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Resilient outage recovery of a distribution system: co-optimizing mobile power sources with network structure

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Abstract

Outage recovery is important for reducing the economic cost and improving the reliability of a distribution system (DS) in extreme weather and with equipment faults. Previous studies have separately considered network reconfiguration (NR) and dispatching mobile power sources (MPS) to restore the outage load. However, NR cannot deal with the scenario of an electrical island, while dispatching MPS results in a long power outage. In this paper, a resilient outage recovery method based on co-optimizing MPS and NR is proposed, where the DS and traffic network (TN) are considered simultaneously. In the DS, the switch action cost and power losses are minimized, and the access points of MPSs are changed by carrying out the NR process. In the TN, an MPS dispatching model with the objective of minimizing power outage time, routing and power generation cost is developed to optimize the MPSs' schedule. A solution algorithm based on iteration and relaxation methods is proposed to simplify the solving process and obtain the optimal recovery strategy. Finally, numerical case studies on the IEEE 33 and 119-bus systems validate the proposed resilient outage recovery method. It is shown that the access point of MPS can be changed by NR to decrease the power outage time and dispatching cost of MPS. The results also show that the system operation cost can be reduced by considering power losses in the objective function.

Keywords: Resilient outage recovery, Network reconfiguration, Mobile power sources, Co-optimization, Traffic network

1 Introduction

Distribution systems (DS) are exposed to growing threats of outage caused by extreme weather and equipment faults [1]. Power outage can lead to substantial economic loss and dissatisfaction for consumers. Therefore, it is critical to perform efficient outage recovery to minimizing economic losses. However, the more complex DS topology makes it challenging to perform outage recovery [2], and therefore there is a need to research new outage recovery methods to obtain the optimal restoration schedule.

There are three main methods for restoring power supply after faults [3]: (1) Conventional restoration method with black start units; (2) Adopting network reconfiguration (NR); and (3) Applying the island operation mode. It can be challenging for the conventional recovery of power outage resulting from natural disasters, because it is based on the condition that most power sources remain operational and stay connected [3]. In terms of NR, the developed automation techniques provide opportunities to quickly recover the outage load by changing the switch states [4]. NR can be developed as a mixed-integer conic program and mixed-integer linear problem [5]. The system performance can be enhanced by NR, e.g., minimizing power losses [6], regulating node voltage [7], conducting congestion management [8], etc. There are many studies focusing on power outage recovery with the help

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of NR. To reduce the outage load, the recovery service is treated as an NR problem where operators transfer maximum load from the part with the fault to the 'un-faulted' part by operating the switches [9]. A two-stage scheme considering pre-disaster strengthening and post-catastrophe system reconfiguration is proposed to minimize load curtailment after hurricane events [10]. Taking the distributed generators' start-up requirements into consideration, a multi-stage method with limited NR steps is provided to address the outage problem, and a relaxed AC-power flow formulation is added to ensure the feasibility of the solution [11]. A method combining demand response programs and hourly NR is introduced to minimize the residential load curtailments in severe contingency conditions [12]. Although the outage recovery based on NR is effective in several scenarios, it is difficult for NR to meet the requirements of outage load when electrical islands occur because of multiple faults.

In the island operation mode, there are independent generation units which can temporarily meet the power demand of the nodes in the electrical islands. Many studies have explored the electrical operation model to realize outage recovery. The role of electric vehicles with storage capacity and charging flexibility as grid-supporting units is discussed in power recovery [13], while distributed generation is used to recover the critical loads after natural disasters [14]. Mobile power sources (MPSs), including electric vehicle fleets, truck-mounted mobile energy storage systems [15, 16] and mobile emergency generators [17, 18], provide the opportunity for the island operation mode to deal with a power outage. A mixed integer quadratic programming of MPSs' schedule is proposed to maintain the power supply of critical load after a fault, where the MPSs are considered as grid-support services and traffic congestion is considered [19]. Considering the pre-positioning of MPSs, a two-stage dispatch framework is introduced, in which the pre-positioning places of MPSs are decided before the natural disaster and the real allocation is optimized after the disaster strikes [17]. To take into account incomplete information (e.g., unknown switch states of branches in damaged areas), a two-stage robust optimization formulation is adopted to obtain the MPSs' dispatch to maximize the restored critical loads [20]. MPSs play an important role in the island operation mode after the fault. However, the dispatch of MPSs in the outage recovery is based on a fixed electrical island structure, and there will be a longer power outage.

In order to solve the problems of only applying NR or dispatching MPS to recover power supply after a fault, some studies have attempted to combine the two methods for better outage recovery. A co-optimization model is formulated to maximize the restored loads and minimize the total number of required repair crews and MPSs, by considering the repair crews' schedule, MPSs' routing and network structure [21]. A two-stage robust optimization model is constructed for enhancing the resilience of a DS in a fault condition, in which the MPSs are prepositioned and the DS is reconfigured into a less impacted or stressed state in the first stage. In the second stage, MPSs' scheduling, dynamic NR and DS's power dispatch are co-optimized to maximize the recovered loads, and minimize the transportation and battery lifecycle degradation costs [22]. Although both methods consider the coupling effect of the traffic network (TN) and the DS, only the restoration load and corresponding economic cost are included in the objective function, while the DS operation cost and the power outage time are not considered. NR has a unique advantage in outage management, that is, the power outage time is nearly 0 by performing NR to restore the power supply. This is because of the development of high-speed switching devices [23]. Thus, NR is an effective technique for quickly restoring the power supply after a fault and optimizing the DS operational condition. However, NR is passively realized following the MPSs' dispatch and not actively optimized in [21, 22], when considering that the unique advantage of NR is not reflected in the objective function of the two methods.

Therefore, to obtain a more effective power outage recovery, it is necessary to further study a new method which will simultaneously consider the MPS dispatching and NR models. The method can make NR actively work in the outage recovery. There are three challenges to realizing more effective power outage recovery: (1) How to build the coupling relationship between MPSs' dispatching model and the NR model; (2) How to set the objective function to achieve shorter power outage time, lower economic cost and higher reliability of DS; and (3) How to analyze the mathematical model quickly to obtain the optimal schedule.

To address these challenges, a resilient outage recovery method is proposed, in which MPSs' dispatching model in the TN and NR model in DS are jointly considered by the co-optimization model. In the DS, the structure of radial grid and electrical islands is optimized through NR based on the MPSs' schedule. The change in electrical islands' structure changes the access points of the MPSs. In the TN, given the structure and access points of electrical islands, the MPSs' schedule is optimized to meet the load demand of nodes in the electrical islands. The goal of the co-optimization model is set to minimize the power outage time, MPSs' routing cost, power generation cost, and power losses simultaneously. To solve the co-optimization problem, a solution algorithm combining the iteration and relaxation methods is proposed. The iterative method is used to decouple the NR process and

MPS dispatching, and the relaxation method reduces the difficulty by merging the variables of the MPSs' dispatching model.

