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Active Distribution Network Expansion Planning Considering Distributed Generation Integration and Network Reconfiguration

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Abstract – This paper proposes the method of active distribution network expansion planning considering distributed generation integration and distribution network reconfiguration. The distribution network reconfiguration is taken as the expansion planning alternative with zero investment cost of the branches. During the process of the reconfiguration in expansion planning, all the branches are taken as the alternative branches. The objective is to minimize the total costs of the distribution network in the planning period. The expansion alternatives such as active management, new lines, new substations, substation expansion and Distributed Generation (DG) installation are considered. Distribution network reconfiguration is a complex mixed-integer nonlinear programming problem, with integration of DGs and active managements, the active distribution network expansion planning considering distribution network reconfiguration becomes much more complex. This paper converts the dual-level expansion model to Second-Order Cone Programming (SOCP) model, which can be solved with commercial solver GUROBI. The proposed model and method are tested on the modified IEEE 33-bus system and Portugal 54-bus system.

Keywords: Active distribution network, Distributed generation, Distribution network expansion planning, Network reconfiguration

1. Introduction

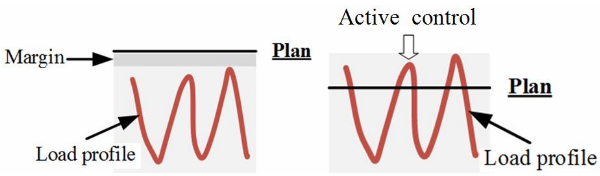
Distribution Network Expansion Planning (DNEP) has been largely reported in the published papers [1, 2]. DNEP includes determining the location, capacity, and time of installation of new equipment, taking constraints on feeder capacity, voltage drop, and network topology into account.

The traditional distribution network is designed with close-looped structure and operated with open-looped structure. The topology is seldom interfered only when the emergency occurs. So the traditional distribution network has to prepare higher reserve capacity to deal with the uncertainties. The capacity-to-load ratio is normally set to 1.8~2.2 for the distribution network in China according to the code for planning and design of urban distribution network (GB 50613-2010). The planning method leads to lower asset usage rate and higher investment.

Recently, environment protection and energy-saving have received primary concerns in power utilities. Distributed Generation (DG), mainly intermittent energy, is playing an increasingly important role in the electric power system infrastructure and market. In order to decrease the equipment investment and increase the DG penetration, the traditional distribution network planning need to be transferred to the refined one with active management as shown in Fig. 1.

Fig. 1(a) shows the traditional distribution network planning, the plan normally have margins to meet the demand when contingency happens. The traditional planning have not milked the distribution network dry and the total equipment utilization hours are lower. The refined distribution network planning in Fig. 1(b) tries to develop all the capability of the distribution network to meet the future demand incensement. The plan is lower than the traditional planning, the demands beyond the plan are met with the active controlling of the equipment in the distribution network. The "active control" can be on-load tap changer adjusting, DG dispatching, reactive power compensating, Distribution Network Reconfiguration (DNR), etc.

Many papers have been proposed for the active distribution network planning considering "active control" [3-7].



(a) Traditional planning (b) Refined planning

Fig. 1. The comparison between the traditional plan and refined plan

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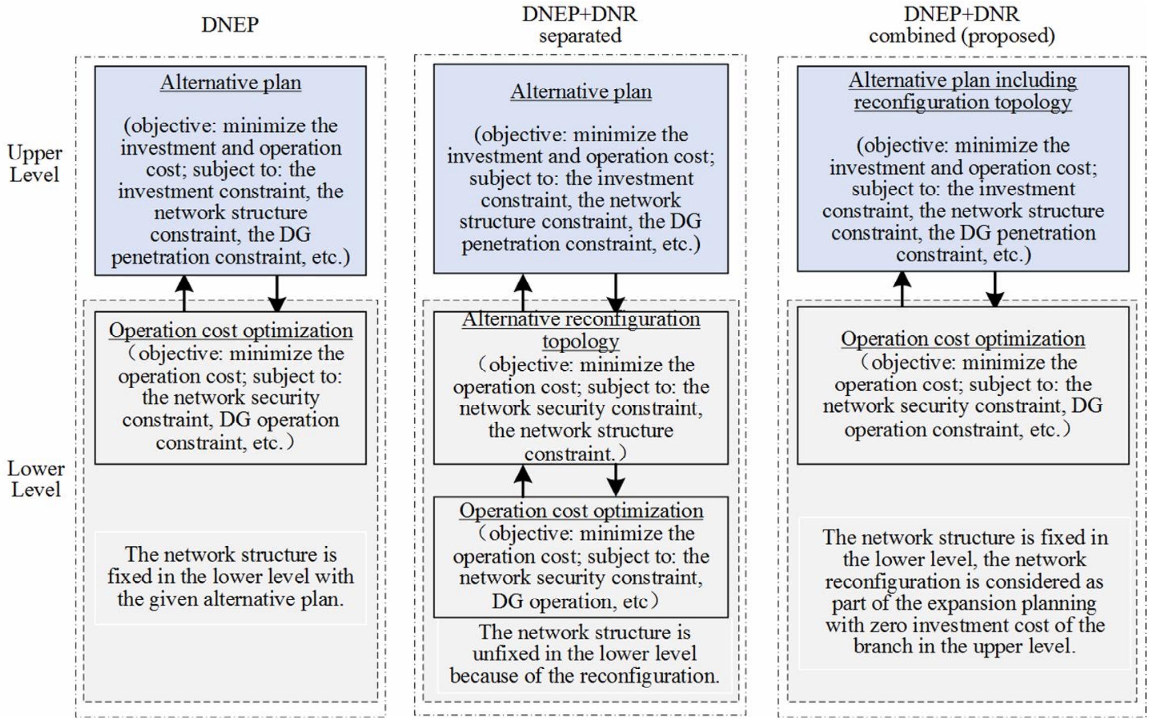

