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Networked microgrids with roof-top solar PV and battery energy storage to improve distribution grids resilience to natural disasters

Eric Galvan[a], Paras Mandal[b,*], Yuanrui Sang[b]

[a] Economic Research Department, El Paso Electric, El Paso, TX 79960, USA
[b] Department of Electrical and Computer Engineering, University of Texas at El Paso, El Paso, TX 79968, USA

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ABSTRACT

Electric power systems are prone to several threats. However, some potential threats e.g., extreme weather or natural disasters, are unavoidable and this can affect socio-economic activities, energy security, and also quality of life. Hence, improving the electric power grid resilience in order to reduce the impact from natural disasters has to be thoroughly studied and understood. This paper presents the challenges and advantages of having sections of a power distribution system constituted by networked microgrids (MGs) to efficiently manage distributed energy resources (DERs), in particular roof-top solar photovoltaic and battery energy storage systems, in order to improve the power distribution system resilience to natural disasters. In this regard, this paper provides a detailed resilience analysis process considering two major case studies, moderate damage and heavy damage, which are tested under different scenarios and levels of disruption, that are evaluated utilizing various resilience metrics. Test results indicate that networked MGs incorporating DERs show the potential to provide support to the power distribution system by scheduling the discharge of battery energy storage systems during outages and improve the resilience of the distribution grid to natural disasters.

1. Introduction

Today's electricity grid faces challenging issues with aging infrastructure and high concerns regarding cyber and physical system security. As infrastructure ages, many risks arise with it, e.g., increased maintenance and operation costs, equipment failure, inefficient operation, and in severe cases cascading blackouts [1]. While blackouts are considered as low-probability events, the socioeconomic costs and impacts are extensive [2]. Over the past decades, hundreds of major blackouts have occurred in the U.S. causing an estimated one billion dollars per event and over one trillion dollars in total damages, with most of these outages (over 90%) occurring primarily at the power distribution level [3,4]. The National Oceanic and Atmospheric Administration (NOAA) also reported losses of more than 1 billion dollars due to 30 weather/climate events that occurred in past two years 2017–2018 [3]. The number of occurrence and intensity of these natural events have increased in recent years with three events, i.e., hurricanes in Houston, Florida, and Puerto Rico, occurring in 2017 are the lesson learning examples of the impacts of natural disasters on power systems. With a growing dependency on electricity to perform daily activities and important services, e.g., but not limited to, health care, communications, education, transportation, and emergency responses, there is a great need to enhance the electric power distribution systems resilience to lower the adverse impact from potential threats, e.g., natural disasters, which can affect quality of life as well as impede socio-economic activities and national/energy security. Enhancing the distribution systems resilience can be achieved through the development of microgrid (MG), which is a localized distribution network that consists of distributed energy resources (DERs) such as wind energy, solar energy, storage system, electric vehicles, and others. In recent years, MGs have received special attention as different research and pilot projects have shown the potential of MGs to make distribution networks sustainable.

Several literatures are available that have focused on control strategies for MGs [5–9]. The concept of multi-microgrid and community-microgrid, where MGs interact with the main grid and other MGs, is well discussed in [10,11]. Che et al. [12] reported the coordination of different control levels in a MG in order to achieve its economic operation. The control of DERs within a MG pilot-project at the Illinois Institute of Technology showed to be an effective way of enhancing the resilience of the MG under emergency events [13]. In [14], an optimal arrangement of MGs is proposed using graph-theories based on modularity to quantify the resilience level of electric distribution systems. A methodology to quantify the resilience improvement in a building-MG

* Corresponding author.
E-mail address: pmandal@utep.edu (P. Mandal).

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by integrating solar photovoltaic (PV) and energy storage is presented in [15]. A two-stage stochastic program for designing resilient distribution grids with networked MGs is proposed in [16] in which, individual MGs, hardened networks, and a combination (networked MGs) are utilized to evaluate costs of increasing system resilience. Zhua et al. [17] proposed a MG formation method based on network reconfiguration for a resilient operation of distribution systems under emergency situations. A software-defined networking (SDN) architecture equipped with event-triggered communication is reported in [18] to transform isolated local MGs into integrated networked MGs capable of energy-sharing to improve system efficiency as well as resilience. Shahida et al. [19] presented an islanding detection algorithm to detect sectioned areas of a distribution system to ensure the system remained operational while experiencing islands. A detailed literature review of resilience enhancement strategies for power systems is available in [20]. A conceptual framework that considers resilience during the planning stages of a MG is well discussed in [21]. A model to determine the location of MGs for resilience improvements in a power grid by considering the probability of equipment failure is presented in [22]. Amirioun et al. [23] studied a flood-preventive scheduling scheme that isolates vulnerable areas of a MG during floods to improve MG resilience. In [24], a network reconfiguration algorithm for MGs that considered grid topology and hierarchy of loads (critical and no-critical) is presented and evaluated utilizing different resilience metrics such as demand served and weather intensity. A framework to prevent and minimize overgeneration and load shedding during power outages caused by hurricanes is presented in [25] where a preventive unit commitment is carried out considering severe weather projections and transmission line failure probabilities. Hussain et al. [26] proposed a heuristic approach in which the resilience of distribution systems was improved by forming MG clusters while minimizing losses and load shedding during outages. In [27], the subdivision of a power distribution grid into MGs during outage events by minimizing energy not served is proposed to improve the reliability and resilience of the distribution grid. In [28], a two-stage coordination framework to improve distribution system resilience by creating multiple microgrids using a spanning forest algorithm to supply critical loads during contingencies has been described. Flow battery energy storage is utilized by Panwar et al. [29] to improve the resilience of advanced distribution grids by optimizing the power and energy ratio of the energy storage system. A case study using REopt® software to determine the optimal generation mix for a hospital MG by considering cost minimization and resilience of critical infrastructure is described in [30]. In [31], robust optimization is applied in a MG energy management to optimize the operation of a microgrid under various levels of costs and infrastructure failure uncertainties to test the overall reliability of the MG. Distribution system component fragility curves and a probabilistic storm model were utilized to evaluate the resilience of a MG to extreme weather events such as windstorms [32]. Battery energy storage was optimally managed in a commercial MG to improve its resilience to severe events while minimizing the operational costs and considering electricity and generation uncertainties using the conditional value at risk [33].

Although several studies have been conducted related to the resilience of power distribution systems, there are still gaps in the literature, specifically in developing realistic case studies and utilizing appropriate resilience metrics. Furthermore, quantifying the actual impacts on the electricity consumers caused by the disruption of electrical service due to natural disasters or other disruptive events needs to be thoroughly studied. Moreover, failing to quantify the potential impacts of blackouts caused by such events using the correct resilience metrics can limit the ability of decision makers to identify the best approach for infrastructure investments and additions to improve the overall resilience of the power distribution system. In contrast to the existing papers, this paper addresses the aforementioned challenge of quantification of natural disasters' impact on electricity consumers by analyzing and evaluating the potential improvements in power distribution system resilience to natural disasters using appropriate resilience metrics under two consequence classes, electrical service and monetary, thus making this paper novel. In general, the novelty of this paper lies on two aspects as described by (i) evaluating the impact of outages on system loads by adopting an emerging and promising prosumer-centric networked MGs mechanism with an effective utilization of solar PV and Battery Energy Storage Systems (BESS) as DERs and (ii) assessing the monetary impacts the utility or system operator and customers will experience due to the natural disasters.