2 Resilient outage recovery method

The resilient outage recovery method is based on the DS and TN as shown in Fig. 1. It optimizes the NR strategies in DS and MPSs' schedule in TN to realize the best recovery schedule. From Fig. 1a, the DS contains tie switches and sectionalizing switches, and realizes the power supply for each node. In the normal operation scenario, the tie switches are open while the sectionalizing switches are closed. The TN shows the location of many depots, one of which contains several MPSs. There is an access point for MPS around each node of the DS, and the MPSs can reach the access points through the TN. Therefore, the MPSs can support the power supply of nodes in the DS in specific scenarios.

In the normal operation scenario, the DS operates radially. When an electrical fault occurs, the fault node and other nodes connected to it become an electrical island without a power supply, while the other parts remain operating radially. The power supply of electrical islands can be met by MPSs at the access points, while the other parts are supplied by the utility grid. In Fig. 1, nodes 15 and 16 form an electrical island due to the fault in the branch 14–15, while nodes 12, 13, and 14 remain connected to the utility grid.

NR can recover the power supply of some electrical islands in a short time and reduce the power losses by closing the tie switch, e.g., the power supply of node 18 can be restored by closing the tie switch in branch 18–19. However, some electrical islands must be powered by the MPSs, e.g., those formed by nodes 20 and 11. The access points of MPSs can be at any point in the electrical island. These access points of MPSs are affected by NR, as the electrical islands vary with the DS topology. Take the fault branch 10–11 in Fig. 1 as an example, the MPS in depot 2 will arrive in node 11 to support its power demand in the traditional method. In the resilient outage recovery method, the power supply of node 11 can be restored by closing the tie switch in branch 11–20, while dispatching the MPS in depot 3 to node 20. This can reduce the power outage time and improve the resilience of the DS.

Multiple access points result in different routing distances from the depots. This affects the power outage time and routing cost. The route selection of MPSs in a TN also affects the power outage time and routing cost. In addition, there is a switch cost in NR. Therefore, in the proposed resilient outage recovery method, the comprehensive objective function is the optimal restoration schedule with the shortest power outage time, smallest dispatching cost and power losses, while the decision variables are the switch action, MPSs' access point, route, number, and generation power.

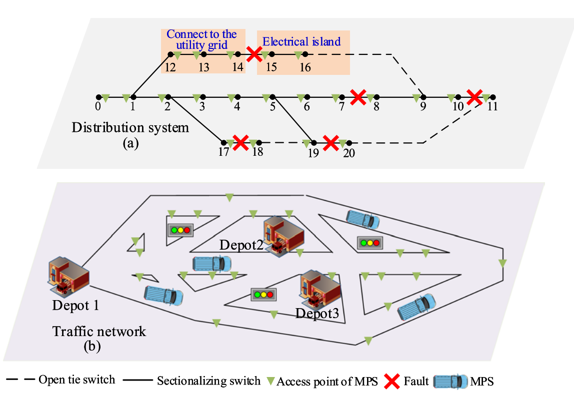

Fig. 1 The distribution system coupled with traffic network

3 System model

3.1 MPS dispatching model

In a TN, an MPS dispatching model is developed to find the optimal access point, route, number, and generation power of MPSs, while the power outage time and economic cost are considered in the objective function. Once the MPSs are connected to the access points, the power supply of the electrical island can be recovered. Therefore, the power outage time is the routing time of the MPSs. The MPSs' routing time describes the time consumption from the depot to the access point in the electrical island. The dispatching cost includes MPSs' routing cost and power generation cost.

(i) *Power outage time.* Multiple MPSs are pre-allocated in various depots, and arrive in the access points from the corresponding depots. The power outage time, i.e., routing time of MPSs, is determined by velocity, the routing distance between the depot and access point. Using a length matrix $L_{d,f,i}$ to describe the routing distance between depots and access points, the power outage time is expressed as:

$$T=\sum_{i=1}^{I}\sum_{f=1}^{F_i}\sum_{d=1}^{D}\alpha_{d,f,i}\cdot\left(L_{d,f,i}\right)^{-}\Big/v \tag{1}$$

where $\alpha_{d,f}$ is a binary variable, which is used to express whether the MPSs in depot d will arrive in the access point f of the electrical island i, if the MPSs in depot d arrives in access point f, $\alpha_{d,f,i}=1$, otherwise, $\alpha_{d,f,i}=0$. $(\bullet)^{-}$ is the matrix transposition.

(ii) *Dispatching cost.* The dispatching cost comes from MPSs' routing cost and power generation cost. There are various routes for MPSs to arrive at the access points of the electrical island, and the corresponding routing distances are different. The unit price of an MPS moving one kilometer is determined by the fuel price, which is a constant pri_f in this study. Considering the power generation limit of MPS, multiple MPSs may be dispatched to meet the power demand of one electrical island. Therefore, the MPSs' routing cost is decided by routing distance, the unit price of an MPS moving one kilometer and the number of dispatched MPSs, as:

$$C_1 = \sum_{i=1}^{I} \sum_{f=1}^{F_i} \sum_{d=1}^{D} \sum_{g=1}^{X_d} \left(L_{d,f,i}\right)^{-} \cdot pri_f \cdot x_{d,g,f,i} \tag{2}$$

where $x_{d,g,f,i}$ is a binary variable which expresses whether MPS g in the depot d is dispatched to the access points f of the island i. if MPS g is dispatched, $x_{d,g,f} = 1$, otherwise, $x_{d,g,f} = 0$.

The power generation cost of MPSs is determined by the generation power and the price of the materials used to generate power. The price of the materials is a constant in this study and expressed as pri_e. Therefore, the power generation cost model for the MPSs is expressed as:

$$C_2 = \sum\nolimits_{i\in I} \sum\nolimits_{f\in F_i} \sum\nolimits_{d\in D} \sum\nolimits_{g\in X_d} x_{d,g,f,i} \cdot E_{d,g,f,i} \cdot pri_e \tag{3}$$

where $E_{d,g,f,i}$ is the generation power of MPS g, which arrives at the access point f of the electrical island i from the depot d.

According to the MPSs' routing cost and power generation cost, the total dispatching cost for MPSs is expressed as:

$$C = \xi_1 \cdot C_1 + \xi_2 \cdot C_2 \tag{4}$$

where ξ_1 and ξ_2 are the weight coefficients of the MPSs' routing cost and power generation cost, respectively.

