Multi-Level Optimization Framework for Resilient Distribution System Expansion Planning with Distributed Energy Resources

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Abstract

A multi-stage optimization framework is proposed in this paper for the resilient electric distribution system expansion planning problem. The Non-utility Distributed Energy Resources (NDERs) can deliver their electricity to the distribution system in normal and external shock conditions. However, the NDERs bidding strategies in external shock conditions are an important issue and they can withhold their electricity generation in a contingent condition. The distribution system must tolerate the external shocks and determine the optimal contribution scenarios of NDERs in these conditions. The proposed algorithm determines the initial topology and system parameters of the planning horizon, at the first stage of optimization. Then, it explores the bidding strategies of NDERs in the second stage. At the third stage, the procedure calculates different market power indices to determine the optimal price of NDERs contributions in its different operational conditions and contracts with the selected NDERs. The problem has different sources of uncertainty that are modelled in the proposed algorithm. To assess the proposed method, 21-bus and 123-bus test systems are considered and the introduced procedure reduced the aggregated investment and operational costs of systems by about 11.82% and 23.74%, respectively, in comparison with the custom expansion planning exercise.

Keywords: Resilient Expansion Planning; Strategic Bidding; Market Power; Intermittent Electricity Generation; Uncertainty Modelling.

1. Nomenclature

Abbreviations

CHP	Combined Heat and Power
DER	Distributed Energy Resource
DG	Distributed Generation

DLC	Direct Load Control
DRP	Demand Response program Providers
DSO	Distribution System Operator
EDS	Electric Distribution System
ENSC	Energy Not Supplied Cost
ESS	Electrical Storage System
LMP	Locational Marginal Price
MDLMP	Maximum Daily LMP
MLI	Modified Lerner index
MPI	Market Power Index
NDER	Non-utility Distributed Energy Resource
NWSR	Nodal Withholding-Supply Ratio
ORDSEP	Optimal Resilient Distribution System Expansion Planning
MPCMI	Modified Price-Cost Margin Index
PHEV	Plug-in Electric Vehicle
PSO	Particle Swarm Optimization
PVS	PhotoVoltaic System
REDS	Resilient Electric Distribution System
RSI	Residual Supply Index
TOU	Time Of Use
UDER	Utility Distributed Energy Resource
WT	Wind Turbine

Set and Indices

i	Year of planning index
j	Number of external shock index
k	First stage uncertainty modelling index
l	UDERs facility installation site index
m	Third stage uncertainty modelling index
n	Switch installation site index
r	Feeder route installation index
t	Second stage uncertainty modelling index

a	NDERs index
b	Normal and external shock conditions index
d	Fourth stage uncertainty modelling index
e	Index of load bus
g	Index of generation bus
m' , n'	Indices of system buses

Scalars and parameters

L	Length of feeder
μ	Net present value factor
NExtShocks	Number of external shocks that are determined in the second stage of uncertainty modelling
NNDERs	Number of NDERs
Nyear	Number of planning years
NFSUM	Number of first stage uncertainty modelling scenarios
NSSUM	Number of second stage uncertainty modelling scenarios
NTSUM	Number of third stage uncertainty modelling scenarios
NFOSUM	Number of fourth stage uncertainty modelling scenarios
NNExtShocks	Number of normal and external shock conditions
NLs	Number of load buses
NGs	Number of generation buses
ε, α	Pre-defined constant
prob	Probability of scenario
ϑ_{WSM}^{Active}	Price of active energy that is purchased from wholesale market
$\vartheta_{WSM}^{Rective}$	Price of reactive energy that is purchased from wholesale market
$\vartheta_{NDERs}^{Active}$	Price of active energy that is purchased from NDERs
$\vartheta_{NDERs}^{Rective}$	Price of reactive energy that is purchased from NDERs
γ_{NDERs}	Capacity payment fee that is paid to NDERs
γ_{DRPs}	Capacity payment fee that is paid to DRPs
W	Weighting factor
K	Weighting factor
LMP	Locational marginal price of bus
$Y_{UDERs\ SITE}$	Number of available installation site for UDERs facilities

$Y_{Switches\ SITE}$	Number of available installation site for switches facilities
$Sections$	Number of available installation site for sections of feeders
$S^{REDS\ max}$	REDS line maximum apparent power
Y	Admittance of line

Continuous variables

B_{NDERs}	Benefit of NDERs
$C^{WSM}_{Purchased}$	Cost of electricity purchased from the wholesale market
$C^{DRPs}_{Purchased}$	Cost of electricity purchased from DRPs
$C^{NDERs}_{Purchased}$	Cost of electricity purchased from NDERs
C_{UDERs}	Net present value of capital and operational costs of UDERs
$C^{UDERs}_{Capital}$	Capital cost of UDERs installation
$C^{UDERs}_{O\&M}$	Operational and maintenance cost of UDERs
$C_{Switches}$	Net present value of capital and operational costs of switches
$C^{Switches}_{Capital}$	Capital cost of switches installation
$C^{Switches}_{O\&M}$	Operational and maintenance cost of switches
C_{Feeder}	Net present value of capital and operational costs of feeders
$C^{Feeder}_{Section}$	Capital cost of section of feeder installation
$C^{Feeder}_{O\&M}$	Operational and maintenance cost of sections of feeder
Cap_{NDERs}	Allocated capacity volume that is purchased from NDERs
Cap_{DRPs}	Allocated capacity volume that is purchased from DRPs
C_{NDERs}	Operational cost of NDERs
C_{DRPs}	Operational cost of DRPs
mc	Marginal cost
MPI	Market Power Index
$Penalty_{NDERs}$	Penalty that paid by NDERs to the system
Γ	Weighted values of LMPs
MLI	Modified Lerner index
RSI	Residual Supply Index
$MPCMI$	Modified Price-Cost Margin Index
$NWSR$	Nodal Withholding-Supply Ratio

S_{NDERs}	Apparent power of NDERs
$\Delta P^{withhold}$	NDER/DRP electricity generations that are withheld from the market
$ENSC$	Energy not supplied cost
P^{e}	NDER/DRP electricity generation in the oligopoly market
τ	Time duration of operation
P_{PCC}^{REDS}, Q_{PCC}^{REDS}	Electric distribution system active and reactive power transactions with wholesale market at point of common coupling
$P_{n'm'}^{REDS}$, $Q_{PCC\,n'm'}^{REDS}$	Active and reactive power flow of distribution system line
P^{NDERs}, Q^{NDERs}	Purchased active and reactive power from NDERs
P^{DRPs}, Q^{DRPs}	Purchased active and reactive power from DRPs
P_L	Active power of load bus
P_G	Active power of generation bus
$Revenue_{NDERs}$	Revenue of NDERs
π	Price of power sold to electric system by NDER
V	Voltage of distribution system bus
θ	Voltage angle

Integer variables

I	Binary decision variable of UDER or switches or feeders allocation and capacity selection
J	Binary decision variable of commitment of dispatchable NDER

2. Introduction

A Resilient Electric Distribution System (REDS) should tolerate the external shock, continue to deliver electricity, recover from the previous contingent condition and resume to new steady-state conditions [1]. The shock sources are external and internal to the system. The external shocks are due to natural catastrophic events or attacks, and the internal shocks are the electric distribution system severe contingencies [2].

A REDS may utilize Distributed Energy Resources (DERs) to mitigate the impacts of external and internal shocks. The DERs can be categorized into Utility DERs (UDERs) and/or Non-utility DERs (NDERs). The UDERs and/or NDERs consist of solar photovoltaic systems, wind turbines, energy storage systems, plug-in electric vehicles parking lots, gas-fired Combined Heat and Power (CHP) units and boilers and Distributed Generation (DG) units [3].

The NDERs commitment strategies in external shock conditions is a crucial issue in operational paradigms. The NDERs contributions can completely change the distribution system controllability and resiliency based on the fact that these resources can withhold their electricity generation in normal and contingent condition. Thus, the Distribution System Operator (DSO) should exactly determine the NDERs contribution scenarios in its external shock conditions for expansion planning exercises; calculate the optimal price of NDERs contribution in its different operational conditions; contract with the selected NDERs and penalize them based on the bilateral contract's parameters when they exercise strategic bidding.

The Optimal Resilient Distribution System Expansion Planning (ORDSEP) problem involves obtaining the optimal parameters of energy resources capacity, location, and time of installation. The ORDSEP should take into account the capacity withholding analysis of NDERs, probabilistic behaviour of the energy carrier prices, reliability criteria and cost-benefit analysis [4]. The expansion planning exercises of energy carrier systems are carried out using dynamic, semi-dynamic, and static models [4-15]. Further, the resilient distribution system expansion planning can be categorized into the resilient expansion planning practices with the custom N-K contingency selection method and the worst-case contingency constrained resilient expansion planning methods [4].

Nazar et al [4] proposed a basis for resilient distribution system expansion planning that considered NDERs contribution scenarios. The proposed algorithm decomposed the main problem into five sub-problems modelled by a Mixed Integer Non-Linear Programming (MINLP) problem. The N-K contingency method was utilized to model the severe operating conditions and a genetic algorithm was used to optimize the model, but the NDERs contribution scenarios in external shock conditions and their impacts on the Locational Marginal Prices (LMPs) were not modelled. Two 9-bus and urban test systems were considered for case studies.

Wei Yuan et al. [5] presented a multi-stage and multi-zone based resilient planning of a distribution system and considered the temporal dynamics of uncertain natural disasters based on a traditional N-K contingency scheme. The proposed method used column constraint generation decomposition algorithm for two-stage robust optimization and the method was evaluated for the 33-bus and 123-bus test systems. The model did not consider the impacts of NDERs commitment strategies on the adequacy of system resources and marginal prices of the system.

Gilani et al [6] presented a mixed-integer linear programming algorithm for restoration of critical loads and considered DERs and Demand Response program Providers (DRPs) based on the worst-case resilient operation of the electric distribution system, but the non-utility DERs dispatching strategies in external shock conditions were not modelled. The proposed algorithm was assessed on the IEEE 33-bus test system and an urban distribution system.

Mishra et al. [7] introduced a framework for optimal resilient expansion planning of a distribution system. The model proposed a hierarchical decision method to coordinate microgrids in different operational conditions. The model considered the worst-case contingency and operational uncertainties in a two-stage constrained mixed-integer linear programming formulation. The method was evaluated for three islands on the west coast of Norway.

