The Demand Response Support Under Weather Impacts Using PV Generation and EV Energy Storage

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***Abstract*—This paper investigates the impact of the grid integration of roof-top Photovoltaic (PV) generation and Electric Vehicles (EVs) energy storage on the demand response. The risk indices are introduced and risk map is created to predict the potential weather impact on the PV and EV owners. Based on the predictions, the aggregator bidding strategies to enable the EVs' stored energy and PV generation to participate in the ancillary service market considering the stochastic behavior are proposed. The role of programs for demand-side management (DSM) (in daily operation) and outage management (OM) (when fault happens) to mitigate the negative weather impacts on the customers is explored. Numerical experiments are implemented to validate the proposed approach and illustrate the impact of PV generation and EVs' ability to charge/discharge the stored energy on the flexibility of the electricity customer demand.**

Keywords— photovoltaic generation; electric vehicles; ancillary services; risk assessment;

I. INTRODUCTION

The solar energy resource is economically promising, environmentally clean, and naturally abundant. U.S. solar industry has expanded by 34% over the year 2013, and the solar capacity of the country is expected to double by the end of year 2016 [1]. Besides, EVs are encouraged as an alternative choice for transportation, being both environmentally and economically friendly. EV batteries can behave as mobile energy storage, with the flexibility of charging via grid-to-vehicle (G2V) as a "load" or discharging via vehicle-to-grid (V2G) or vehicle-to-building (V2B) as a "generator" or a dispatchable "back-up storage" [2]. Since the EVs and roof top PVs may be owned by customers, how to effectively integrate these two elements into the grid operation and markets remains a challenge.

The reliability and availability of the electricity supply caused by severe weather elements, which in turn is caused by the global climate change, is affecting customers [3-5]. The wholesale market operators use ancillary services to better handle the imbalance of supply and demand, which might be caused by the weather. The demand response providers can participate in the ancillary service market and offer bids with the aggregated capacities from customers in response to market dispatch schedules [6]. The demand response providers who have the ability to aggregate customers, may be utility companies, service companies that represent utility customers, etc. [7]. With proper control of PV generation and EV energy storage, customers' electricity demand could be potentially more flexible, since they can choose to charge the vehicles when load is light, and stop charging or even supply energy back to the grid or buildings when load is high. They can also use their PV generation capacity to charge the EVs' battery or supply power to the grid. Such increased demand flexibility has enabled the demand response providers with more capabilities in response to the wholesale electricity price changes.

To ensure the efficient deployment of the demand response capacities when selected and called upon, the program of DSM and OM can be applied by distribution system operators, during the normal operation or fault condition, to enable customers' participation to assure a reliable energy supply. Customers are participating in the programs of DSM and OM, operated by distribution system operators, to support the demand response to track the weather impacts on the supply in real time. Different techniques for DSM and OM have been evaluated in earlier studies [8-10]. In this paper, the benefit of the grid integration of both EVs and PVs and their participation in DSM and OM to correctively mitigate the weather-caused risk for customers is studied.

This paper discusses the integration of PVs and EV energy storage and how it supports supply of electricity to the customers under the weather impacts. To predict weather impacts, first a risk assessment and associated indices need to be determined. Customer Interruption Cost (CIC) index can be used as the cost consequence [11-13]. In this paper, the CIC index formula is improved and risk assessment is implemented for both potential power outage and demand fluctuation caused by weather change.

Based on the day-ahead prediction results from the risk assessment, certain capacity of EV energy storage and PV generation can be integrated by demand response providers to participate in the day-ahead contingency reserve service (CRS) market. Some past reports discussed integrating EV energy storage into electricity market, especially ancillary service market [14-17]. In this paper, the proposed bidding strategy considers not only the stochastic nature, but also the purpose of alleviating the weather impact based on the risk prediction results.

