Evaluation of Customer-oriented Power Supply Risk with Distributed PV-Storage Energy Systems

Mike Brian Ndawula, Antonio De Paola
Centre for Sustainable Power Distribution
University of Bath, Bath, UK
M.B.Ndawula@bath.ac.uk, A.De.Paola@bath.ac.uk

Ignacio Hernando-Gil
ESTIA Institute of Technology
University of Bordeaux, F-64210 Bidart, France
I.Hernandogil@estia.fr

***Abstract*—The valuation of whether network operators meet users' expectations in ensuring a continuous supply to their premises is important in determining their willingness-to-pay (WTP) for electricity. Distributed resources such as photovoltaic (PV) systems will dominate future networks, and thus customers' WTP will vary dynamically, both spatially and temporally. Whereas system-wide indices are typically used to assess network performance, there is a requirement to complement these with customer-based indices to accurately quantify the risk of outages to affected and worst-served customers. This paper presents an enhanced Monte Carlo simulation technique, which performs reliability assessment of a typical MV/LV urban distribution network. Two smart grid scenarios considering controllability of PV and energy storage (ES) are designed to improve network performance. Customer-based reliability indices, measuring the frequency and duration of interruptions, and energy not supplied are thoroughly assessed. Results demonstrate the potential of hybrid PV-ES in reducing the power supply risk for worst-served customers.**

***Index Terms*—energy not supplied, energy storage, monte carlo simulation, reliability indices, willingness-to-pay.**

I. INTRODUCTION

Customer willingness-to-pay (WTP) is an important parameter in electricity markets because its quantification establishes the market value and thus business case for the provision of electricity. A higher willingness to pay is often ensured by confidence in the continuity of supply [1, 2], which is characterised by various quality dimensions – frequency and duration of interruptions, and energy not supplied (ENS) per year. A key motivator for developing accurate methods of network performance assessment is the strong correlation between a continuous power supply to customers and their valuation of electricity as a commodity. Accordingly, failures in distribution networks account for over 80% of customer interruptions. Thus, distribution network operators (DNOs) are keen on ensuring an optimal network performance, culminating in higher levels of customer satisfaction [3]. This is also fuelled by requirements from network regulators (such as OFGEM-UK) for DNOs to optimise their supply continuity in a cost-effective manner, with due consideration of customer expectations and their WTP. Adherence to these security and quality of supply (SQS) regulations results in satisfactory network performance, leading to increased profits for DNOs through avoidance of not only lost revenues, i.e. due to customer interruptions, but also penalties for failure to meet network performance targets. Also, increased investments in the last mile of power supply have proportionately improved network performance, which is evidenced e.g. in the UK where in 2016-17 all DNOs exceeded their performance targets (Fig. 1) [4]. Accordingly, system-wide indices [5], quantifying frequency and duration of interruptions, are periodically required from each DNO to assess network performance against these set targets. However, one of their major drawbacks is that these indices include customers who enjoy uninterrupted power supply for substantially long periods, thereby concealing some of the shortcomings of network performance, especially to worst served customers.

Therefore, this paper analyses customer-based indices i.e. those measuring frequency of long (LI) and short (SI) interruptions, duration of LI, as well as ENS, for only those customers who are affected by interruptions. These indices present a more accurate picture of the customer-view of network performance and can therefore be useful in ascertaining the customers' WTP, as well as an understanding of some of the best strategies to manage their expectations [6]. Distributed energy resources (DERs) e.g. wind, hydro, geothermal, and photovoltaic (PV) systems will invariably dominate future power systems [1]. Consequently, methods