Mousavizadeh et al. [8] presented the modularity idea to quantify the resiliency level of a distribution system. The formation of microgrids was analysed based on dependency-based indices and for the worst-case contingencies. The switching scenarios, DGs parameters and controllable loads were considered in the model. Different case studies confirmed the effectiveness of the proposed method. Ref. [7] and [8] did not consider the non-utility energy resources models in their proposed optimization frameworks.

Lin et al. [9] proposed a tri-level defender-attacker-defender resilient model to find the best hardening plan under malicious external shocks for the distribution system. The first stage used hardening decisions; the second stage found the worst-case attack scenario and the third stage considered resilient operation using the CCG method. The method was assessed for the 33-bus test system and a real 94-bus system.

Zare-Bahramabadi et al. [10] introduced a two-stage method for switching device allocation in the distribution system to increase the resiliency of the system. At the first stage, the impact of extreme weather condition on the system components was analyzed and at the second stage, the resiliency index was calculated. A mixed-integer linear programming algorithm was utilized to optimize the two-stage model. Ref. [9] and [10] did not model the NDERs contributions and marginal price variations in external shock conditions.

Bessani et al. [11] proposed a time-to-event model to analyze the structural resilience and quantify the energy delivered in extreme operating conditions of the distribution system. The structural and performance indices were used to evaluate the post-contingency conditions and Monte Carlo simulation was carried out to estimate the resilience in sever conditions.

Wu et al. [12] presented a two-stage stochastic optimization framework to determine the optimal capacity and allocation of DERs considering normal and external shock operational conditions. The model utilized mixed-integer linear programming to optimize the two-staged problem and different scenarios of operation were considered to evaluate the survivability level of the system. Ref. [11-12] did not consider NDERs strategic capacity withholding that may completely change the expansion-planning and operational paradigms of a distribution system.

The non-utility commitment strategies can change the availability, price of procurement and optimality of the distribution system resource expansion planning practices. Thus, the assessment of the feasibility and optimality of non-utility contribution scenarios in the external shock conditions is a crucial issue. An integrated framework that considers the impact of the NDERs on the ORDSEP is less frequent in the literature and is not presented in the available literature before, to the best of the authors′ knowledge.

The main contributions of this paper can be summarized as:

- The proposed three-stage algorithm considers the impacts of strategic bidding of NDER on the planning and operational paradigms;

- The proposed model considers five uncertainty sources: electricity price, NDERs time and installation location, NDERs power generation pattern, UDERs electricity generation, and external shocks location, duration and magnitude for the designed system;
- The model considers the impacts of different types of external shocks on the ORDSEP;
- The problem evaluates the market power of NDERs in the restoration plans in contingency conditions.

The rest of the paper is organized as follows. The proposed problem formulation and solution algorithm are presented in Sections 3 and 4, respectively. In Section 5, simulation results are investigated, and Section 6 concludes the paper.

3. Problem Formulation

When a distribution system considers energy transactions with the NDERs in its normal state and external shocks conditions, its optimal operation and expansion planning of energy resources are highly dependent on the pattern, time and volume of the transacted energy with the NDERs. However, NDERs can withhold their capacity and energy generation in normal and external shock conditions of distribution system to maximize their benefits, increase the operational costs of the system as well as the electricity price that is delivered to the system's consumers.

The dynamic expansion model is utilized to consider the energy resources dynamic behaviours and NDERs commitment [13-15].

3.1. Capacity Withholding of NDERs

An NDER may have market power and strategically bid to maximize its profit. The network congestion and energy loss may change the LMPs of system [16]. The NDER can change the value of LMPs by increasing its bid price or reducing its output; these procedures are known as economic withholding and capacity withholding, respectively [16].

In this paper, only capacity withholding of NDER is considered. The capacity withholding assessment can be performed in ex-ante and/or ex-post methods [17]. When the electric distribution grid is congested, the ability of NDERs for strategic behaviour will be increased. The Distribution System Operator (DSO) must consider the impact of different capacity withholding strategies of NDERs on its expansion-planning problem and operational paradigms in an ex-ante manner to prevent these procedures.

The DSO has different control variables and paradigms to mitigate strategic behaviour of NDERS in the external shock conditions that can be categorized into the following groups:

1) The system energy resources location and capacity that is determined in the planning stage,

2) The system energy resources commitment that is determined in the operational stage,

3) The DSO can pay capacity and energy fees to selected NDERs and buy their generated electricity based on the bilateral contract,

4) Penalize the NDERs that exercise strategic bidding.

The DSO supplies its heating loads through its boilers and CHPs; meanwhile, its DERs delivers the electricity to the electric loads through the main grid. The DRP alternatives are Direct Load Control (DLC) and Time Of Use (TOU) methods [18].

3.2. Uncertainty Modelling of ORDSEP

The NDERs can be categorized into dispatchable NDERs and non-dispatchable NDERs. The ORDSEP procedure considers only dispatchable NDERs.

The electricity market price and NDERs time and location of installation uncertainties are classified in the first stage of uncertainty modelling. Then, the REDS initial topology, time, location and capacity of devices are determined.

A scenario-driven N-K contingency method is used to analyse the external shocks as described in [4]. The external shocks location, duration and magnitude parameters for the designed system are determined in the second stage of uncertainty modelling. The NDERs intermittent power generation scenarios are classified in the third stage of uncertainty modelling. The uncertainties of intermittent UDERs electricity generation are modelled in the fourth stage of uncertainty modelling.

The uncertain power generation parameters are modelled as a stochastic process and autoregressive integrated moving average models are utilized for generating scenarios of stochastic processes. Then, a scenario reduction method is applied as presented in [18].

3.3. First stage Problem

The ORDSEP must minimize total investment costs and aggregated operation costs of REDS for normal and external shock conditions. The objective function of ORDSEP problem is presented in (1).

$$Min\ Z_1 = \sum_{i=1}^{Nyear} \sum_{j=1}^{NExtShocks} \sum_{k=1}^{NFSUM} prob_{ij}.prob_{ik}.(C_{UDERs\ ijk}\ .I_i^{UDER} + C_{Switches\ ijk}\ .I_i^{Switches} + C_{Feeder\ ijk}\ .I_i^{Feeder} + ENSC_{ijk} + C_{Purchased\ ijk}^{WSM} + C_{Purchased\ ijk}^{NDERs} + C_{Purchased\ ijk}^{DRPs}) \tag{1}$$

$$\text{S.t:}\ G_1(x,y,z) = 0\ , \qquad H_1(x,y,z) \le 0$$

The objective function is given by: 1) the investment and operation costs of UDERs, 2) the investment and operation costs of feeders, 3) the investment and operation costs of tie-switches, 4) the Energy Not Supplied Costs (ENSCs), 5) the electricity purchased from wholesale market costs, 6) the electricity purchased from NDERs costs, and 7) the DRPs costs.

The net present value of UDERs and switches capital and operational costs can be written as:

$$C_{UDERs} = \mu * \sum_{l=1}^{Y_{UDERs\ SITE}} (C_{Capital\ l}^{UDERs} + \sum_{m=1}^{NTSUM} prob_{lm}.C_{O\&M\ lm}^{UDERs}.\tau_{lm}) \tag{2}$$

$$C_{Switches} = \mu * \sum_{n=1}^{Y_{Switches\ SITE}} (C_{Capital\ n}^{Switches} + \sum_{m=1}^{NTSUM} prob_{nm}.C_{O\&M\ nm}^{Switches}.\tau_{nm}) \tag{3}$$

The net present value of feeder capital and operational costs are presented as (4):

$$C_{Feeder} = \mu * \sum_{r=1}^{Sections} (L_r . C_{Section\ r}^{Feeder} + C_{O\&M\ r}^{Feeder}) \tag{4}$$

The energy purchased from the wholesale market, NDERs and DRPs costs can be presented:

$$C_{Purchased}^{WSM} = \sum P_{PCC}^{REDS} . \vartheta_{WSM}^{Active} + Q_{PCC}^{REDS} . \vartheta_{WSM}^{Rective} \tag{5}$$

$$C_{Purchased}^{NDERs} = \sum \gamma_{NDERs} . Cap_{NDERs} + P^{NDERs} . \vartheta_{NDERs}^{Active} + Q^{NDERs} . \vartheta_{NDERs}^{Rective} \tag{6}$$

$$C_{Purchased}^{DRPs} = \sum \gamma_{DRPs} . Cap_{DRPs} + P^{DRPs} . \vartheta_{DRPs}^{Active} + Q^{DRPs} . \vartheta_{DRPs}^{Rective} \tag{7}$$

Eq. (5) presents the energy purchased costs consist of active and reactive power costs [13]. Eq. (6) and Eq. (7) present the costs of energy purchased from NDERs and DRPs that consist of capacity fee costs and active and reactive power costs [14-15].

The first stage constraints can be categorized into the facilities-loading constraints, AC load-flow, demand-supply balancing constraints, radiality constraints, and static-security constraints [19]. The demand-supply balancing constraints and static-security constraints can be written as:

- Demand-supply balancing constraints:

  The demand-supply constraints can be presented as (8) and (9):

$$\begin{cases} \sum\left(\pm P^{NDERs} + P^{UDERs} \pm P^{DRPs}\right) \\ - \sum |V_{n'}| . |V_{m'}| . |Y_{n'm'}| . cos\left(\theta_{n'}^{REDS} - \theta_{m'}^{REDS}\right) = 0, \end{cases} \tag{8}$$

$$\begin{cases} \sum(\pm Q^{NDERs} + Q^{UDERs} \pm Q^{DRPs}) \\ + \sum |V_{n'}| . |V_{m'}| . |Y_{n'm'}| . sin\left(\theta_{n'}^{REDS} - \theta_{m'}^{REDS}\right) = 0, \end{cases} \tag{9}$$

- Static-security constraints:

  The static-security constraints are the voltage limits of buses and apparent power flow of lines that can be written as:

$$\sqrt{P_{n'm'}^{REDS^2} + Q_{n'm'}^{REDS^2}} \le S_{n'm'}^{REDS\ max} \quad , \forall n', \forall m' \tag{10}$$

$$V_{n'}^{min} \le \left|V_{n'}\right| \le V_{n'}^{max} \quad , \forall n, \forall t \tag{11}$$

All of the first stage equality and inequality constraints can be presented by $G_1(x, y, z)$ and $H_1(x, y, z)$, respectively. Where, x, y, z present the control variable vector, state variable vector, and topology variable vector, respectively.

