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Authors

Baik, Sunhee
Morgan, M Granger
Davis, Alexander L

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Providing Limited Local Electric Service During a Major Grid Outage: A First Assessment Based on Customer Willingness to Pay

Sunhee Baik,* M. Granger Morgan, and Alexander L. Davis

While they are rare, widespread blackouts of the bulk power system can result in large costs to individuals and society. If local distribution circuits remain intact, it is possible to use new technologies including smart meters, intelligent switches that can change the topology of distribution circuits, and distributed generation owned by customers and the power company, to provide limited local electric power service. Many utilities are already making investments that would make this possible. We use customers' measured willingness to pay to explore when the incremental investments needed to implement these capabilities would be justified. Under many circumstances, upgrades in advanced distribution systems could be justified for a customer charge of less than a dollar a month (plus the cost of electricity used during outages), and would be less expensive and safer than the proliferation of small portable backup generators. We also discuss issues of social equity, extreme events, and various sources of underlying uncertainty.

KEY WORDS: Backup during long power outages; equity and electric power backup; islanded electric service

1. INTRODUCTION

Because the services provided by electricity have become critical in modern society, power outages can result in large economic and social costs. While they are rare, blackouts of large geographic extent with durations of several days or more occur more frequently than one might think (Fig. 1).(1–3) In the past, such blackouts have been caused by extreme weather and by faults and errors in the operation of the bulk power system. With a changing climate, the frequency and intensity of extreme weather events is expected to increase.(4) Large future outages could also be caused by terrorist events and by large solar mass ejections.(5,6)

In a companion paper, we developed and demonstrated a method for helping individuals think systematically about their willingness to pay (WTP) to avoid the effects of power outages that are widespread and of long duration.(7) For simplicity in developing and demonstrating the method, we focused on the amount that individual homeowners would be willing to pay to avoid service interruptions only to their own home (i.e., not their neighbors or near by critical social services). In addition to asking about the full service, we also asked respondents about their WTP to retain a low-amperage (e.g., 20A) service during an outage. The study results suggested that the respondents valued their high priority (HP) loads much more than their lower priority (LP) loads.(7) Hence, the social benefit of providing many customers with a small amount of electricity to cover their HP loads (such as lights or air conditioning

Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA, USA.
*Address correspondence to Sunhee Baik, Department of Engineering and Public Policy, Carnegie Mellon University, Baker Hall 129, 5000 Forbes Avenue, Pittsburgh, PA 15213, USA; tel: (412)-680-0412; sunheeb@andrew.cmu.edu.

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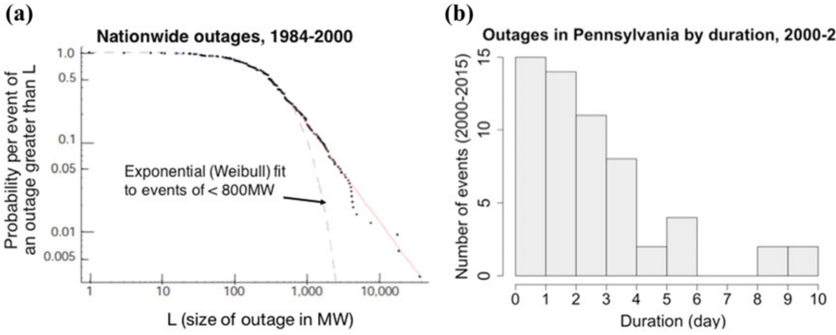

Fig. 1. Large blackouts are more common than one might expect. (a) Distribution of large blackouts in the United States during the period from 1984 to 2000 (data compiled by NERC).(2) (b) Distribution of large blackouts (major electric disturbance event reported through OE-417) in the State of Pennsylvania during the period from 2000 to 2015 (data compiled by EIA).(3)

during summer) is likely greater than serving a few customers full power to also meet their LP loads (such as using a speaker dock, DVD/video player, and LED TV to play a game). Although we only considered an outage of 24 hours on a hot summer weekend, the method could be applied to longer time periods and different times of year.