Combining with power outage time and dispatching cost, the objective of the MPS dispatching model is expressed as:

$$f_1(\boldsymbol{\alpha}, \mathbf{x}, \mathbf{E}) = \gamma_1 \cdot \xi \cdot T + \gamma_2 \cdot C \tag{5}$$

where the coefficient ξ is used to convert the power outage time into the economic cost. Parameters γ_1 and γ_2 are the respective weights of the goals about power outage time and dispatching cost, which can adjust the importance of the two goals. $\boldsymbol{\alpha}, \boldsymbol{x}, \boldsymbol{E}$ are the sets of $\alpha_{d,f,i}$, $x_{d,g,f,i}$, $E_{d,g,f,i}$, respectively. The binary variable $\alpha_{d,f,i}$ can be determined based on the binary variable $x_{d,g,f,i}$.When there is at least one MPS dispatched from depot d to the access point f, $\alpha_{d,f,i} = 1$, which can be shown as:

$$\alpha_{d,f,i} = x_{d,1,f,i} \otimes x_{d,2,f,i} \otimes \cdots \otimes x_{d,g,f,i}, \qquad g \in X_d \tag{6}$$

If at least one of the values of a and b is 1, $a \otimes \mathrm{b} = 1$, otherwise, $a \otimes \mathrm{b} = 0$.

There are many constraints to consider in MPS scheduling, as shown in (7)–(10). Constraint (7) indicates one electrical island must be supported by at least one depot, while constraint (8) means the number of dispatched MPSs in the depot d is not greater than its total number. Constraint (9) shows the MPSs' power generation cannot exceed the upper limit, while constraint (10) ensures the power supply of the nodes in each electrical island is satisfied by the dispatched MPSs, so the power balance is guaranteed.

$$\sum_{d=1}^{D} \alpha_{d,f,i} > 0, \qquad \forall f \in F_i, \forall i \in I \tag{7}$$

$$\sum\nolimits_{i\in I} \sum\nolimits_{f\in F_i} \sum\nolimits_{g\in X_d} x_{d,g,f,i} \le X_d, \quad \forall\, d \in D, \tag{8}$$

$$0 \le E_{d,g,f,i} \le E_{d,g\_\max} \tag{9}$$

$$\sum\nolimits_{j\in J} P_{i,j} = \sum\nolimits_{f\in F_i} \sum\nolimits_{d\in D} \sum\nolimits_{g\in X_d} x_{d,g,f,i} \cdot E_{d,g,f,i}, \ \forall i \in I \tag{10}$$

where $P_{i,j}$ is the load power of node j, and J is the maximum number of nodes in all electrical islands. It is noted that if node j belongs to the electrical island i, $P_{i,j} > 0$, otherwise, $P_{i,j} = 0$. According to the relationship of the access point and electrical island, $F_i \in J$ can be obtained.

3.2 Network reconfiguration model

The original DS is divided into multiple electrical islands and one partial radial system after the fault. Through NR, the switch states are changed, which changes the topology of the partial radial system and electrical islands. The access points selected by MPSs vary with the electrical island structure, and can be changed through NR. There is a specific life span for one switch, and changing the state reduces its life span. The reduction of switch life span is regarded as a kind of economic cost in the NR model [24]. Moreover, the change of switch state will affect the power losses of the DS, which can result in significant economic losses. Therefore, the objective function of the reconfiguration model is expressed as:

$$f_2(\mathbf{k}) = c_s \cdot \sum\nolimits_{m,n \in N} \Delta k_{mn} + c_p \cdot \sum\nolimits_{b \in B} fl_b \tag{11}$$

$$fl_b = \frac{\left(P_m^{in}\right)^2 + \left(Q_m^{in}\right)^2}{U_m^2} r_b \tag{12}$$

where Δk_{mn} is a binary variable, and expresses whether the state of switch in the branch m–n changes. If the state changes, $\Delta k_{mn} = 1$, otherwise, $\Delta k_{mn} = 0$. m and n are the respective nodes in the DS, and the total number of nodes is N. $\boldsymbol{k}$ is the set of Δk_{mn}, and c_p is a coefficient to convert the power losses into the economic cost.

During the optimization of NR, the constraints of power flow, power balance, and radial structure should be satisfied in each electrical island and the partial radial system. Constraints (13–15) show the power flow constraints, i.e., constraint (13) is the calculation method for power flow, constraints (14) and (15) mean the branch power and the node voltage within its lower and upper bound of normal operation requirement, respectively. Constraints (16–19) are the radial structure constraints [5]. Constraint (16) ensures the system structure is a tree, constraint (17) is the parent node number constraint that restricts only one of two nodes can be the parent of the other one at a time for a connected branch, constraint (18) shows that there is only one parent node for each node, except for the substation node in the radial network, and constraint (19) indicates that there is no parent node for the substation node.

$$\{P_b, U_m\} = H(P_m, Q_m, r_b, x_b) \tag{13}$$

$$P_{b\_\min} \le P_b \le P_{b\_\max} \tag{14}$$

$$U_{m\_\min} \le U_m \le U_{m\_\max} \tag{15}$$

$$\sum\nolimits_{m,n \in N} k_{mn} = N - 1 \tag{16}$$

$$\beta_{mn} + \beta_{nm} = k_{mn} \tag{17}$$

$$\sum\nolimits_{n \notin N_{Sub}} \beta_{mn} = 1 \tag{18}$$

$$\sum\nolimits_{n \in N_{Sub}} \beta_{mn} = 0 \tag{19}$$

where k_{mn} is the switch state in the branch m–n. The binary variable β_{mn} indicates whether the node n is the parent of the node m, and N_{Sub} is the set of substation nodes.

3.3 Co-optimization model of MPS and NR

To consider both the TN and DS in the resilient outage recovery method, the co-optimization model of MPS and NR is formulated as:

$$f(\boldsymbol{\alpha}, \mathbf{x}, \mathbf{E}, \mathbf{k}) = \mu_1 \cdot f_1 + \mu_2 \cdot f_2 \tag{20}$$

where parameters μ_1 and μ_2 are the weights of the goals on MPS dispatch and reconfiguration, respectively.

In the co-optimization model, it is evident that the goals of MPS and NR are interactional and conflicting. Through NR, the electrical island structure changes. Then the access points selected by MPSs also change and the routing distance from the depot may be reduced. In this scenario, the power outage time and dispatched MPSs' cost are reduced, but the switch action cost is increased while the switch action changes the power losses. However, it is also possible that the routing distance from depot increases with the change of selected access points. In addition, the electrical island structure determines the value of outage load, and this affects the number of dispatched MPSs. For NR, the switch action cost is reduced and power losses are changed by dispatching MPSs. Therefore, the optimal outage recovery schedule is obtained by the co-optimization model of MPS and NR.