Fig. 2. The comparison between the traditional DNEP, DNEP+DNR separated and DNEP+DNR combined

Reference [8] proposes active distribution network planning model to maximize the wind turbine generation; the on-load tap changer voltage control, DG active power curtailment and power factor adjustment are considered. The maximum wind turbine generation capacity is analyzed based on different combination of active management schemes. Reference [9] accesses the maximum DG capacity under different active management schemes based on a proposed multi-configuration multi-period optimal power flow technique. Reference [10] defines a mixed-integer Second-Order Cone Programming (SOCP) problem with a convex formulation of AC optimal power flow to optimally locate and size the energy storage system in the active distribution network.

Reference [11] presents a methodology for active distribution network dynamic expansion planning considering DG integration, network reconfiguration, etc. The paper takes DNR as a measure for the load transferring during multi-period DNEP. DNR is not taken as a refined active management scheme to be applied in the optimal operation. Reference [12] proposes a multi-period optimal power flow approach, then assesses the DG hosting capacity improvement in distribution systems by applying network reconfiguration (static reconfiguration or dynamic reconfiguration) and active network management schemes. The DNR is considered only for the DG hosting capacity, the DNEP is not combined.

Most of aforementioned references have been developed for siting and sizing of DG, DNEP considering active control. The authors have also presented the DNEP considering active control [13, 14]. However, a DNEP combined with DNR has not been developed yet. This paper focuses on DNEP considering DG integration and DNR. The DNR, new wiring, substation installation, substation expansion and DG integration are considered for the network expansion. The main contributions in this paper include: 1) a new method of the DNEP considering DNR is proposed; the DNR is taken as the expansion planning alternative with zero investment cost of the branches; during the process of the reconfiguration in expansion planning, all the branches are taken as the alternative branches; 2) the active DNEP model considering the DNR is solved based on the SOCP model with GUROBI solver.

2. The Proposed Method

2.1 Outline of the proposed method

Distribution network is designed with close-looped structure and operated with open-looped structure. The distribution network has many tie switches and sectional switches for emergency response. The traditional DNEP method is based on a fixed network structure, the original network structure before expansion is assumed to be unchangeable during the planning period. The flexible distribution network structure and its variety are not considered.

The outline of traditional DNEP, “DNEP+DNR separated” and “DNEP+DNR combined” is shown in Fig. 2. Traditional DNEP has not considered the DNR, which can be divided into one main problem (alternative planning) and one sub-problem (operation optimization) as shown in Fig. 2. The alternate iteration finally gives out the optimal plan.

"DNEP+DNR separated" can be extended from the traditional DNEP. Unlike traditional DNEP, the problem becomes much complicated as the network structure can be reconfigured during the network expansion. The "DNEP+ DNR separated" is a three level optimization problem. The middle level problem is to find the optimal network configuration based on the alternative plan with fixed network structure in the top level. The bottom level is an optimal power flow problem.

"DNEP+DNR combined" is the method proposed in this paper. In order to decrease the difficulty of the "DNEP+ DNR" problem solving, the top level and middle level of "DNEP+DNR separated" are combined. The idea comes from the essentially similarity between the DNEP and DNR. DNEP in some cases is to find the optimal power supply path for the new load. Binary variable is used, "1" stand for one alternative path is constructed, "0" otherwise. DNR is to find the optimal switch operation with the preset objective. Binary variable is used, "1" stand for the switch on the power supply path is opened, "0" otherwise. In order to combined the DNEP and DNR, all the existing loads are taken as the new constructed load, the sectionalizing switch lines and tie switch lines are taken as the alternative lines with zero construction cost.

2.2 Procedure of the proposed method

The "DNEP+DNR combined" procedure can be explained with Fig. 3. Suppose, the initial line set is Φ_0 which is shown with solid lines, the alternative line set is Φ_1 which is shown with dotted lines; the initial load set is $\Psi_0 =\{1, 2, 3, \ldots, 16\}$, the new load set is $\Psi_1=\{17, 18, 19, \ldots, 50\}$, the tie switch line set is Ω_0={Line (2-8), Line (10-15)} which is shown with dash-dotted line.

1) Add the initial lines and the tie switch lines into the alternative line set. Update the alternative line set to $\Phi_0 \cup \Phi_1 \cup \Omega_0$, the total alternative line quantity changes from 45 to 63. Some lines in Φ_0 can be eliminated in order to decrease the calculation burden, e.g. some sectionalizing switches which cannot be opened for the continuous power supply.