3.4. Second Stage Problem Formulation

The REDS utilizes price based unit commitment to estimate the optimal bidding scenarios of NDERs [18]. The objective function of the second stage problem can be presented as (12). The second stage problem is calculated for each of the wholesale market price scenarios.

$$Max\ Z_2 = \sum_{m=1}^{NTSUM} \sum_{t=1}^{NSSUM} prob_{mt}.\left[J_{mt}.B_{NDERs\ mt}\right]$$
$$S.t: G_2(x,y,z) = 0\ , \qquad H_2(x,y,z) \leq 0 \tag{12}$$

$$B_{NDERs} = \sum_{a=1}^{NNDERs} (Revenue_{NDERs\ a} - C_{NDERs\ a}) \tag{13}$$

$$Revenue_{NDERs} = \sum Cap_{NDERs} \cdot \gamma_{NDERs} + \sum \vartheta_{NDERs}^{Active}. P^{NDERs} + \sum \vartheta_{NDERs}^{Rective}. Q^{NDERs} \tag{14}$$

The revenue of NDER consists of capacity payment and active and reactive energy fees that are paid by the REDS as presented in (14).

The second stage constraints are the same as the first stage problem constraints that can be categorized into the facilities-loading constraints, AC load-flow, demand-supply balancing constraints, radiality constraints, and static-security constraints. The compact form of the presented constraints can be written as $G_2(x,y,z)$ and $H_2(x,y,z)$ that are equality equation and inequality equation constraints, respectively.

It is assumed that the NDERs submit the outputs of their optimization process to the REDS operator and the REDS evaluates the optimality of submitted bids in the third stage.

3.5. Third Stage Problem Formulation

REDS utilizes hourly security-constrained unit commitment to schedule the REDS energy resources and dispatchable NDERs in normal and external shock conditions based on the (15) formulation. At this stage, the accepted bids of NDERs are considered as the optimal values of capacity payment and energy fees. The third stage objective function minimizes the expected value of UDERs/DRPs costs, penalties and Market Power Index (MPI) as presented in (17); meanwhile, it maximizes the benefit of dispatchable NDERs.

$$Min\ Z_3 = \sum_{b=1}^{NNExtShocks} prob_b \,.(\sum_{d=1}^{NFOSUM} prob_{bd}.\Big[K_{bd}.(C_{UDERs\ bd} + C_{DRPs\ bd})$$
$$- B_{NDERs\ bd} + MPI_{bd} + \sum_{a=1}^{NNDERs} Penalty_{\ NDERs\ abd} + ENSC\Big]) \tag{15}$$

$$S.t: G_3(x,y,z) = 0\ , \qquad H_3(x,y,z) \leq 0$$

$$Penalty_{NDERs} = \begin{cases} \alpha . S_{NDERs} & if\ NWSR \geq \varepsilon \\ 0 & if\ NWSR \leq \varepsilon \end{cases} \tag{16}$$

$$MPI = W_1.\Gamma + W_2.MLI + W_3.RSI - W_4.MPCMI + W_5.NWSR \tag{17}$$

$$\Gamma = (\sum_{e=1}^{NLs} LMP_e.P_{L\,e} - \sum_{g=1}^{NGs} LMP_g.P_{G\,g}) / \sum_{e=1}^{NLs} LMP_e.P_{L\,e} \tag{18}$$

$$MLI = \frac{\pi - mc}{\pi} \tag{19}$$

$$MPCMI = \frac{\pi - mc}{mc} \tag{20}$$

$$RSI = \frac{\sum_{e=1}^{NLs} P_{L\,e} - P}{\sum_{e=1}^{NLs} P_{L\,e}} \tag{21}$$

$$NWSR = \frac{\Delta P^{withhold}}{P^e} \tag{22}$$

Eq. (17) presents the MPI index that consists of the weighted value of differences of locational marginal price generation and load buses, Modified Lerner index (MLI), Residual Supply Index (RSI), Modified Price-Cost Margin Index (MPCMI) of system, and Nodal Withholding-Supply Ratio (NWSR) as presented in (18), (19), (20), (21), and (22), respectively [20]. Where, mc is the marginal cost of NDER or DRP and P is the generated power of NDER or DRP. The NWSR index presents the potential ability of NDER for capacity withholding in the presence of the distribution system congestion [20]. P^e and $P^{withheld}$ are the NDER/DRP in the oligopoly market and deviation of NDER/DRP electricity generations that are withheld from the market, respectively. The Lerner index and PCMI are used in the uniform price market. However, in the locational marginal price market, these indices can be modified and the π variable is the Average LMP (ALMP) of the system [10].

The third stage constraints are the same as the first stage constraints and the compact form of the third stage constraints can be written as $G_3(x, y, z)$ and $H_3(x, y, z)$ that are equality equation and inequality equation constraints, respectively.

At the third stage of the optimization problem, the REDS must consider different cases for capacity payment and energy fees to buy generated electricity of NDERs based on the bilateral contract to overcome the impacts of probable external shocks. Further, the REDS can reconfigure its system and change the status of its tie-switches to reduce the MPI in normal states and perform restoration plans in external shock conditions. Thus, the third-stage problem can be formulated as an iterative problem. The bilateral contract parameters and restoration of the system are considered for the N-K external shock contingencies. The REDS must calculate MPI and NWSR for each interval of the third stage optimization.

4. Solution Algorithm

The proposed model of ORDSEP is an MINLP problem that has non-linear, non-convex discrete and continuous variables. Fig. 1 shows the flowchart of the proposed ORDSEP algorithm. The proposed ORDSEP problem is formulated as an iterative three-stage stochastic program. For the first stage optimization problem, a particle swarm optimization (PSO) is used. The candidates of facilities installation are determined at the first stage optimization. The details of PSO is presented in [21]. Then, the external shocks scenarios based on the N-K contingency method are generated for the designed system.

At the second stage, bidding scenarios of NDERs are generated and different bidding conditions of NDERs are considered. For the second stage problem, the DICOPT solver is utilized [22].

At the third stage, the PSO algorithm is utilized and the optimal scheduling of the REDS energy resources is established. At the third stage and for the normal operational condition, the REDS evaluates the NDERs bidding parameters and it can reconfigure its system topology to reduce the value of MPI in normal state. Further, for the designed system, the commitment of REDS resources are considered for each external shock scenario and a restoration procedure is processed to minimize the ENSC.

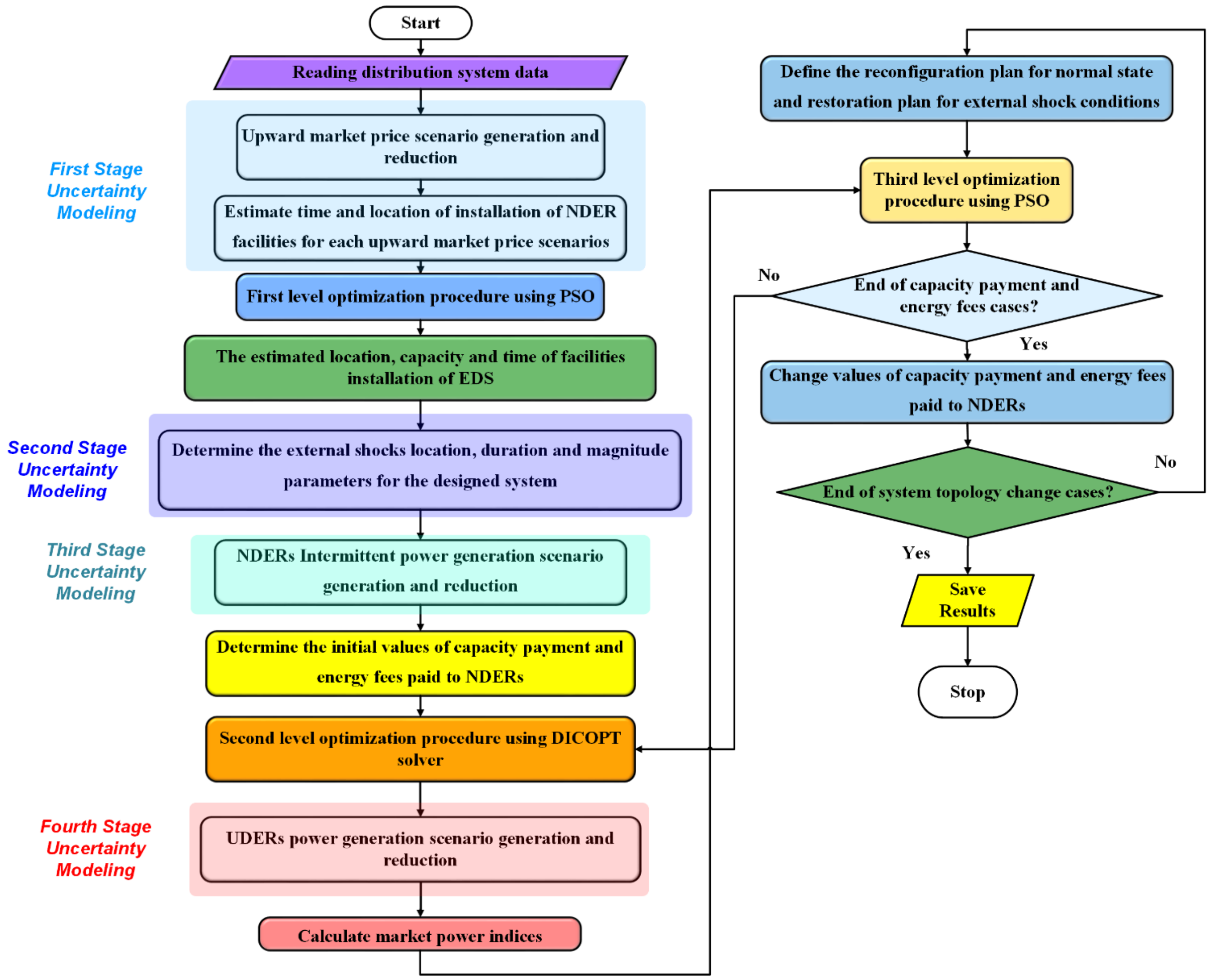


Fig. 1. The proposed ORDSEP algorithm.