In the co-optimization model, the load power of each node should be satisfied by the utility grid and MPSs. Also, the constraints of the MPS dispatch model and NR model should be met. Therefore, the constraints of the co-optimization model are expressed as:

$$P_m = P_{sm}, \quad \forall m \in N \tag{21}$$

$$\text{Equations } (7-10, 13-19), \tag{22}$$

where P_{sm} is the load power of the node m.

4 Solution algorithm for the co-optimization model

4.1 Relaxation method for the MPS dispatching model in TN

The decision variables $\alpha_{d,f,i}$, $x_{d,g,f,i}$ are binary variables, and the power generation $E_{d,g,f,i}$ is a continuous variable in the MPS dispatching model. Considering the objective function (3) and coupled variables, MPS dispatching in a TN is a nonlinear mixed-integer programming (NMIP) problem when the electrical islands and outage load are determined. The challenge to solve the problem is the mixed-integer characteristic. Therefore, the relaxation method is used to relax the binary variable $x_{d,g,f,i}$ into a continuous variable $y_{d,g,f,i}$, and the following constraint should be satisfied:

$$0 \le y_{d,g,f,i} \le 1 \tag{23}$$

Then, the binary variable $\alpha_{d,f,i}$ can be expressed by the continuous variable $y_{d,g,f,i}$, as:

$$\alpha_{d,f,i} = y_{d,1,f,i} \otimes y_{d,2,f,i} \otimes \cdots \otimes y_{d,g,f,i}, \qquad g \in X_d \tag{24}$$

It should be noted that the optimality of the MPSs' schedule will not be affected by the relaxation of the binary variable $x_{d,g,f,i}$. The reason is that the objective function on power outage time and routing cost is a linear function of the binary variable $\alpha_{d,f,i}$. Therefore, by constraining the relaxed continuous variable between 0 and 1, the optimal solution can be guaranteed. Although the objective function of MPSs' generation cost is affected by the binary variable $x_{d,g,f,i}$ and the continuous variable $E_{d,g,f,i}$ based on (3), the relaxation will not affect its solution, as the value of $x_{d,g,f,i}$ only determines whether $E_{d,g,f,i}$ is equal to 0, without affecting the optimization of $E_{d,g,f,i}$ in the non-zero scenario. The relationship is shown as:

$$\begin{cases} E_{d,g,f,i} > 0, & x_{d,g,f,i} = 1 \\ E_{d,g,f,i} = 0, & x_{d,g,f,i} = 0 \end{cases} \tag{25}$$

The objective functions (2–5) and (20), and constraints (8) and (10) are reformulated by $y_{d,g,f,i}$, as:

$$C_1' = \sum_{i=1}^{I}\sum_{f=1}^{F_i}\sum_{d=1}^{D}\sum_{g=1}^{X_d} \left(L_{d,f,i}\right)^{-} \cdot pri_f \cdot y_{d,g,f,i} \tag{26}$$

$$C_2' = \sum\nolimits_{i\in I}\sum\nolimits_{f\in F_i}\sum\nolimits_{d\in D}\sum\nolimits_{g\in X_d} y_{d,g,f,i} \cdot E_{d,g,f,i} \cdot pri_e \tag{27}$$

$$C' = \xi_1 \cdot C_1' + \xi_2 \cdot C_2' \tag{28}$$

$$f_1'\left(\mathbf{y}, \mathbf{E}\right) = \gamma_1 \cdot \xi \cdot T + \gamma_2 \cdot C' \tag{29}$$

$$f'\left(\mathbf{y}, \mathbf{E}, \mathbf{k}\right) = \mu_1 \cdot f_1' + \mu_2 \cdot f_2 \tag{30}$$

$$\sum\nolimits_{i\in I}\sum\nolimits_{f\in F_i}\sum\nolimits_{g\in X_d} y_{d,g,f,i} \le X_d, \ \forall d \in D \tag{31}$$

$$\sum\nolimits_{j\in J} P_{i,j} = \sum\nolimits_{f\in F_i}\sum\nolimits_{d\in D}\sum\nolimits_{g\in X_d} y_{d,g,f,i} \cdot E_{d,g,f,i}, \ \forall i \in I \tag{32}$$

where C_1', C_2', C', f_1' and f' are the corresponding routing, power generation and dispatching costs, objective function of MPS dispatching model, and objective function for the co-optimization model after relaxation.

The original NMIP problem can be relaxed into a nonlinear optimal programming (NOP) problem through the relaxation method. The solution complexity of the NOP problem is less than the original NMIP problem. Therefore, the computation time for obtaining the optimal MPSs' schedule is shortened, and the used computation resource is reduced.

4.2 Harmony search algorithm for reconfiguration in distribution system

The reconfiguration model in (11–19) changes switch state to obtain the optimal DS and electrical island structure. It is a complex combinatorial optimization problem related to graph theory, and is difficult to solve. The solution space increases exponentially with the network scale expansion, which makes it difficult to solve in an ergodic way. In addition, the power flow calculation is nonlinear and time-consuming. Therefore, the harmony search algorithm (HSA) is used to solve the reconfiguration model in DS.

The HSA is a heuristic search algorithm and has been widely applied to solve the combinatorial optimization problem [25, 26]. It aims to find the best harmony (i.e., the global optimal solution) for the musician under instruments with different tones playing together. There is a predetermined auditory standard to evaluate and find the best harmony, and there is a special pitch range for each instrument. In the NR model, changing the switch state is equivalent to playing an instrument, the cost function in (11) is the auditory standard, the constraints in (13–19) are equivalent to the pitch ranges of instruments, and the system structure with minimum cost is the best harmony.

The solving process of HSA consists of initializing the parameters, randomly generating the initial harmony memory (***HM***), improvising a new harmony, updating the ***HM***, and selecting the best harmony. The parameters include harmony memory size (*HMS*), harmony memory considering rate (*HMCR*), pitch adjusting rate (*PAR*), tuning bandwidth (*bw*), and maximum iterations (T_{max}). The harmony is the switch state set, i.e., system structure. The principle for improvising a new harmony is expressed as:

$$hm_{new} = \begin{cases} hm, & \tau_1 < HMCR,\ \tau_2 > PAR \\ hm + bw \cdot \tau_3, & \tau_1 < HMCR,\ \tau_2 \le PAR \\ hm', & \tau \ge HMCR \end{cases} \tag{33}$$

where hm_{new} is a new switch state set, hm is an element of $\boldsymbol{HM}$, $hm^{'}$ is a randomly generating switch state set. τ_1, τ_2, τ_3 are random numbers between 0 and 1.

