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# Role of Outage Management Strategy in Reliability Performance of Multi-Microgrid Distribution Systems

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***Abstract*— This paper develops a general framework for reliability assessment of multi-microgrid (MMG) distribution systems. It also investigates reliability impacts of coordinated outage management strategies in a MMG distribution network. According to the proposed reliability evaluation framework, which is based on sequential Monte Carlo simulation method, distribution system is divided into smaller sections/microgrids based on protection system configuration and operating measures are efficiently simulated considering different operation modes. In order to demonstrate the role of outage management strategy in reliability performance of MMG distribution systems, at first, the required features of an outage management strategy are identified. Then, suitable centralized and hierarchical schemes are introduced for operation of such systems during outage events. The proposed schemes, which are based on model predictive control (MPC) approach, minimize total load curtailments in the system. Moreover, they are flexible and can effectively deal with multiple contingencies as well as uncertainties of outage duration. The developed reliability assessment framework is applied to a test system and performance of the presented outage management schemes are explored through extensive case studies. Obtained results suggest that implementation of an appropriate coordinated scheme is crucial to reliable operation of MMG distribution systems.**

***Index Terms*—Distribution system reliability, model-predictive-control (MPC), multi-microgrid (MMG) distribution system, outage management scheme (OMS).**

## NOMENCLATURE

*Indices and Sets*

| | |
|---|---|
| $g, NG$ | Index and number of dispatchable DG units. |
| $r, NR$ | Index and number of renewable DG units. |
| $b, NB$ | Index and number of energy storage units. |
| $l, NL$ | Index and number of different load types. |
| $i, j, N$ | Index and number of microgrids/sections. |

*Parameters and Constants*

| | |
|---|---|
| $np$ | Duration of scheduling horizon. |
| $c^G$ | Operation cost of dispatchable DG units. |
| $c^R$ | Operation cost of renewable DG units. |
| $c^B$ | Utilization cost of stored energy in ESSs. |
| $c^L$ | Cost of load curtailments at Stage I. |
| $c^X$ | Utilization cost of offered power at Stage II. |
| $c^D$ | Value of curtailed demand at Stage II. |
| $\eta^{\mathrm{ch}}, \eta^{\mathrm{dch}}$ | Charging/discharging efficiencies. |
| $u_{ij}$ | Binary indicator for availability of tie-line *ij*. |
| $L$ | Load demand. |
| $UR, DR$ | Ramp-up/down rates of dispatchable DG units. |
| $\Delta t$ | Timeslot duration. |

*Variables*

| | |
|---|---|
| $X$ | Excess power of MGs/sections at Stage II. |
| $D$ | Unsatisfied demand of MGs/sections at Stage II. |
| $T_{ij}$ | Power transfer from microgrid *j* to microgrid *i*. |
| $E$ | Energy stored in ESSs. |
| $P$ | Active power. |
| $LS, DS$ | Curtailed load at Stages I and II. |
| $\delta^{\mathrm{ch}}, \delta^{\mathrm{dch}}$ | Charge/discharge binary indicators of ESSs. |

*Symbols, Abbreviation and Acronyms*

| | |
|---|---|
| ch,dch | Charge and discharge. |
| min, max | Minimum and maximum. |
| *,** | Optimal values of variable at Stages I and II. |

## I. INTRODUCTION

MICROGRIDS (MGs) can be viewed as small-scale power systems with self-supply and islanding capability. Presence of distributed generation (DG) units and energy storage systems (ESSs) close to demand centers significantly enhances the reliability of these systems. In this context, MGs can be isolated from the upstream network in case of disturbances and sustain the supply of local loads through optimal management of available resources [1].

However, MGs have limited energy handling capability, considering their local nature of power-supply. According to the IEEE recommendations, maximum capacity of MGs is normally limited to 10MVA [2]. Hence, a large amount of demand can only be supplied by splitting the load into several smaller load units and supplying each unit by one MG [3]. This can be translated to presence of multiple MGs in the future distribution networks. These MGs can be managed in uncoordinated fashion, based on the policy of their operators. In

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this case, each MG has to install sufficient generation and storage capacities to achieve the acceptable level of supply security. In contrast, coordinated operation of MGs can reduce total investment and operation costs and would significantly enhance reliability of the whole distribution system [4]. In this context, various approaches are proposed for coordinated operation and management of multi-microgrid (MMG) distribution systems and different aspects of this concept are studied in the literature [4]-[9]. In line with these works, this paper focuses on reliability performance of MMG distribution systems and explores the role of adopted outage management strategy via a systematic approach.

Reliability studies of MGs and active distribution networks have mainly focused on two topics. The first one, which has been the subject of numerous works, is reliability evaluation of grid-connected or isolated MGs [10]-[13]. Reliability assessment of distribution systems integrated with MGs is the other topic, which on the contrary, has received less attention [14]-[17]. In these studies, simple load restoration rules are adopted for simulating MGs operation during outage events and allocation of available resources among different loads. These load restoration rules have been implemented in various forms such as priority orders [14], [15], division rules [16], or heuristic rules such as electrical proximity [17].

In a MMG distribution system, it is quite likely that MGs have different ownerships and they are managed and operated under different strategies. Considering this new environment, simple load restoration rules are unable to represent advanced operating schemes of microgrids during emergency conditions and the mechanisms that they would utilize for deciding about their assistance to other MGs or outside loads, particularly in face of different uncertainties. This fact should be appropriately addressed in reliability studies of MMG distribution systems to obtain dependable results.

Motivated by the aforementioned concerns, this paper investigates the reliability performance of MMG distribution systems and examines the role of adopted outage management strategy in this context. In doing so, a general framework for reliability assessment of MMG distribution systems is developed. This framework, which is based on sequential Monte Carlo Simulation (MCS) approach, is able to accurately quantify the impacts of different operating schemes during normal and emergency conditions. According to this framework, distribution grid is divided into smaller sections/MGs based on the network configuration as well as location of protective devices and operating measures are simulated in sequential timeslots to evaluate the reliability indices of different sections/MGs as well as distribution system.