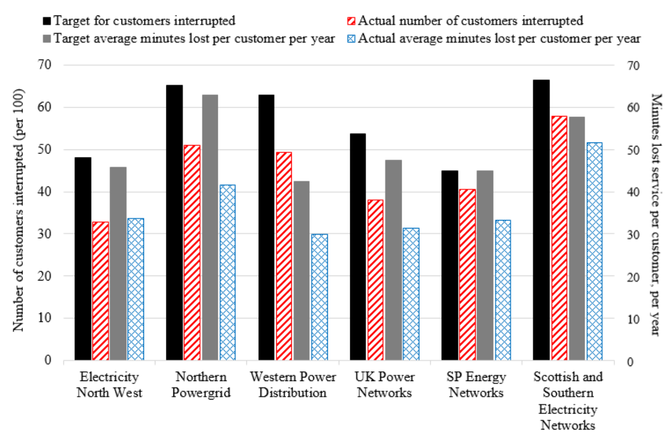

Figure 1. UK Customer interruptions and minutes lost 2016-17 [4].

commonly used to improve traditional distribution network reliability such as corrective and preventive maintenance; installation of re-closers, fuse saving and clearing schemes, etc. [7] must be updated to ensure maximum asset utilisation. Accordingly, this research designs two smart grid scenarios - local uncontrolled PV in combination with a novel technique for customer demand-side response (DSR) designed to improve reliability; and local energy storage (ES) controlled by an energy management system (EMS), also combined with DSR. Both interventions are applied to an urban medium and low voltage (MV/LV) distribution network representing a metropolitan area, and reliability indices are calculated to characterise the benefits.

II. Methodology

The major benefit of simulation methods in reliability assessment is establishing a more accurate picture of the deficiencies suffered by the system. Sequential simulation approaches are required as historical events affect present conditions, especially considering the non-uniform ageing of power components (PCs) [8, 9]. Accordingly, the effect of PV-storage systems on the reliability performance of distribution networks is demonstrated in this paper through an enhanced time-sequential Monte Carlo simulation (MCS). This ensures accurate reproduction of PC random behaviour, the stochastic nature of PV, and focuses on supply continuity.

A. Reliability Performance Assessment

Aggregation techniques, producing both electrical and reliability equivalents based on [10], are used to reduce the complexity of a highly meshed urban MV/LV distribution network, with 48 LV load points (LPs) supplying residential demand. This lowers the computational time and effort required to perform accurate reliability assessments. Previous work in [11, 12] provides more details about the design of this test network and the engineering assumptions. Subsequently, all network PCs are assigned two main characteristic parameters – failure rate and repair time, based on historical information from UK DNOs. These are the two basic inputs to the aforementioned MCS technique, which is enhanced by the inclusion of time-varying load demand profiles, and PC failure rates to increase accuracy in the reproduction of random network behaviour. Moreover, system interruptions are differentiated into LI and SI using previously recorded data to reproduce the variability of the type of faults suffered in distribution networks [13]. Further details on the MCS implementation, including the algorithms and uncertainty assessment, are presented in [12-14]. PSS®E (automated using Python scripting) is used to simulate network performance and thus calculation of average values and probability distribution functions (PDFs) of desired reliability indices. After establishing a base-case network performance, two smart grid scenarios are modelled to assess reliability benefits.

B. Network Scenarios for Reliability Enhancement

1) SC-1 Base Case

The reliability performance of the urban MV/LV network, with no DERs, is used to establish a base case for assessing the benefits of the considered scenarios. The network is modelled with backup capabilities and the implementation of (UK) SQS regulation. This is based on DNO practices typically employed to ensure regulator-set limits for the risk of customer outages are not exceeded. Markedly, the most significant benefit from this method is that a comparative analysis of reliability indices with other network scenarios is not hampered by varying levels of uncertainty, as the results obtained from the reference case maintain the same level of uncertainty [9]. This ensures benefits from the proposed DER strategies are based on a mathematically sound approach.