In light of the related work, this paper contributes to the state-of-the-art in power distribution grid resilience to enhance its capability under moderate damage and heavy damage events caused by natural disasters. The major contributions of this paper are:

(1) Development of a detailed resilience analysis presenting realistic case studies that show the potential benefits that DERs, when effectively managed in prosumer-centric networked MGs, can provide to power distribution grids;
(2) Calculation of resilience metrics for electrical service and monetary impacts using DERs. The considered metrics are total customer-hours of outage (h), total customer energy not served (kWh), total and average number of customers experiencing outages, total loss of utility revenue ($), total outage costs ($), and total avoided costs ($);
(3) Consideration of different natural disaster their intensities to obtain the best/worst case scenario outcomes; and
(4) Use of different weather scenarios preceding the natural disaster to effectively quantify the potential support the DERs will be able to provide the power distribution system under favorable (sunny day) and unfavorable (rainy day) weather conditions.

The rest of the paper is organized as follows: Section 2 presents the system models and resilience metrics. Simulation results and discussion are presented in Section 3 that also includes test system, case studies, scenarios, and data assumptions. Section 4 concludes the paper.

2. System modeling and resilience metrics

To evaluate the resilience of the distribution grid with networked MGs and DERs, an analysis based on the Resilience Analysis Process (RAP) is conducted. The RAP was developed at SANDIA national laboratories to provide a means and a set of metrics to analyze the resilience of energy systems [34]. Frequently, resilience and reliability are confused as being similar although they account for different types of events and use different metrics, i.e., resilience analysis considers low probability, high consequence events, and the resilience metrics focus on the impacts on humans. Contrary to the resilience analysis, reliability analysis considers high probability, low impact events, and the focus is on system impacts [34].

2.1. Classification of consequences and resilience metrics

In this paper, the consequences and resilience metrics that are considered for the case studies are presented in Table 1. The metrics shown in Table 1 are based on the consequences and resilience metrics reported in [35].

2.2. Definition of hazards and level of disruption of the distribution system

The potential hazards that are considered for simulation purposes are storms of different intensities, i.e., moderate intensity and high intensity. The expected levels of damage to the grid assets under different scenarios are based on the hazard's intensity, i.e., similar damages will be considered (moderate damage and high damage). Specifically, the damages that are anticipated to occur in the distribution grid are downed distribution lines and feeders. The consequence

Table 1
Consequence classification and resilience metrics.

Consequence Class	Resilience Metric
Electrical Service	Total customer-hours of outages (h) Total customer energy not served (kWh) Total and average number of customers experiencing outage during the specified time period
Monetary	Total loss of utility revenue ($) Total outage costs ($) Total avoided outage cost ($)

data of the hazards for the case studies is obtained through the execution of power flow in the distribution system [36]. When running the power flow analysis, the bus voltages and power outputs of the DERs are calculated to estimate which loads would be unserved during the outage. In this case, power flow will be executed for the case studies time period (1-day) under the different scenarios that are described in Section 3. These simulations allow us to determine as well as to quantify the effects of the hazards on the customers being served in the distribution system and the ability of the utility or system operator to deliver electrical energy to its customers.

2.3. Consequences and resilience metrics calculations

The consequence and resilience metrics that have been evaluated are listed in Table 1. Each metric is calculated as follows.

Electrical service class

Total customer-hours of outages

$$\sum_{t=1}^{n}\sum_{i=1}^{k} x_i\cdot(t) \tag{1}$$

where $x_i\cdot(t)$ is the number of customer-hours without power of customer i for the duration of event n, for all customers k experiencing an outage.

Total customer energy not served

$$\sum_{t=1}^{n}\sum_{i=1}^{k} E_i\cdot(t) \tag{2}$$

where $E_i\cdot(t)$ is the total energy not served per customer.

Total and average number of customers experiencing outages during the specified time period

$$\bar{X} = \frac{\sum_{s=1}^{T_s}\sum_{i=1}^{k} x_{i,s}}{T_s} \tag{3}$$

where $\bar{X}$ is the average number of customers experiencing an outage during scenario s and T_s the total number of scenarios.

Monetary class

Total loss of utility revenue

$$C_{LUR,s} = C_e * \left(\sum_{t=1}^{n}\sum_{i=1}^{k} E_{i,s}\cdot(t)\right) \tag{4}$$

where $C_{LUR,s}$ is the loss of utility revenue ($), C_e is the cost of energy ($/kWh), and$E_{i,s}\cdot(t)$ is the total energy not served for the duration of the event.

Total outage costs

$$C_{out,s} = C_o * \left(\sum_{t=1}^{n}\sum_{i=1}^{k} x_{i,s}\cdot(t)\right) \tag{5}$$

where $C_{out,s}$ is the total outage cost ($) and C_o is the outage cost per hour ($/h).

Total avoided outage cost

$$C_{avd,s} = C_{out-base} - C_{out,s} \tag{6}$$

where $C_{avd,s}$ are the avoided costs ($) and $C_{out-base}$ is the total outage cost ($) of the base scenario.

3. Numerical results and discussion

In this section, case studies are presented to evaluate the resilience metrics described in the previous subsections. This paper considers two case studies: (1) first case where *moderate damage* affects the power distribution system and (2) second case where *heavy damage* occurs to the system. For both cases, it is assumed that groups of residential customers own roof-top solar PV. A 33-bus test system with three MGs is considered to run the simulations [37]. The simulations are carried out for each case and then a comparison of the statistics of each case with a base case that has no DERs is shown. This process is modeled for a day (24 h) with outages occurring over a three-hour period following the natural disaster event. To estimate the cost of energy not served a fixed energy rate is assumed [38]. In the case of outage costs, a value of 5.1 $/h is utilized to calculate the total costs [39]. Following assumptions are made for the case studies:

- There are sufficient repair crews to attend all damaged lines
- The estimated time for line repairs is 3 h
- All lines are repaired simultaneously
- BESS units are utility-owned

The assumed time of 3 h for line repair is based on the average interruption time in electricity service observed in the United States due to major and non-major events [40]. It should be noted that the assumptions that all lines are repaired simultaneously with the same duration of time is to be able to compare the impact of various scenarios presented in the case studies under similar conditions. In certain situations, particularly when major events occur this may not be the case as the damage can be severe and repair crews might be limited, for example the longest outage experienced in the United States during 2018 had a duration of approximately 6 days (135 h) [41].