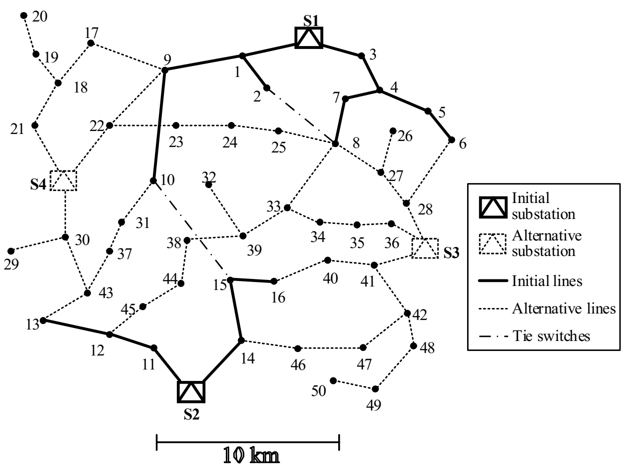

Fig. 3. The Portugal 54-bus system

2) Add the initial load buses into the alternative load set. Update the new load set to $\Psi_0 \cup \Psi_1$, the total new load quantity changes from 34 to 50. Some loads in Ψ_0 can be eliminated as in 1) in order to decrease the calculation burden.

Active distribution network adds more decision variables and constraints, superposing on uncertainties, its operation states become much complex. There are some methods proposed including genetic algorithm [15], mixed integer linear programming [16], mixed integer SOCP [10], etc. As genetic algorithm cannot find the global optimum solution, mixed integer linear programming is not suitable for the nonlinear model, this paper solves the "DNEP+ DNR combined" problem with SOCP method based on the commercial solver GUROBI [17].

3. Problem Formulation

The initial parameters of the optimization problems contain uncertainty behaviors of DGs and loads over a period time, like: daily, seasonally, and yearly. To handle these uncertainties, a reasonable quantity of operation scenarios should be considered. However, if all the possible scenarios are considered, the computation complexity will lead to high computation burden of the CPU and numerous local optimum. Usually the quantity of the operation scenarios is decreased to a reasonable one through some data clustering method. In this paper, the K-means data clustering method [14] is used to cluster the input data and decrease the quantity of total input scenarios.

The DNEP in this paper considers alternatives of network reconfiguration, new wiring, substation installation, substation expansion and DG integration.

3.1 Objective function

The proposed active DNEP model minimizes total investment and operation cost of the distribution system.

$$\min f = \mathrm{C}^{inv} + \mathrm{C}^{ope} \tag{1}$$

$$\begin{aligned} \mathrm{C}^{inv} &= \sum_{i\in\Psi_L^N} u_i^L C^L l_i + \sum_{j\in\Psi_D} Z_j^{DG} C_j^{DG} p_{rated}^{DG} \\ &+ \sum_{l\in\Psi_{S1}} u_l^{SS} C_l^{SS} + \sum_{m\in\Psi_{S2}} u_m^{SS} C_m^{SS} \end{aligned} \tag{2}$$

$$\mathrm{C}^{ope} = \sum_y \gamma \sum_{sc} D_{sc} \cdot \left(\sum_t \left(P_t^{loss} C_t^P + \sum_{j\in\Psi_D} f\left(P_{j,t}^{DG}\right) \right) \right) \tag{3}$$

$$\gamma = 1\big/\left(1+\delta\right)^{y-1} \tag{4}$$

where f is the total expansion cost; C^{inv} is the investment cost of the expansion planning, including the new wiring investment, DG installation cost, substation installation and substation expansion cost in sequence. C^{ope} is the operation cost, including the active power loss cost, DG operation cost. P_t^{loss} is the total power loss at time t, $P_t^{loss} = \sum I_{ij}^2 r_{ij}$, $(i,j)\in\Psi_B$, where r_{ij}, I_{ij} are resistance and current over branch (i, j).

Ψ_L^N, Ψ_D, Ψ_{S1}, Ψ_{S2}, Ψ_B are the set of alternative wirings (based on the proposed method in section 2, the set of DG installation buses, the set of new substation installation, the set of substation expansion and the set of total branches respectively.

u_i^L, u_l^{SS}, u_m^{SS} are all binary variables. u_i^L takes the value 1 if the i^{th} line is constructed and 0 otherwise; u_l^{SS} takes the value 1 if the $S1^{\text{th}}$ substation is constructed and 0 otherwise; u_m^{SS} takes the value 1 if the $S2^{\text{th}}$ substation is expanded and 0 otherwise. Z_j^{DG} stands for the quantity of unit capacity DG installed on bus j, $Z_j^{DG}=0$ means there is no DG installed on bus j.

C^L, C_j^{DG}, C_l^{SS}, C_m^{SS} are separately the line cost per unit length, the DG investment cost per unit capacity on bus j, the cost to install the $S1^{\text{th}}$ substation and the cost to expand the $S2^{\text{th}}$ substation.

p_{rated}^{DG} is the unit capacity of DG. $P_{j,t}^{DG}$ is the active power from DG on bus j at time t. $f_k^{DG}(\cdot)$ is the DG cost function on bus k, when the DG is the renewable like wind turbine generation, the cost function equals zero, when the DG is the micro turbine generation, the linear cost function is used.

y is the index of the planning period, δ is the discount rate, $1\big/\left(1+\delta\right)^{y-1}$ is the present value factor. D_{sc} is the number of days in the sc^{th} scenario. C_t^P is electricity price at time t.

3.2 Constraints

1) DG installation constraints, including (5) maximum DG installation capacity in the DG site candidate and (6) DG penetration constraint

$$0 \le \sum_{j\in\Psi_D} Z_j^{DG} \le Z_j^{DG,\max} \tag{5}$$

$$\sum_{j\in\Psi_D} Z_j^{DG} p_{rated}^{DG} + \sum_{j\in\Phi_D} P_{j,rated}^{DG} \le \beta\cdot\sum_{j\in\Psi_n} P_j^L \tag{6}$$

where (5) is the total quantity of unit capacity DG installation constraint on bus j, $Z_j^{DG,\max}$ is the maximum allowed quantity of unit capacity DG installed on bus j. Eq. (6) is the total allowed DG installation capacity constraint, the DG penetration rate should be smaller than the allowed penetration rate β; Φ_D is the set of bus where DGs have already been installed; $P_{j,rated}^{DG}$ is the DG rated power which has been already installed on *bus j*; Ψ_n is the set of total loads, P_j^L is the rated active power of load on bus j.