In the next step, main features and requirements of a coordinated outage management scheme (OMS) in MMG distribution systems are identified. Subsequently, two general categories of OMSs, i.e. centralized or decentralized coordination schemes, are discussed and advantages and disadvantages of each approach are identified. Moreover, appropriate centralized and decentralized operating schemes are introduced that meet the identified requirements of outage management in MMG distribution systems. On these bases, the main contributions of this paper can be listed as follows:

- A general framework for reliability assessment of MMG distribution systems is developed. It is based on sequential MCS method and can accurately quantify the impacts of different operating schemes on reliability of such systems.
- Main features and requirements of appropriate coordinated OMS in MMG systems are identified and advantages and disadvantages of different outage management strategies, i.e. centralized and decentralized coordination schemes are discussed.
- A novel centralized scheme based on model predictive control (MPC) approach is introduced for coordinated outage management of MMG systems. It is flexible, optimally minimizes load curtailments in emergency conditions, and addresses the uncertainties of outage duration.
- Comparative case studies are presented to provide insights on reliability performance of different outage management approaches in MMG distribution systems. Moreover, impacts of various parameters on the performance of the presented schemes are explored via sensitivity analyses.

The rest of this paper is organized as follows. Section II describes different operation modes of distribution grids integrated with MGs. Reliability evaluation framework is introduced in Section III. Different OMSs are outlined in Section IV and their main features are highlighted. Case studies are presented in Section V, followed by conclusions in Section VI.

## II. System Description and Operation Modes

Distribution networks are usually divided into several smaller sections using protective devices, in order to facilitate the process of fault isolation and restoration of the loads in the unfaulted sections [13], [14], [18]. Moreover, available distributed energy resources (DERs) in islanded portion of the network can supply some loads during upstream faults, and thus improve the overall system reliability.

In order to further illustrate these facts, consider the sample distribution system presented in Fig. 1. Upon occurrence of a contingency event in this system, a MG/section will experience one of the following situations:

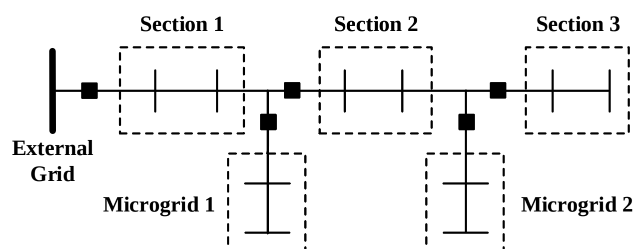


Fig. 1. Sample system for illustrating different operating modes.

a) *Faulted*: Disconnection of all customers in the faulted MG/section is inevitable. Assuming there are no further sectionalizing equipment within this MG/section, the entire load has to be interrupted until the faulted equipment is repaired/replaced.

b) *Grid-Connected*: After fault isolation, some sections/MGs might be able to import the required power from

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upstream network or inject their excess power to it. Given that external grid is able to fulfil the entire distribution system load and also absorb the excess generated power [13], the customers within these MGs/sections would not be interrupted. Referring to Fig. 1, after isolating the faults in MG 1, MG 2 or section 3, sections 1 and 2 can still import the required power from the external grid.

c) *Islanded*: fault isolation might disconnect some MGs/sections from the upstream network. In this case, MGs are able to continue supplying loads in island mode. Moreover, multiple MGs/sections may form a larger island and based on the agreed OMS, share the available generation and storage resources to supply high priority loads. In this context, MGs/sections can both import/export power within the formed island and the MGs/sections with excess generation capacity can export power to the MGs/sections with power deficit. For example, if a contingency occurs in section 1 of Fig. 1, MGs can switch to island mode. Considering the network configuration, MGs may also assist the unfaulted sections by forming a larger island and supply the loads via coordination. Another example is a disturbance in the external grid that leads to isolation of the entire distribution system. In this case, MGs may operate autonomously, or form a single island in order to assist each other as well as section 1-3 and thereby, enhance the supply security in the whole network. Note that in case there are extra switching devices within a MG/section, the introduced classification will be still true for the associated subsections [13].

## III. Proposed Reliability Evaluation Framework

In this section, the reliability evaluation framework for MMG distribution systems is introduced. This framework, which is based on sequential MCS method, is able to accurately capture the operational measures of the system. The main assumptions considered for reliability studies are as follows:

- It is assumed that external grid is able to serve the entire distribution system load or absorb the excess generated power [13] and the customers within grid-connected MGs/sections will experience no interruptions. This assumption does not restrict the generality of the proposed framework, and the operation and simulation procedure can be modified to address this issue.
- Only active power is considered for calculation of reliability indices. In doing so, active power balance within each MG/section, capacity limits of DERs and power transfer constraints among MGs and the rest of distribution grid are modeled. Moreover, it is assumed that voltage level of all buses and nodes can be maintained within the allowable range and therefore, voltage-related constraints are not considered in this paper. Furthermore, active power losses are not considered in this study. These assumptions are commonly accepted in adequacy studies of MGs and active distribution networks [11]-[20]. However, if this is not the case in certain situations, a detailed AC power flow can be used which in turn, increases the computational burden of the studies.
- Protective devices are assumed to be fully reliable and functioning in the intended manner.
- Period of studies is divided into timeslots (one-hour intervals in this paper). Renewable power generation and load level are assumed to be constant during each timeslot.

The proposed reliability evaluation framework is shown in Fig. 2. Before launching the studies, required data should be collected. These include reliability data of components (mean-time-to-failure (MTTF) and repair (MTTR)), and chronological data of load and renewable power generation. Then, the following steps should be taken for reliability analysis:

1) Operating states of external grid as well as all the equipment within distribution system (including buses, circuits, DG units) are determined in each timeslot via random sampling method [21].

2) Considering the outcome of random sampling in step 1, operation mode of each MG/section in the current timeslot is determined. Based on the discussion made in Section II, possible modes are *grid-connected*, *islanded* or *faulted*.