The rest of the paper is organized as follows: Section II presents the framework of the proposed work; methodologies and formulations on risk assessment, market participation as well as the scheme of OM and DSM are introduced in Section III; case studies are conducted and analyzed in Section IV; and finally Section V concludes with the contributions of this paper.

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II. Framework

The proposed method is in accordance with the sequence of "predictive – preventive – corrective" actions. First, utility operators conduct the risk assessment, which provides predictive results of the evaluation of potential weather impact. Based on the prediction results, demand response providers participate in the day-ahead reserve market with the aggregated resources from customers, which preventively reserves some capacity in face of the predicted weather impact. As corrective actions to alleviate the negative weather impact, DSM and OM, with customers' participation, are conducted by utility operators as the predicted weather impact unfolds in real time. Fig. 1 shows the framework of the proposed method and Table I lists the players and their corresponding roles.

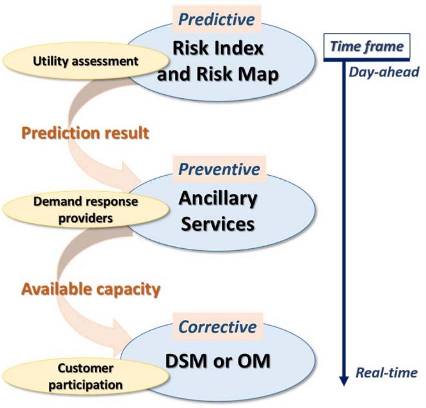

Fig. 1. Framework to integrate EV energy storage and PV generation

TABLE I. Players and Roles Based on Our Proposed Framework

Players	Service	Purpose	Time Attribute
Market operator	Day-ahead CRS market operation	Balance demand and supply	Preventive
Demand response provider	Day-ahead CRS bidding	Offer bidding in the day-ahead CRS market and collaborate with utility operators to ensure the deployment of the capacities when called	Preventive
Utility operator	Risk assessment	Predict the weather impact	Predictive
	DSM	Aggregate customers to support demand response under normal operation	Corrective
	OM	Aggregate customers to support demand response under fault condition	Corrective

III. Methodology

A. Risk Assessment

The framework of risk assessment estimating the weather impact on electricity customers is described in detail in [11]. The risk index is presented by the product of three elements: *hazard*, *vulnerability* and *worth of loss*. *Hazard* is mainly based on the accuracy of weather forecast, and *vulnerability* is determined by historical weather-caused outage data. In this paper, we focus on the modeling of *worth of loss* which is the estimation of customer interruption losses in case of the weather-caused power outage (in need of OM) or the customer losses in case of the weather-caused power demand change (in need of DSM). The customer losses take into account the distribution network and the basic information about the customers covered in the target area, e.g. population, customer type (residential, industrial, commercial, medical), expected power consumption, etc.

The customer interruption losses used in the risk assessment for potential outage is formulated as follows, [18]

$$Loss^{t,FA} = \sum_{i\in FA}\begin{pmatrix} CDF_i^{t,FA} + EL_{i,OM}^{t,FA}\left(q(ct(i))\right) \\ + HL_{i,OM}^{t,FA}\left(q(ct(i))\right) \end{pmatrix} \tag{1}$$

The loss at time t for each feeder area (FA) consists of customer damage function (CDF) (including cost of expected energy not supplied (EENS)), function of additional loss (EL) caused by environment elements, and function of health loss (HL), for each customer *i*. A customer can be a residential household, a hospital, an industry, a community, a school, etc. Assume customer type *ct(i)*=1 for medical facility, 2 for industry, 3 for school, 4 for commercial facility, 5 for residential household, etc. *q(ct(i))* represents the percentage of interrupted energy not supplied for each customer type.

The customer losses used in the risk assessment for demand change is formulated as (2),

$$Loss^{t,FA} = \sum_{i\in FA}\begin{pmatrix} CI^{ct(i)}\cdot EENS_i^t + EL_{i,DSM}^{t,FA}\left(p(ct(i))\right) \\ + HL_{i,DSM}^{t,FA}\left(p(ct(i))\right) \end{pmatrix} \tag{2}$$

where *CI* represents the cost index used to indicate the value of not supplied energy for each customer type. *p(ct(i))* represents the percentage of the demand change that are not supplied for each customer type.