2) SC-2 PV+DSR

Most DNOs are reluctant to depend on PV generation for adequacy in power delivery capacity as it does not directly reduce the peak demand. However, it shortens the duration of the load peak, which is useful for current-carrying PCs [15]. Among others, unpredictable cloud movements affect the range of power fluctuations at PV installations. These cloud transients cause voltage fluctuations and often require applying controls or altering settings of associated protection systems [16]. PV peak-power output models, representing mainly cloudless days, are usually used in assessing PV benefits. However, for more accurate reproduction of the unpredictability of PV, it is more accurate to model the most probable PV power output, i.e. considering the same output for each residential dwelling, which avoids overestimation of benefits by accounting for the clouding effects. Given the high levels of DER penetration in future networks, this scenario illustrates the effect of uncontrolled PV with 50% penetration [17]. A novel technique for DSR is also designed solely for reliability improvement, where demand is decreased when the probability of fault occurrence is highest, to ensure that upstream faults do not interrupt as much load. Further details on the clouding effects and DSR development (and benefits) are available in [12] and [13] respectively.

3) SC-3 ES+DSR

Whilst many control techniques for ES focus on peak shaving applications and energy cost reduction, the ES in this paper is designed to improve reliability performance by providing a backup capacity per customer, per fault, with the intention of reducing the ENS and duration of sustained interruptions [11]. The backup capacity designed for this study is 3.67 kWh, guided by the (UK) ENA G83 Engineering Recommendation for peak power that can be provided by a small-scale single-phase rooftop PV [18]. ES operation is controlled by an EMS to provide seamless power switching capabilities and continuous supply to the end-customers. The energy is stored from microgeneration (MG) operating in islanded mode and is expected to result in a better reliability performance than the uncontrolled PV (SC-2). For accurate modelling of realistic ES systems, varying state of charge (SOC) characteristics for the storage devices are modelled into the EMS-controlled ES operation. The SOC behaviour is modelled based on electricity tariffs during grid supply, solar irradiation (PV generation) and load demand [19]. Lastly, the SOC limits are set to 40% and 100% to prevent overheating and ensure long battery lifetime. As in SC-2, DSR for reliability improvement is added to the ES application. This combination of smart interventions - both preventive (i.e. DSR) and corrective (i.e. ES), to improve quality of supply, is expected to culminate in the most benefits for customer reliability performance as it combines novel techniques for localised energy management.

III. Customer-oriented Reliability Evaluation

Table I presents the resultant customer-oriented reliability indices for each of the network scenarios. The benefits of the uncontrolled (PV) and controlled (ES) energy applications are characterised by comparative assessment with the base case. The following subsections discuss the average values and PDFs for each of the presented indices. This facilitates an understanding of the network deficiencies and the capabilities of each technology to impact network performance.

TABLE I. Network reliability Performance Evaluation

Index	SC-1 Base Case	SC-2 PV+DSR	*	SC-3 ES+DSR	*
Duration of LI (hours)	3.507	2.595	26.0%	1.800	48.7%
CAIDI (hours/aff. cust.)	3.678	2.751	25.2%	6.243	-69.7%
CAIFI (ints/aff. cust.)	0.720	0.720	0%	0.557	22.6%
CIII (aff. custs./int.)	0.654	0.654	0%	0.459	29.7%
LPs affected by LIs (avg)	6.644	6.644	0%	1.643	75.3%
CAMIFI (ints/aff. cust.)	0.797	0.797	0%	0.819	-2.7%
LPs affected by SIs (avg)	8.387	8.387	0%	8.595	-2.5%
ACCI (kWh/aff. cust.)	1090.41	828.99	24.0%	1790.79	-64.2%