3) The adopted operation strategy of each section/MG is simulated in the current timeslot and different reliability indices are updated. In doing so, operation states of DG units, available power from renewable energy sources (RESs) and demand level are specified. Moreover, state of charge (SOC) of ESSs is obtained from simulation of the previous timeslot. Based on the operation mode of each MG/section, the simulation process should be conducted as follows:

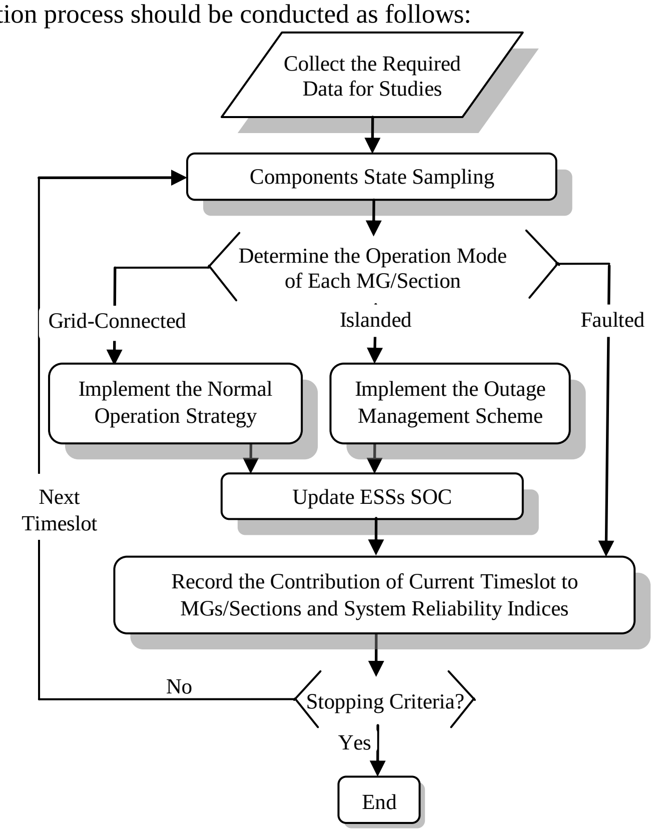


Fig. 2. The proposed reliability evaluation framework.

*Grid-Connected:* According to the assumptions, the MGs/sections would be able to import the required power from external grid or export their excess generation to it [22]-

[24] and as mentioned before, no interruptions would be experienced during current timeslot. However, the SOC of ESSs needs to be updated for the next timeslot. In this paper, this is achieved via solving an optimization problem to minimize the operation cost of such ESSs over the following twenty-four hours and the charging/discharging power at the first timeslot of this period is specified [25]. This value can then be used for calculation of the SOC in the next timeslot, as detailed in (14).

*Islanded:* In this case, different MGs/sections implement the adopted OMS. Depending on the agreements and considering the network configuration, the DSO might coordinate the operation of multiple MGs/sections in order to improve the reliability, as discussed before. In this context, MGs/sections can both import/export power within the formed island [22]-[24] and the MGs/sections with excess generation capacity can export power to the MGs/sections with power deficit. After implementing the operating strategy during current timeslot, charging/discharging power of ESSs are determined and their SOCs for the next timeslot are updated using (14). Moreover, if implementation of OMS leads to load curtailments, contribution of the simulated timeslot to reliability indices should be recorded. In this paper, two commonly used distribution system indices, i.e. average energy not supplied (AENS) and system average interruption duration index (SAIDI) are calculated as below [26]:

$$\text{SAIDI} = \frac{\sum_{lp=1}^{NLP}\sum_{t=1}^{NTS} d_t^{lp} NC_{lp}}{\frac{NTS.\Delta t}{8760}\sum_{lp=1}^{NLP} NC_{lp}} \quad \text{(hour/customer.year)} \tag{1}$$

$$\text{AENS} = \frac{\sum_{lp=1}^{NLP}\sum_{t=1}^{NTS} LS_t^{lp} d_t^{lp}}{\frac{NTS.\Delta t}{8760}\sum_{lp=1}^{NLP} NC_{lp}} \quad \text{(kWh/customer.year)} \tag{2}$$

where *lp, NLP* are the index and number of load points. *NC, NTS* are the numbers of customers and total simulated timeslots, respectively, and *d* represents the load curtailment duration.

*Faulted*: In this case, no simulations are required and the entire load of faulted MGs/sections is curtailed for the whole duration of timeslot. Moreover, as both charging and discharging power are equal to zero, no update procedure is necessary for the ESSs of the faulted Sections/MGs.

4) After simulating system operation in the current timeslot and updating the reliability indices, stopping criteria are checked. Simulation stops when coefficient of variation for calculated indices becomes smaller than a predetermined value or maximum number of simulation years is reached [21]. Otherwise, steps (1)-(3) are followed for the next timeslot. It should be noted that during the isolation process of the faulted sections/MGs, some loads might be temporarily disconnected. However, as only *energy* and *duration* adequacy indices are investigated in this paper, the impact of such temporary interruptions on the values of SAIDI and AENS are neglected and only sustained interruptions are considered [22].

## IV. Outage Management Strategies in MMG Systems

### A. *Main Features and Requirements of a Coordinated OMS in MMG Distribution Systems*

As discussed earlier, coordinated outage management can significantly improve the reliability of a MMG distribution system in face of different contingencies. A coordinated OMS in such a system should possess the following features:

- In general, MGs have different ownerships and they are managed and operated under different strategies. Moreover, DSO might be responsible for operation of some DERS in distribution grid [27]. Therefore, any OMS developed for such a system must recognize this fact and does not restrict the autonomy of different parties as much as possible. Additionally, it should divide the available resources in a fair fashion.
- As previously discussed, available resources in each MG are limited. Hence, adopted OMS should diversify the supply options and make the most out of available resources to minimize load curtailments in face of different contingencies.
- As MGs are able to continue supplying loads after disturbances in the upstream network, multiple contingencies might occur during islanded operation [15]. Hence, adopted OMS should be flexible enough to rapidly respond to these incidents and adjust the operational measures within a short time.
- In many islanding events, system operators are not aware of the exact duration of disconnection from upstream network [28]. Therefore, adopted OMS should deploy appropriate measures to address these uncertainties.

Considering the abovementioned requirements, distribution system and MG operators can make fair and appropriate agreements on how to share their resources and realize the coordinated operation during contingency events.

In order to demonstrate the reliability benefits of coordinated outage management in a MMG distribution system, suitable centralized and decentralized OMSs are presented in the following section and their compliance with the extracted requirements are discussed. It should be emphasized, however, that presented reliability evaluation framework in this paper is general and alternative operational strategies can be readily integrated into the reliability assessment process.

### B. *Centralized Coordinated Outage Management*

The proposed centralized OMS in this section is based on MPC approach [19]. In this approach, the control actions for a system are optimized over a predetermined horizon in the future, in order to obtain the sequence of optimal actions before each time step, but only the ones associated with the first operational step are implemented and this procedure is constantly repeated. The main advantage of MPC lies in the fact that it can constantly update the control actions of the next timeslot, and at the same time, accounts for the future states of the system. In the context of multi-microgrid system's outage management, the scheduling problem is solved over a predetermined horizon in the future, but only the actions associated with the next time step are implemented and this procedure continues until the end of islanding period.