3.1. Test System, case studies and Scenarios, and data assumptions

The IEEE 33-bus radial distribution system with three MGs presented in [37] is used for simulation purposes with minor changes made to the system data. The main difference in the system data compared to [37] is the BESS is utility owned and no electric vehicle loads are considered, other than these assumptions the rest of the system data remained the same. To run the simulations, hourly data of load and roof-top solar PV power output were utilized. The solar data was obtained from [42]. Load data was obtained from the U.S. Department of Energy Open Data Catalog, residential load at TMY3 locations [43]. For simulations, three load profiles were selected from locations surrounding Ashland, Oregon. The BESS has been modeled based on a Tesla Powerwall [44]. Table 2 presents the data utilized in the test system. In Table 2, PCG and CG are prosumer community groups and consumer groups, respectively. CGs are groups of customers that only consume energy and PCGs are composed by customers that produce and consume energy. For the proposed resilience analysis, two case studies with five scenarios under each case study are considered and they are presented below.

Case 1: Moderate damage

1.1. Base scenario no DERs
1.2. Sunny day preceding the event and all load supplied
1.3. Sunny day preceding the event and only critical loads are supplied
1.4. Rainy day preceding the event and all load supplied
1.5. Rainy day preceding the event and only critical loads are

Table 2
Case study data for resilience analysis.

	Bus	Households	Load (kW)	PV (kW)	BESS	
					Capacity (kWh)	Output(kW)
Microgrid 1						
PCG1	23	10	32	50	270	50
PCG2	24	12	34	60	324	60
CG1	25	15	42	–	–	–
Microgrid 2						
PCG3	19	10	28	50	270	50
CG2	20	11	30	–	–	–
PCG4	21	12	38	60	324	60
PCG5	22	12	34	60	324	60
Microgrid 3						
CG3	7	40	70	–	–	–
CG4	8	40	100	–	–	–
PCG6	9	20	48	100	540	100
PCG7	10	20	48	100	540	100
CG5	11	20	35	–	–	–
PCG8	12	25	45	125	675	125
Rest of System						
CG6	2	15	48	–	–	–
CG7	3	20	56	–	–	–
CG8	4	48	120	–	–	–
CG9	5	24	60	–	–	–
CG10	6	24	60	–	–	–
CG11	13	24	60	–	–	–
CG12	14	48	120	–	–	–
CG13	15	24	60	–	–	–
CG14	16	24	60	–	–	–
CG15	17	24	60	–	–	–
CG16	18	36	90	–	–	–
CG17	26	24	60	–	–	–
CG18	27	24	60	–	–	–
CG19	28	24	60	–	–	–
CG20	29	48	120	–	–	–
CG21	30	80	200	–	–	–
CG22	31	60	150	–	–	–
CG23	32	84	210	–	–	–
CG24	33	24	60	–	–	–

supplied

Case 2: Heavy damage

2.1. Base scenario no DERs
2.2. Sunny day preceding the event and all load supplied
2.3. Sunny day preceding the event and only critical loads are supplied
2.4. Rainy day preceding the event and all load supplied
2.5. Rainy day preceding the event and only critical loads are supplied

The base scenarios consider there are no DERs interconnected with the power distribution system. For the rest of the scenarios, DERs are considered to be interconnected to the distribution grid. Fig. 1 shows the solar PV power output profiles for the sunny day and rainy day that are considered in the case studies. The profiles shown in Fig. 1 are assumed to be the same for all residential customers that are classified as prosumers. The sizing of the PV installation for each prosumer is assumed to be 5 kW, which is the equivalent to two times of their peak demand. This specific sizing was set to ensure the demand of the prosumer would be fulfilled by the roof-top solar PV array in most weather conditions even when solar irradiance is low. The BESS sizing for the PCGs is based on the surplus energy that is estimated to be produced by each PCG.

3.2. Resilience analysis of the distribution grid under moderate damage case

In this case, three MGs are assumed to be located in a 33–bus radial distribution system as shown in Fig. 2 where each bus represents a distribution transformer and the dotted lines indicate normally open tie lines. Connected to the transformer are sets of residential customers that are aggregated as CGs or PCGs depending on their classification, i.e., consumer or prosumer. To evaluate the impacts of MGs and DERs on enhancing the resilience of distribution system to natural disasters, it is assumed a storm occurred and created moderate damage to the feeders of the system. Specifically, to branches 2–19, 3–23, and 6–7, as shown in Fig. 2. The event is assumed to have occurred at 17:00 and the duration of the outage is 3 h (17:00 to 20:00). The 3-hour time period is based on the average duration of an outage in th U.S. and the estimated time it takes a crew of linemen to reestablish the service of the branch that has been damaged. To alleviate the impact of the damaged branches, the normally-open tie lines 8–21, 12–22, 18–33, and 25–29 are connected. The use of tie-lines during failure or damage to branches of the distribution grid is a common practice in most power distribution systems, when available.

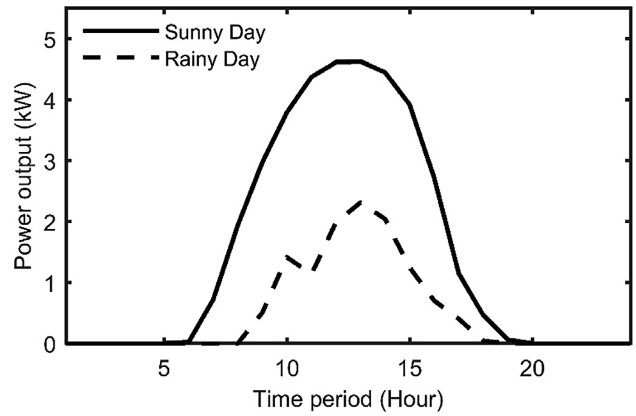

Fig. 1. Solar PV power output for a sunny day and a rainy day.

To test the system under failure, five scenarios are considered. The base scenario 1.1 would be the representation of a conventional power distribution system that utilizes available tie-lines to maintain the service of its customers when a high impact event occurs. Scenarios 1.2–1.5 assume DERs are available in the MGs. For scenario 1.2 it is considered a sunny day proceeded the event and as soon as the branches are lost the BESS located in MGs are dispatched to supply the local demand of each MG. Scenario 1.3 also assumes a sunny day proceeded the event and similar to scenario 1.2 the BESS are dispatched after the event occurs. However, in this scenario, it is assumed only critical loads (50% of the customers) are met and the rest of the loads are curtailed. Scenario 1.4 observes a similar operation as that of scenario 1.2 with the difference that a rainy day proceeded the event. Similarly, scenario 1.5 considers the same operation as scenario 1.3 under rainy day conditions before the event. These scenarios are chosen to represent the various operational strategies including varying weather. The weather aspect is of fundamental importance as this will affect how much energy is produced by the roof-top solar generators and at the same time how much energy can be stored into the BESS to dispatch when events like the ones considered here occur.