For each of external shock condition, the strategic bidding of NDERs is assessed by different indices and the feasibility of their bidding in external shock conditions is evaluated. Then, the REDS can determine the optimal values of capacity payment and energy fees to specified NDERs/DRPs and buying their generated/injected electricity based on the bilateral contract.

5. Simulation Results

The proposed ORDSEP algorithm was assessed on 21-bus and 123-bus test systems [23-24]. All of the weighting factors are assumed equal to one. Table 1 provides the optimization input data for the 21-bus test system. Fig. 2 (a) and (b) illustrate the 21-bus and 123-bus tests systems.

Three cases were considered for case studies as follows:

a) ORDSEP without considering the MPI in third stage objective function, the bilateral contract between REDS and NDERs in external shock conditions, and reconfiguration of REDS in normal condition,

b) ORDSEP without considering bilateral contract between REDS and NDERs in external shock conditions,

c) The complete ORDSEP procedure.

5.1. The 21-bus test system

The data wind turbine and solar panel data are given at [18]. Further, the DRP data are available in [18]. Table 2 presents the external shocks categories that are considered in the ORDSEP.

Fig. 3 (a) presents the utility photovoltaic systems and wind turbines electricity generation for the horizon year of planning. Fig. 3 (b) depicts the stacked column of gas engine UDERs electricity generation for the third scenario and 5th year of the planning horizon.

Table 1. The optimization input data for the 21-bus test system.

Parameter	Value
Planning horizon year	**5**
Discount rate (%)	**10**
Inflation rate (%)	**7**
Load power factor	**0.98**
Load growth rate (%)	**4**
Number of NDERs power generation scenarios	**4000**
Number of upward market price scenarios	**100**
Number of UDERs power generation scenarios	**3500**
Number of NDERs power generation reduced scenarios	**40**
Number of UDERs power generation reduced scenarios	**35**
Number of upward market price reduced scenarios	**10**

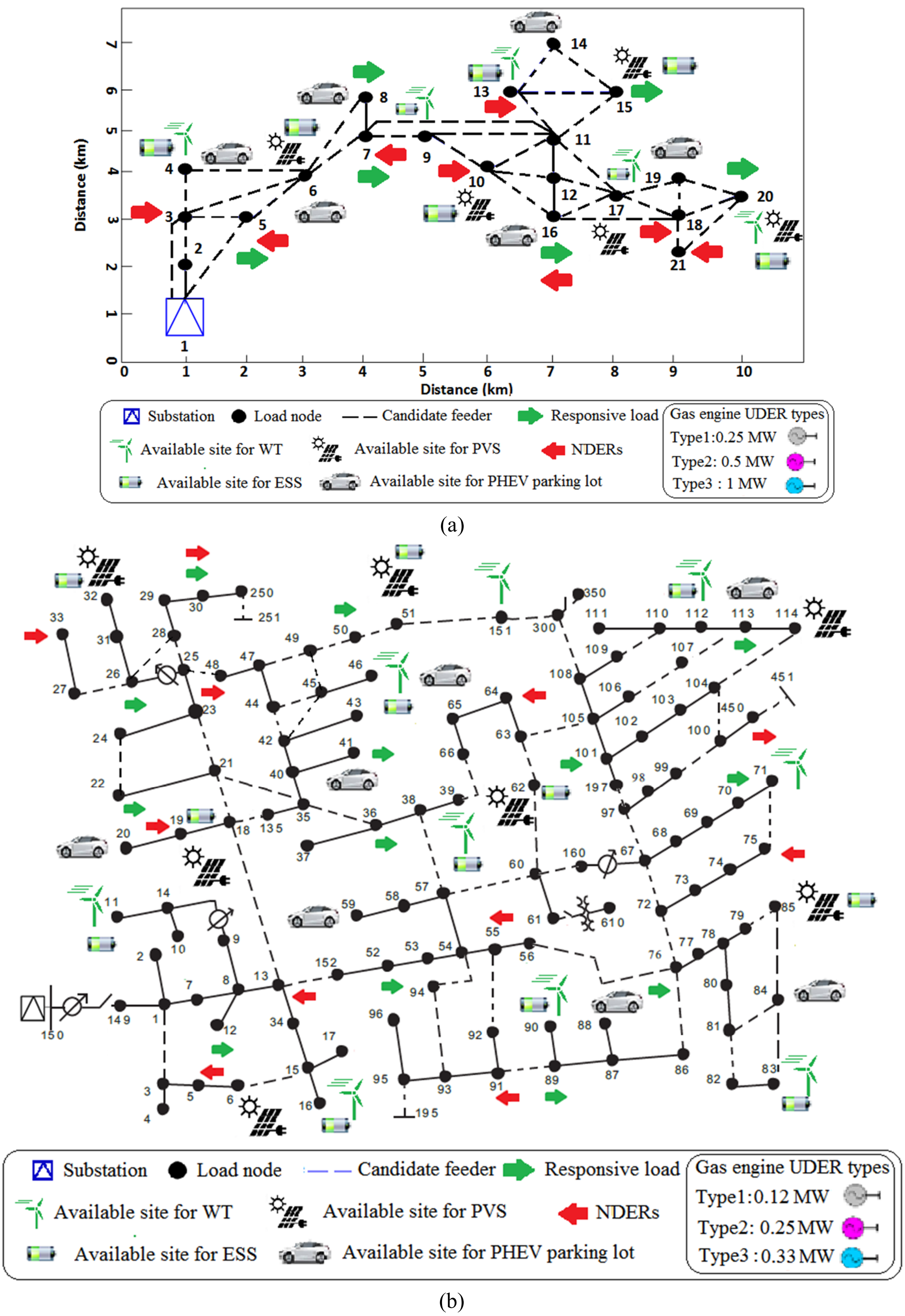


Fig. 2. Case study test systems: (a) 21 bus; (b) 123-bus

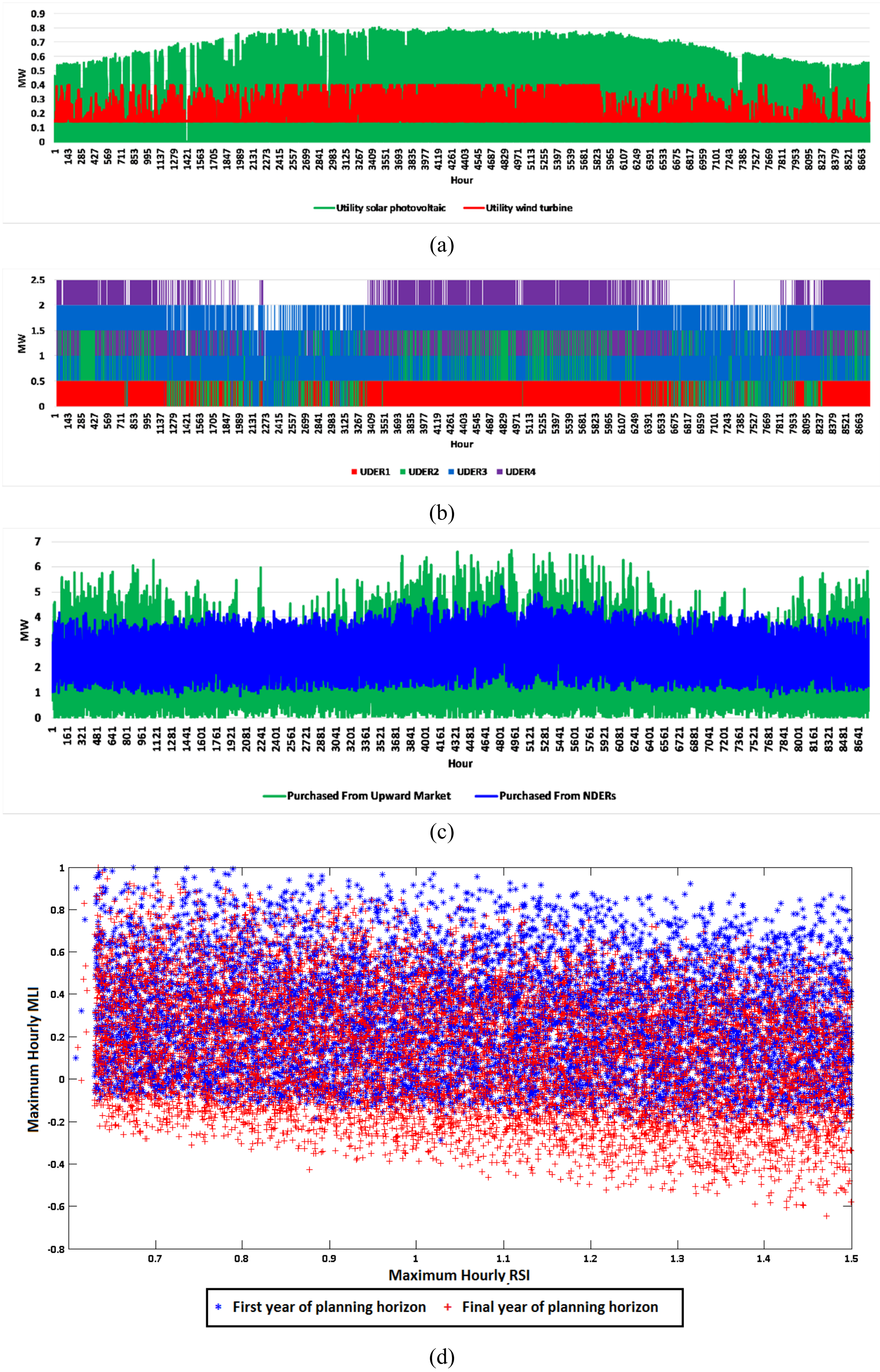


Fig. 3. Expected electricity generation, electricity purchased and sold and market power indices for the planned 21-bus REDS

(a) Expected electricity generation of photovoltaic systems and wind turbines, 5th planning year, 3rd scenario

(b) Expected electricity generation of UDERs, 5th planning year, 3rd scenario

(c) Expected electricity purchased, 5th planning year, 3rd scenario

(d) Expected maximum hourly MLI versus RSI for the third scenario and different planning years

Table 2. The external shock scenarios.