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According to this scheme, DSO takes full responsibility of the system's optimization and control during emergency conditions. In doing so, upon occurrence of an islanding event at timeslot $k$, DSO examines the system configuration after fault isolation and checks the feasibility of coordinated operation among islanded MGs/sections. If this is the case, it identifies the MGs/sections that may participate and requests them to announce the required data to DSO. These data include characteristics of available DERs, SOC of ESSs at current timeslot, and predictions of load demand and renewable power generation over the period $\tau = \{k+1,...,k+np\}$. Then DSO tries to minimize the operation cost of the islanded portion by scheduling the available resources over $\tau$. This operation cost consists of load curtailment costs and utilization cost of different resources.

After solving this optimization problem, schedules of power transfers among MGs/sections, operating points of DERs and unavoidable load curtailments are determined over $\tau$. However, only schedule of the next timeslot $(t = k+1)$ is implemented, and this procedure will continue in the following timeslots $(t = k+2, k+3, ...)$ until the end of islanded operation. General framework of this scheme is illustrated in Fig. 3.

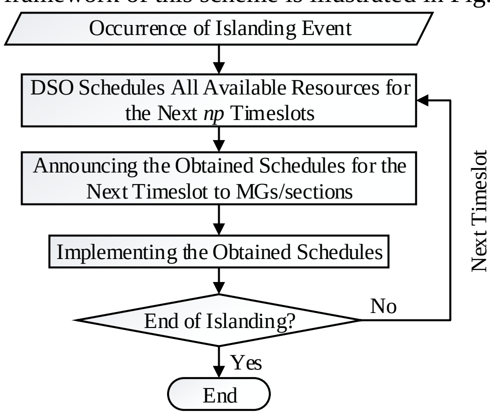

Fig. 3. The proposed centralized outage management scheme.

Implementation of the proposed MPC-based approach enables DSO to optimize the system operation for the next timeslot, and at the same time, take advantage of available data in form of short-term forecasts. On the other hand, as prediction and optimization procedures are repeated at each timeslot, the presented OMS would be flexible enough to update the operational measures in response to the unforeseen failures in the system. Furthermore, as DSO sequentially schedules the resources over pre-determined horizons (the following *np* timeslots), it does not need to know the exact duration of islanding period. Therefore, the proposed scheme can appropriately deal with the uncertainties of islanding duration. Finally, since all system data are available to DSO and it can decide about the schedule of all resources, this centralized strategy improves the performance of outage management, as far as optimality of final schedules is concerned, and this would be beneficial for the whole system.

According to the presented OMS, different resources as well as unavoidable load curtailments should be scheduled over horizon $\tau = \{k+1,...,k+np\}$ in the first step. The associated optimization problem can be formulated as below:

*Objective Function:* The objective is to minimize total operation cost over $\tau$.

$$Min \sum_{i=1}^{N} \sum_{t=k+1}^{k+np} \Delta t \left\{ \sum_{g=1}^{NG_i} c_g^{G,i} P_{g,t}^i + \sum_{r=1}^{NR_i} c_r^{R,i} P_{r,t}^i + \sum_{b=1}^{NB_i} c_b^{B,i} P_{b,t}^{i,dch} \right\} + \sum_{i=1}^{N} \sum_{t=k+1}^{k+np} \Delta t \sum_{l=1}^{NL_i} c_l^{L,i} LS_{l,t}^i \tag{3}$$

The first three terms in (3) are operating costs of dispatchable and renewable DGs, and utilization cost of stored energy in ESSs, respectively. The fourth term is curtailment cost of different load types. Since load curtailment cost is considered higher than that of other resources, in case of unavoidable load shedding, the objective is effectively equivalent to minimizing total load curtailment costs. In other cases, the entire load will be supplied with minimum possible operation cost. The priorities of supplying different loads can be involved in (3) through proper selection of curtailment costs for each load. Note that this objective differs from the works that focus on active-reactive optimal power flow (A-R-OPF) or planning of active distribution networks and their objective is maximizing the benefits of system operation in normal conditions via optimal scheduling of the resources such as ESSs and DG units as well as power transactions with the main grid [29]-[31].

*Power Balance:* For each MG/section at each timeslot, sum of total power generated by DG units, charging/discharging power of ESSs, and net imported power from other MGs/sections must be equal to the total supplied load. It should be noted that $T_{ij}$ can assume both positive and negative values. Positive values of $T_{ij}$ denote power import form MG/section $j$ to $i$, while negative values mean that MG/section $i$ exports power to MG/section $j$. On these bases, the power balance equation (4) can be equally applied to the MGs/sections that import power and the ones that export their excess power:

$$\sum_{g=1}^{NG_i} P_{g,t}^i + \sum_{r=1}^{NR_i} P_{r,t}^i + \sum_{b=1}^{NB_i} \left( P_{b,t}^{i,dch} - P_{b,t}^{i,ch} \right) + \sum_{j=1, j\neq i}^{N} T_{ij,t} = \sum_{l=1}^{NL_i} \left( L_{l,t}^i - LS_{l,t}^i \right) \quad \forall i,t \tag{4}$$

In this context, $\sum_{j=1, j\neq i}^{N} T_{ij,t}$ denotes total imported power of MG/section $i$ from other MGs/sections which is delivered to its PCC. The net imported power is then considered in the internal power balance equation of MG/section $i$, as indicated in (4). It should be noted that negative values of $\sum_{j=1, j\neq i}^{N} T_{ij,t}$ imply that MG/section $i$ is exporting power and therefore, it should provide this excess power using its internal resources.