Once the damage to the system and the contingency measures have been set, the distribution system operation is simulated. For all simulations in this paper, power flow is utilized to resemble the operation of the distribution system. When power flow is executed, the power outputs of the roof-top solar and BESS, as well as the bus voltages of the distribution network, are determined. For simulation purposes, it is assumed that the load at any bus with a voltage under 0.9p.u. will be curtailed. This assumption is made because loads cannot operate under normal conditions with voltages below this value and power flow solution would be infeasible. Fig. 3 shows the bus voltages for the full day under study. It can be seen that from 17:00 to 20:00 the voltages at

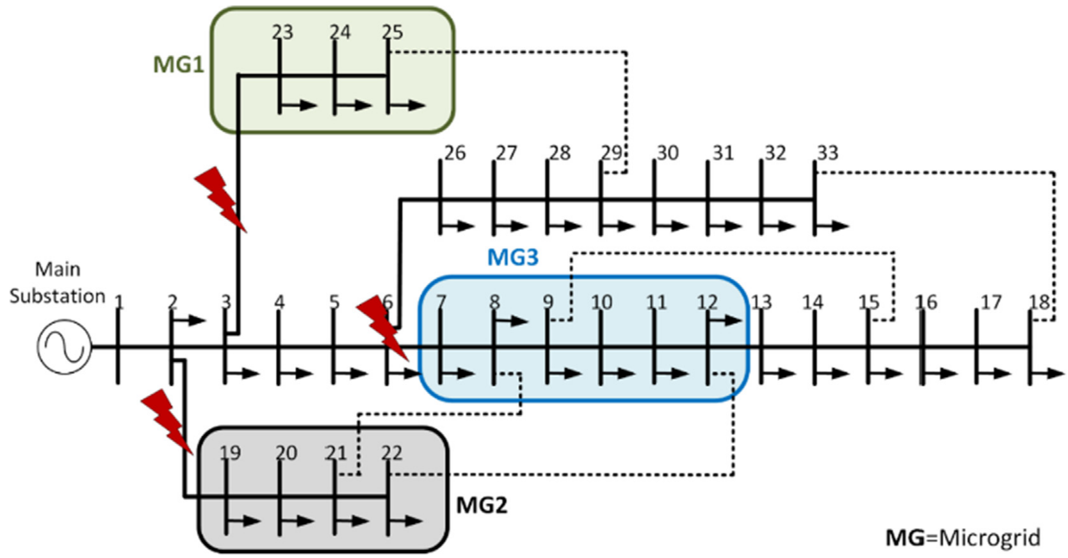

Fig. 2. Networked microgrids in an IEEE 33-bus distribution network-moderate damage case.

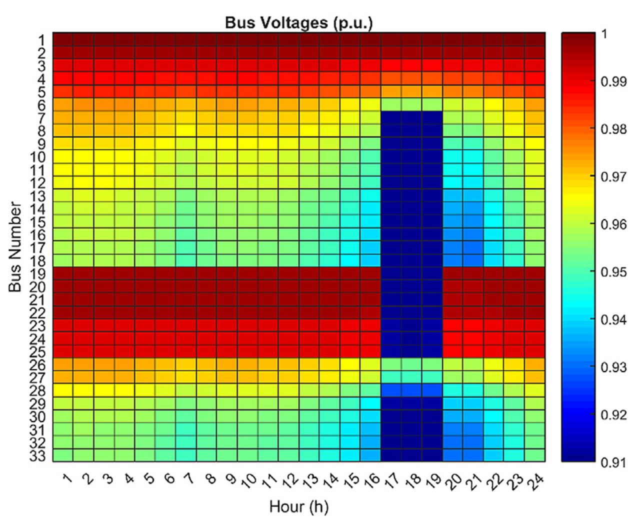

Fig. 3. Bus voltage profiles base Scenario 1.1 – moderate damage case.

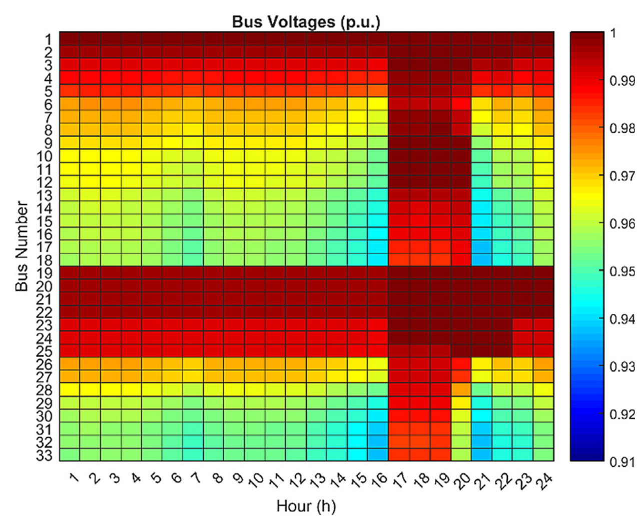

Fig. 4. Bus voltage profiles sunny day Scenario 1.2 – moderate damage case.

buses 7–22 and 31–33 are below 0.9p.u. and therefore would be curtailed.

Analyzing Fig. 4 (scenario 1.2), it is noticeable that all bus voltages are above 0.9p.u. This is achieved by having the MGs supply their local demand through the energy stored in BESSs. Under this scenario, no load has to be curtailed during the duration of the outage. In the case of scenario 1.3 (Fig. 5), only critical loads (50% of loads) remain connected and the rest are curtailed. Having to supply only critical loads ensures that all bus voltages remain above 0.9p.u. during the duration of the outage. Furthermore, the BESS units can supply the local demand of each MG for longer periods of time.

Figs. 6 and 7 depict the bus voltages for scenarios 1.4 and 1.5, respectively. These scenarios assume a rainy day precedes the outage. In scenario 1.4, it is observed that from 6:00 pm to 8:00 pm, the voltages at buses 7–22 and 31–33 are below 0.9p.u., therefore loads connected to those buses would be curtailed. Another observation is that due to the outage being proceeded by a rainy day the BESSs can only provide support for 1 h compared to 3 h when the outage occurs after a sunny day. For scenario 1.5, critical loads are met by the BESS and the demand is supplied at the MGs for 2 h (17:00 to 19:00). Afterwards, the loads at buses 7–14 and 19–22 have to be curtailed at 19:00 hrs as the BESSs can no longer supply the demand of the MGs. These two

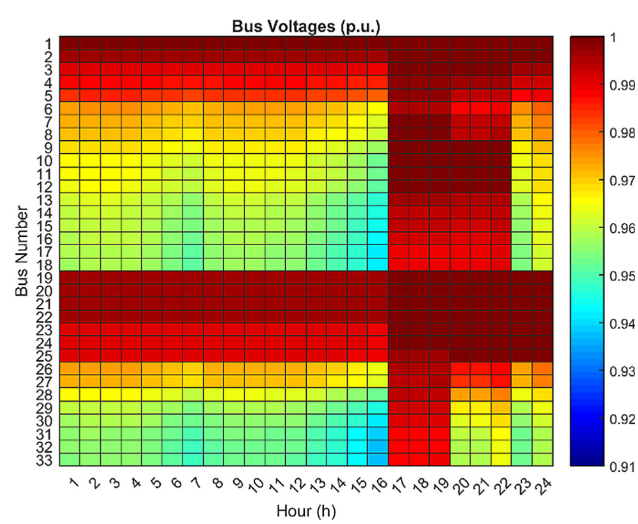

Fig. 5. Bus voltage profiles sunny day Scenario 1.3 – moderate damage case.

