winter working day, and winter non-working day. Fig. 2 illustrates daily load curves of the three categories for the representative days in a per-unit scale with the base value set to the maximum load at each planning stage.
- Based on [23], hourly electricity retail price is equal to \$57.7/MWh, \$70.0/MWh, and \$85.3/MWh for low, medium and high power consumption hours, respectively. Low power consumption time interval is considered from 1 to 7. Medium power consumption hours are 8–10, 14–18, and 23–24. High power consumption periods are assumed 11–13 and 19–22. Additionally, coefficient α is set to 0.9.
- The set of candidate nodes for installation of conventional DG units is $\Omega^{G} = \{6,10\}$. Also, the set of candidate nodes for installation of BESS is $\Omega^{B} = \{4,12\}$
- It is assumed that 20% of the demand connected to each load node is elastic, which can be flexibly scheduled over a day. Coefficient β_l is also set to \$100/MWh for all customers.
- Location, capacity, and other parameters associated with RES units and other data used in the simulations are available in [30].

Since the proposed DSEP model is in MILP form, reaching the global optimal solution is guaranteed through using standard optimization toolboxes. CPLEX is one of the most widely used commercially available solvers due to its capability to solve very large, real-world optimization problems. Thus, all the cases have been solved using CPLEX 12.6 under GAMS 24.2 on a PC with a 3.40 GHz Intel Core i7-4770 processor with 32 GB of RAM. The optimality gap is also set to 1% as the solver's stopping criteria.

4.1. Policies impact on the planning studies

In order to illustrate the impact of the regulatory policies on distribution system net loads, the presented planning model is solved for the cases presented in Table 1. The only difference among the cases is the type of policy considered in each of them. The computation time for each case was 1.3 h, 12.8 h, 12.2 h,4.1 h, and 6.8 h, respectively.

As a consequence of imposing various policies on the Disco, different solutions for multistage expansion of the sample distribution network were resulted, two of which are presented in Fig. 3. In the figure, the rectangles depict substation nodes, and the circles represent load nodes. The grey-filled and blue-filled nodes show the candidate nodes for the installation of DG and BESS, respectively. Moreover, fixed, replaceable, and addable feeder sections are represented by single lines, double lines, and dotted lines, respectively. The sign written on the installed addable feeder sections stands for the selected alternative. For example, the sign "A1" shows that the first alternative of addable feeder sections is chosen to be installed. The simulation results are presented and discussed in the following.

Solving the proposed optimization model, the number, location, and capacity of installed dispatchable DG units and BESS are extracted as presented in Table 2. Fig. 4 shows the test system net load curves for a summer non-working day for Cases 1–5. Since the Disco is sufficiently motivated to install conventional DG units in Cases 2–5, there are more the local sources of flexibility in the distribution system. Consequently, hourly ramp rates of the system net load have decreased.

Nonetheless, owing to their high investment costs, no BESS is installed in Cases 2–5. Yet, as the battery prices are declining at a high rate, leveraging them to enhance the flexibility of distribution systems will be more economical in the future, and, therefore, they will probably be an efficient source of flexibility.

In Fig. 4, the midday peak in the net load curves is caused by the peaks in both residential and commercial load curves (As it is a non-working day, the industrial load is constantly at a low level according to Fig. 2). Moreover, the steep ramps after hour 15 are caused by the decreasing solar generation and increasing residential and commercial demands. By implementing the proposed regulatory policies, both features are improved, and the ramps are smoothed.

In order to better illustrate the impact of each policy on the system net load, the summation and maximum value of hourly net load ramp rates for the representative day considered in Fig. 4 are presented in Table 3. According to Fig. 4 and Table 3, it can be concluded that by imposing the linear cost function policy (Case 2), the hourly ramps of the system net load will be eliminated except those around the daily net load peak. In fact, only the hourly net load variations with slight slopes are avoided. In contrast, by imposing the 3-step cost function (Case 3) or hourly constraint policy (Case 4), the hourly net load ramps with steep slopes are avoided. Moreover, the system net load ramps can

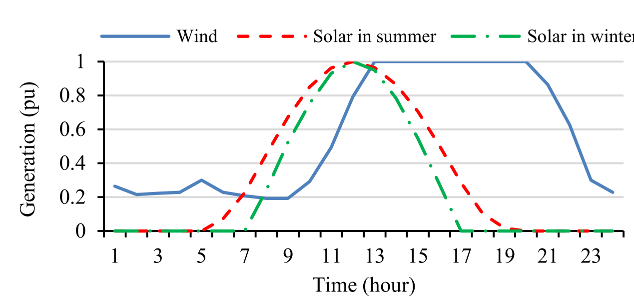

Fig. 1. Generation profiles of RES.