B. Market Participation

To preventively alleviate the potential negative weather impact, demand response providers can schedule the available capacity of EV energy storage and PV generation to participate in the day-ahead CRS market, so that certain amount of capacity can be reserved in advance to deal with the potential negative weather impact. The stochastic modeling is adopted here to optimize the bidding strategy for the demand response providers. Different scenarios are generated according to the previous assessment on weather's impact, and ρ_s is the probability of the occurrence of some negative weather impact, i.e. outage, peak load, etc.

$$\begin{aligned}\min:\ & \sum_{i\in T_1}\begin{pmatrix} R_{E,i}^{s_0}p_{e,i}^{s_0} + C_{EV}f_{ev,i}^{s_0}pr_{EV,i}^{s_0} - R_{E,i}^{s_0}f_{ev,i}^{s_0}pr_{EV,i}^{s_0} \\ -R_{R,i}pr_{EV,i}^{s_0} + R_{E,i}^{s_0}p_{EV+,i}^{g,s_0} - B_{solar}p_{solar,i}^{g,s_0} \end{pmatrix} \\ & + \sum_{s\in S}\rho_s\sum_{i\in T_2}\begin{pmatrix} R_{E,i}^{s}p_{e,i}^{s} + C_{EV}f_{ev,i}^{s}pr_{EV,i}^{s} - R_{E,i}^{s}f_{ev,i}^{s}pr_{EV,i}^{s} \\ -R_{R,i}pr_{EV,i}^{s} + R_{E,i}^{s}p_{EV+,i}^{g,s} - B_{solar}p_{solar,i}^{g,s} \end{pmatrix}\end{aligned} \tag{3}$$

$$\text{s.t.}\quad L_i + p_{EV+,i}^{g,s} + p_{EV+,i}^{l,s} = p_{e,i}^{s} + P_{solar,i} - p_{solar,i}^{g,s} + f_{ev,i}^{s}pr_{EV,i}^{s},\quad i\in T_1\cup T_2,\ s\in\{s_0\}\cup S \tag{3.a}$$

$$p_{solar,i}^{g,s} + p_{solar,i}^{l,s} = P_{solar,i},\ i\in T_1\cup T_2,\ s\in\{s_0\}\cup S \tag{3.b}$$

$$0\le p_{solar,i}^{g,s}\le P_{solar,i},\ i\in T_1\cup T_2,\ s\in\{s_0\}\cup S \tag{3.c}$$

$$0 \le p^{l,s}_{solar,i} \le P_{solar,i}\ ,\ i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S \quad (3.d)$$

$$0 \le p^{g,s}_{EV+,i} + p^{l,s}_{EV+,i} \le p^{\max}_{EV+,i}\ ,\ i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S \quad (3.e)$$

$$0 \le p^{g,s}_{EV+,i} \le p^{\max}_{EV+,i}\ ,\ i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S \quad (3.f)$$

$$0 \le p^{l,s}_{EV+,i} \le p^{\max}_{EV+,i}\ ,\ i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S \quad (3.g)$$

$$0 \le pr^{s}_{EV,i} \le p^{\max}_{EV-,i}\ ,\ i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S \quad (3.h)$$

$$p^{l,s}_{EV+,i} \le p^{l,s}_{solar,i}\ ,\ i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S \quad (3.i)$$