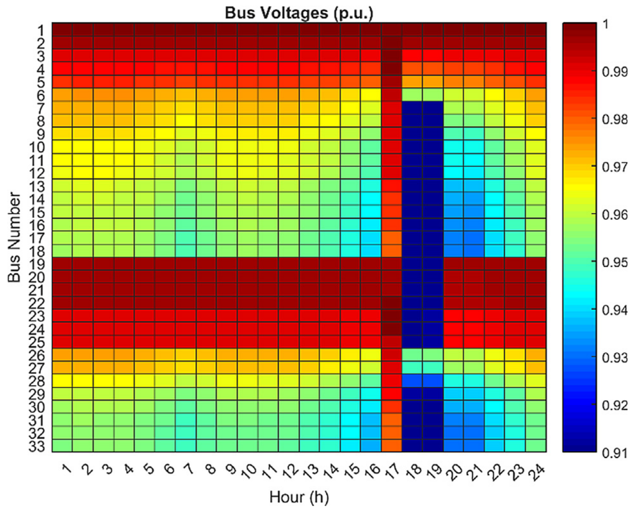

Fig. 6. Bus voltage profiles rainy day Scenario 1.4 – moderate damage case.

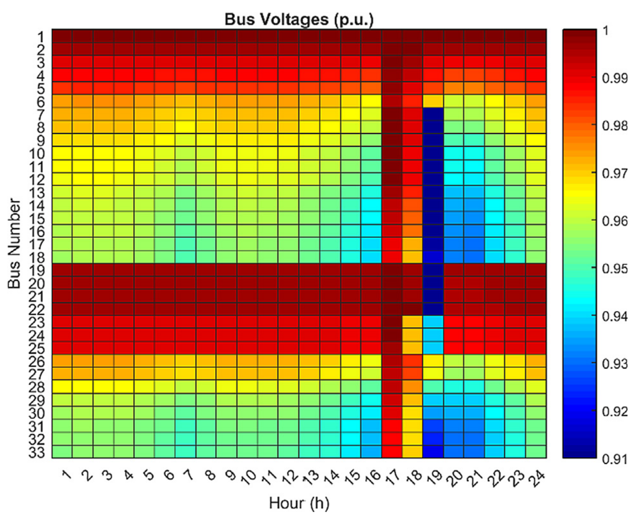

Fig. 7. Bus voltage profiles rainy day Scenario 1.5 – moderate damage case.

scenarios clearly demonstrate the impact of weather on the support capabilities that the BESS can provide as it is dependent on roof-top solar power generation.

Tables 3 and 4 present a summary of the two resilience metrics categories that are used to measure the resilience impacts that DERs can have on the power distribution grid. Table 3 presents the resilience metrics for the electrical service consequence category. The metrics for this category are the total customer-hours of outage, the total customer energy not served, the total number and percentage of customers experiencing outage, and the average number of customers experiencing outages.

Table 3
Resilience metrics for electrical service: Case 1 moderate damage.

Total Customer-Hours of Outage (h)				
Base Scenario 1.1 1674	Scenario 1.2 0	Scenario 1.3 1389	Scenario 1.4 1116	Scenario 1.5 1668
Total Customer Energy Not Served (kWh)				
Base Scenario 1.1 3415	Scenario 1.2 0	Scenario 1.3 2796	Scenario 1.4 2277	Scenario 1.5 3196
Total Number and Percentage of Customers Experiencing Outage				
Base Scenario 1.1 558 (60%)	Scenario 1.2 0 (0%)	Scenario 1.3 463 (50%)	Scenario 1.4 558 (60%)	Scenario 1.5 463 (50%)
Average Number and Percentage of Customers Experiencing Outage				
Base Scenario 1.1 558 (60%)	Scenarios 1.2 and 1.4 279 (30%)		Scenarios 1.3 and 1.5 463 (50%)	

Table 4
Resilience metrics for monetary impact: Case 1 moderate damage.

Total Loss of Utility Revenue ($)				
Base Scenario 1.1 355	Scenario 1.2 0	Scenario 1.3 290	Scenario 1.4 236	Scenario 1.5 332
Total Outage Costs ($)				
Base Scenario 1.1 8537	Scenario 1.2 0	Scenario 1.3 7084	Scenario 1.4 5692	Scenario 1.5 7803
Total Avoided Outage Costs ($)				
Base Scenario 1.1 0	Scenario 1.2 8537	Scenario 1.3 1454	Scenario 1.4 2846	Scenario 1.5 734

Comparing the results of the different scenarios, scenario 1.2 displayed the best performance out of all the scenarios for all resilience metrics, i.e., no customer service was interrupted and therefore no energy demand was unserved. Scenario 1.4 also showed a good performance and when estimating the average with scenario 1.2 the number of customers experiencing an outage is reduced 30% when compared to the base scenario (see Table 3). Scenarios 1.3 and 1.5 had a much lower improvement compared to the base scenario only a 10% difference in the average number of customers experiencing outages. However, it should be noted that the outage was a low duration outage (3 h) and that in cases where the outage spans a longer time frame the supply of only critical loads could be more beneficial.

From a monetary consequence perspective (Table 4), a similar outcome is observed, scenarios 1.2 and 1.4 obtained the best performance as their average avoided outage cost is $5692 or a 67% reduction compared to the base scenario. In the case of loss of utility revenue, the best outcome was obtained by scenario 1.2. Interesting observations are the great differences between the loss of utility revenue and outage costs, i.e., it provides a good context of the financial impacts that are created when electric energy is lost.

3.3. Resilience analysis of the distribution grid under heavy damage case

In this case, three MGs are also assumed to be located in a 33-bus radial distribution system as shown in Fig. 8. To evaluate the impact of the MGs and the DERs to the resilience of the distribution system to natural disasters, it is assumed that a storm occurred and created heavy damage to the feeders of the system. Specifically, to the main feeder branch 1–2 as shown in Fig. 8. The event is assumed to have occurred at 17:00 and the duration of the outage is 3 h (17:00 to 20:00). To test the system under failure, five scenarios are considered. The base scenario 2.1 would be the representation of a conventional power distribution system. In this case, the use of tie lines is not sufficient to reestablish the power distribution system as the main feeder guides power to the whole distribution system. Scenarios 2.2–2.5 assume that the DERs are available in the MGs. For scenario 2.2 it is considered a sunny day preceded the event and that as soon as the main branch is lost the BESS located in MGs are dispatched to supply the local demand of each MG. Scenario 2.3 also assumes a sunny day proceeded the event and similar to scenario 2.2, the BESS are dispatched after the event occurs. However, in scenario 2.2 it is assumed only critical loads (50% of the customers) are met and the rest of the loads are curtailed. Scenario 2.4 observes the same operation of scenario 2.2 with the difference that a rainy day proceeded the event. Scenario 2.5 considers the same operation as scenario 2.3 under rainy day conditions before the event.