The values of the objective functions (i.e., the cost function) under hm_{new} and hm are compared and the smaller is selected to update the $\boldsymbol{HM}$. The process is repeated until T_{max} is reached. Finally, the optimal system structure is obtained by selecting the smallest value of the cost function from $\boldsymbol{HM}$.

4.3 Solution process for the co-optimization model

The relaxed co-optimization model of MPS and NR is obtained based on the simplified MPS dispatching model, as:

$$Equation(30) \tag{34}$$

$$Equations\ (7, 9, 13-19, 23, 31-32) \tag{35}$$

For the relaxed co-optimization model of MPS and NR shown in (34–35), the optimization in the TN is coupled with the optimization in DS so they cannot be separately solved. However, MPS dispatch in the TN can be optimized under one specific DS structure. Although the constraints in (13–19) of the reconfiguration model in DS are affected by MPS dispatch, its objective function (11) is independent of the TN. Considering the mentioned characteristics of the optimization problem, the optimization method of the MPS dispatching model is embedded into the HSA to deal with the coupling effect, to reduce the solution complexity and shorten the computation time.

In the iteration method, the optimization method of the MPS dispatching model and the generation of a new DS structure in the HSA are performed sequentially and alternately. The optimized result in the TN (DS) is based on a definite scenario of the DS (TN), e.g., the MPS dispatch schedule is obtained based on the known electrical island structure and outage load. In the process of generating a new DS structure satisfying the constraints (13–19), it can be assumed that the constraints relating to MPS dispatch are always satisfied. Finally, the overall optimal solution of the co-optimization model in (34–35) is obtained by the interaction of MPS dispatch optimization and reconfiguration. The detail of the solution algorithm is as follows:

Solution algorithm for the co-optimization model

1. Input the initial data of the TN $L_{d,f,i}$, the data of the DS P_m, Q_m, r_b, x_b, the constant v, pri_f, pri_e, X_d, E_{d,g_max}, c_s, c_p, P_{b_min}, P_{b_max}, U_{m_min}, U_{m_max}, D, and set the parameters, ξ_1, ξ_2, γ_1, γ_2, μ_1, μ_2, ξ, $HMCR$, PAR, HMS, bw, T_{max}.

2. Randomly generate the initial harmony memory (***HM***), i.e., DS structure.

3. ***For*** $in = 1$ to HMS

 (1) Optimize the MPS dispatching model in TN based on objective functions (1) and (26-29) and constraints (7), (9), (23), and (31-32) and the DS structure HM_{in}.

 (2) Calculate the objective function $f_0^{'}$ of co-optimization model based on equation (30).

 End For in

4. ***For*** $iter = 1$ to T_{max}

 For $in = 1$ to HMS

 (1) Improvise a new DS structure $hm_{new,in,iter}$ based on equation (33) and the random numbers τ_1, τ_2, τ_3.

 (2) Optimize the MPS dispatching model in TN based on objective functions (1) and (26-29), and constraints (7), (9), (23), and (31-32) and the DS structure $hm_{new,in,iter}$.

 (3) Calculate the objective function $f_{new,in,iter}^{'}$ of joint optimization model based on equation (30).

 (4) ***If*** $f'_{new,in,iter} \ge f'_{in,iter}$

 $f'_{in,iter} = f'_{new,in,iter}$

 $hm_{in,iter} = hm_{new,in,iter}$

 End If

 End For in

 End For $iter$

5. Select the smallest one from $f'_{new,in,iter}$, and obtain the optimal outage recovery schedule.

5 Case study

5.1 Basic data

The IEEE 33 [27] and 119-bus systems [28] are used as test cases to verify the effectiveness of the proposed model and solution algorithm. In the DS, the load demand of each node is satisfied by the utility grid under normal operation conditions, in which the tie switches are open and the sectionalizing switches are closed.

Table 1 The parameters of this model

Parameter	Value	Parameter	Value	Parameter	Value
μ_1	1.0	v	60 km/h	pri_f	0.5 CNY/km
μ_2	1.0	ξ	1.0 CNY/h	pri_e	1.0 CNY/kW
γ_1	1.0	ξ_1	1.0	c_s	20 CNY
γ_2	0.5	ξ_2	0.5	c_p	2.0 CNY/kWh

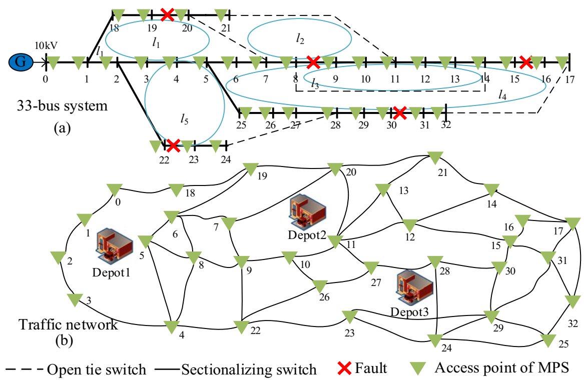

Fig. 2 The IEEE 33-bus system coupled with traffic network

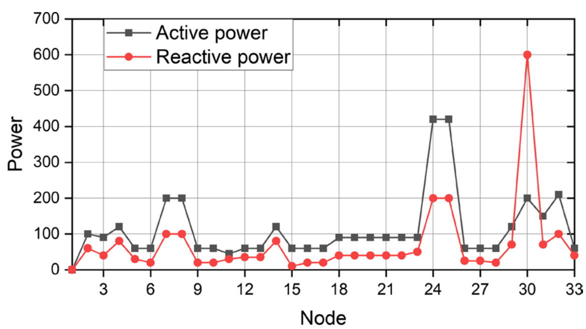

Fig. 3 The load distribution of DS

There is one access point for MPS in each node to guarantee the electricity supply after the fault. In terms of the TN, there are multiple roads between any two nodes in the DS. The parameters in the model are listed in Table 1. The test case is implemented in a computer with Intel Core i5-8250 CPU 1.60 GHz, 16 G memory, and MATLAB 2018a is used as the testing environment for the solution.