*Reduction from Base Case; aff. cust. = affected customer; int = interruption

A. *Duration of Sustained Interruptions*

Table I shows that EMS-controlled ES combined with DSR (SC-3) provides nearly a halving (48.7%) of the duration of LI from the base case, as compared to only 26% reduction in scenario SC-2. This is a significant result for DNOs as they might take advantage of this enhancement to avoid penalties from a non-satisfactory performance. However, these results reveal that controllability of PV can adversely affect the customer average interruption duration index (CAIDI), which quantifies the duration of interruption only for those customers affected by outages. Table I shows a 69.7% increase in the hours of unavailability when SC-3 is implemented, as opposed to a 25.2% reduction in this outage time when SC-2 is deployed. Accordingly, if e.g. a customer experienced a 2-hour interruption previously, the outage duration would increase to 3.4 hours with the implementation of ES+DSR, yet it would decrease to 1.5 hours if PV+DSR were deployed. However, this 'increase' is due to the fact that CAIDI is directly calculated from the ratio of SAIDI to SAIFI (system-wide indices for LI duration and frequency respectively) and is thus dominated by the magnitude of change between these two indices. Thus, the large increase in CAIDI is due to ES reducing the number of customer interruptions significantly more than it does with the total duration of the interruptions.

A probabilistic analysis for the duration of interruptions to affected customers is presented in Fig. 2, where SC-3 increases the CAIDI average value, as well as the long tail of the resulting PDF. This corresponds to longer plausible outage hours for those interrupted customers only. As expected, SC-2 contributes to the reduction of CAIDI, however, this is ultimately unfeasible as the uncontrolled PV does not reduce the frequency of LI, and yet it lowers their duration.

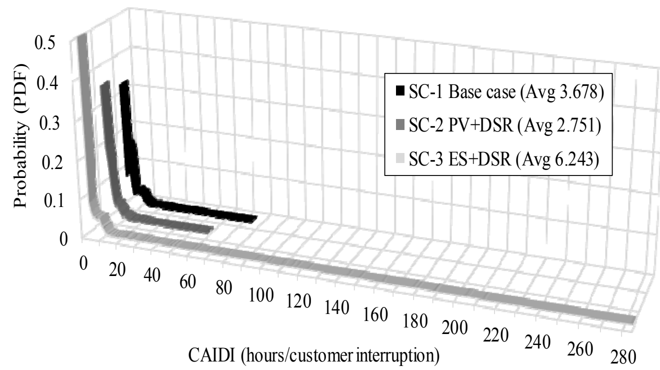

Figure 2. Impact on the duration of interruptions to affected customers.

B. *Frequency of Sustained Interruptions*

Customer average interruption frequency index (CAIFI) measures the frequency of long interruptions to affected customers only. It is particularly useful in recognising chronological trends in the reliability of a distribution network, highlighting those years when not all supplied customers are affected by interruptions and many experience supply continuity. The reciprocal of this index is the 'customers interrupted per interruption' index (CIII) [20], which quantifies the average number of customers interrupted during an outage. In this analysis, the application of PV+DSR does not affect the frequency of LI (i.e. 0% reductions from the base case in both CAIFI and CIII), as no control technique is implemented and thus it only provides additional energy during the occurrence of faults.

The probability distributions for CAIFI (Fig. 3) demonstrate the benefit of the proposed intervention with ES+DSR. Notably, all considered scenarios (SC-1, SC-2 and SC-3) do not have any values occurring within the range 0-1, as CAIFI is only calculated for customers affected by interruptions, implying that individual average CAIFI values can only be less than 1 if they are 0 – i.e. not in between. Accordingly, Fig. 3 illustrates a 'peak' over the value CAIFI = 1 due to the coincidence of faults and number of affected customers, especially when system faults affect large parts of the network and lead directly to interruptions of loads.

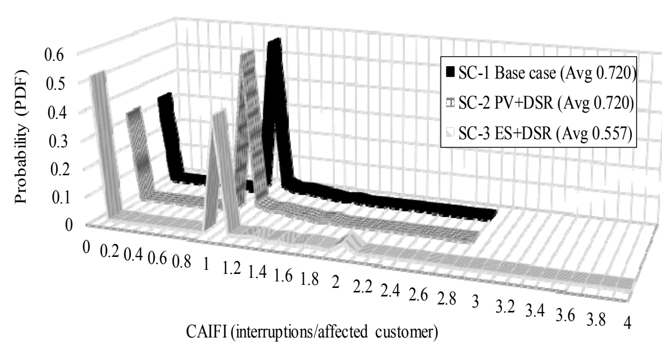

Figure 3. Probability distribution of CAIFI.