*Dispatchable DG Units Constraints:* These constraints include capacity limits (5), and ramping up/down limits (6), (7):

$$P_{g,t}^{i,\min} \le P_{g,t}^i \le P_{g,t}^{i,\max} \quad \forall g,t,i \tag{5}$$

$$P_{g,t}^i - P_{g,t-1}^i \le UR_g^i \quad \forall g,t,i \tag{6}$$

$$P_{g,t-1}^i - P_{g,t}^i \le DR_g^i \quad \forall g,t,i \tag{7}$$

*RESs Constraints:* The amount of utilized power from each RES should be limited by the maximum available power:

$$0 \le P_{r,t}^{i} \le P_{r,t}^{i,\max} \quad \forall r,t,i \tag{8}$$

*Loads Constraints:* For each load type, the amount of load curtailment must not exceed the total load:

$$0 \le LS_{l,t}^{i} \le L_{l,t}^{i} \quad \forall l,t,i \tag{9}$$

*ESSs Constraints:* Allowable charging and discharging power limits are specified in (10) and (11). Constraint (12) represents SOC allowable limits. Simultaneous charging and discharging is avoided in (13) and the relationship between charging/discharging power and SOC is modeled in (14).

$$0 \le P_{b,t}^{i,\mathrm{ch}} \le \delta_{b,t}^{i,\mathrm{ch}} P_{b,t}^{\mathrm{ch,max}}, \quad \delta_{b,t}^{i,\mathrm{ch}} \in \{0,1\}, \forall b,t,i \tag{10}$$

$$0 \le P_{b,t}^{i,\mathrm{dch}} \le \delta_{b,t}^{i,\mathrm{dch}} P_{b,t}^{\mathrm{dch,max}}, \quad \delta_{b,t}^{i,\mathrm{dch}} \in \{0,1\}, \forall b,t,i \tag{11}$$

$$E_b^{\min} \le E_{b,t}^{i} \le E_b^{\max} \quad \forall b,t,i \tag{12}$$

$$\delta_{b,t}^{i,\mathrm{ch}} + \delta_{b,t}^{i,\mathrm{dch}} = 1 \quad \forall b,t,i \tag{13}$$

$$E_{b,t+1}^{i} = E_{b,t}^{i} + \left(P_{b,t}^{i,\mathrm{ch}} \eta_b^{\mathrm{ch}} \Delta t - P_{b,t}^{i,\mathrm{dch}} \Delta t / \eta_b^{\mathrm{dch}}\right) \quad \forall b,t,i \tag{14}$$

*Power Transfer Constraints:* Constraint set (15) limits power transfers among MGs/sections. Note that $T_{ij}$ would be positive if MG $j$ exports its excess power to MG $i$, and it would be negative otherwise. Binary parameters $u_{ij}$ indicate availability of interconnections between MGs/sections $i$ and $j$ (equal to one if the associated interconnection is available, and zero otherwise), while $T_{ij}^{\max}$ is the associated power transfer capacity. Moreover, constraint (16) specifies the relationship between the two variables that correspond to different directions of power transfer via an interconnection. On these bases, it can be concluded that $\max\left\{\sum_{j=1, j\ne i}^{N} T_{ji,t}, 0\right\}$ gives total excess generation of MG/section $i$ in timeslot $t$.

$$-u_{ij,t} T_{ij,t}^{\max} \le T_{ij,t} \le u_{ij,t} T_{ij,t}^{\max} \quad \forall i,j \in \{1,\dots,N\}, i \ne j \tag{15}$$

$$T_{ij,t} + T_{ji,t} = 0 \quad \forall i,j \in \{1,\dots,N\}, i \ne j \tag{16}$$

The DSO will obtain the optimal schedule of system resources over $\tau$, through solving the mixed integer linear programming (MILP) problem described in (3)-(16). Active power generation of dispatchable and renewable DG units, charging/discharging curtailment power of ESSs as well as the associated binary status indicators, schedule of flexible loads, and active power transfers are decision variables of this optimization problem. Subsequently, it announces the obtained schedule of timeslot $t = k+1$ to MGs so that they can implement the result in that timeslot. This procedure will be sequentially repeated to determine system's schedule in the subsequent timeslots $(t = k+2, k+3, \dots)$.

As a note, since prediction and optimization procedures are constantly repeated in the presented MPC-based schemes, it is assumed that the most accurate short-term forecasts are used for optimization of operating schedule at each timeslot [19] and as a result, load and RESs prediction errors have not been considered in this paper. It should be noted however, that if prediction errors cannot be neglected in some studies, the uncertainties of load and RESs can be readily incorporated in the energy management process as an appropriate set of stochastic scenarios [32], [33].

### C. Decentralized Coordinated Outage Management

Prerequisite of the introduced centralized scheme is that DSO possesses sufficient optimization and processing capabilities, and the associated data communication requirements are met. Most importantly, all MGs must agree to grant full control of their resources to DSO. However, as mentioned earlier, an appropriate coordinated OMS should not restrict the autonomy of different parties as much as possible. It has been shown that decentralized approaches can overcome such issues [7].

On these bases and in order to compare the reliability performance of the two approaches, a decentralized OMS is also introduced, which satisfies the extracted requirements addressed in Part A. It is based on the authors' previous work [34] and in contrast to the centralized scheme, consists of two stages (Fig. 4). In Stage I, different resources of MGs as well as the sections integrated with DERs are scheduled by minimizing their operating costs over $\tau$. These schedules can be obtained by solving the optimization problem (3)-(14) for each MG/section, except that power transfer variables should not be considered in the power balance constraint (4).

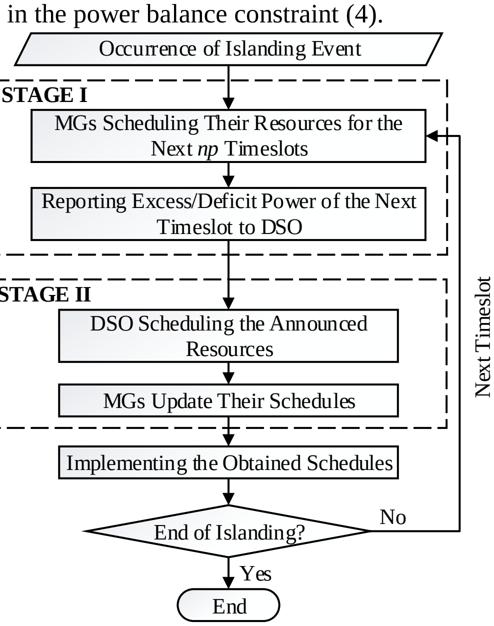


Fig. 4. The presented decentralized outage management scheme.