2) Network structure constraint

$$\sum_{i\in\Psi_L^N} u_i^L = \tilde{N} \tag{7}$$

Eq. (7) is the network structure constraint, which is based on the graph theory. The quantity of new load buses equals the quantity of new branches. $\tilde{N}$ is the quantity of new load buses, which is updated to include the initial load buses based on the proposed methodology in section 2.

Only (7) cannot ensure the radial topology, which may cause isolated load or load chain [14]. Fortunately all the load buses have to satisfy the power flow equations in (8), which avoids the possibility of isolated load or load chain. Eq. (8) assures that all the loads are supplied from the substation. Eq. (7) and (8) assure that there are no loops and the topology structure is radial. The analysis is based on the premise that there are no DGs in the distribution network. If the capacity of total installed DGs is smaller than the total loads in the same bus, the radial topology can still be assured. When the installed DGs are capable to feed some of the loads independently, we need to take other loop elimination method to ensure the radial topology of distribution network during the network expansion [18, 19].

3) Distribution network forward-backward sweep power flow equations

$$\begin{aligned} \sum_{k:(j,k)\in\Psi_B} P_{jk} &= \sum_{i:(i,j)\in\Psi_B}\left(P_{ij}-I_{ij}^2 r_{ij}\right) - P_j^L + P_j^{DG} \\ \sum_{k:(j,k)\in\Psi_B} Q_{jk} &= \sum_{i:(i,j)\in\Psi_B}\left(Q_{ij}-I_{ij}^2 x_{ij}\right) - Q_j^L + Q_j^{DG} + Q_j^C \end{aligned} \tag{8}$$

$$\begin{aligned} V_j^2 &\le V_i^2 - 2\left(r_{ij}P_{ij}+x_{ij}Q_{ij}\right) + \left(r_{ij}^2+x_{ij}^2\right)I_{ij}^2 + \mathrm{M}\left(1-b_{ij}\right) \\ V_j^2 &\ge V_i^2 - 2\left(r_{ij}P_{ij}+x_{ij}Q_{ij}\right) + \left(r_{ij}^2+x_{ij}^2\right)I_{ij}^2 - \mathrm{M}\left(1-b_{ij}\right) \end{aligned} \tag{9}$$

where b_{ij} is the binary variable, which takes the 1 if the branch (i, j) is installed and 0 otherwise; M is a very large integer number to control the inequality constraints (9). When branch (i, j) is not installed, M disables (9), when branch (i, j) is installed, (9) is converted to an equality constraints.

P_j^L, Q_j^L are respectively the active and reactive power from load on bus j; P_j^{DG}, Q_j^{DG} are respectively the active and reactive power from DG on bus j; Q_j^C is the reactive power of the capacitors on bus j. x_{ij} is the reactance of the branch (i, j); P_{ij}, Q_{ij} are respectively the active and reactive power on the front end of branch (i, j); V_i, V_j are respectively the voltage magnitude on bus i and j; P_{jk}, Q_{jk}, are respectively the active and reactive power on the front end of branch (j, k).

4) Voltage limits

$$V_i^{\min} \le V_i \le V_i^{\max} \quad i \in \Psi_n \tag{10}$$

Eq. (10) is the bus voltage constraint. V_i is the bus voltage on bus i; $V_i^{\min}$, $V_i^{\max}$ are lower and upper limits of the voltage on bus i respectively.

5) Branch current limits

$$\left|I_{ij}\right| \le I_{ij}^{\max} \quad (i,j) \in \Psi_B \quad i,j \in \Psi_n \tag{11}$$

Eq. (11) is the branch current constraint, I_{ij}, $I_{ij}^{\max}$ are current and maximum limit of the current on branch (i, j) respectively.

6) Active management constraints

$$P_j^{DG} \le P_{j,\max}^{DG} \quad j \in \psi_{\mathrm{M}} \tag{12}$$

$$Q_m^{C,\min} \le Q_m^C \le Q_m^{C,\max} \quad m \in \psi_C \tag{13}$$

where, Eq. (12) is the DG active management constraints, $P_{j,\max}^{DG}$ is the maximum DG active power on bus j, ψ_{M} is the set of the dispatchable DG installation buses. Eq. (13) is the reactive power compensating constraint. $Q_m^{C,\min}$, $Q_m^{C,\max}$ are the lower and upper limits of the reactive power respectively.

3.3 Solving methodology with SOCP

SOCP is widely used in the practical engineering problems within power system domain [22, 23]. This paper introduces two new variables $\upsilon_i = V_i^2$, $\zeta_{ij} = (P_{ij}^2 + Q_{ij}^2)/V_i^2$ to convert the proposed mathematical model to a mixed integer SOCP model [20, 21]. With the new introduced variables, all the objectives and constraints can be converted to the second-order cone format. The detailed conversion can be found in [14].