Once the damage to the system and the contingency measures have

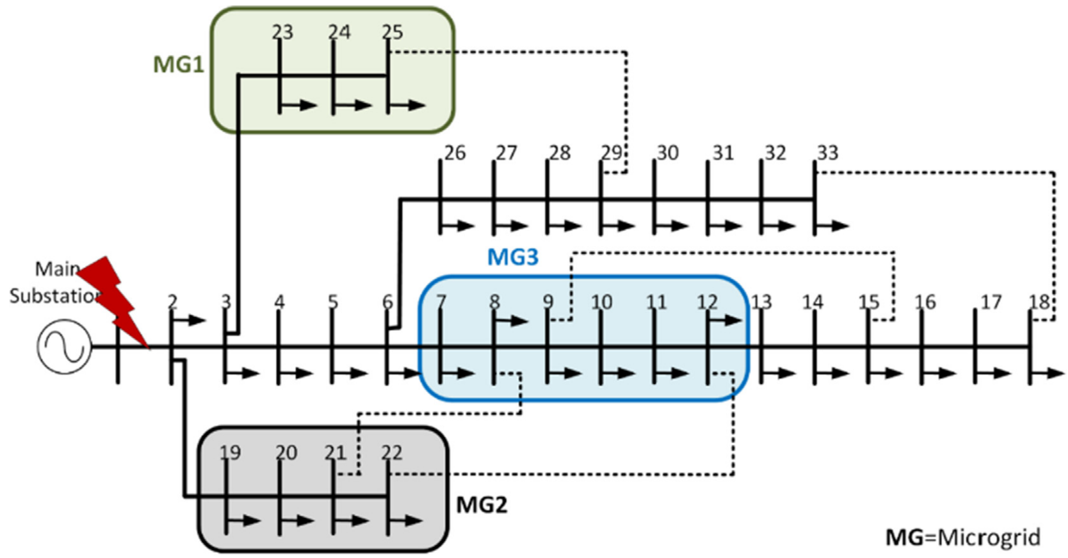

Fig. 8. Networked microgrids in an IEEE 33-bus distribution network-heavy damage case.

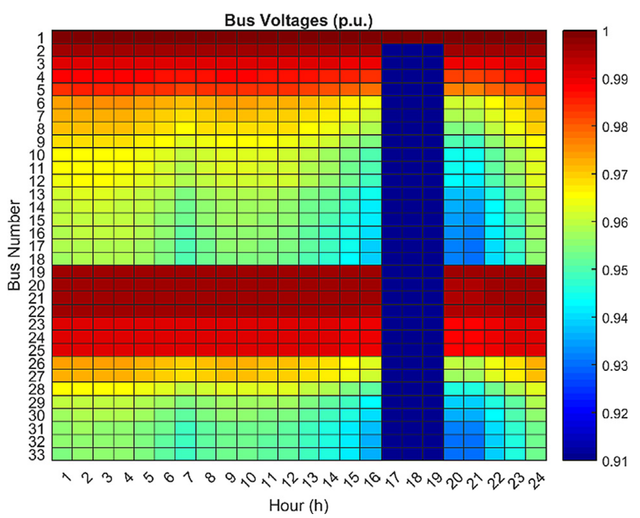

Fig. 9. Bus voltage profiles base Scenario 2.1 – heavy damage case.

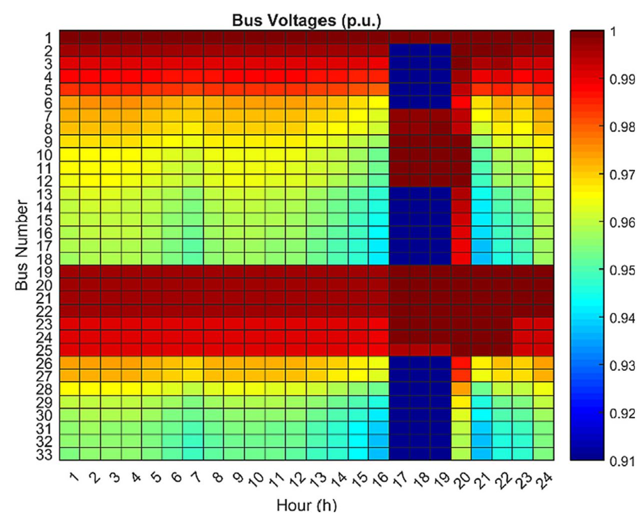

Fig. 10. Bus voltage profiles sunny day Scenario 2.2 – heavy damage case.

been set, the distribution system operation is simulated. In the same manner as Case 1, for simulation purposes, it is assumed that the load at any bus with a voltage under 0.9p.u. will be curtailed. Fig. 9 shows the bus voltages for the full day under study. It can be seen that from 17:00 to 20:00, the voltages at buses 2–33 are below 0.9p.u. and therefore would be curtailed. Analyzing Fig. 9 (scenario 2.1), it is noticeable that due to the damage suffered to the main branch 1–2, the whole system goes into a blackout.

For scenario 2.2 (Fig. 10), only the MG buses 7–12 and 19–25 remain energized through the use of the roof-top solar and the BESSs for the duration of the outage (3 h). When supplying only the critical loads and curtailing the remaining 50% of the loads (scenario 2.3), the buses of the MGs are also the only buses in the distribution system that remain operational. This can be observed in Fig. 11.

When a rainy day precedes the outage (Fig. 12), only buses 23–25 can remain operational for the time frame of the outage (3 h), with buses 7–12 and 19–22 remaining online for only 1 h, and the rest of the buses being under complete blackout. Finally, for scenario 2.5 (rainy day and only critical loads supplied), only buses 23–25 can remain operational for the 3-hour outage, buses 7–12 and 19–22 remaining online for 2 h, and the rest of the buses are under outage as shown in Fig. 13.

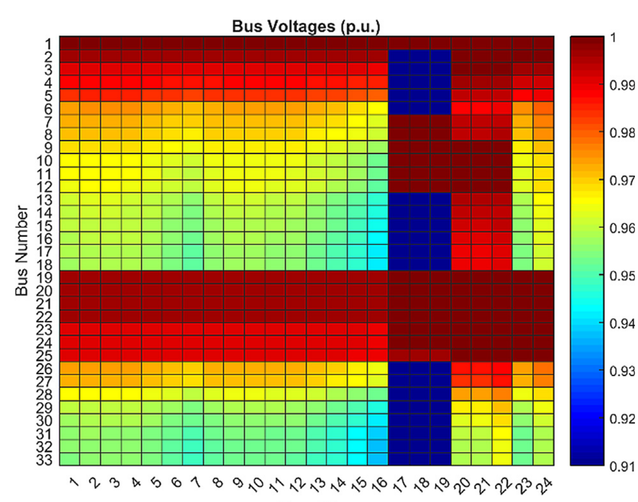

Fig. 11. Bus voltage profiles sunny day Scenario 2.3 – heavy damage case.