External Shock Category	Shocks
Extreme	Triple line outage
	Triple DG outage
	Combination of above shocks
Expected	Double line outage
	Double DG outage
	Single line and double DG outage
	Combination of above shocks
Routine	Single line and DG outage
	Double line outage

As shown in Fig. 3 (b) the aggregated power generation of gas engine UDERs is 2.5 MW and the third UDER has been continuously committed. Fig. 3 (c) shows the aggregated purchased electricity from upward and NDERs. Table 3 presents the percentage of expected average values of total annual energy sold to REDS for different cases. According to Table 3, NDERs were sold electricity to REDS about 0.4351, 0.3935, and 0.3712 per-unit of total energy consumption for the first, second and third scenario, respectively. Fig. 3 (d) depicts the expected maximum hourly MLI versus RSI. As shown in Fig. 3 (d) the MLI is reduced for the final year of planning horizon based on the fact that the ORDSEP is reduced the market power of NDERs.

The total energy of load and energy generated by the intermittent power generation for the final planning horizon and the third case were 37766.11 MWh and 15581.38 MWh, respectively. The percentage of penetration of renewables for the final planning horizon was about 41%. The intermittent power generation facilities were equipped with the electrical energy storage systems and the REDS optimally dispatched the system resources in the external shock conditions.

By analysing of Table 3, it is can be concluded that the second case reduced the market power of NDERs. Further, the third case that considered the bilateral contract between REDS and NDERs has prevented NDERs to impose market power. Fig. 4 depicts the final topologies of the 21-bus test system for different scenarios planning at the 5th year of the planning horizon. As shown in Fig. 4 (c), the ORDSEP installed more UDERs and tie switches for the third scenario to reduce the strategic behaviour of NDERs and reduce the total costs of the REDS.

Table 4 depicts the expected average values of MPI components for different scenarios and planning years. The values of MLI, RSI, NWSR, and Γ were reduced in the second and third cases with respect to the first case. Thus, the ability of NDERs to impose market power was reduced. Further, the MPCMI values were increased from case 1 to case 3 and the ability of NDERs for market power imposing was reduced. The MPI value was decreased by about 19.01% and 25.87% for the second and third case with respect to the first case.

Table 3. Expected electricity sold to REDS by NDERs for different years and scenarios for the 21-bus test system.

	NDER Number	1	2	3	4	5	6	7	8
Year 1	Case 1	0.0551	0.0532	0.0548	0.0548	0.0547	0.0532	0.0546	0.0548
	Case 2	0.0485	0.0495	0.0492	0.0492	0.0492	0.0495	0.0492	0.0492
	Case 3	0.0464	0.0472	0.0460	0.0460	0.0461	0.0472	0.0462	0.0460
Year 2	Case 1	0.0608	0.0594	0.0608	0.0590	0.0609	0.0576	0.0598	0.0587
	Case 2	0.0541	0.0554	0.0537	0.0551	0.0541	0.0543	0.0545	0.0538
	Case 3	0.0497	0.0512	0.0494	0.0510	0.0500	0.0523	0.0509	0.0508
Year 3	Case 1	0.0645	0.0623	0.0655	0.0638	0.0640	0.0615	0.0632	0.0656
	Case 2	0.0566	0.0570	0.0585	0.0585	0.0569	0.0576	0.0574	0.0574
	Case 3	0.0539	0.0558	0.0549	0.0546	0.0549	0.0566	0.0549	0.0540
Year 4	Case 1	0.0670	0.0635	0.0664	0.0662	0.0662	0.0629	0.0660	0.0654
	Case 2	0.0596	0.0607	0.0602	0.0585	0.0594	0.0590	0.0600	0.0602
	Case 3	0.0562	0.0563	0.0556	0.0551	0.0555	0.0571	0.0550	0.0551
Year 5	Case 1	0.0686	0.0645	0.0685	0.0673	0.0681	0.0646	0.0662	0.0680
	Case 2	0.0597	0.0605	0.0600	0.0594	0.0596	0.0604	0.0611	0.0597
	Case 3	0.0560	0.0590	0.0571	0.0568	0.0564	0.0573	0.0556	0.0560

Table 4. The average values of MPI components for the 21-bus test system.

Case	Year	MLI	RSI	MPCMI	NWSR	GAMA
Case 1	**Year 1**	0.2751	0.2471	0.2533	0.2176	0.1503
Case 2		0.1617	0.2195	0.3363	0.1771	0.1029
Case 3		0.1116	0.1475	0.4376	0.1364	0.0514
Case 1	**Year 2**	0.2937	0.2770	0.2684	0.2276	0.1559
Case 2		0.1653	0.2444	0.3649	0.1997	0.0969
Case 3		0.1273	0.1637	0.4348	0.1596	0.0541
Case 1	**Year 3**	0.3180	0.2862	0.2843	0.2705	0.1654
Case 2		0.1609	0.2350	0.3395	0.1882	0.1072
Case 3		0.1225	0.1654	0.4978	0.1487	0.0555
Case 1	**Year 4**	0.3291	0.2908	0.3338	0.2781	0.1941
Case 2		0.1856	0.2588	0.4025	0.2039	0.1075
Case 3		0.1381	0.1671	0.4838	0.1678	0.0556
Case 1	**Year 5**	0.3267	0.3257	0.3503	0.2935	0.2024
Case 2		0.1867	0.2638	0.4034	0.2341	0.1166
Case 3		0.1365	0.1970	0.5726	0.1783	0.0627

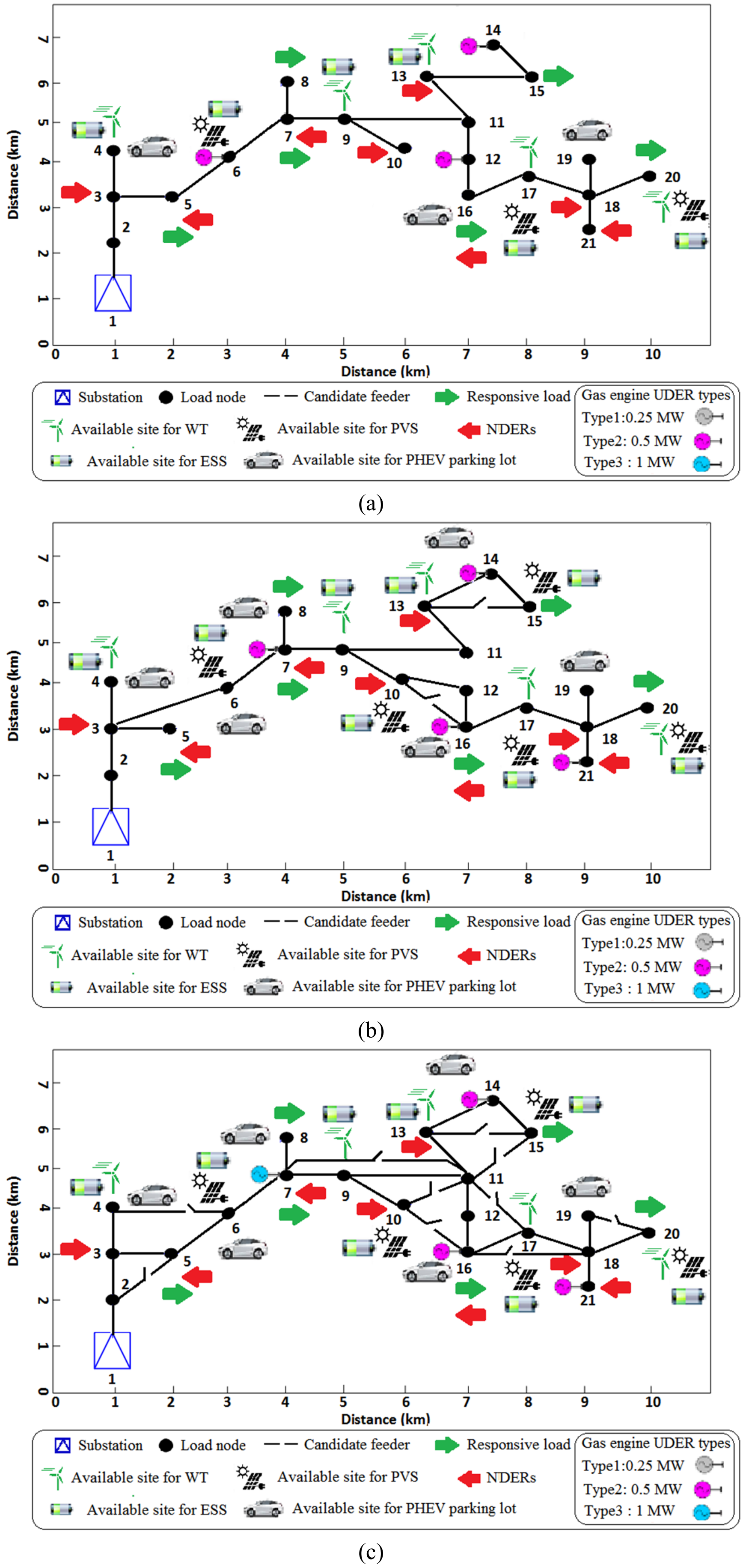


Fig. 4. The optimal topology of the 21-bus test system for the 5th year of the planning horizon (a) First scenario (b) Second scenario (c) Third scenario

Fig. 5 (a) presents the expected values of Maximum Daily LMP (MDLMP) for the third scenario and fifth year of planning year of 21-bus system. The minimum and maximum values of MDLMP are 28.32 (MU/kWh) and 67.92 (MU/kWh), respectively. The average value of MDLMP is reduced by about 19.32% with respect to the first scenario for the fifth year of planning year. Fig. 5 (b) presents the expected bidding values of apparent power, active power and reactive power of NDERs for the fifth year of the planning horizon and third scenario that are the outputs of the second stage problem. The average values of active and reactive power of NDERs biddings are about 2.9857 MW and 0.9241 MVAR, respectively. Further, Fig. 5 (c) presents the expected accepted bidding values of apparent power, active power and reactive power of NDERs for the fifth year of the planning horizon and third scenario that are the outputs of the third stage problem. The average values of accepted active and reactive power of NDERs biddings are about 2.5515 MW and 0.9124 MVAR, respectively. Fig. 5 (d) shows the total electricity generation costs by UDERs, electricity purchased from wholesale and NDERs costs, investment and operational costs and aggregated costs for first, second and third scenarios. As shown in Fig. 5 (d), the ORDSEP reduced the aggregated costs of REDS by about 11.82% with respect to the first scenario. The purchased electricity from DRPs were about 0.179, 0.292 and 0.41 of the corresponding values of electricity purchased from NDERs for the 1st, 2nd and 3rd scenarios, respectively.