$$E^{s}_{EV,i-1} - E^{s}_{EV,i} = \begin{cases} \dfrac{1}{\eta^{+}}\left(f^{s}_{ev,i} pr^{s}_{EV,i} - p^{g,s}_{EV+,i} - p^{l,s}_{EV+,i}\right)\Delta T \\ \qquad , p^{g,s}_{EV+,i} + p^{l,s}_{EV+,i} \le f^{s}_{ev,i} pr^{s}_{EV,i} \\ -\eta^{-}\left(p^{g,s}_{EV+,i} + p^{l,s}_{EV+,i} - f^{s}_{ev,i} pr^{s}_{EV,i}\right)\Delta T \\ \qquad , p^{g,s}_{EV+,i} + p^{l,s}_{EV+,i} > f^{s}_{ev,i} pr^{s}_{EV,i} \end{cases} \quad (3.j)$$

$$, i \in T_1 \cup T_2\ ,\ s \in \{s_0\} \cup S$$

$$E^{s}_{EV}\Big|_{i=t_k} \ge C_{req}\ ,\ s \in S \quad (3.k)$$

Where S is the set including all stochastic scenarios ($s_0 \notin S$); s denotes the index for scenarios, and s_0 refers to the deterministic scenario; T_1 and T_2 are the sets of deterministic and stochastic time steps; $R^{s}_{E,i}$ is the energy price at time i under scenario s; C_{EV} is EVs' discharging cost; $f^{s}_{ev,i}$ denotes EVs' participation factor at time i under scenario s; $R_{R,i}$ is the reserve price at time i under scenario s; B_{solar} is the unit benefit of selling solar energy; L_i is the load forecast at time i; $P_{solar,i}$ is the solar prediction at time i; $p^{\max}_{EV+,i}$ and $p^{\max}_{EV-,i}$ are EVs' maximum charging/discharging power at time i respectively; η^{+} and η^{-} are EVs' charging/discharging efficiency; ΔT is the scheduling interval; C_{req} is EVs' energy requirement; $p^{s}_{e,i}$ is the power to be purchased at time i under scenario s; $pr^{s}_{EV,i}$ is EVs' power to serve as reserve at time i under scenario s; $p^{g,s}_{EV+,i}$ is EVs' charging power from the grid side at time i under scenario s; $p^{l,s}_{EV+,i}$ is EVs' charging power from the local side at time i under scenario s; $p^{g,s}_{solar,i}$ and $p^{l,s}_{solar,i}$ denote the solar energy to be sold to the grid side and local side at time i under scenario s; $E^{s}_{EV,i}$ is EVs' aggregated energy at time i under scenario s.

The objective function (3) is to minimize the total cost; the constraint (3.a) describes the local energy balance; equations (3.b) to (3.d) model the limits on the solar energy bidding; equations (3.e) to (3.h) present EVs' charging and discharging limits; equation (3.i) models the upper limit for EVs' local charging, and here we assume that PV energy is the only local source for EVs to charge other than the grid; equation (3.j) is EVs' energy dynamic equation; and equation (3.k) describes the EV energy requirement. In order to consider about EVs' stochastic mobility, EVs' maximum charging/discharging power can be calculated according to [19], in which EVs' available charging/discharging capacity is estimated in a probabilistic way considering their mobility. The results of the proposed model gives the day-ahead bidding strategy of EV storage.

C. OM & DSM

- Benefit of OM in alleviating the weather impact

Power supply outage may take place if power delivery infrastructure is damaged or fault is caused by the severe weather conditions. In this case, outage management need to be implemented to restore the power supply as soon as possible and alleviate the impact of the power interruption. If a bad weather condition is predicted one day ahead, the risk of customer impact caused by potential power interruptions can be evaluated based on the predicted weather information and customer information in that region. In the day-ahead market, the energy of the participant EV battery and PV generation to be reserved is calculated. According to the reserved energy, the distributed EVs and PV generation in the distribution network can be coordinated to provide electricity to the interrupted customers if power outage happens at the predicted time. The priority order of the power supply is assigned based on the importance of the customers.