5.2 Case I: IEEE 33-bus system

5.2.1 Results of the IEEE 33-bus system

Figure 2 illustrates the topology of the IEEE 33-bus system with the coupled TN. The load distribution of each node is shown in Fig. 3. The fault is considered to be in

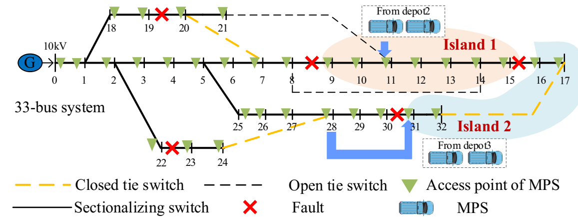

Fig. 4 The result of outage recovery for IEEE 33-bus system

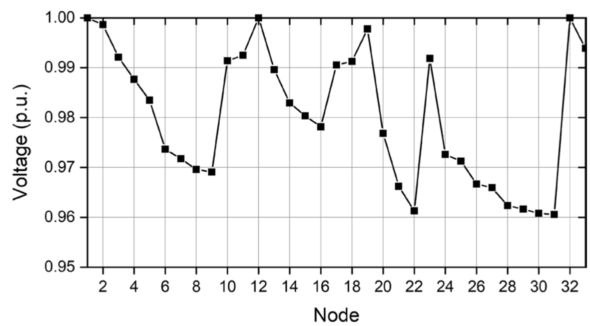

Fig. 5 The node voltage of DS

branches {8–9, 15–16, 19–20, 22–23, 30–31}, and the depots (1, 2, and 3) are set around nodes 5, 11, and 28, respectively. There are three MPSs with an upper limit of power generation of 300 kW in each depot. It is clear that there is always a road for MPS from the depot to the access point of the electrical island.

Through the resilient outage recovery method, optimal strategies can be obtained and are shown in Fig. 4. In terms of the DS, the tie switches in branches {7–20, 17–32, 24–28} are closed, leading to the formation of two electrical islands. From Fig. 4, the electrical island 1 consists of nodes 9, 10, 11, 12, 13, 14, 15, while the electrical island 2 is formed by closing the tie switch in branch {17–32}, connecting branch {16–17} and branch {31–32}. The two islands and other nodes are separately supplied by the MPSs and utility grid. It is clear that the DS apart from the islands satisfies the radial operation condition. The power outages in nodes 20, 21, 23 and 24 caused by the fault are recovered by performing NR, and another power outage load is recovered with the help of MPS. The optimized node voltage is presented in Fig. 5, which shows that the voltage of every node is higher than 0.95 and meets the voltage constraints. Due to the access of MPS, the voltage of nodes 11 and 31 is 1 p.u..

In terms of the TN, MPSs in depots 2 and 3 are dispatched to the electrical island 1 and 2, respectively. The access point in electrical island 1 is in node 11, and there is a depot (i.e., depot 2) near node 11. Therefore, the corresponding routing distance and power outage time are

Table 2 The comparison of optimal objective function value for the IEEE 33-bus system

Objective	Power outage time	Routing cost of MPS	Power generation cost of MPS	The number of switch action	Power losses
Only dispatching MPS	167.66 min	2770.80 CNY	476.25 CNY	0	68.04 kW
Only performing network reconfiguration	∞	0	0	3	504.83 kW
Without considering power losses	34.01 min	944.65 CNY	210.00 CNY	4	543.14 kW
Resilient outage recovery method	34.01 min	944.65 CNY	442.50CNY	3	123.92 kW

both the shortest, and the routing cost of MPS is the smallest. The optimal access point is node 31 for the electrical island 2. This can obtain the shortest power outage time and smallest routing cost from depot 3. Considering the power generation upper limit of the MPS, two MPSs in depot 2 and 3 are separately dispatched to satisfy the load demands of 465 kW and 420 kW in electrical islands 1 and 2, respectively. The load demand can be met in nodes 16 and 17 without MPS accessing the nodes, because the tie switch in branch {17–32} is closed by NR.

5.2.2 *Comparison between the resilient outage recovery method and different scenarios*

(1) Comparison with the scenario of only dispatching MPS

The scenarios of only dispatching MPS, only performing NR, and without considering power losses are analyzed, and objective function values are shown in Table 2. Compared with the scenario of only dispatching MPS, it is evident that the power outage time, routing cost of MPS and power generation cost of the resilient outage recovery method are lower, but the power losses are higher. The reason is that MPS will be dispatched to fewer electrical islands to restore power supply after a fault if NR is considered. This decreases the power outage time, routing cost and power generation cost, while improving the resilience of the DS. However, in the scenario of only dispatching MPS, since the DS operates in the form of a multi-island and the voltage of load nodes connected by the MPS increases, the power loss of a single line decreases, and then the total power loss of DS decreases. Therefore, NR can effectively reduce power outage time and dispatching cost of MPS while slightly increasing power losses.

(2) Comparison with the scenario of only performing network reconfiguration

Under the scenario of only performing NR, the optimal reconfiguration strategy is to close the tie switch in branches {8–14, 7–20, 24–28}, and the power loss is 504.83 kW. The routing cost and power generation cost of MPS are 0, because no MPS is dispatched. From Fig. 2, it is clear that there are two electrical islands in the reconfiguration strategy, i.e., nodes 16 and 17, and nodes 31 and 32. Since there are no MPSs, the power supply of the two electrical islands cannot be restored. Therefore, the power outage time is infinity, as shown in Table 2. Compared with the scenario only performing NR, although the MPSs' routing cost and power generation cost obtained by the resilient outage recovery method are higher, the power outage time and power losses are smaller. The reason for smaller power losses is that loads of nodes 9–15 are not restored by the main grid, which decreases the power losses on branches {0–1, 1–2, 2–3, 3–4, 4–5} and {23–24, 5–25, 25–26, 26–27, 27–28, 28–29, 29–30}. To sum up, the MPS dispatching model and NR are co-optimized in the resilient outage recovery method, ensuring the power supply being restored and the cost resulting from the fault being reduced.