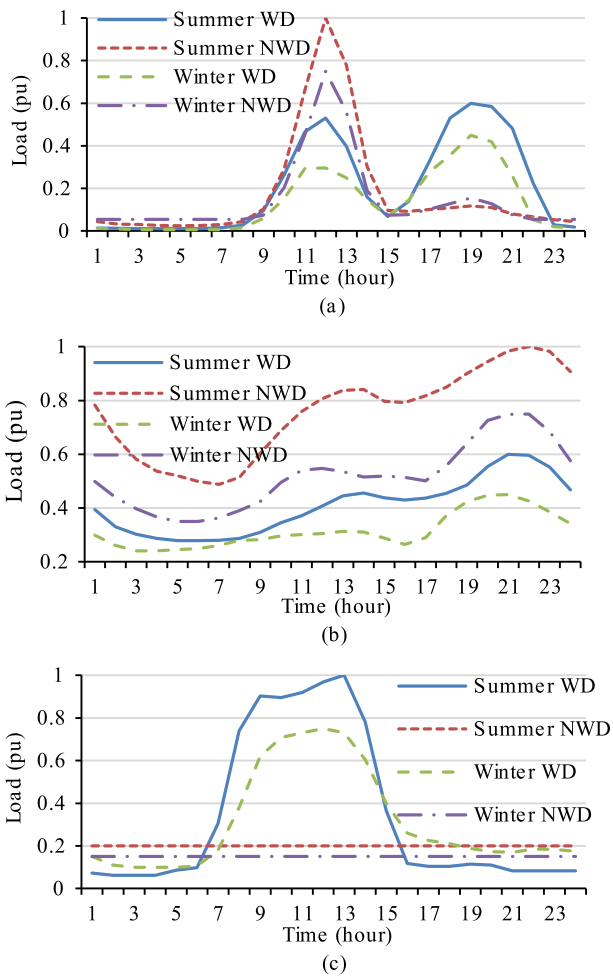

Fig. 2. Daily load curves for (a) Residential load, (b) Commercial load, and (c) Industrial load.

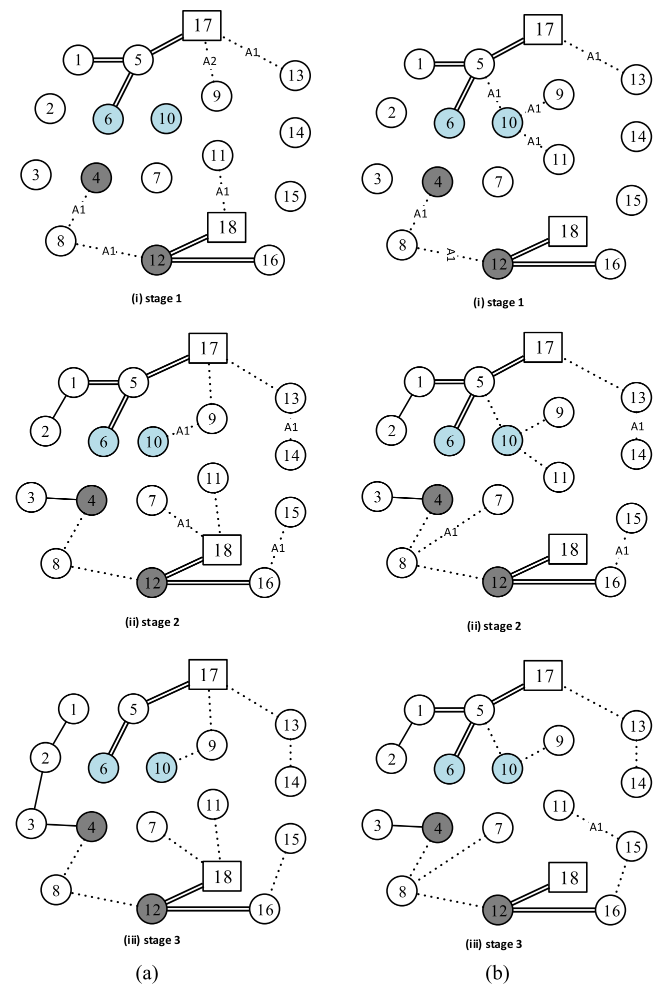

Fig. 3. Solution for expansion in (a) Case 1 and (b) Case 5.

Table 1
Investigated test cases.