$$\max_{E^{t,FA=k}_{EV}} \sum_{k=1}^{N}\left\{\left(\sum_{j=1}^{m(k)}(\mathrm{w}(ct=j)\cdot \sum_{i\in FA=k} D^{t}(ct(i)=j))\right)\cdot(E^{t,FA=k})\right\} \quad (4)$$

$$, k = 1, 2, ..., N$$

$$\text{s.t.} \quad \sum_{k=1}^{N} E^{t,FA=k} = E^{t,total}_{EV} + E^{t,total}_{PV} \quad (4.a)$$

$$\sum_{k=1}^{N} E^{t,FA=k}_{EV} = E^{t,total}_{EV} \quad (4.b)$$

$$\sum_{k=1}^{N} E^{t,FA=k}_{PV} = E^{t,total}_{PV} \quad (4.c)$$

$$E^{t,FA=k} = E^{t,FA=k}_{EV} + E^{t,FA=k}_{PV},\quad k = 1, 2, ..., N \quad (4.d)$$

$$0 \le E^{t,FA=k}_{PV} \le E^{FA=k}_{PVcapacity},\quad k = 1, 2, ..., N \quad (4.e)$$

$$0 \le E^{t,FA=k}_{EV} \le E^{FA=k}_{EVcapacity},\quad k = 1, 2, ..., N \quad (4.f)$$

where $E^{t,FA=k}$ represents the energy provided by EV battery ($E^{t,FA=k}_{EV}$) and PV generation ($E^{t,FA=k}_{PV}$) for the k^{th} feeder area at time t; $E^{t,FA=k}_{PV}$ is determined by the availability of solar generation in feeder area k; N is the number of feeder areas; $E^{t,total}_{EV}$ and $E^{t,total}_{PV}$ are the total participant energy of EV and PV generation obtained from the ancillary market; $E^{FA=k}_{EVcapacity}$ and $E^{FA=k}_{PVcapacity}$ represent the capacity of total EV energy storage and PV generation in feeder area k; $\omega(ct = j)$ represents the weight for each customer type j and $m(k)$ is the number of customer types in feeder area k; and D^{t} is the normal electricity demand at time t. This objective function (4) is used to schedule participant EV energy for each feeder area in order to support more significant customers. Constraints (4.a)-(4.d) are sum equations and (4.e)-(4.f) shows the limits of the schedulable energy from EV battery and PV generation.

After obtaining the participant energy for each feeder area, how to coordinate the power supply for each customer type are optimized by (5)

$$\min_{E_{ct=j}^{t,FA=k}} \quad \sum_{j=1}^{m} Loss_{ct=j}^{t,FA=k}(E_{ct=j}^{t,FA=k}), \quad k=1,2,...,N \quad (5)$$

$$\text{s.t.} \sum_{j=1}^{m} E_{ct=j}^{t,FA=k} = E_{EV}^{t,FA=k} + E_{PV}^{t,FA=k}, \quad k=1,2,...,N \quad (5.a)$$

$$0 \le E_{ct=j}^{t,FA=k} \le \left(E_{EV}^{t,FA=k} + E_{PV}^{t,FA=k}\right), \quad k=1,2,...,N \quad (5.b)$$

$$0 \le q(ct(i)) \le 1 \text{ ,for each } i \in FA=k \quad (5.c1)$$

$$q(ct(i)) = \frac{D^t(ct(i)=j) - E_{ct=j}^{t,FA=k}}{D^t(ct(i)=j)}, \quad j=1,2,...,m \quad (5.d1)$$

$$\text{If } q(i) > 0, q(j) \ne 0 \text{ ,for every } i<j \quad (5.e1)$$

where $Loss_{ct=j}^{t,FA=k}$ is calculated according to (1). This objective function (5) is to minimize the total cost for each feeder area. Constraints (5.d1) shows the relation between $E_{ct=j}^{t,FA=k}$ and $q(ct(i))$ used in (1). (5.e1) indicates the priority of the customer types.