To assess the accuracy of the proposed algorithm, the whole state-space of the problem was searched. The simulation was carried out on a PC (Intel Core i7, quad-core, 2.93 GHz, 8 GB RAM). The simulation time for the proposed and the full search methods for the 21-bus tests system were about 5149 seconds and 99733 seconds, respectively.

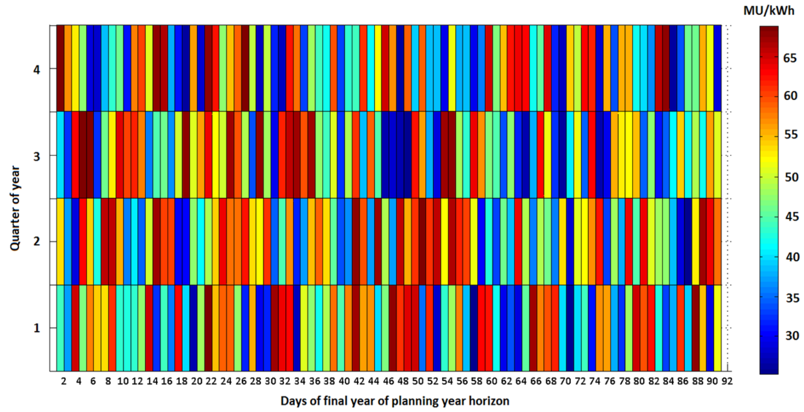
Table 5 depicts the results of the full search method. By comparing the corresponding values, it can be concluded that the proposed ORDSEP found the absolute optimal solution.

Table 5. The solution of the full search method for ORDSEP of the 21-bus test system

	Electricity Generation Costs	Electricity purchased from NDERs costs	Electricity purchased from market costs	Electricity purchased from DRPs costs	ENSC	Total Operational Costs	Investment Costs	Total Costs
Case 3	3.0575E+07	2.0190E+07	4.1900E+07	8.2900E+06	5.0500E+06	1.0600E+08	5.8300E+07	1.6400E+08

5.2. The 123-bus test system

Table 6 depicts the input parameters of the optimization procedure for the 123-bus test system. For this case study, the external shocks are the same as the previous case study. The simulation time for the 123-bus tests system was about 19761 seconds.



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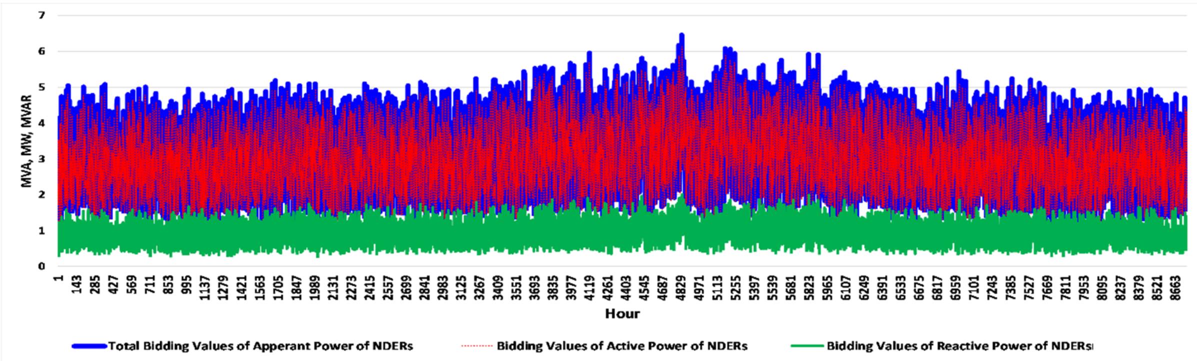

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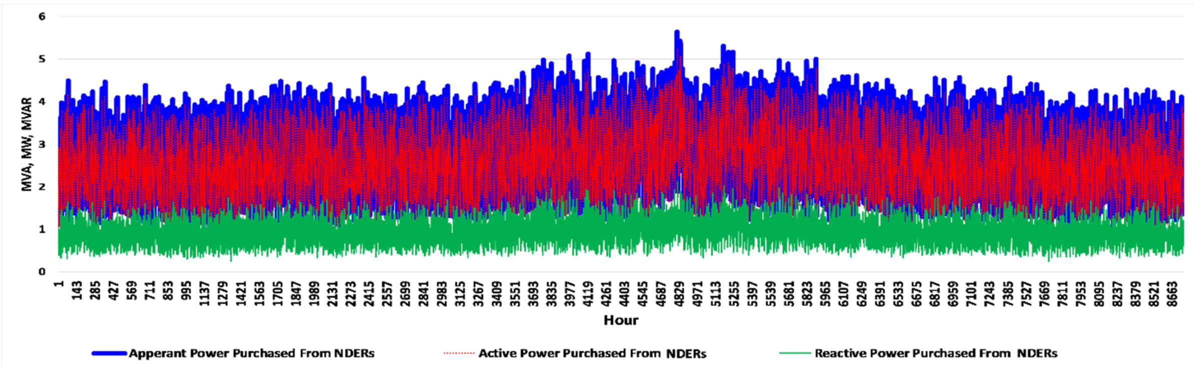

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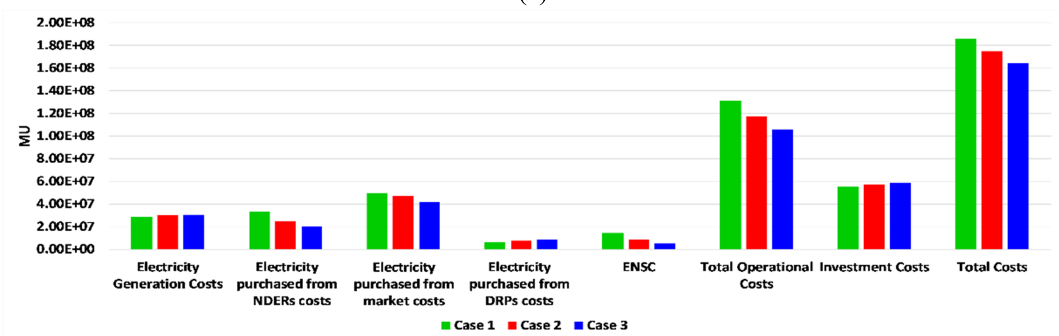


(d)

Fig. 5. (a) The expected values of maximum daily LMP for the third scenario and fifth year of planning year of the 21-bus system

(b) Total expected bidding values of apparent power, active power and reactive power of NDERs for the fifth year of planning and third scenario (Second stage problem outputs)

(c) Total expected accepted bidding values of apparent power, active power and reactive power of for the fifth year of planning and third scenario (Third stage problem outputs)

(d) The expected values of electricity generation costs, electricity purchased costs and components of aggregated planning and operational costs for different ORDSEP scenarios

Table 6. The optimization input data for the 123-bus test system.

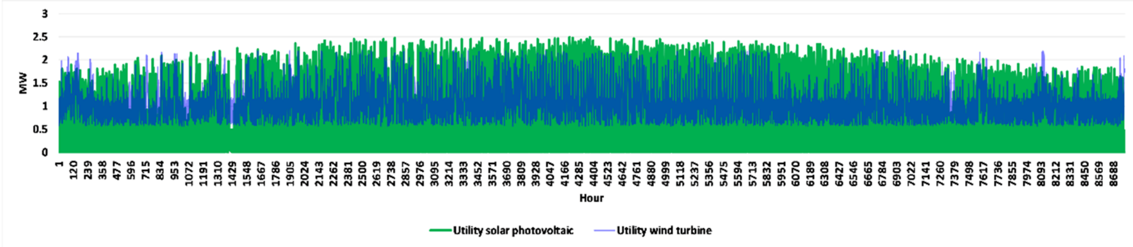
Parameter	Value
Planning horizon year	**5**
Discount rate (%)	**10**
Inflation rate (%)	**7**
Load power factor	**0.99**
Load growth rate (%)	**5**
Number of NDERs power generation scenarios	**12000**
Number of upward market price scenarios	**100**
Number of UDERs power generation scenarios	**10500**
Number of NDERs power generation reduced scenarios	**120**
Number of UDERs power generation reduced scenarios	**70**
Number of upward market price reduced scenarios	**10**

Fig. 6 (a) depicts the 123-bus utility photovoltaic systems and wind turbines electricity generation for the horizon year of planning. Fig. 6 (b) presents the stacked column of gas engine UDERs electricity generation of the 123-bus system for the third scenario and the 5th year of the planning horizon. Fig. 6 (c) shows the NDERs unit commitment for the 5th year of the planning horizon and the third scenario. As shown in Fig. 6 (c), the NDER1, NDER2 and NDER3 were fully committed and the REDS purchased all of their generated electricity. Fig. 6 (d) presents the expected maximum hourly MLI versus RSI for the third scenario and the 1st and 5th year of planning years. As shown in Fig. 6 (d) the MLI highly is reduced for the final year of the planning horizon and market power of NDERs is reduced.

The total energy of load and energy generated by the intermittent power generation for the final planning horizon and the third case were 131387.2 MWh and 15489.05 MWh, respectively. The percentage of penetration of renewables for the final planning horizon was about 11.78%. Further, the intermittent power generation facilities were equipped with the electrical energy storage systems and the REDS optimally dispatched the system resources in the external shock conditions.

Table 7 presents the percentage of expected average values of total annual energy sold to REDS for different cases. NDERs sold electricity to REDS about 0.199, 0.197, and 0.1720 per-unit of total energy consumption for the first, second and third scenario, respectively.