From a base case CAIFI value of 0.72 interruptions per customer interrupted, PV+DSR does not alter this average value. However, it is reduced by 22.6% to 0.557 when ES+DSR is deployed. In addition, Fig. 3 proves that whilst ES+DSR can benefit network reliability performance by increasing the probability of lower interruption frequency for affected customers, it simultaneously increases the largest plausible number of interruptions that can be suffered at a single LP to 4, from 2.8 in the base case. This effect is best explained by the fact that EMS-controlled ES is deployed as a corrective action when faults occur. Whilst in most cases it can completely ensure supply continuity by alleviating the effects of upstream network faults, in cases where it only lowers the interruption duration, the net effect is to have fewer customers affected but a higher number of interruptions, when assessed per customer. In summary, ES reduces the number of customers affected significantly more than it reduces the total number of customer interruptions, thus resulting in a higher plausible CAIFI value. The reductions from the base case in CAIFI and CIII indices in SC-3 are further explained by analysing the number of LPs affected by supply interruptions (Table I). When SC-3 is implemented, LI affect only 1 out of every 4 LPs (75.3% reduction). Combined with the fact that ES provides energy per fault, thereby reducing the frequency of LI, it means that ES+DSR considerably lowers the interruption frequency to those affected customers (CAIFI). Moreover, only 3 out of every 10 LI-affected customers experience continuous supply when SC-3 is implemented (29.7% reduction in CIII). This is a significant gain as it can be directly linked to customers' satisfaction, the valuation of electricity, and therefore their WTP.

A probability analysis for the particular number of LPs affected by interruptions is shown in Table II. While PV+DSR offers no discernible improvement to the number of LPs affected by interruptions, ES+DSR increases the probability of not having any LP affected by interruptions by almost 60%. In fact, ES+DSR application increases the probability of having only one LP affected by 55% from the base case. This is significant as this intervention simultaneously lowers by 95% the probability of having all 48 LPs affected by LI. Table II also shows that the probability of LI affecting anywhere between 2 and 47 LPs is nearly halved in this scenario.

TABLE II. NUMBER OF LPS AFFECTED BY SUSTAINED INTERRUPTIONS

Number of LPs affected	SC-1 Base Case	SC-2 PV + DSR		SC-3 ES + DSR	
	Probability	*Probability*	*	*Probability*	*
0	0.320	0.320	0%	0.508	-58.8%
1	0.147	0.147	0%	0.228	-55.1%
2-47	0.471	0.471	0%	0.261	44.6%
48	0.062	0.062	0%	0.003	95.2%

*Reduction from Base Case

Moreover, as shown in Fig. 4, in some cases the reduction in the number of affected LPs by ES+DSR is so great, that it completely negates supply interruption to that number of LPs e.g. for LPs 17-24, 26, 30, 32 and 33. Likewise, Fig. 5 demonstrates the capability of ES+DSR to 'confine' the effect of supply interruptions to much fewer LPs than in the base case scenario. ES+DSR 'localises' LI effects by lowering the number of affected customers significantly.