Many distribution systems now have installed automation that allows utilities to automatically change the topology of the distribution networks, for example, changing the location from which a circuit is fed, isolating a damaged portion of a circuit, or connecting two circuits together.(8) More advanced automated sectionalizing switches (such as S&C electric company's IntelliRupter®)[1] and related protection devices can communicate with each other, sense direction of current flow, and adapt appropriately as the configuration of a distribution feeder changes. Many systems are also installing smart meters that allow utilities to connect and disconnect customers remotely.(9) Finally, growing amounts of gas-fired distributed generation (DG) are being installed, often with combined heat and power (CHP).(10–13) With modest upgrades to such systems, including backup battery power for control circuits and meters, the ability to synchronize DG when an isolated feeder is being repowered (i.e., local black start),[2] and some modest reprogramming or upgrading of some protection systems,(14–17) it would be possible to operate a distribution feeder as an isolated island using DG to provide a low-amperage service to homes and selected HP loads in the event of an outage in the bulk power system. This is illustrated in Fig. 2.

In this article, we perform a series of order of magnitude calculations to illustrate how values elicited in the companion paper can be used to inform investment decisions about the distribution system upgrades that could make service provision more robust in the event of major outages. Whether investing in such upgrades makes sense depends on the following three factors: (1) an assessment by the community of the likely future frequency and duration of possible large widespread outages; (2) the incremental cost of system upgrades to make a low-amperage service available; and (3) the willingness of individuals and the community to cover the costs of the necessary incremental investments.

2. ORDER OF MAGNITUDE ESTIMATES FOR ONE- AND FIVE-DAY OUTAGES

For the purpose of illustration, we consider implementing a low-amperage backup service for a distribution feeder that serves 2,500 customers. Following the strategies suggested by Narayan and Morgan,(8) we assume that either the distribution utility itself has sufficient DG to supply 20A service to all 2,500 customers on the islanded feeder(s) $(20A \times (120V{-}220V) \times \frac{1}{1000} kW/A \cdot V \approx 6MW{-}11MW)$, or that it has contracted with private DG owners who can supply that much power in the event of an outage. In either case, we assume that most of the time these DG units are being used for nonemergency purposes so that it is only necessary

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[1] See http://www.sandc.com/en/products--services/products/intellirupter-pulsecloser-fault-interrupter/ for example. Accessed on January 31, 2017.

[2] Here we are not considering individual roof-top PV (which with present inverter designs and regulations only operate when there is grid power) or small-scale DG (of the sort that individual residential customers might install). Rather our focus is on larger micro-turbines and CHP systems of the sort that medium-sized and larger institutions and utilities might deploy.(10)

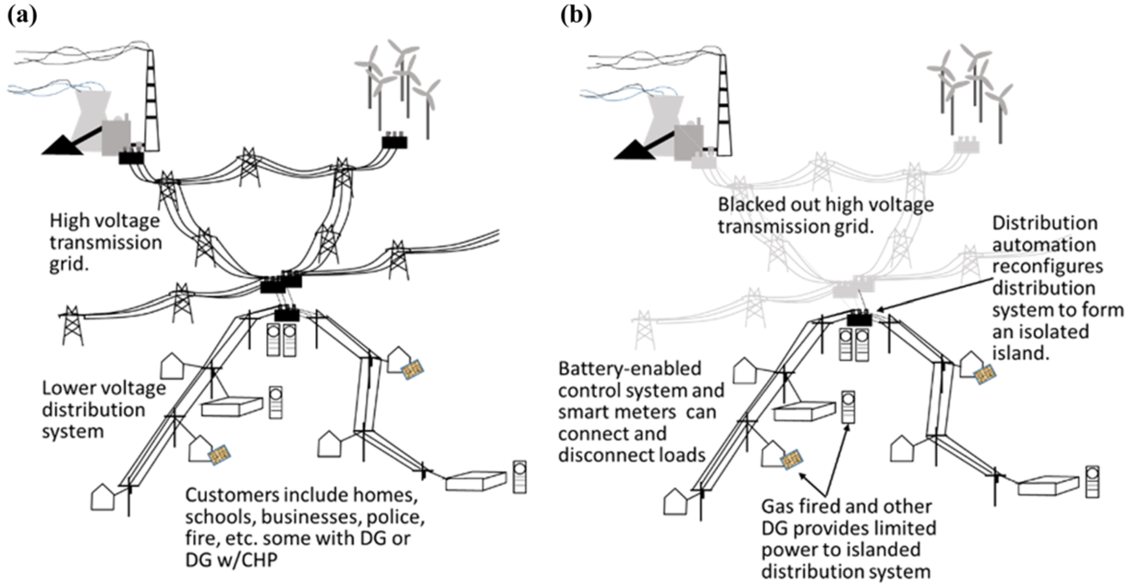

Fig. 2. (a) Conventional power system with high-voltage grid feeding distribution systems; (b) Illustration of the way in which distribution automation, smart meters, and distributed generation (DG) could be used to create an island with limited local electric service when power is not available from the bulk power system. The smart meters need to have battery backup so that they can drop loads and not reconnect until the DG has been brought up and synchronized.

to cover the cost of emergency generation during the outage.