Fig. 7 shows the final topologies of the 123-bus test system for different scenarios planning at the 5th year of the planning horizon. Table 8 presents the expected average values of MPI components for different scenarios and planning years of the 123-bus system. The MLI, Γ and NWSR values were decreased about 45.3%, 71.2% and 16.69% for the third case with respect to their values in the first case.



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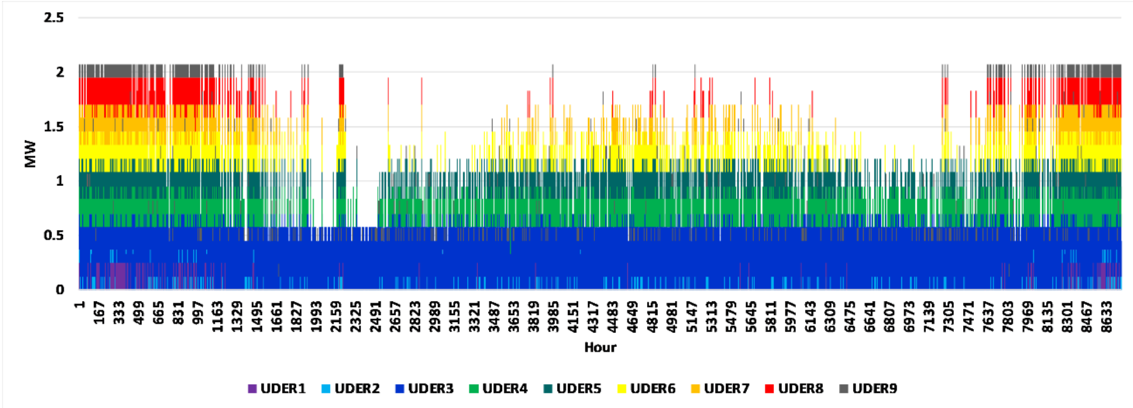

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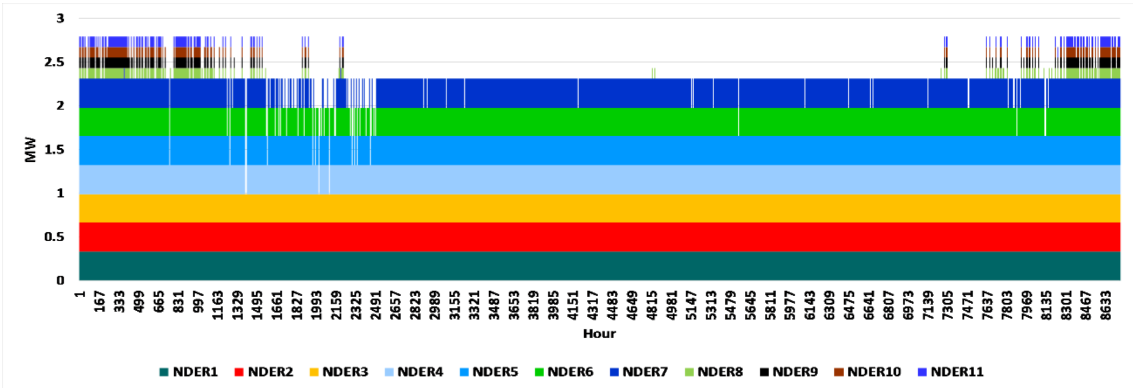

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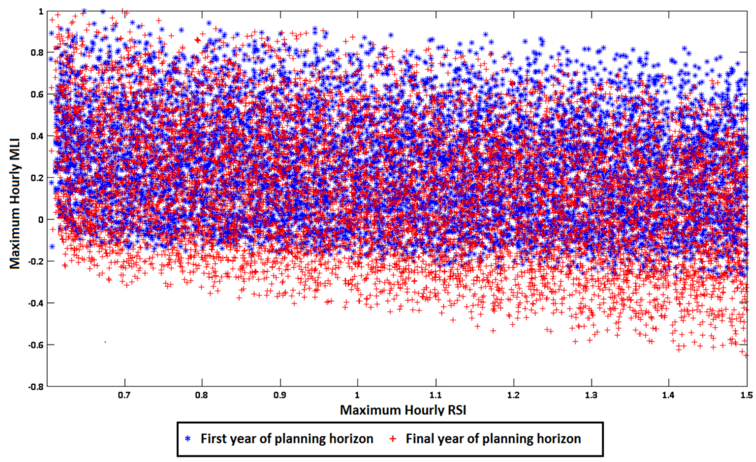


(d)

Fig. 6. Expected electricity generation, electricity purchased and sold and market power indices for the planned 123-bus REDS

(a) Expected electricity generation of photovoltaic systems and wind turbines, 5th planning year, 3rd scenario

(b) Expected electricity generation of UDERs, 5th planning year, 3rd scenario

(c) Expected electricity purchased, 5th planning year, 3rd scenario

(d) Expected maximum hourly MLI versus RSI for the third scenario and different planning years

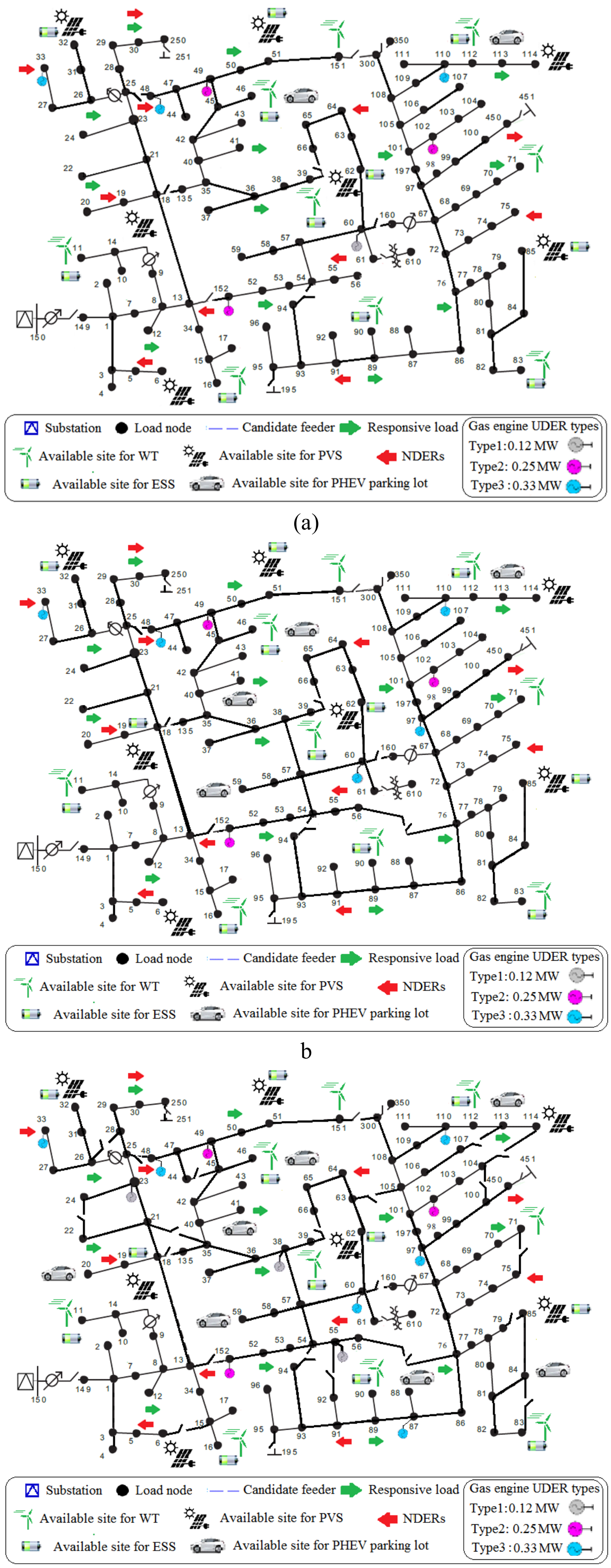


Fig. 7. The optimal topology of the 123-bus test system for the 5th year of planning horizon for (a) First scenario (b) Second scenario (c) Third scenario expansion planning horizon

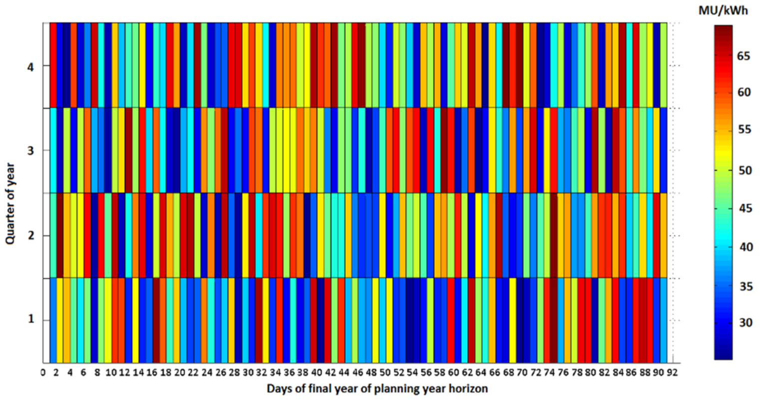
Table 7. Expected electricity sold to REDS by NDERs for different years and scenarios for the 123-bus test system.