C. *Frequency of Momentary Interruptions*

Short interruptions, voltage sags and swells can potentially damage sensitive equipment. To evaluate system reliability, the momentary average interruption frequency index (MAIFI) considers momentary interruptions that may affect several types of loads. The length of SI (the main subject of power quality analyses) depends on different standards – 1min in [21] and 3min in [1]. Most studies assessing the frequency of SI present average values of MAIFI [7, 22], which is a system-wide index considering all customers, including those not subject to momentary loss of power supply. There is a reluctance to quantify the SI frequency to only the affected customers [1, 23]. Accordingly, this research proposes a new index – customer average momentary interruption frequency index (CAMIFI), described mathematically by (1), to enable characterisation of SI to affected customers only. Table I shows no discernible improvement in CAMIFI after application of PV+DSR. ES+DSR also provides only a 2.7% increase in average CAMIFI value from the base case (0.797 SI per affected customer).

$$\text{CAMIFI} = \frac{\text{total number of customer momentary interruptions}}{\text{total number of customers affected}} \quad (1)$$

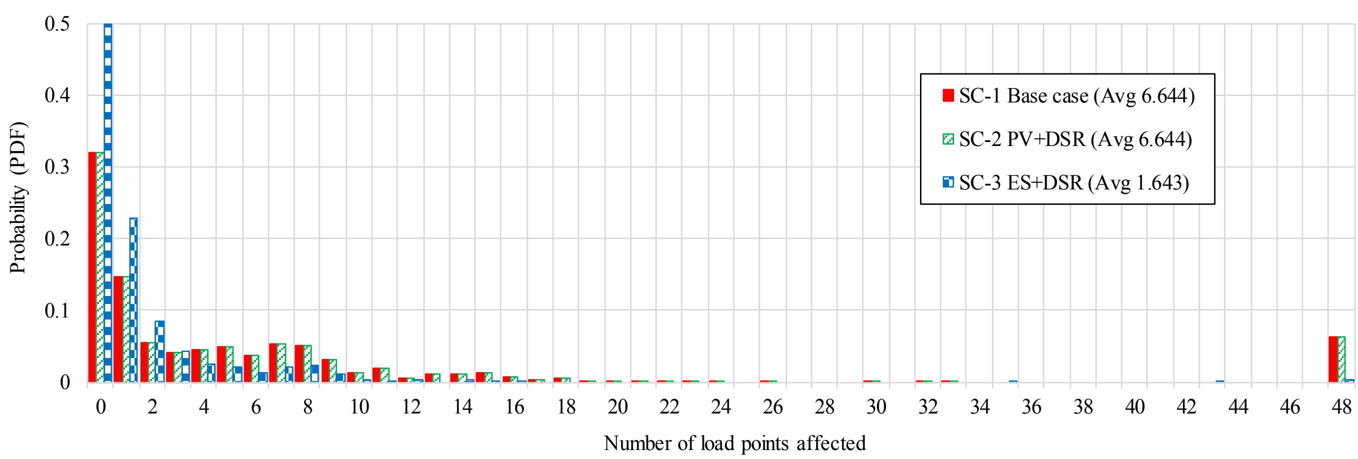

Figure 4. Probability of number of load points affected by supply interruptions.