- Benefit of DSM in alleviating the weather impact

Even when the weather condition is not so severe that the system is under normal operation, the weather change can still cause the imbalance of supply and demand. In this case, demand side management need to be implemented to handle the imbalance and alleviate the impact of the demand change. Similar to the process as in OM, the risk of customer impact caused by potential demand change can be evaluated. According to the reserved energy participating in the ancillary market, the distributed EVs and PV generation in the distribution network can be coordinated to provide electricity to balance the demand difference.

The optimization function for obtaining the total participant energy by EV and PV generation for each feeder area is (6)

$$\min_{E_{EV}^{t,FA=k}} \quad \sum_{k=1}^{N} \left\{ \left(\sum_{j=1}^{m(k)} (\mathrm{w}(ct=j) \cdot \sum_{i \in FA=k} DC^t(ct(i)=j)) \right) \cdot (E^{t,FA=k}) \right\} \quad (6)$$
$$, \quad k=1,2,...,N$$

where DC^t is the expected demand change at time t. The constraints are the same as (4.a)-(4.f).

The optimization function for coordinating the power supply for each customer type is similar to (5), but $Loss_{ct=j}^{t,FA=k}$ is calculated according to (2). Moreover, the constraints (5.c1)-(5.c2) should be replaced by

$$0 \le p(ct(i)) \le 1 \text{ ,for each } i \in FA=k \quad (5.c2)$$

$$p(ct(i)) = \frac{DC^t(ct(i)=j) - E_{ct=j}^{t,FA=k}}{DC^t(ct(i)=j)}, \quad j=1,2,...,m \quad (5.d2)$$

$$\text{If } p(i) > 0, p(j) \ne 0 \text{ ,for every } i<j \quad (5.e2)$$

IV. CASE STUDY

A distribution network with 20 feeders [20] and 45000 customers is used to implement the risk assessment. Both historical weather data obtained from weather stations and forecasted weather data obtained from the National Digital Forecast Database (NDFD) are used to assign weather element values. The risk analysis is implemented and visualized in time and space using ArcGIS software. We assume that the distribution network is connected to Bus 114 in a modified IEEE-RTS 96 test case [21] on which the participation of 15,000 EVs and 140 MW PV generation capacity in the ancillary services is simulated. Our proposed approach is tested under two scenarios in which the cases with and without EV energy storage or PV generation are compared and analyzed.

A. *Scenario 1: Mitigation of Weather Impact Using Outage Management*

This scenario considers the possible power interruptions caused by the weather change and estimates the consequent impact on the customers. In the case study, a severe weather condition is predicted to happen the next day around 12:00 pm. Two cases are compared in terms of weather impact on customers under scenario I: case 1- no EV energy storage or PV generation are available; case 2 – with EV energy storage and PV generation.

Fig. 2 shows the risk map for case 1, and different colors indicate value of various risk indices with the monetary value in dollars. The weather impact on customers in some areas is significant because either a large number of people are affected or some critical customers are located there. The participation of EV energy storage and PV generation in the ancillary services in case 2 is shown in Fig. 3. We can observe that they preventively tend to offer more capacity to serve as a reserve during the predicted outage.

When the predicted power interruption does happen, OM is conducted based on the available resources at that time. Based on the severity of the customer types covered by the feeder areas, the available PV generation, and the required reserved energy participating in the market, the participant EVs are assigned to provide electricity back to the customers. Table II shows partial results of the energy provided by the participant EVs and PV generation. Compared with feeder area 7 with only residential customers, the EV participation in feeder area 17 is much higher, since there are 6 hospitals, 5 communities, 1 industry and 3 schools in that area. It is shown in the fourth column of Table II that about 20% of the peak demand can be supported by EV battery energy and PV generation. Fig. 4 compares the estimated customer cost results for partial feeder areas for case 1 and case 2. It turns out that, OM together with the available capacity reserved by the integration of EVs and PVs can help reduce 73% of the estimated customer cost caused by possible outage due to the weather impact.