Case	Policy type	Related parameters
1	No Policy	–
2	Cost (linear)	$RC_{d,h} = 0.5RP_{d,h}$
3	Cost (3-step)	$RC^{SS}_{d,h} = 0.5RP_{d,h}$, $p = 0.5$, $RC^{TS}_{d,h} = 2RP_{d,h}$, $q = 2$
4	Constraint (Hourly)	$\bar{lc}^h = 1$
5	Combined [a]	$RC_{d,h} = 0.5RP_{d,h}$, $\bar{lc}^h$=1

[a] In this case, both financial penalization and hourly limit are imposed.

Table 2
Installed dispatchable DG units and BESS.

Case	DGs' Location	DGs' total capacity (MW)	BESS' locations	BESS' total capacity (MWh)
1	–	0	–	0
2	6	2	–	0
3	6,10	4	–	0
4	6	2	–	0
5	6,10	4	–	0

become smoother by imposing a combination of both policy types, as shown in Fig. 4.

Comprehensive results associated with different cases are also presented in Table 4, where the average and maximum value of the hourly ramp rates are considered as flexibility metrics. The total expansion and operating costs of the cases with the flexibility policies are higher than that of Case 1 in which no policy is imposed, as expected. Furthermore, as the average and maximum values of the hourly ramp rates decrease (i.e., the flexibility enhances), the total expansion and operating cost increases since the planner resorts to select more expensive alternatives in response to the imposed policies. For instance, in Case 3 and Case 5, both flexibility metrics decrease when compared with those in Case 2 (according to Table 3), since in those cases more dispatchable DG units are installed. As another example, in both Case 2 (linear cost function) and Case 4 (hourly constraint), the planner invests in one dispatchable DG unit. Nevertheless, as a consequence of the imposed hourly constraint in Case 4, the dispatchable DG is mainly used to smoothen the steep ramps during more limited time slots and, hence, cannot be as profitable as it is in Case 2, where it generates more power. In other words, in Case 2, the DG unit operates mostly at its full capacity to make more profit. However, in Case 4, only in certain times (e.g., around the daily net load peak), the DG unit operates at its full capacity for the hourly ramp rates must not exceed the limit. As a result, the total cost is much higher in Case 4 as compared to Case 2. Moreover, demand response program is deployed more in Case 4 to smoothen the ramps, and, consequently, the Disco is required to pay more discomfort cost to the consumers.

Therefore, in order to compare these cases to select the best policy, the system regulator should be aware of the costs of flexibility enhancement in various levels of the power system. Nonetheless, as mentioned earlier, enhancing the flexibility at the distribution level is vital, yet its optimal amount relies on the system condition. Therefore, the regulator should select a policy, which is cost-effective while

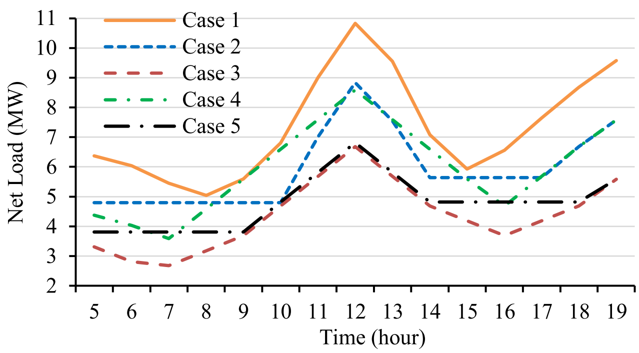

Fig. 4. The system net load curves for Cases 1–5.

Table 3
Summation and maximum values of system net load ramp rates (MW/hour).

Case	Summation	Maximum
1	22.796	2.472
2	15.854	2.213
3	15.718	1
4	19.718	1
5	11.456	1

providing the flexibility requirements at the distribution level.

4.2. Sensitivity analysis

Two sensitivity analyses are performed to study the effects of imposing stricter policies on Discos. In the first one, an analysis is carried out on Case 2, i.e., linear cost function, to assess the impact of ramping cost. As shown in Fig. 5, the net load becomes smoother by increasing ramping cost from $0.5RP_{d,h}$ to $2RP_{d,h}$ as a result of investing more in dispatchable DG units and exploiting more demand response. Therefore, as could be expected, imposing stricter policies on Discos results in flexibility enhancement in distribution systems.

Another sensitivity analysis is carried out to investigate the impact of ramp rate limit on the system net load variations. As presented in Fig. 6, hourly net load variations decrease as allowable ramp rate limit is reduced. However, unlike the previous sensitivity analysis, the number of installed dispatchable DG units is the same in all four cases. In fact, the system net load ramps become markedly slighter owing to more demand response deployment and RES generation curtailment.