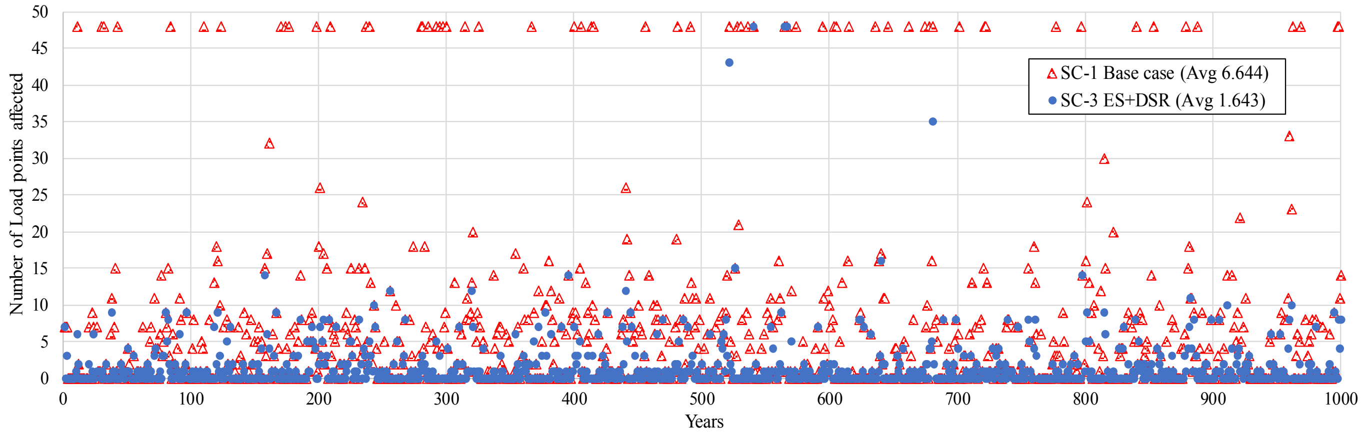

Figure 5. Number of network load points affected by supply interruptions.

While ES+DSR is unable to ensure complete backup capability during a sustained fault, but can only offer a high percentage alleviation of the upstream network fault, it 'converts' some LI to SI thereby changing their classification. This insignificant impact on CAMIFI is also due to ES+DSR systems being locally installed, and given the varying distances between LPs and fault locations, it is not feasible for different EMS systems to respond simultaneously to SI. A more significant impact would be expected from larger-capacity ES given the advanced technology and detection of momentary faults [23].

D. *Energy Not Supplied*

Although the conventional approach has been to focus on interruption frequency and duration, energy not supplied is an important index as it has a strong correlation with price signals in electricity markets. ENS to only affected customers is assessed using the average customer curtailment index (ACCI) [9]. Through this quantification, it is possible to establish not only the necessity of implementation of the proposed reliability improvement techniques but also the network infrastructure requiring most intervention. Regarding the risk associated with the energy not supplied to customers, Table I presents the results for ACCI index. Uncontrolled PV, in combination with DSR, positively affects this category of customers – reducing ACCI by 24%, because it provides additional energy during faults. Therefore, PV reduces the average ENS per affected customer, even though it has no net effect on the average number of LPs affected by LI since it is locally uncontrolled and thus could not alleviate the effects of upstream network faults. Notably, the percentage increase in ACCI (of 64.2% in SC-3) should not be interpreted as a weakness from the EMS-controlled ES technology. As applied in this design, the reason for this increase is due to the net effect from the ES technology, which reduces heavily the number of interruptions – in most cases, ensuring a continuous supply. This means the total number of affected customers reduce so greatly that the denominator for the calculation of ACCI renders the resulting value higher than the base case. ES+DSR is therefore especially useful in reducing the ACCI as it also lowers the number of affected LPs (by 75.3%).

Fig. 6 further illustrates the positive impact offered by ES+DSR, by assessing the probability of occurrence for different values of energy not supplied per customer interruption. Accordingly, SC-3 greatly improves the probability of having no energy curtailment to nearly 0.5, from 0.32 in the base case. This is directly related to an enhancement in reliability performance and hence continuity of supply. However, an important feature in Fig. 6 is the higher probability for larger values of ENS (> 4000 kWh/customer interruption) when ES is deployed, as compared to values from the uncontrolled PV or the base case. Although initially perceived as a weakness, this is explained by the fact that ES has the capacity to 'convert' system interruptions into continuous supply, as experienced by the customer. For the calculation of ACCI, this means relatively short LI may be converted to continuous supply, rendering those LPs no longer affected by the upstream faults. That is not the case for the relatively longer LI, leading to less affected customers, but relatively unchanged individual interruption durations and energy unsupplied. This is typified by an example adapted from the results data, where for one particular year (before any smart interventions – base case), there were 8 affected LPs, with 1 relatively long LI and 7 relatively short LI. After the application of ES+DSR, the 7 relatively short LI were converted to continuous supply, but the duration of the relatively long LI was only marginally reduced, thus slightly decreasing the ENS for that period only. This resulted in a much higher ACCI for that particular year when ES is deployed, as compared to the base case, due to the modified number of customers affected. Therefore, it is important to emphasise that ES is a most useful technology to improve such aspects of network reliability performance.