B. *Scenario 2: Mitigation of Weather Impacts Using Demand Side Management*

Scenario 2 investigates the possible load peak that may lead to the imbalance of supply and demand due to the weather change. Similarly, two cases without and with EVs and PV generation are compared in case 3 and case 4 respectively. The load peak is predicted to happen between 10:00 and 17:00 the next day, and the severity of risk that the demand change may not be balanced in case 3 is illustrated in Fig. 5. It is noted that the risk index values for feeder area 11 and 17 are comparably higher since the number of significant customers whose demand may be affected by the weather change are higher.

The participation of EVs and PV generation in case 4 is also shown in Fig. 3. The aggregated energy purchases under two scenarios are illustrated in Fig. 6. The bidding strategy proposed in this paper takes advantage of the load flexibility to purchase more energy during the off-peak, so that less energy is needed to be purchased during the peak hour. Under Scenario 1, less energy is scheduled to be purchased when an outage is predicted to happen, as circled in orange in Fig. 6.

From Fig. 3, we can observe that the generation of both PV and EVs reaches its peak during the predicted hours with outage or peak loading. Moreover, EV batteries are charged and store the energy during the off-peak hours, and discharged during the peak hours. During the hour with predicted outage, EVs' discharging power reaches its peak, since EV energy storage, together with PV energy, serves as the back-up generation to alleviate the negative weather impact. The collaboration between PV and EVs enables PV energy to be stored to some extent in face of the potential outage and load peak.

Suppose that the load peak does happen the next day, DSM has to be called to shave the peak. Following the similar process as case 2, EVs are assigned to provide electricity back to the customers. Table III shows partial results of the energy provided by the participant EVs and PV generation. Compared with the results in case 2, the power supply from the PV generation are the same due to the fixed capacity of solar generation. However, the EV participation are less since the power supply in need during outage is much more than that for demand fluctuation. It can also be indicated by the fourth column of Table III that less percentage of the peak demand can be supported by EV battery energy and PV generation in case 4, compared with Table II in case 2. Fig. 7 compares the estimated customer cost results for partial feeder areas for case 3 and case 4. It turns out that, DSM together with the available capacity reserved by the integration of EVs and PVs can help reduce 94% of the estimated customer cost caused by demand change due to the weather impact.

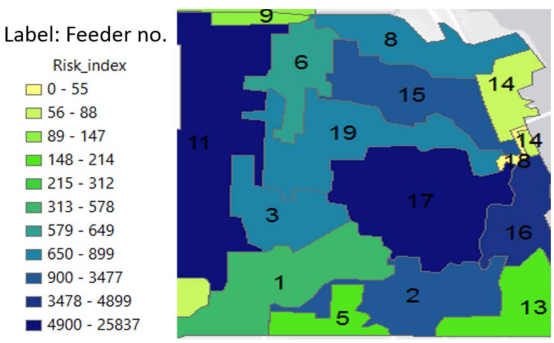

Fig. 2. Prediction of risk map under scenario 1

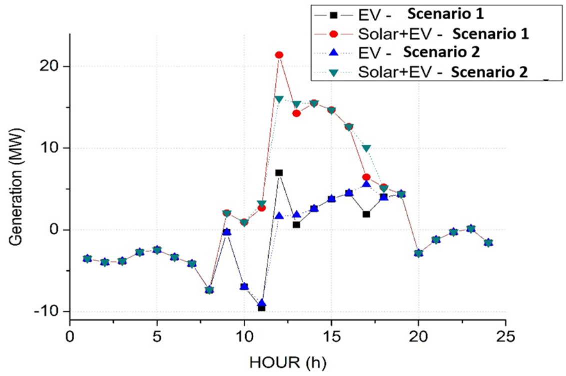

Fig. 3. Illustration on the particiapation of EV enrgy storage and PV generation in the ancilliary services

TABLE II. PARTIAL RESULTS OF THE ENERGY PROVIDED BY THE PARTICIPANT EVS AND PV GENERATION – CASE 2

Feeder No.	EV Energy (kWh)	Solar + EV energy (kWh)	% of power supplied by solar + EV
1	828	1745	26%
2	576	1787	20%
6	167	926	17%
7	58	177	20%
14	137	812	16%
17	1497	3720	23%