	NDER Number	1	2	3	4	5	6	7	8	9	10	11
Year 1	Case 1	0.0256	0.0256	0.0256	0.0256	0.0256	0.0247	0.0242	0.0031	0.0031	0.0031	0.0031
	Case 2	0.0256	0.0256	0.0256	0.0256	0.0256	0.0247	0.0242	0.0031	0.0031	0.0031	0.0031
	Case 3	0.0216	0.0220	0.0214	0.0214	0.0214	0.0220	0.0215	0.0031	0.0031	0.0031	0.0031
Year 2	Case 1	0.0261	0.0261	0.0261	0.0261	0.0261	0.0252	0.0247	0.0031	0.0031	0.0031	0.0031
	Case 2	0.0261	0.0261	0.0261	0.0261	0.0261	0.0252	0.0247	0.0031	0.0031	0.0031	0.0031
	Case 3	0.0220	0.0224	0.0218	0.0218	0.0219	0.0224	0.0219	0.0031	0.0031	0.0031	0.0031
Year 3	Case 1	0.0269	0.0269	0.0269	0.0269	0.0269	0.0259	0.0254	0.0032	0.0032	0.0032	0.0032
	Case 2	0.0269	0.0269	0.0269	0.0269	0.0269	0.0259	0.0254	0.0032	0.0032	0.0032	0.0032
	Case 3	0.0227	0.0231	0.0225	0.0225	0.0225	0.0231	0.0226	0.0032	0.0032	0.0032	0.0032
Year 4	Case 1	0.0279	0.0279	0.0279	0.0279	0.0279	0.0269	0.0264	0.0033	0.0033	0.0033	0.0033
	Case 2	0.0279	0.0279	0.0279	0.0279	0.0279	0.0269	0.0264	0.0033	0.0033	0.0033	0.0033
	Case 3	0.0235	0.0239	0.0233	0.0233	0.0234	0.0239	0.0234	0.0033	0.0033	0.0033	0.0033
Year 5	Case 1	0.0282	0.0282	0.0282	0.0282	0.0282	0.0271	0.0266	0.0034	0.0034	0.0034	0.0034
	Case 2	0.0282	0.0282	0.0282	0.0282	0.0282	0.0271	0.0266	0.0034	0.0034	0.0034	0.0034
	Case 3	0.0238	0.0242	0.0236	0.0235	0.0236	0.0242	0.0236	0.0034	0.0034	0.0034	0.0034

Table 8. The average values of MPI components for the 123-bus test system.

Case	Year	MLI	RSI	MPCMI	NWSR	GAMA
Case 1	**Year 1**	0.2861	0.2590	0.2620	0.2388	0.1443
Case 2		0.1469	0.2181	0.3168	0.1945	0.0945
Case 3		0.1187	0.1541	0.4030	0.1360	0.0483
Case 1	**Year 2**	0.2789	0.2652	0.2804	0.2481	0.1559
Case 2		0.1657	0.2383	0.3702	0.1992	0.1049
Case 3		0.1196	0.1500	0.4696	0.1407	0.0486
Case 1	**Year 3**	0.3011	0.3016	0.2749	0.2373	0.1700
Case 2		0.1732	0.2385	0.3790	0.1875	0.0961
Case 3		0.1152	0.1563	0.4996	0.1551	0.0482
Case 1	**Year 4**	0.3140	0.3015	0.3287	0.2811	0.1814
Case 2		0.1769	0.2633	0.4091	0.2119	0.1187
Case 3		0.1326	0.1852	0.5298	0.1641	0.0524
Case 1	**Year 5**	0.3383	0.3101	0.3556	0.2759	0.1921
Case 2		0.1926	0.2560	0.4206	0.2375	0.1209
Case 3		0.1475	0.1889	0.5189	0.1719	0.0612

Fig. 8 (a) presents the expected values of MDLMP for the third scenario and fifth year of planning year of 123-bus system. The minimum and maximum values of MDLMP are 27.65 (MU/kWh) and 68.85 (MU/kWh), respectively. The average value of MDLMP is reduced by about 23.68% with respect to the first scenario for the fifth year of planning year. Fig. 8 (b) presents the expected bidding values of apparent power, active power and reactive power of NDERs for the fifth year of the planning horizon and third scenario for the 123-bus system. The average values of active and reactive power of NDERs biddings are about 2.1336 MW and 0.6612 MVAR, respectively.



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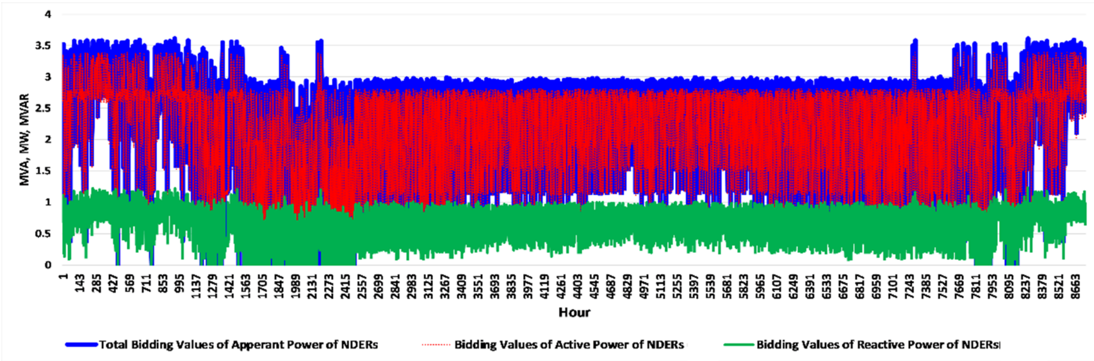

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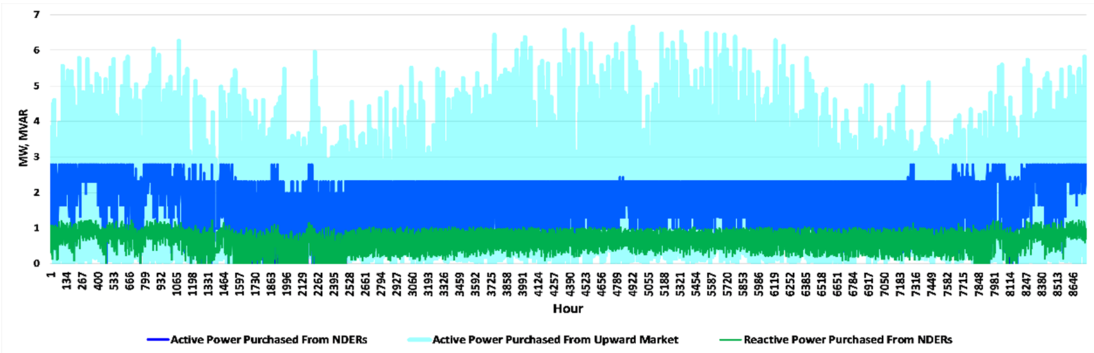

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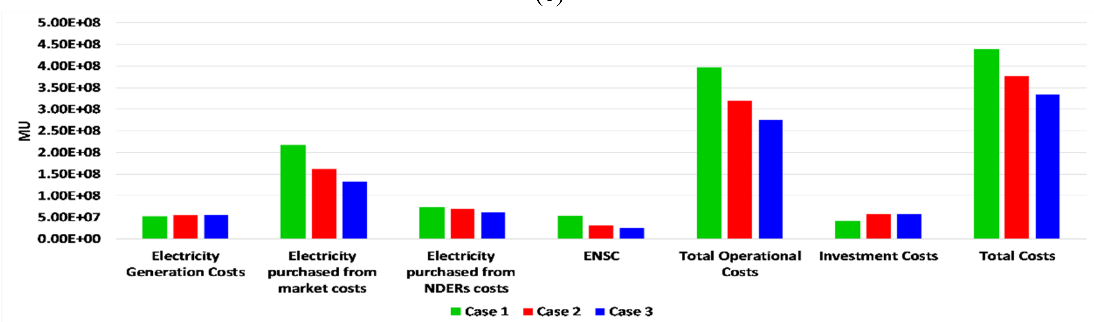

(d)

Fig. 8. (a) The expected values of maximum daily LMP for the third scenario and fifth year of planning year of 123-bus system
(b) Total expected bidding values of apparent power, active power and reactive power of NDERs for the fifth year of planning and third scenario (Second stage problem outputs)
(c) Total expected accepted bidding values of apparent power, active power and reactive power of NDERs and purchased active power from the upward market for the fifth year of planning and third scenario (Third stage problem outputs)
(d) The expected values of electricity generation costs, electricity purchased costs and components of aggregated planning and operational costs for different ORDSEP scenarios

Fig. 8 (c) presents the expected accepted bidding values of apparent power, active power and reactive power of NDERs and purchased active power from the upward market for the fifth year of the planning horizon and third scenario for the 123-bus system. The average values of accepted active and reactive power of NDERs biddings are about 1.8232 MW and 0.6597 MVAR, respectively. Fig. 8 (d) shows the total electricity generation costs by UDERs, electricity purchased from wholesale and NDERs costs, investment and operational costs and aggregated costs for first, second and third scenarios. The aggregated costs of REDS was reduced by about 23.74% with respect to the first scenario. The aggregated planning costs of 123-bus tests system was reduced more than 21-bus tests system based on the fact that the larger system may expose to more severe external shocks and the ORDSEP can optimally present the expansion planning and operational paradigm.

6. Conclusion

This paper introduced a multi-stage optimization framework for resilient expansion planning of distribution systems that transacted energy with non-utility distributed energy resources in its normal and external shock conditions. Different sources of uncertainties were modelled in the algorithm that consisted of upward electricity price, non-utility distributed energy resources time, location of installation, and power generation pattern, utility-owned energy resources electricity generation, and the external shocks location, duration and magnitude for the designed system. The conclusion can be summarized as follows:

- The introduced algorithm problem is formulated as an iterative three-stage stochastic program.
- At the 1st stage, the system forecasts upward market prices for the planning horizon and it estimates different scenarios for non-utility energy resources power injections into the system. The external shocks scenarios based on the N-K contingency method are generated for the designed system. It minimizes the aggregated investment, operational and energy not-supplied costs for the planning year horizon.
- At the 2nd stage, bidding scenarios of non-utility energy resources are generated and different bidding conditions are considered based on a price based unit commitment procedure.
- At the 3rd stage and for the normal operational condition, the system evaluates the non-utility energy resources bidding parameters and tries to reduce the value of market power indices in normal state. Further, for the designed system, the commitment of system resources are considered for each external shock scenario and a restoration procedure is processed to minimize the energy not-supplied costs. For each external shock condition, the strategic bidding of non-utility energy resources is assessed by different indices and the feasibility of their bidding in external shock conditions is evaluated. Then, the system can determine the optimal values of capacity payment and energy fees to specified non-utility energy resources and demand response providers and buying their generated/injected electricity based on the bilateral contract.

- Two test systems were considered. The algorithm decreased the combined total costs for the 21-bus and 123-bus systems in 11.82% and 23.74% comparatively to the custom expansion planning exercises. Further, the average value of maximum daily locational marginal price for the 21-bus and 123-bus test systems were reduced by about 19.32% and 23.68% with respect to their corresponding first scenario value.

In conclusion, the proposed algorithm reduces significantly the system planning and operational costs and increases the resiliency of the system.

Acknowledgment

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