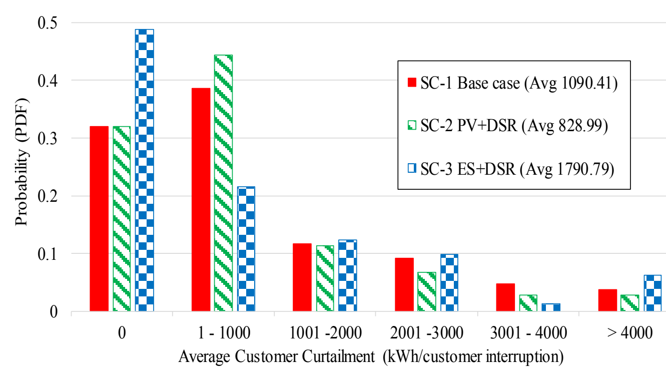

Figure 6. Probability of energy not supplied to interrupted customers.

E. Comparison with System-wide Reliability Evaluation

To demonstrate the variance between customer-oriented and system-wide reliability indices [5], Table III presents each index grouped by different reliability parameters i.e. frequency and duration of interruptions and ENS. Comparing each customer index with its system equivalent reveals a disproportionate gap between these indices. For example, system ENS is at least 7 times smaller than ENS to affected customers in SC-1 and SC-2. This proves the requirement to assess network reliability from the customer perspective, in addition to more system-centric evaluations.

TABLE III. CUSTOMER-BASED VS SYSTEM-WIDE RELIABILITY METRICS

Parameter	*Index*	SC-1 Base Case	SC-2 PV+DSR	SC-3 ES+DSR
Duration of LI	*CAIDI (hours/aff. cust.)*	3.678	2.751	6.243
	SAIDI (hours/cust./year)	0.550	0.407	0.282
Frequency of LI	*CAIFI (ints/aff. cust.)*	0.720	0.720	0.557
	SAIFI(ints/cust./year)	0.157	0.157	0.039
Frequency of SI	*CAMIFI (ints/aff. cust.)*	0.797	0.797	0.819
	MAIFI (ints/cust./year)	0.208	0.208	0.216
Energy not supplied	*ACCI (kWh/aff. cust.)*	1090.41	828.99	1790.79
	ENS (kWh/cust./year)	146.37	110.63	85.21

*Reduction from Base Case; aff. cust. = affected customer; int = interruption

IV. CONCLUSIONS AND FURTHER WORK

The key drawback in the use of system-wide reliability indices to assess network performance is the fact that they do not accurately represent the effects of network outages to affected customers only. These indices must be complemented with customer-oriented indices to accurately assess power supply risk, especially to worst served customers. Limited to continuity of supply, the results demonstrate that intelligently designed EMS-controlled ES, combined with the use of a novel DSR technique, is significantly useful in improving reliability performance. This is through reductions to the number of customers affected by interruptions, and the frequency and duration of each interruption. Whilst an uncontrolled use of PV, combined with DSR, also proves beneficial especially in reducing the duration of interruptions, the value in controlling MG using ES, from a reliability perspective, is exemplified by this work. This is through quantification of the capability of EMS-controlled ES to reduce the ENS to affected customers, which is usually accompanied by a saving in financial terms. Therefore, this analysis justifies the installation of local ES systems, whose deployment is often cautioned by the attached costs. This work also demonstrates the need to accelerate the development of innovative ES control methods for higher energy efficiencies. Finally, the deployment of PV-storage systems also proves these technologies do not offer a significant impact on momentary interruptions. Further work will increase the resolution of the applied MCS time-step, thus enabling the testing of novel interventions using smart grid technologies to alleviate the effects of SI.

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