Based on the outcome of this scheduling stage, unused generation/storage capacitates, or unsupplied demands of different MGs/sections at $t = k+1$ are determined and announced to DSO. These values are calculated as follows:

$$\begin{aligned} X_{i,k+1}^{\max} = &\sum_{g=1}^{NG_i} \min\left\{\left(P_g^{\max} - P_{g,k+1}^{i*}\right), \left(P_{g,k}^{i**} + UR - P_{g,k+1}^{i*}\right)\right\} \\ &+ \sum_{b=1}^{NB_i} \min\left\{\min\left\{E_{b,k+np+1}^{i*}, E_{b,k}\right\} \times \eta_b^{\mathrm{dch}} / \Delta t, P_{b,t}^{\mathrm{dch,max}}\right\} \\ &+ \sum_{r=1}^{NR_i} \left(P_r^{\max} - P_{r,k+1}^{i*}\right) \quad \forall i \end{aligned} \tag{17}$$

$$D_{i,k+1} = \sum_{l=1}^{NL_i} LS_{l,k+1}^{i*} \quad \forall i \tag{18}$$

The first term in (17) is the maximum surplus power from dispatchable DG units considering ramp-up limits. The second and third terms respectively yield the attainable power from ESSs and RESs, while total power deficit is specified in (18).

Note that in constraint (17), it is assumed that each MG/section firstly calculates the SOC of ESSs at timeslot $k+np+1$ ($E_{b,k+np+1}^{i*}$). If $E_{b,k+np+1}^{i*}$ is positive, the MG/section would offer this energy to DSO, considering current SOC and maximum discharge power limit. By doing so, it is ensured that sufficient stored energy is available for implementation of Stage I schedules over $\tau$, in case any interruptions occur in the coordinated outage management. It should be remarked that the first stage scheduling is not carried out for the sections without DERs. However, their total demand is calculated from (18) and announced to DSO for Stage II. In addition, their excess power should be simply set to zero.

In Stage II, DSO schedules the announced resources for supplying the unserved loads of Stage I, by solving the following linear programming (LP) problem:

$$Min\sum_{i=1}^{N}\Delta t\left\{c_i^X X_{i,k+1}+c_i^D DS_{i,k+1}\right\} \tag{19}$$

$$X_{i,k+1}+\sum_{j=1,\, j\neq i}^{N} T_{ij,k+1}=D_{i,k+1}-DS_{i,k+1}\quad \forall i \tag{20}$$

$$0\leq X_{i,k+1}\leq X_{i,k+1}^{\max}\quad \forall i \tag{21}$$

$$0\leq DS_{i,k+1}\leq D_{i,k+1}\quad \forall i \tag{22}$$

where, excess power generation and load curtailment of each MG at Stage II, as well as active power transfer schedule are decision variables of this optimization problem. The first term in (19) is utilization cost of offered resources and the second term represents the value of curtailed demand. The associated prices are specified in MGs' agreement with DSO. Power balance constraint for each MG/section is ensured in (20), and the limits of offered power and load curtailment are respectively specified in (21) and (22). Note that power transfer constraints are the same as (15)-(16) and are not repeated here. Since values of curtailed demand are usually higher than that of utilization prices, total value of load curtailments is minimized in case of unavoidable load shedding. In other words, unserved demands of different MGs are supplied in priority order of curtailment values (the most expensive loads are supplied first). In other cases, the entire load will be supplied with minimum possible utilization cost. It should be noted that financial aspects of emergency energy transactions among microgrids can be handled in alternative ways, such as future and real-time markets or bilateral contracts [35], [36].

Once DSO completes the scheduling of Stage II, it announces the results to MG operators so that they can update their schedules for timeslot $t = k+1$. In doing so, MGs/sections whose offers are accepted by DSO, should provide more power by modifying their Stage I schedules. As it is reasonable to assume that they would provide the extra power with minimum possible cost, the final schedules can be obtained from (3)-(14), except that offered power limits of different resources in (17) should be observed and power balance constraint in (4) should be modified as below:

$$\sum_{g=1}^{NG_i}P_{g,k+1}^{i}+\sum_{r=1}^{NR_i}P_{r,k+1}^{i}+\sum_{b=1}^{NB_i}\left(P_{b,k+1}^{i,\mathrm{dch}}-P_{b,k+1}^{i,\mathrm{ch}}\right)=\sum_{l=1}^{NL_i}L_{l,k+1}^{i}+X_{i,k+1}^{**}\quad\forall i \tag{23}$$

where, $X_{i,k+1}^{**}$ is the amount of accepted excess generation in DSO's scheduling. After updating the schedules, they are implemented in timeslot $k$+1, and this procedure will continue in the subsequent timeslots until the islanded operation is over.

In contrast to the centralized approach, implementation of this hierarchical scheme does not restrict the autonomy of different operators as they can follow their own operating strategies. Additionally, since scheduling is conducted in two levels, complexity of optimization and control would be greatly reduced for DSO. This scheme also minimizes the data exchange between DSO and the MGs. It should be noted however, that due to decentralized nature of the scheme, total load curtailments might be higher than that of the centralized approach. This fact will be further explored in the following section.

As a note, it has been demonstrated that a portion of active power could be rejected in active distribution networks [22]. In our study, two cases of power transfer can occur. The first one is power transfer among MGs/sections within distribution grid. In this case, DSO verifies the feasibility of arranged power transactions in both cases of centralized and decentralized outage management via constraints (15)-(16). In doing so, it can determine the maximum allowable capacity of power transfer among MGs/sections based on the operating conditions. Therefore, in this case no generated power would be rejected. The second case of power transfer is between distribution network and the external grid. As earlier mentioned, it is assumed that external grid is able to serve the entire distribution system load or absorb the excess generated power [13], [29], [30]. In other words, in this case too, power rejection would not be an issue.

## V. Case Studies

### A. *Test System and Main Assumptions*

In order to compare reliability performance of the presented OMSs, they are applied to the IEEE 34-node test system [37]. This feeder is modified by integration of three microgrids as shown in Fig. 5. The MGs include microturbines (MTs), wind turbine generators (WTGs), photovoltaic (PV) units, ESSs and load. DG units and ESSs characteristics are given in Tables I-III. It has been assumed that loads of the feeder and three MGs are of residential type and have the same hourly profile. Annual peak load of each MG and feeder are 1 MW and 0.4 MW, respectively. Chronological data of load and RESs generation profiles as well as operation cost of different resources are borrowed from [34]. Electricity price is adopted from [25]. It should be noted that no sectionalizing devices are considered within the feeder or microgrids.