Accordingly, the stricter the policy, the higher is the total investment and operating costs of the Disco. Thus, as mentioned before, the regulator should select a suitable policy based on the flexibility requirements at the distribution level.

5. Conclusion

In this paper, two types of regulatory policies have been proposed to be imposed on Discos aiming at motivating them to invest in the local sources of flexibility. In order to assess the consequences of imposing these policies, a novel model has been proposed for DSEP considering the local flexibility requirements. In this model, the installation of dispatchable DG units and BESS, demand response program, and RES generation curtailment are considered as the candidate alternatives for flexibility provision at the distribution level. The presented DSEP model has been implemented on a sample distribution system. The simulation results show that in case of selecting appropriate parameters for each policy, distribution system planners are likely to invest in the local sources of flexibility, e.g. dispatchable DG units. However, no investment has been made on the BESS due to their high capital prices. Yet, it is likely that investing in them becomes efficient in the future as the battery prices are declining at a fast pace.

Furthermore, it was determined that imposing stricter policies stimulates Discos to exploit more demand response and increase the penetration of dispatchable DG units. However, the stricter the policy is, the more the total network costs would be. Thus, depending on the bulk power system condition, distribution system regulators can determine the proper policy to be implemented.

Recently, the concept of distribution network's providing flexibility to the transmission system has attracted much attention. In this respect, an aggregator will control the RES with the goal of managing the active and reactive power exchange at the interconnection to the upstream grid. This represents one of our future research focuses. Moreover, the authors are currently working on extending the DSEP model presented in this paper to leverage electric vehicles that are charged at parking lots and at charging stations, so as to enhance the flexibility at the distribution level.

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.

Table 4
Simulation results.

Case	Stage	Average ramp rate	Maximum ramp rate	Network inv. cost (K$)	Network oper. cost (K$)	DR cost (K$)	FLC (K$)	Total cost[a] (K$)
1	1	0.5155	2.875	155.2	2.3	0	–	247.2
	2	0.6515	2.604	90.1	5	0	–	
	3	0.8795	3.417	0	7.1	1.6	–	
2	1	0.3215	2.701	1137.7	−108.1	0	102.7	247.5
	2	0.4263	2.213	67.6	−86.7	0	141.5	
	3	0.6759	3.417	22.5	−2.6	1.6	222.1	
3	1	0.1514	1	2117.7	−253.1	0	6.9	542.7
	2	0.3708	1	67.59	−460.8	1.1	23.8	
	3	0.5261	1	0	−340	5.4	61.9	
4	1	0.3138	1	1137.7	−173.4	11.1	–	404.1
	2	0.5632	1	67.6	−236.7	7.2	–	
	3	0.6433	1	22.5	−86.4	27.2	–	
5	1	0.1514	1	2117.7	−213.1	0	49.5	583.8
	2	0.3074	1	67.6	−366.2	0.1	104	
	3	0.4868	1	0	−234	4.4	157.5	

[a] "Total cost" in the table is equal to the total expansion and operating costs of the network assets.

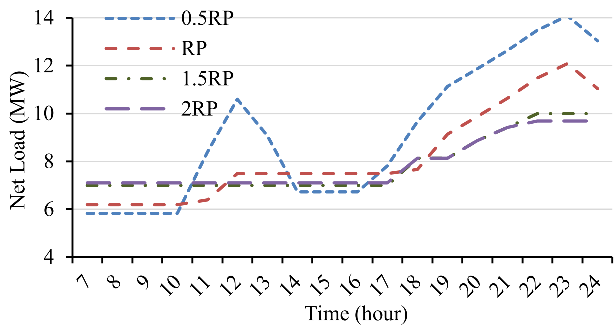

Fig. 5. The system net load curves in Case 2 (linear cost function) for different ramping costs in a summer non-working day at stage three.

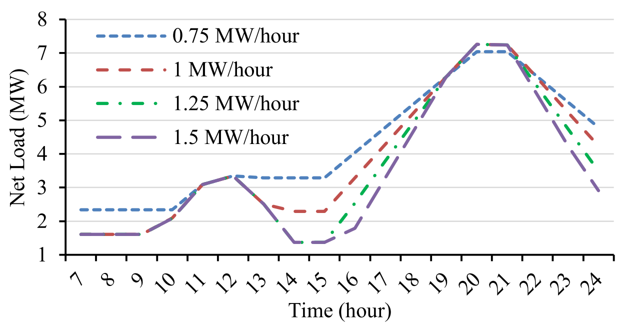

Fig. 6. The system net load curves in Case 5 for different ramp rate limits (MW/hour) in a summer working day at stage three.

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