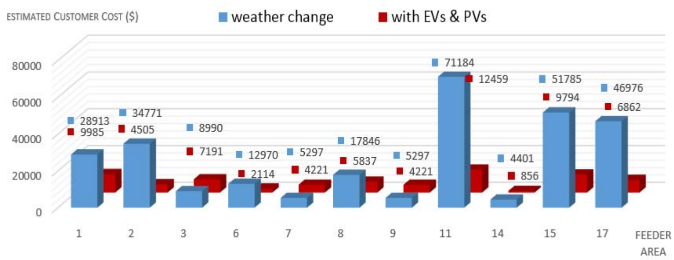

Fig. 4. The Estimated Customer Cost in case 1 & 2

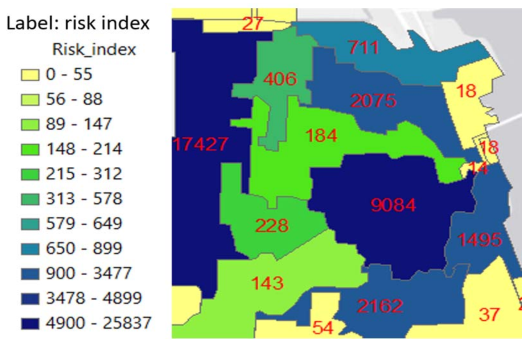

Fig. 5. Prediction of risk map under scenario 2

TABLE III. PARTIAL RESULTS OF THE ENERGY PROVIDED BY THE PARTICIPANT EVS AND PV GENERATION –CASE 4

Feeder No.	EV Energy (kWh)	Solar + EV energy (kWh)	% of power supplied by solar + EV
1	197	1114	17%
2	137	1349	15%
6	40	798	14%
7	14	133	15%
14	33	707	14%
17	356	2579	16%

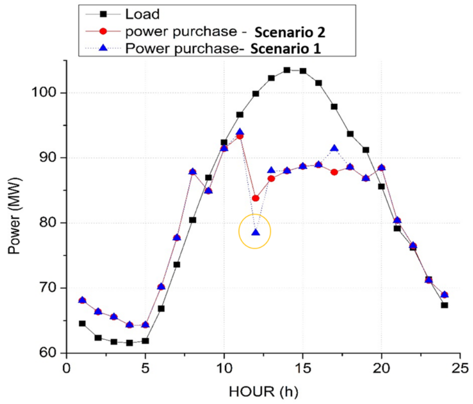

Fig. 6. Illustration on the energy purchase from the market under two scenarios

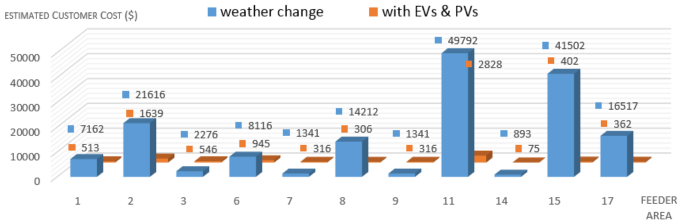

Fig. 7. The Estimated Customer Cost in case 3 & 4

V. CONCLUSION

The contributions of this work are summarized as follows:

- The improved CIC index is calculated and risk maps are created to predict the weather impact on customers' electricity supply;
- The preventive strategy is proposed to enable the customer to offer both their EV energy storage and rooftop PV generation in the day-ahead CRS market considering both the risk prediction and the stochastic nature of EV and PV participation;
- Both the EV energy storage and PV generation are evaluated based on their participation in the DSM and OM services to correctively alleviate negative weather impact on reliability of customers' electricity supply;
- Numerical experiments are conducted to validate the contribution of EV energy storage and PV generation in mitigating negative weather impacts on the power supply.

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