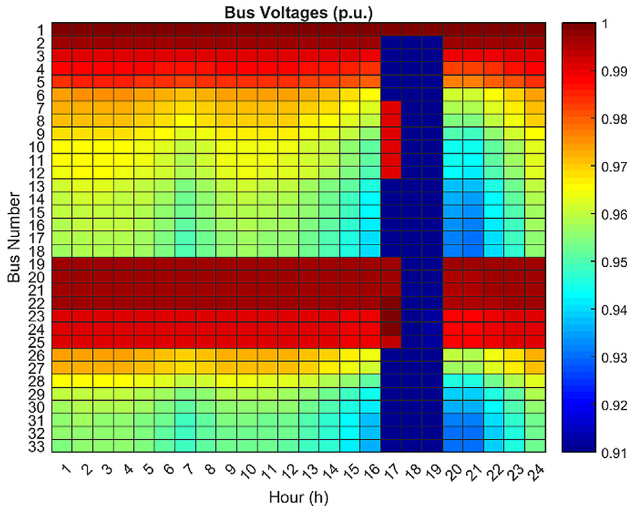

Fig. 12. Bus voltage profiles rainy day Scenario 2.4 – heavy damage case.

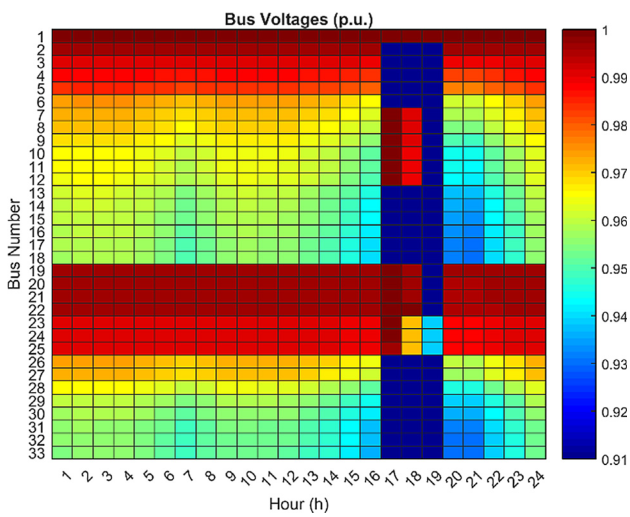

Fig. 13. Bus voltage profiles rainy day Scenario 2.5 – heavy damage case.

Table 5
Resilience metrics for electrical service impact: Case 2 heavy damage.

Total Customer-Hours of Outage (h)				
Base Scenario 2.1 2778	Scenario 2.2 2037	Scenario 2.3 2408	Scenario 2.4 2457	Scenario 2.5 2513
Total Customer Energy Not Served (kWh)				
Base Scenario 2.1 5955	Scenario 2.2 4614	Scenario 2.3 5103	Scenario 2.4 5368	Scenario 2.5 5419
Total Number and Percentage of Customers Experiencing Outage				
Base Scenario 2.1 926 (100%)	Scenario 2.2 349 (38%)	Scenario 2.3 803 (87%)	Scenario 2.4 889 (96%)	Scenario 2.5 803 (87%)
Average Number and Percentage of Customers Experiencing Outage				
Base Scenario 2.1 926 (100%)	Scenario 2.2 and 2.4 619 (67%)		Scenario 2.3 and 2.5 803 (87%)	

One of the interesting observations from scenario 2.5 is that curtailing load and only supplying critical loads extends the period of time for which the BESSs could provide energy. As it can be observed from Figs. 12 and 13, that buses 7–12 and 19–22 went from only being supplied for 1-hour to 2-hours. This reinforces what has been mentioned in Section 3.2, that in certain situations, especially, for long-duration outages or when limited energy is stored in the BESS curtailing the load can allow sections of the distribution system to remain online instead of all being under blackout. When analyzing the resilience metrics for electrical service (Table 5), it is shown that scenarios 2.2 and 2.4 provided the best performance by having approximately 33% fewer customers under outage. Compared to Case 1 (moderate damage) the tie lines are not sufficient to maintain the system under operation as the main feeder was damaged and all customers would lose service if no DERs were present.

Looking into the resilience metrics for monetary impact (Table 6), scenarios 2.2 and 2.3 achieved the highest avoided outage costs, which are 27% and 13% less than the base scenario 2.1, respectively. In this specific case (Case 2), where there is a major failure to the distribution system, outage costs and loss of utility revenue are high for all scenarios. Showing that although DERs can provide support to the power distribution system, the support is dependent on the weather (solar irradiance availability) and the availability of energy storage, i.e., without energy storage, roof-top solar can only provide limited support to the distribution grid. This can be observed in Figs. 14 and 15. Figs. 14 and 15 show the net load of the two prosumer groups located in MG-1 during a sunny day and a rainy day, respectively. It is clear from Fig. 14 (sunny day), that the support of the roof-top solar PV only occurs when the intensity of the solar irradiance is high between hours 8:00 and 17:00. In the case of a rainy day (Fig. 15), the power output of the solar PV is reduced due to cloud coverage and only provides support between hours 10:00 and 15:00.

However, by adding the BESS, energy can be provided during periods of time where solar irradiance is unavailable. Figs. 16 and 17 depict the use of BESS to provide power during hours where the sun is no longer shining. In Fig. 16, the BESS is able to provide power from hours 17:00 to 23:00. Fig. 17 illustrates the use of the BESS during a rainy day. Although there is a reduction of the energy stored during the rainy

Table 6
Resilience metrics for monetary impact: Case 2 heavy damage.

Total Loss of Utility Revenue ($)				
Base Scenario 2.1 618	Scenario 2.2 479	Scenario 2.3 530	Scenario 2.4 557	Scenario 2.5 563
Total Outage Costs ($)				
Base Scenario 2.1 14,168	Scenario 2.2 10,389	Scenario 2.3 12,278	Scenario 2.4 12,531	Scenario 2.5 12,814
Total Avoided Outage Costs ($)				
Base Scenario 2.1 0	Scenario 2.2 3779	Scenario 2.3 1890	Scenario 2.4 1637	Scenario 2.5 1354

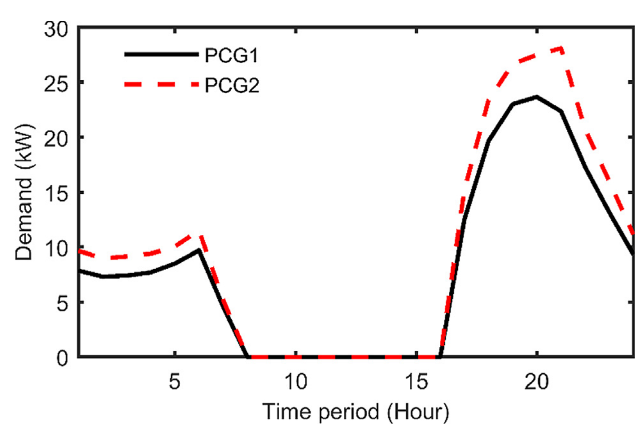

Fig. 14. Net load of prosumer groups in MG-1 on a sunny day.