The new introduced variable brings about the following equality constraint:

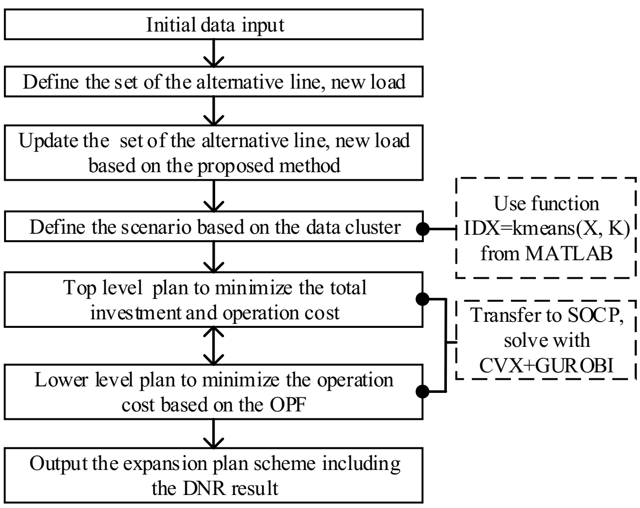

Fig. 4. The solving procedure

$$\zeta_{ij} = \left(P_{ij}^2 + Q_{ij}^2\right)\Big/\upsilon_i \tag{14}$$

Constraint (14) can be relaxed to the below SOCP format:

$$\left\| \begin{pmatrix} 2P_{ij} \\ 2Q_{ij} \\ \zeta_{ij} - \upsilon_i \end{pmatrix} \right\|_2 \le \zeta_{ij} + \upsilon_i \tag{15}$$

where $\|\cdot\|_2$ is the 2-norm. The relaxation (15) is proved and verified to be correct in [24], the optimal solution is not affected. From above, the SOCP model of active DNEP is built.

The CVX-MATLAB interface [25] has been selected for the mixed integer SOCP problem, and the GUROBI 6.5 [17] solver has been used to solve it. The GUROBI solver is a commercial optimization solver for linear programming, quadratic programming, quadratically constrained programming, mixed integer linear programming, mixed integer quadratic programming, and mixed-integer quadratically constrained programming. The GUROBI Optimizer supports a variety of programming and modeling languages including C++, C, MATLAB, Java, .NET, Python, et al. The solving procedure is shown in Fig. 4.

4. Application Example and Result

4.1 IEEE 33-bus system

4.1.1 IEEE 33-bus system application

The modified practical example from [26] is selected for the verification, the initial distribution system is shown in Fig. 5. The system is radial distribution network with one single substation, which has 33 buses, 35 lines, 32 sectionalizing switches, 5 tie switches, voltage of 12.66 KV, and nominal load of 3715 kW and 2700 kvar. The tie switches are installed on branch 7-20, 8-14, 11-21, 17-32 and 24-28. The DG types include Micro Turbine Generation (MTG), Wind Turbine Generation (WTG) and Photovoltaic Generation (PVG). The WTG and PVG

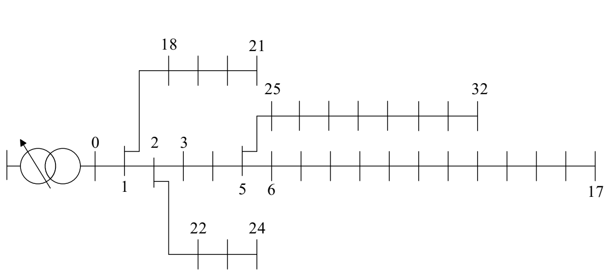

Fig. 5. The initial system of application example IEEE 33-bus system

Table 1. The parameter of DNEP in IEEE 33-bus system

Item	Parameter
DG type	MTG, WTG, PVG
DG unit capacity	50 kW
DG maximum penetration rate	35%
Electricity price	0.337 RMB/kWh (6:00~22:00); 0.677 RMB/kWh (other time)
MTG investment cost MTG operation cost	2000 RMB/kW 0.4 RMB/kWh
Alternative MTG install sites	Bus: 2/24
WTG investment cost WTG operation cost	3000 RMB/kW 0 RMB/kWh
Alternative WTG install sites	Bus: 5/17/32
PVG investment cost PVG operation cost	5000 RMB/kW 0 RMB/kWh
Alternative PVG install sites	Bus: 15/21/30
Bus voltage limit	0.95 p.u.~ 1.05 p.u.
Branch capacity limit	10 MVA
Planning period	5 years
Discount rate	10%

Note: RMB is the Chinese currency

Table 2. Reconfiguration result of the IEEE 33-bus system DNEP considering DNR

Load incr.	Opened switch
0%	6-7, 8-9, 13-14, 27-28, 31-32
20%	6-7, 8-9, 13-14, 17-32, 24-28
40%	6-7, 8-9, 13-14, 17-32, 24-28
60%	8-9, 13-14, 27-28, 7-20, 17-32
80%	8-9, 13-14, 16-17, 27-28, 7-20

Table 3. DG installation result of the IEEE 33-bus system DNEP considering DNR

Load incr.	WTG	MTG
0%	5(0), 17(0), 32(0)	2(0), 24(0)
20%	5(450 kW), 17(0), 32(0)	2(0), 24(0)
40%	5(850 kW), 17(50 kW), 32(0)	2(0), 24(0)
60%	5(1000 kW), 17(0), 32(0)	2(0), 24(500 kW)
80%	5(1000 kW), 17(550 kW), 32(0)	2(0), 24(750 kW)

Note: the number out of the brackets stands for the DG install bus

cannot be dispatched. The MTG is dispatchable. Some simulation parameters are listed in Table 1. The other network and load parameters can be found in [26].