(3) Comparison with the scenario of without considering the power losses in the objective function

The optimal schedule of the scenario without considering the power losses in the objective function is closing the tie switches in branches {8–14, 11–21, 17–32, 24–28}, and dispatching two MPSs from depot 3 to node 31. In this scenario, there is only one electrical island, i.e., island 2 in Fig. 4. It can be seen from Table 2 that the power outage time and routing cost of MPS are the same, both from depot 3 to node 31. It is noted that the routing distance from depot 2 to node 11 is nearly 0 as the result of the outage management framework. However, the MPS power generation cost of the resilient outage management framework is higher, because there are more electrical islands. The number of switch actions is decreased by one, which increases the switch life. The power losses of the scenario with the resilient outage recovery method are greatly decreased by 77.18%, compared to the scenario without considering power losses in the objective function. The reason is that the loads at nodes 9–15 are not restored by the main grid in the scenario with the resilient outage recovery method. This decreases the power losses of branches {0–1, 1–2, 2–3, 3–4, 4–5} by reducing the injecting power of nodes 1, 2, 3, 4, and

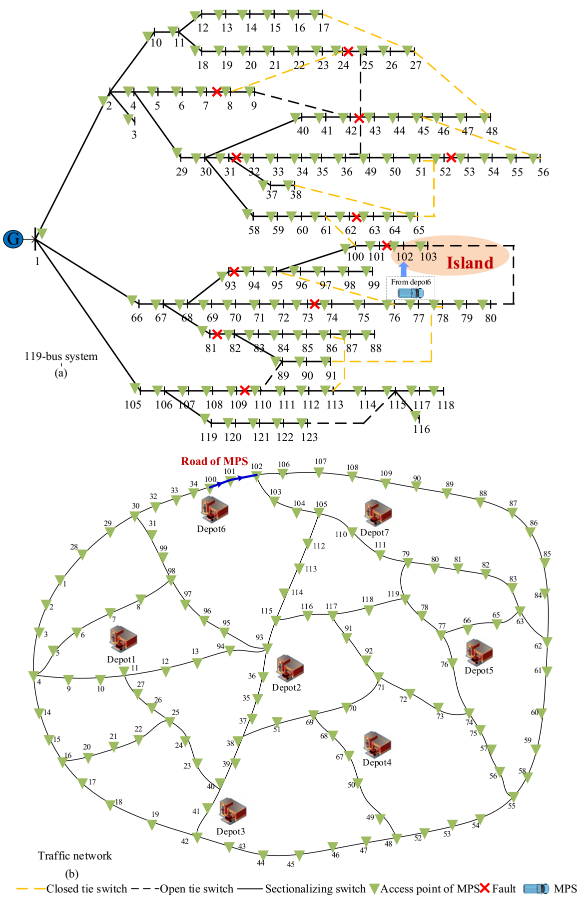

Fig. 6 The IEEE 119-bus system coupled with traffic network

5. In addition, the current flowing through branches {23–24, 5–25, 25–26, 26–27, 27–28, 28–29, 29–30} is less resulting from loads at node 9–15 being restored by MPS, which reduces the power losses on these branches. In conclusion, the proposed resilient outage recovery method simultaneously minimizes power outage time, dispatching cost of the MPS and power losses by comprehensively considering multiple objectives and it enhances the DS's ability to deal with faults.

Through the comparison between the resilient outage recovery method and different scenarios, it is clear that the power supply can be quickly restored and costs resulting from the fault can be minimized simultaneously by this method. Thus, it can be concluded that the proposed method has better performance in power outage recovery for the IEEE 33-bus system.

5.3 Case II: IEEE 119-bus system

5.3.1 Results of the IEEE 119-bus system

The test in the IEEE 119-bus system is used to verify the scalability of the proposed resilient outage recovery method and solution algorithm. The IEEE 119-bus system and coupled TN are shown in Fig. 6. There are 15 loops and 118 nodes in the IEEE 119-bus system. It is evident that there is one access point for MPS near the node. 7 depots are built in the traffic network, and are respectively set near nodes 11, 36, 42, 67, 76, 100, 110. Each depot has 7 MPSs with an upper limit of the power generation of 300 kW. There is at least one road for MPS from the depot to the access point. The load distribution of each node in the IEEE 119-bus system is shown in Fig. 7. The electrical faults happen in branches {7–8, 24–25, 31–32, 42–43, 52–53, 62–63, 73–74, 81–82, 93–94, 101–102, 109–110}. In the initial operational condition, all the tie switches are open to satisfy the radial structure.

The optimized results are obtained by the resilient outage recovery method and are shown in Fig. 6. Through closing the tie switches in branches {8–24, 17–27, 27–48, 45–56, 38–65, 51–65, 61–100, 76–95, 78–91, 86–113}, the power supply of corresponding outage load resulting from the fault in branches {7–8, 24–25, 31–32, 42–43, 52–53, 62–63, 73–74, 81–82, 93–94, 109–110} is restored. There is no loop structure in the optimized DS, but an electrical island is formed after switch actions. The electrical island consists of two load nodes, i.e., nodes 102 and 103, whose power demand is supplied by the MPS from the nearest depot. In terms of the TN, the MPS is dispatched from depot 6 located near node 100 to the access point in node 102, as shown in Fig. 6b. The load demand of the electrical island is 72.38 kW. Thus only one MPS is needed to supply the outage load. The number of MPS needed is reduced by NR, which greatly reduces the dispatching cost of MPS. Because performing NR is quicker than dispatching MPS, the power outage time is decreased and quick outage recovery is realized.

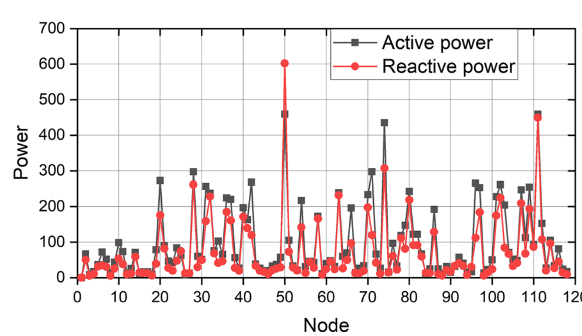

Fig. 7 The load distribution of the IEEE 119-bus system

Table 3 Comparison of optimal objective function values for the IEEE 119-bus system

Objective	Power outage time	Routing cost of MPS	Power generation cost of MPS	The number of switch action	Power losses
Only dispatching MPS	107.51 min	1493.23 CNY	3167.43 CNY	0	334.38 kW
Only performing network reconfiguration	0	0	0	11	1370.98 kW
Without considering power losses	0	0	0	11	1687.80 kW
Resilient outage recovery method	25.27 min	350.93 CNY	36.19 CNY	10	824.96 kW

5.3.2 Comparison between the resilient outage recovery method and different scenarios

(1) Comparison with the scenario of only dispatching MPS

Table 3 shows objective function values of four scenarios. The values are power outage time, routing cost of MPS, power generation cost, the number of switch actions, and power losses. In the resilient outage recovery method, the power outage time and routing cost of MPS are only a quarter of those in the scenario of only dispatching MPS, and the power generation cost of MPS is much lower than that of that scenario. There is only one electrical island as the result of the outage management framework, but 11 electrical islands exist if only dispatching MPS to recover the power supply of electrical islands. The more electrical islands the longer the routing distance and there is more generation power required of the MPS. Also, the formation of multiple electrical islands leads to the reduction of the radical network scale, which decreases the power losses of DS. However, considering the stability of the operation, the island operation mode only runs for a short time and the resilience of DS is extremely low in the island operation mode. Therefore, the optimal recovery strategies obtained by the proposed resilient outage recovery methods are superior to the scenario of only dispatching MPS.