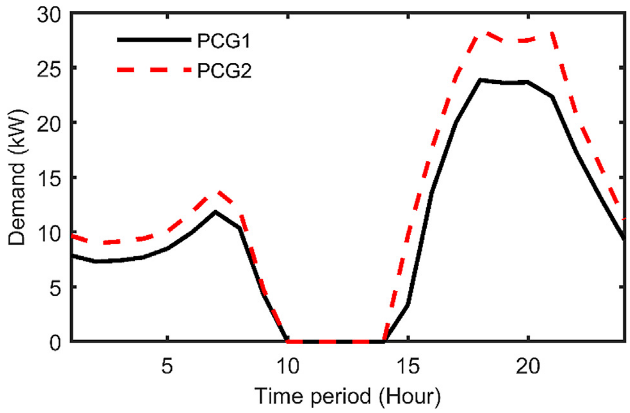

Fig. 15. Net load of prosumer groups in MG-1 on a rainy day.

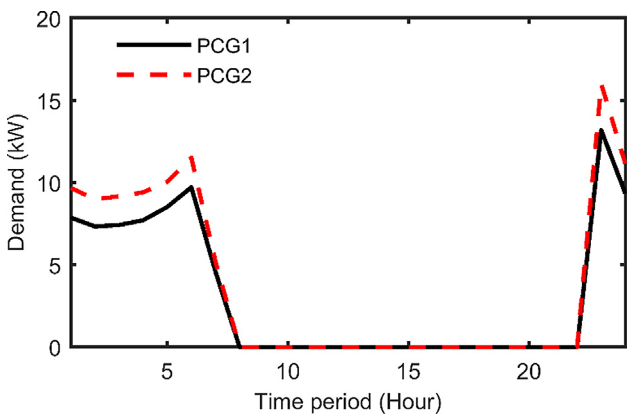

Fig. 16. Net load of prosumer groups in MG-1 with BESS on a sunny day.

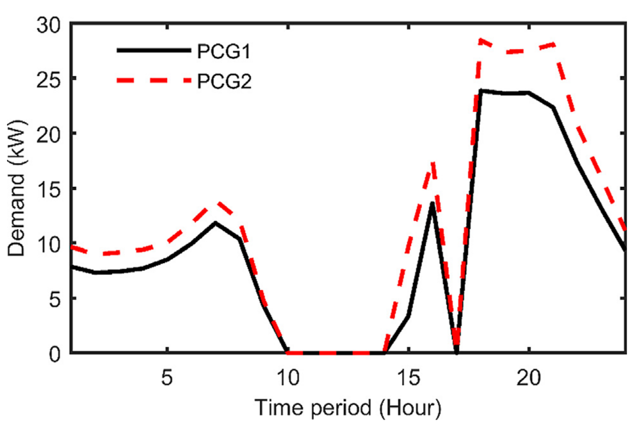

Fig. 17. Net load of prosumer groups in MG-1 with BESS on a rainy day.

day, the BESS is able to provide power for one hour from hour 17:00 to 18:00. Thus, having hybrid solar PV and BESS systems increases the capability and flexibility to provide distribution grid support services during outages regardless of the time of the day. An important aspect that must be carefully studied is the amount of surplus roof-top solar power that will be available to properly size the BESS. Neglecting this ratio can lead to over/under sizing of the BESS and in turn limit the power the BESS can provide during system outages. For the case studies presented in this paper both aspects were considered; first, the roof-top solar PV arrays were sized to produce twice the amount of the household peak load to ensure surplus power would be available, and secondly, by estimating the daily maximum production profile of the solar PV arrays, the BESS was sized to store the surplus energy. In cases where the solar PV arrays may already be installed, maximum power production profiles of the solar PV arrays should be modeled to estimate the availability of surplus power. Furthermore, estimating the amount of energy that can be stored will determine the power that will available during potential outages and the duration of the supply.

Costs associated with purchase and installation of the BESS are not considered in the case studies presented in this paper. However, these costs should be considered by developing a cost-benefit analysis to verify the financial feasibility of the capacity and number of BESS units that are to be installed. For example, the estimated cost of the BESS units considered in the case studies with a total installed capacity of 3267 kWh at a cost of 380 $/kWh would be approximately $1,241,460 [45]. Therefore, installing the BESS for grid resilience purposes might not justify the financial investments unless multiple outages are experienced throughout the year. In situations where outages are less frequent, BESS has the ability to value stack, i.e., maximize their value by providing various services besides grid resilience purposes. These services can be and are not limited to the following, arbitrage, firm capacity, operating reserves, congestion relief, and black-start [46]. Thus, finding the right balance of grid services can make the use of BESS financially viable and should be accounted for when evaluating cost-benefit analysis and monetary resilience metrics.

The results presented in this paper are simulated and implemented in MATLAB R2017a using MATPOWER version 6.0 [36]. All simulations are conducted using a personal computer with 2.8 GHz CPU, 4 GB RAM.

4. Conclusions

This paper presented and analyzed the significance of DERs to improve the resilience of electric power distribution system to natural disasters. A resilience analysis process was carried out with two case studies considering different levels of damages (heavy and moderate) to the system that were tested under various scenarios and evaluated utilizing resilience metrics. This paper contributed to provide an insight into the benefits that DERs, when effectively managed in networked MGs, can provide to a power distribution grid. Test results demonstrated that DERs can provide power generation support and bus voltage improvements to the power distribution system by effectively scheduling the discharge of BESS during outages. Test results also elucidate the importance of having BESS to shift surplus energy produced by roof-top solar to those periods of time when these DERs are not available (night time), for further expanding their capabilities to support the distribution grid during outages. For the specific case studies when considering roof-top solar PV and BESS in networked MGs, these DERs can reduce the number of customers experiencing an outage between 38% and 58% on a sunny day and between 8% and 9% on a rainy day when compared to the base scenarios without DERs. Furthermore, the avoided outage costs lie in the range of 20–58% and 11–17% on a sunny day and rainy day, respectively. It is to be noted that the results presented were obtained for the specific case studies described in this paper. However, the evaluation of the resilience metrics presented in this paper can be conducted in case studies with different components and test systems regardless of the size and number of customers. Due to the nature of power distribution systems, there is no single solution that can be applied across the board as resources and weather characteristics of the region can limit the use of DERs. Nonetheless, it is shown that DERs can significantly improve the resilience of power distribution systems. Future work would be interesting to consider random duration faults to test the ability of the DERs to support the distribution system during longer periods of time as well as utilizing other resilience metrics, e.g., time of recovery and restoration costs. Moreover, the inclusion of a cost-benefit analysis to evaluate the economic feasibility of the DERs should also be considered in future studies.

CRediT authorship contribution statement

Eric Galvan: Conceptualization, Methodology, Software, Formal analysis, Investigation, Writing - original draft, Writing - review & editing, Validation, Visualization. **Paras Mandal:** Conceptualization, Methodology, Writing - original draft, Writing - review & editing, Validation, Visualization, Supervision, Project administration. **Yuanrui Sang:** Conceptualization, Methodology, Writing - original draft, Writing - review & editing, Validation, Visualization, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijepes.2020.106239.

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