Reliability data of dispatchable DG units and feeder components are set according to [38] and [39], respectively. Failures of RESs and ESSs are neglected in this study. The equivalent values of MTTF and MTTR for external grid are respectively 1460 and 2 hours, while the associated values for each MG are 4380 and 2 hours. Based on the time-resolutions of load and RESs output-power forecasts, $\Delta t$ is set to 1 hour in the studies. In order to carefully investigate different aspects of the proposed framework, the following Cases are defined:

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- **Case I:** Uncoordinated outage management. In this case, there are no power transfers among different MGs/feeder.
- **Case II:** Centralized coordinated outage management via PCCs. In this case, if failures occur in external grid, MGs would be able to exchange power with the feeder via the points of common coupling (PCCs) (power transfer capacity is 1 MW).
- **Case III:** Same as Case II, except that decentralized scheme is used.
- **Case IV:** Centralized coordinated outage management via PCCs as well as MGs interconnections. In this case, MGs are able to exchange power via the PCCs as well as three tie-lines that connect each MG to the two others [8] (power transfer capacities of each interconnection and PCC are respectively 0.4 MW and 1 MW).
- **Case V:** Same as Case IV, except that decentralized scheme is used.

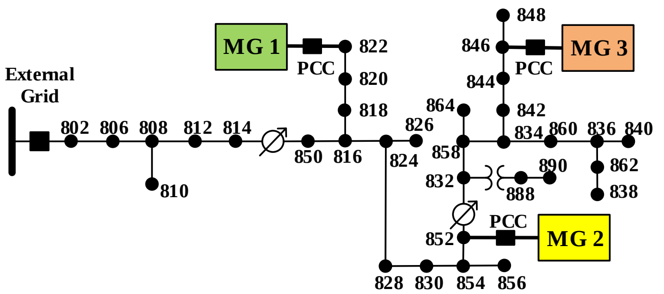


Fig. 5. Single line diagram of the system under study.

TABLE I
DISPATCHABLE DG UNITS CHARACTERISTICS

| Unit | Type | MG | Max Capacity (kW) | Ramp Up/Down Rate (kW) |
|---|---|---|---|---|
| 1 | MT | 1 | 200 | 100 |
| 2 | MT | 2 | 500 | 250 |
| 3 | MT | 3 | 1000 | 500 |

TABLE II
RENEWABLE DG UNITS CHARACTERISTICS

| Unit | Type | MG | Max Capacity (kW) |
|---|---|---|---|
| 1 | WTG | 1 | 1300 |
| 2 | PV | 2 | 1000 |
| 3 | WTG | 3 | 300 |

TABLE III
ENERGY STORAGE UNITS CHARACTERISTICS

| Unit | MG | Min-Max SOC (kWh) | Max Charge/Discharge Power (kW) | Charge/Discharge Efficiency |
|---|---|---|---|---|
| 1 | 1 | 0-800 | 200 | 0.90 |
| 2 | 2 | 0-600 | 200 | 0.90 |
| 3 | 3 | 0-200 | 200 | 0.90 |

It should be noted that for all Cases, system operation was simulated in consecutive years until convergence criteria were met. Moreover, all calculations were implemented in MATLAB software on a 3.4-GHz personal computer with 8 Gigabytes of RAM, and the optimization problems associated with the outage events simulation were solved within a fraction of a second. Moreover, the MILP problems were solved using an internal function of MATLAB software called *"intlinprog"*, which uses *"Branch and Bound"* method for solving such problems [40].

## *B. Results and Analysis*

Reliability indices of feeder, MGs and the whole distribution system in different Cases are reported in Tables IV and V. It is evident from both tables that implementation of coordinated outage management in either form significantly enhances the reliability level of customers in the whole system. Moreover, as far as reliability indices of the whole system are concerned, centralized schemes (Case II, IV) exhibit better performance compared to decentralized counterparts (Cases III, V). As mentioned in Section IV, this result was expectable.

TABLE IV
AENS OF FEEDER AND MGS IN DIFFERENT CASES (KWH/CUSTOMER.YEAR)

| CASE | MG 1 | MG 2 | MG 3 | FEEDER | SYSTEM |
|---|---|---|---|---|---|
| I | 19.101 | 13.456 | 8.642 | 48.934 | 17.874 |
| II | 16.548 | 12.665 | 10.269 | 31.406 | 15.307 |
| III | 19.081 | 13.063 | 8.507 | 32.052 | 15.727 |
| IV | 11.313 | 11.281 | 10.736 | 31.396 | 13.497 |
| V | 14.747 | 11.384 | 8.086 | 34.731 | 14.150 |

TABLE V
SAIDI OF FEEDER AND MGS IN DIFFERENT CASES (HOUR/CUSTOMER.YEAR)

| CASE | MG 1 | MG 2 | MG 3 | FEEDER | SYSTEM |
|---|---|---|---|---|---|
| I | 9.866 | 7.202 | 4.944 | 28.188 | 9.790 |
| II | 8.644 | 6.820 | 5.707 | 17.688 | 8.308 |
| III | 9.798 | 6.986 | 4.850 | 17.937 | 8.473 |
| IV | 6.006 | 6.010 | 5.759 | 17.684 | 7.309 |
| V | 7.557 | 6.074 | 4.586 | 19.198 | 7.617 |

Comparing the results of Case II with Case I, it can be observed that whereas centralized coordination causes a substantial improvement in reliability of the feeder, it does not have an identical impact on the MGs. While it improves reliability level of MGs 1-2, it worsens that of MG 3 compared to the uncoordinated Case.

In this Case, the feeder can import power from MGs and reduce its load curtailments for failures of the external grid. MGs would also be able to exchange power via the PCCs. However, as load curtailment costs are the same for all the loads, no priorities are considered in the supply and this scheme, tends to allocate the available resources to different MGs in a uniform fashion, regardless of the MGs contribution to reliability improvement. In this context, implementation of this scheme does not seem to be fair to MG 3, which has the highest installed capacity of dispatchable DG units.

This is not the case for the decentralized coordination, as it can be observed that reliability indices of all MGs are simultaneously enhanced in Case III in comparison to Case I. This observation can be linked to the hierarchical nature of the presented approach, as MGs would assist the outside loads only if they have excess energy in Stage I.