As there is no new load in this system, the DNEP here is a problem of DG siting and sizing and network reconfiguration. In order to testify the importance of the DNR in the DNEP within the planning horizon, several expansion scenarios with 0%, 20%, 40%, 60%, 80% load increases are analyzed.

The uncertainties of the DGs and load is considered, the historic hourly data of DG and load is used. The data clustering method is used to cluster the input data and decrease the quantity of typical scenarios [10, 14]. In this paper, the MATLAB function IDX=kmeans(X, K) is used for the k-means cluster. Totally 8 scenarios are created after clustering.

There are lower voltages on long feeders 5-17 and 25-32. The lowest voltage is 0.913 p.u. on bus 17 in the initial system. The reconfiguration and DG installation cost

Table 4. The IEEE 33-bus system DNEP cost result considering DNR (10^4 RMB)

Load incr.	Total cost	DG invest cost	Operation cost	Power loss cost
0%	171.49	0	171.49	171.49
20%	300.28	135	165.28	165.28
40%	448.49	270	178.49	178.49
60%	705.14	400	305.14	227.34
80%	1051.01	615	436.01	244.67

Table 5. Total cost comparison with and without considering DNR of IEEE 33-bus system (10^4 RMB)

Load incr.	DNR considered	DNR not considered
0%	171.49	333.27
20%	300.28	545.50
40%	448.49	NAN
60%	705.14	NAN
80%	1051.01	NAN

Note: NAN means DNEP without considering DNR cannot satisfy t he load demand, the optimization problem has no solution

results are shown in Table 2 and Table 3. The cost result is shown in Table 4. Table 5 shows the comparison of total cost with and without considering DNR.

Without load increase, DNR can fulfill the system security constraints, the opened switch is 6-7, 8-9, 13-14, 27-28, 31-32. The loads on heavy-loaded feeder 5-17 are transferred to feeder 18-21. The loads on heavy-loaded feeder 25-32 are partly transferred to feeder 22-24. If DNR is not considered during the DNEP, the DG installation is the only option in this case. A 450 kW WTG is installed on bus 5 and a 300 kW is installed on bus 17. The total cost considering DNR is 171.49×10^4 RMB, which decreases 48.54% compared with the scheme without considering DNR.

When loads increase 20%, DNR cannot satisfy the new load demand. A 450 kW WTG is installed on bus 5, the opened switch is 6-7, 8-9, 13-14, 17-32, 24-28. If DNR is not considered during the DNEP, a 900 kW WTG is installed on bus 5 and a 600 kW is installed on bus 17. The total cost considering DNR is 300.28×10^4 RMB, which decreases 44.95% compared with the scheme without considering DNR.

When load increases 40%, a 850 kW WTG is installed on bus 5 and a 50 kW WTG is installed on bus 17. The opened switch is 6-7, 8-9, 13-14, 17-32, 24-28. If DNR is not considered during the DNEP, only DG cannot satisfy the load demand based on the current alternative DG site and DG penetration constraint. Without DNR, the DG cannot support the system expansion properly with higher load increase. DNR enables the DG ability to support the system expansion with limited DG alternative sites.

When load increases 60%, a 1000 kW WTG is installed on bus 5 and a 500 kW MTG is installed on bus 24. The large capacity of intermittent WTG needs the MTG for peak shaving. The opened switch is 8-9, 13-14, 27-28, 7-20, 17-32.

When load increases 80%, a 1000 kW WTG is installed on bus 5, a 550 kW WTG is installed on bus 17 and a 750 kW MTG is installed on bus 24. The opened switch is 8-9, 13-14, 16-17, 27-28, 7-20. The network topology after DNEP is shown in Fig. 6.

Bus voltage profile of time 17:00 is shown in Fig. 7. Bus voltage profile with 80% load increase has a messy curve as the DNR and MTG power active management. The cost comparison of different load increase is shown in Fig. 8. With load increasing, the total cost increases faster because of the peak shaving MTG installation. PVG is not installed for all the scenarios because of the higher cost.