(2) Comparison with the scenario of only performing NR

The objective function values of the scenario of only performing NR are shown in Table 3. The routing cost and power generation cost of MPS are 0 due to no MPS being dispatched. The number of faults is small and branches where faults occur are scattered, thus power supply can be restored simply by NR. The reason for power outage time being 0 is that NR can be performed instantaneously with the help of a high-speed switching device [23]. However, the power losses obtained by the scenario of only performing NR are higher than that obtained by the resilient outage recovery method. Because the scale of series load in the radial network is larger in the scenario of only performing NR, it results in a larger voltage drop and power losses on each branch. Therefore, the reliability of the DS will be decreased. In conclusion, although the power outage time, MPSs' routing cost and power generation cost obtained by the resilient outage recovery method are larger than those obtained by only performing NR, the optimal schedule of the resilient outage recovery method is better.

(3) Comparison with the scenario without considering the power losses in the objective function

In the scenario without considering power losses in the objective function, the optimal strategy only performs NR by closing the tie switches in branches {8–24, 17–27, 27–48, 45–56, 38–65, 51–65, 76–95, 78–91, 80–103, 86–113,115–123}, but not dispatching the MPS. The reason is that the number of faults is fewer than the number of loops, so the power supply can be recovered only through NR without forming electrical islands. Accordingly, the power outage time, routing cost and generation cost of MPS is 0. However, this recovery strategy results in larger power losses due to the larger scale of the series load. It is clear from Table 2 that the power losses of the resilient outage recovery method are only half that of the scenario without considering power losses. Moreover, the power line heating phenomenon arises because of the large power losses. This can potentially cause new faults and harm the operation of the utility grid. Therefore, even if the power outage time, MPSs' routing cost and power generation cost of the resilient outage recovery method are slightly higher, its recovery strategy is the optimal one on the whole.

Compared with other scenarios, the resilient outage recovery method considers multiple objectives to ensure the operational reliability of the DS and reduce dispatching costs while minimizing power outage time. Therefore, the outage recovery problem can be better solved by the proposed method.

5.4 Analysis of practical feasibility

The proposed algorithm is a centralized algorithm, which is implemented by using a computer with Intel Core i5-8250 CPU 1.60 GHz, 16 G memory, in MATLAB 2018a. There is no interaction nor communication requirement for realizing the algorithm. Thus, the algorithm can be easily realized in the existing power grid infrastructure. In this environment, the computation time of the algorithm is 1.56 min for the IEEE 33-bus system and 5.40 min for the IEEE 119-bus system. The computation time shows the optimal scheduling strategy can be obtained quickly to reduce the power outage time and cost resulting from the fault.

6 Conclusion

In this paper, a resilient outage recovery method based on co-optimization of MPS and NR is proposed, where the goal is to minimize the power outage time, MPSs' routing cost, power generation cost, switch action cost and power losses. In addition, a solution algorithm is proposed to simplify the solving process of the mathematical model and obtain an optimal outage recovery strategy. The case studies are separately conducted in the IEEE 33 and 119-bus systems to show the effectiveness and performance of the proposed model and solution algorithm. The power supply of outage load can be restored quickly with the minimum economic and DS operation costs by the obtained MPSs' dispatch schedule and NR strategies. It is also shown through the case studies that access points of MPSs can be changed by NR. Since there are more electrical islands in the scenario of only dispatching MPSs, the power outage time and dispatching cost of MPSs by only dispatching MPS are higher than those obtained by the proposed method. Moreover, it is clear that if the number of faults is large or branches with faults are concentrated, the power supply of some electrical islands cannot be restored by only performing NR, while the proposed method can quickly restore the power supply of all the electrical islands with lower power losses. When compared with the scenario without considering power losses in the objective function, the proposed method can reduce the power losses, while maintaining small power outage time and MPSs' routing cost. Finally, the practical feasibility of the proposed method is analyzed from the aspect of computation time. Future studies will consider the repair crew's dispatch in the outage management for co-optimizing various emergency resource schedules.

Abbreviations

DS: Distribution system; NR: Network reconfiguration; MPS: Mobile power source; TN: Traffic network; NMIP: Nonlinear mixed-integer programming; NOP: Nonlinear optimal programming; HSA: Harmony search algorithm; *HM*: Harmony memory; *HMS*: Harmony memory size; *HMCR*: Harmony memory considering rate; *PAR*: Pitch adjusting rate; *bw*: Bandwidth; *T*: Power outage time; $L_{d,f,i}$: Distance between depot *d* and access point *f* of the electrical island *i*; *v*: Constant velocity of MPS; F_i: Total number of all possible access points of electrical island *i*; *I*: Total number of electrical islands; F_i: Total number of access points of the island *i*; *D*: Total number of depots; pri_f: Unit price of a MPS moving one kilometer; pri_e: Unit price of the materials used to product unit electricity; C_1: Dispatching cost; X_d: Total number of MPSs in depot *d*; C_2: Power generation cost of MPSs; *C*: Dispatching cost; E_{d,g_max}: The upper limit of the power generation for MPS *g* in depot *d*; c_s: Economic cost of single switching action; fl_b: Power losses of branch *b*; *B*: Total number of the branch; P_m^{in}, Q_m^{in}: Injecting active power and reactive power in the node *m*, respectively; U_m: Voltage of node *m*; r_b, x_b: Resistance and reactance of the branch *b*; $H(\cdot)$: Function to calculate the power flow in DS; P_m, Q_m: Active power and reactive power of node *m*; P_b: Transmission power of branch *b*; P_{b_min}, P_{b_max}: Lower and upper transmission capacity limit of the branch *b*; U_{m_min}, U_{m_max}: Lower and upper bound of node voltage; $f_1(\bullet)$: Objective function of the MPS dispatching model; $f_2(\bullet)$: Objective function of the NR model; $f(\bullet)$: Objective function of the co-optimization model.

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Author contributions

CL: Conceptualization, Methodology, Software, Writing-original draft. YX: Supervision, Writing-Reviewing and Editing. YL: Conceptualization, Methodology, Software, Writing-original draft. NL: Conceptualization, Methodology, Supervision, Funding acquisition. LC: Methodology, Writing-Reviewing and Editing. LJ: Supervision, Writing-Reviewing and Editing. YT: Checking and revising English expression. All authors read and approved the final manuscript.

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Availability of data and materials

Not applicable.

Declarations

Competing interests

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.

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