Power transfers in Case II-III are limited to disconnection events from external grid, and MGs would not be able to assist each other in case of faults in the feeder. Power exchange in such events is also made possible in Case IV-V, where three tie-lines interconnect MGs to each other. It can be clearly seen that this option further enhances the security of supply in the system. Implementation of centralized OMS reduces the values of AENS and SAIDI for the whole distribution system respectively by 24.5% and 25.3%, while the associated values for decentralized scheme are 20.8% and 22.2%.

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It can be seen that reliability indices of different MGs in Case IV, have become even closer to each other, compared to Case II. This implies that as power exchange limitations are reduced in the centralized OMS, reliability indices of different MGs tend to converge to the same value. In contrast, reliability enhancements are balanced in Case V. In this Case, reliability improvement for MG 1 has the highest value. This can be attributed to large share of renewables in its generation portfolio. In this context, MG 1 would be able to import the required power from other MGs when available power from RESs is not sufficient. Coordination is also beneficial for MG 3 that mainly relies on MTs for supplying its loads. This is because it can import power from other MGs in case of MT failures.

### C. *Sensitivity Analysis*

Sensitivity of the obtained results to power transfer capacities in different Cases is depicted in Figs. 6-7. It can be concluded from both figures that coordination dramatically boosts the reliability level, even with low power transfer capacities. Moreover, with increase of these capacities beyond certain values, practically no reliability improvements are gained.

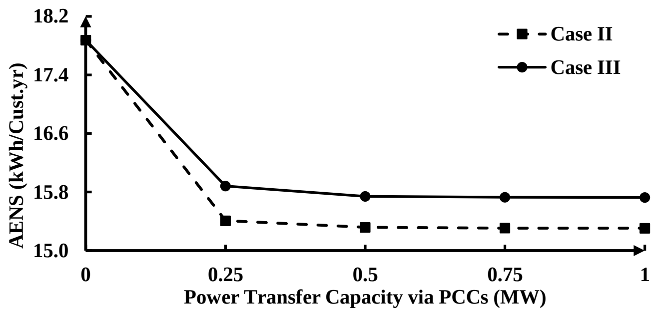


Fig. 6. AENS vs. power transfer capacity in Cases II-III.

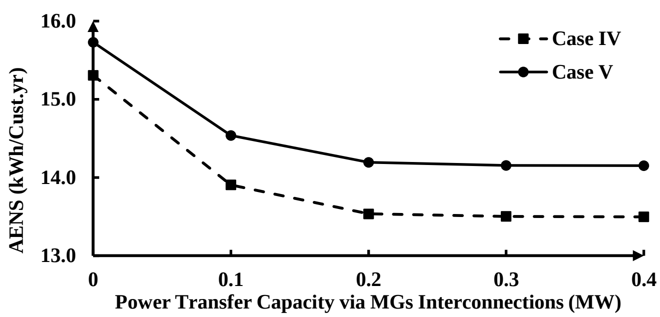


Fig. 7. AENS vs. power transfer capacity in Cases IV-V.

As previously discussed, diversity of resources would improve the system reliability. To explore this fact, a portion of RESs capacities in each MG in Cases IV-V are replaced by PV units. Parameter *w* represents the ratio of wind generation to the total capacity of RESs, while the total renewable generation capacity is maintained constant. The results are depicted in Fig. 8. It can be confirmed that in both Cases, mixed installation of wind and PV units would enhance the reliability, opposed to the Cases where *w* is set to either zero or one. In this context, proper selection of renewable mix in Cases IV-V can reduce AENS by approximately 4.3% and 4.7%, respectively.

Scheduling strategy of microgrids in the first stage is a key factor in successful implementation of the coordinated decentralized scheme. Hence, the role of scheduling horizon (*np*) on reliability performance of the presented OMS in Case V is illustrated in Fig. 9. Note that with selection of very short horizons for Stage I, the system status in the upcoming timeslots cannot be effectively addressed in the scheduling process. Therefore, the obtained schedule over the whole outage period is most likely to be suboptimal. On the other hand, selection of very long horizons encourages the operators to schedule their resources in a conservative manner and as a result, they would not be willing to actively participate in the coordinated outage management. This argument can be confirmed from Fig. 9, where a scheduling horizon of 2 hours exhibits the best reliability performance.

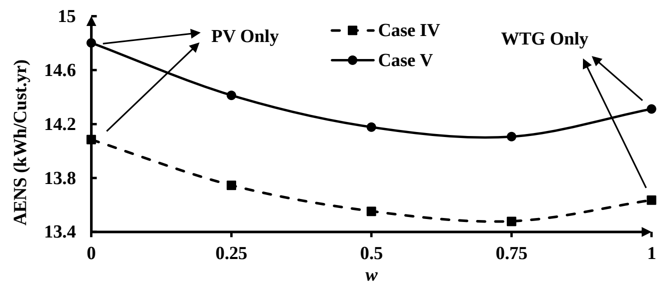


Fig. 8. AENS vs. the mix of RESs in Cases IV-V.

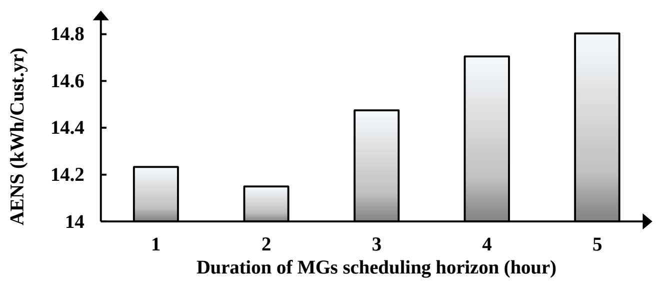


Fig. 9. AENS vs. duration of scheduling horizon in Case V.

## VI. Concluding Remarks

In this paper, reliability performance of a MMG distribution system is investigated and a general framework based on sequential MCS method is presented to evaluate its reliability. In addition, centralized and hierarchical schemes are introduced for coordinated operation of MMG distribution systems during contingencies. The presented schemes, which are based on MPC approach, are flexible and minimize load curtailments in the whole system. Several Cases have been defined to explore the abilities of different operating strategies in improving the reliability level of customers based on the proposed evaluation framework. Obtained results demonstrate the reliability benefits of coordinated operation in MMG distribution systems. Moreover, it is shown that although the centralized scheme exhibits better performance in minimization of total load curtailments, the decentralized approach can better deal with diversified goals of different MGs and it is more suitable for large MMG distribution systems.

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