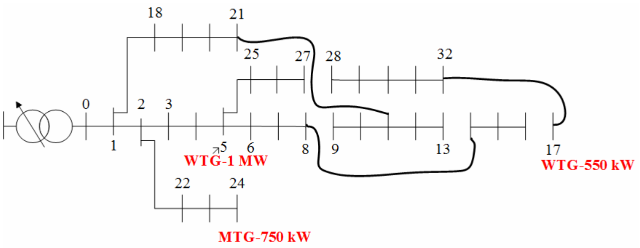

Fig. 6. Network topology after DNEP with 80% load increase

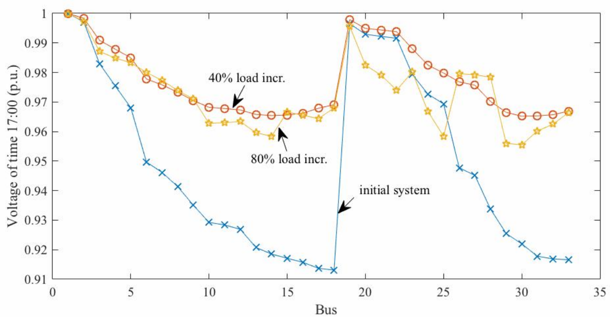

Fig. 7. Bus voltage profile of time 17:00

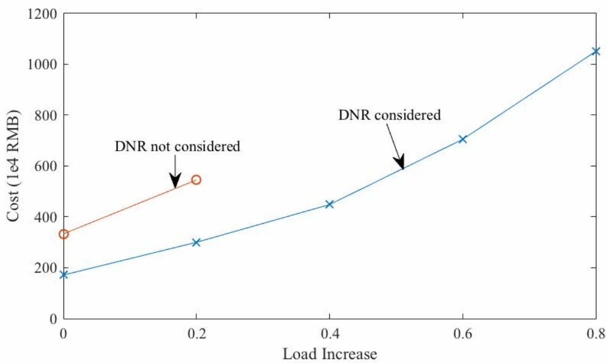

Fig. 8. Total cost comparison with and without considering DNR

4.1.2 IEEE 33-bus system discussion

1) The operation cost

The normal operation cost includes the DG operation cost, the energy purchasing cost from the main grid, and the profit from selling electricity to the customers. As we consider the total social operation cost, we regard the power loss and the inputted DG fuel as the social cost. The energy purchasing cost from the main grid can be counteracted by the profit from selling electricity to the customers. In order to cover the energy purchasing cost from the main grid in the operation cost model, we have changed the operation model in (3) to (16).

$$C^{ope} = \sum_{y} \gamma \sum_{sc} D_{sc} \cdot \left(\sum_{t} \left(\left(P_t^{loss} + P_t^{grid} \right) C_t^P + \sum_{j \in \Psi_D} f\left(P_{j,t}^{DG} \right) \right) \right) \tag{16}$$

where P_t^{grid} is the power purchased from the upper grid at time t.

The application results are as Table 6-7. As the energy purchasing cost accounts for the most of the operation cost, and also accounts for the most of the total cost. The comparison in Table 6 will not have big difference between the proposed method and the method with new operation model.

2) The possible DG installing sites

The quantity of possible DG installing sites will affect the result of the proposed model. Fewer DG installing site will lead to no feasible solution for the DNEP. So we have tried to add some possible installing sites as below to have

Table 6. Total cost comparison with and without considering DNR of new operation model (10^4 RMB)

Load incr.	DNR considered	DNR not considered
0%	4789.31	4828.46
20%	5796.93	5841.72
40%	6821.88	NAN
60%	7933.43	NAN
80%	9093.54	NAN

Table 7. DNEP result of the IEEE 33-bus system with new operation model

Load incr.	Opened switch	WTG	MTG	Operation cost (10^4 RMB)	Power purchased Cost (10^4 RMB)
0%	6-7, 8-9, 12-13, 17-32, 24-28	5(100 kW), 17(400kW), 32(800 kW)	2(0), 24(0)	4402.48	4325.0
20%	6-7, 8-9, 12-13, 17-32, 24-28	5(150 kW), 17(450kW), 32(950 kW)	2(0), 24(0)	5336.40	5223.4
40%	6-7, 8-9, 12-13, 17-32, 24-28	5(400 kW), 17(400kW), 32(1000 kW)	2(0), 24(0)	6289.13	6131.3
60%	6-7, 8-9, 13-14, 16-17, 27-28	5(0), 17(950 kW), 32(1000 kW)	2(0), 24(100 kW)	7343.81	7018.4
80%	6-7, 9-10, 13-14, 27-28, 17-32	5(0), 17(550 kW), 32(850 kW)	2(0), 24(900 kW)	8738.32	7456.3

a further comparison. The bold one in Table 7 is the added possible DG installing sites.

The application results are as Table 9-10. With more DG installing sites, the load increasing from 0%-80% all can be fulfilled through the DG installation without considering the network reconfiguration. But with load increase setting to 120%, the new possible DG installing sites can not satisfy the load demand without the network reconfiguration. As the DG possible installing sites are not unlimited, we regard the results of the original given DG install sites are reasonable.

4.2. Portugal 54-bus system

The Portugal 54-bus system used was extracted from [27]. The system has two initial substations (can be expanded), two alternative substations, 16 initial branches, 45 alternative branches. The voltage level is 15 KV and the total nominal load is 71.6 MW.

The original planning stages in [27] is three, each stage contains 5 years. A single stage planning of total 15 years is considered in this paper. The capacitors are installed on bus 32 in the original system, including 5 groups, each group is 20 kvar. A 1 MW WTG is installed in the original network on bus 26.The simulation parameters are shown in Table 11. The tie switches are installed on branch 2-8 and 10-15. Other data can be obtained from [27].

The detailed expansion result is shown in Fig. 9. The substation S1 is expanded from 2×16.7 MVA to 2×33.4 MVA. The 2×22.2 MVA substation S3 and S4 are installed. Because of DNR, tie switch 10-15 is closed, the load on bus 10 is transferred from heavy-loaded feeder of substation S1 to substation S2. Branch 9-10 is opened as a tie-line.

The total cost considering DNR is 3373.1×10^6 PTE, which has decreased about 18.8% compared with the cost without considering DNR. The DG investment cost is 250×10^6 PTE, active power loss cost is 2245.5×10^6 PTE. The DNR brings about the load transfer, which save the installation of MTG on bus 10. So the DNEP considering

Table 8. The new possible DG installing sites

Alternative MTG install sites	Bus: 2/**5**/**17**/24/**32**
Alternative WTG install sites	Bus: 5/**13**/17/**21**/32
Alternative PVG install sites	Bus: 15/21/30

Table 9. Total cost comparison with and without considering DNR (10^4 RMB)

Load incr.	DNR considered	DNR not considered
0%	4789.31	4821.71
20%	5796.93	5942.39
40%	6821.88	7149.81
60%	7933.43	8393.65
80%	9093.54	9649.85

Table 11. The parameter of DNEP in Portugal 54-bus system

Item	Parameter
DG type	MTG, WTG, PVG
DG unit capacity	100 kW
DG maximum penetration rate	35%
Electricity price	20 PTE ^{4}/kWh (6:00~21:00); 10 PTE/kWh (other time)
MTG investment cost MTG operation cost	4×10^4 PTE/kW 0.12×10^6 PTE/MWh
Alternative MTG install sites	Bus: 5/10/21
WTG investment cost WTG operation cost	5×10^4 PTE/kW 0 PTE/MWh
Alternative WTG install sites	Bus: 30/33/37
PVG investment cost PVG operation cost	6.5×10^4 PTE/kW 0 PTE/MWh
Alternative PVG install sites	Bus: 39/46
Bus voltage limit	0.95 p.u.~ 1.05 p.u.
Branch capacity limit	10 MVA
Planning period	5 years
Discount rate	10%

Note: PTE is the Portuguese currency

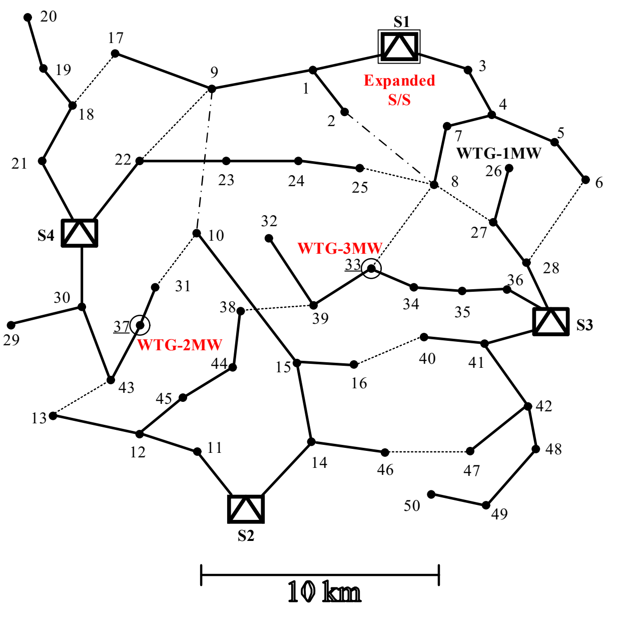

Fig. 9. The expansion result of Portugal 54-bus system considering DNR

Table 10. DNEP result of the IEEE 33-bus system with more DG installing sites

Load incr.	Opened switch	WTG	MTG
0%	6-7, 8-9, 13-14, 17-32, 24-28	5(50 kW), 13(200 kW), 17(250kW), 21(0), 32(800 kW)	2(0), 5(0), 17(0), 24(0), 32(0)
20%	6-7, 8-9, 13-14, 17-32, 24-28	5(50 kW), 13(250 kW), 17(300kW), 21(0), 32(950 kW)	2(0), 5(0), 17(0), 24(0), 32(0)
40%	6-7, 8-9, 12-13, 16-17, 20-21	5(0), 13(400 kW), 17(400 kW), 21(0), 32(1000 kW)	2(0), 5(0), 17(0), 24(0), 32(50 kW)
60%	6-7, 8-9, 13-14, 16-17, 27-28	5(0), 13(0), 17(1000 kW), 21(0), 32(1000 kW)	2(0), 5(0), 17(0), 24(0), 32(50 kW)
80%	5-6, 8-9, 16-17, 8-14, 17-32	5(50 kW), 13(950 kW), 17(150kW), 21(0), 32(1000 kW)	2(0), 5(0), 17(100 kW), 24(0), 32(50 kW)

Table 12. DG installation result of the Portugal 54-bus system

DG	DNR considered	DNR not considered
MTG	5(0), 10(0), 21(0)	5(0), 10(0.3 MW), 21(0)
WTG	30(0), 33(3 MW), 37(2 MW)	30(0), 33(3 MW), 37(2 MW)
PVG	39(0), 46(0)	39(0), 46(0)

Table 13. The cost result of Portugal 54-bus system DNEP (10^6 PTE)

DNEP	Total cost	DG invest cost	DG Operation cost	Power loss cost
DNR considered	3373.1	250	0	2245.5
DNR not considered	3696.7	262	175.6	2385.5

DNR has lower DG invest and operation cost.

5. Conclusion

This paper proposes the SOCP model and solving method of active DNEP considering distributed generation integration and DNR. The DNR is taken as the expansion planning alternative with zero investment cost of the branches. The proposed model and method are testified with the IEEE 33-bus system and Portugal 54-bus system.

DNR transfers the load from the heavy-loaded feeder to the light one to balance the load distribution and postpone the system upgrade. DNR does not need investment of new equipment, which can decrease the total expansion cost especially with larger quantity of tie-switches and section-switches.

In IEEE 33-bus system, without load increase, the total cost considering DNR decreases 48.54% compared with the scheme without considering DNR. With loads increase 20%, the total cost considering DNR decreases 44.95% compared with the scheme without considering DNR. In Portugal 54-bus system, the total cost considering DNR decreases about 18.8% compared with the cost without considering DNR.

Without DNR, the DG cannot support the system expansion properly with higher load increase. In IEEE 33-bus system, with loads increase beyond 40%, the scheme without considering DNR cannot fulfill the load demand. DNR enables the DG ability to support the system expansion with limited DG alternative sites. Thus it is necessary and profitable to consider the distribution network reconfiguration when planning the DG.

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