To estimate the cost to upgrade control and protection equipment for a feeder, we consulted with the director of distribution planning for a major urban utility that has already deployed intelligent distribution automation (including bidirectional smart sectionalizing switches that can sense the direction of current flow and communicate with each other) and smart meters. The total cost of upgrades to the feeder and operation of the associated DG was on the order of \$100,000 for a feeder covering 2,500 customers with additional annual operation and maintenance (O&M) costs of approximately 5% of this initial capital cost (i.e., \$5,000). We assume that these technologies last 20 years based on Narayanan and Morgan.(8) Of course, as noted below, if these cost estimates are optimistic or if some of the necessary upgrades have not already been accomplished and are charged to adding the ability to supply emergency service, costs could be higher.

We assume that basic smart meters are already in place,[3] and if done in bulk, upgrading them by adding batteries for continuous operation in the event of a power outage, and a control circuit that can switch a main breaker from a high-amperage service (e.g., 150A) to a low-amperage service (e.g., 20A) would require an additional investment of \$50 per meter (based on consultation with circuit breaker companies, including labor cost, smart meter cost, and backup battery). Again, we assume a lifetime of 20 years based on Narayanan and Morgan.(8) Because longer widespread outages are rare, here we assume that customers will limit their loads manually (i.e., turn off appliances and open breakers) to meet the 20A constraint.

Finally, we assume the cost of power produced by DG during an outage is 1.5 times that of grid power under normal circumstances (i.e., $\$0.11/kWh \times 1.5\times \approx \$0.17/kWh$).[4] We set the daily electricity cost per residential customer per day as \$9.8 ($20A \times 120V \times \frac{1}{1000} kWh/Wh \times 24 hours \times \$0.17/kWh$), and assume that the charge for electricity occurs when

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[3] Utilities have been deploying smart grid devices and technologies (including upgrading transmission and distribution system with enabling local distribution automation). Major electric utilities already have installed more than 50 million smart meters nationwide.(9,15–17) In addition to being used for billing, these meters provide real-time measurement of customer loads to help monitor and improve power system management.

[4] In many parts of the United States, the levelized cost of electricity from gas-fired DG is close to or actually competitive with the cost of grid power. We assume that long-term contracts have been put in place to secure power from DG in the event of a blackout. For further discussion, see Narayanan and Morgan.(8)

Table I. The Required Service Payment per Household per Outage by the Number of Outages During the Lifetime of Technologies (i.e., 20 Years); We Assume that Upgrading the Distribution System Requires an Investment of \$100,000 and an Investment of \$50/Meter to Upgrade Smart Meters When the Number of Residential Customers Served by a Feeder is 2,500, and Each Residential Customer Is Responsible for the Cost of Electricity

	Number of Outages during the Lifetime									
	1	2	3	4	5	6	7	8	9	10
Required service payment per household per outage	\$90	\$45	\$30	\$23	\$18	\$15	\$13	\$11	\$10	\$9

there is an actual outage. To adjust cost to present value, we used an interest rate of 3%.

If there is no consideration of when the outages occur (i.e., no consideration of time value of money), the required service payment per household per outage is simply the sum of total investment cost divided by the number of outages during the lifetime and the electricity cost (as shown in Table I). However, because power outages occur randomly and the value of money declines over time, we model the occurrence of 24-hour outages using a Poisson arrival model.[5] We consider the case of a 24-hour outage that occurs on average once every 5, 10, and 20 years (i.e., the intervals between successive outages are Poisson distributed with $\lambda = 0.2, 0.1,$ and 0.05). Because the occurrence of outages is probabilistic, in a few realizations of the model, outages occur much less or much more frequently than these mean values.

2.1. Order of Magnitude Estimates for 20A Partial Backup during 24-hour Outages

While the primary motivation for implementing a capability to provide limited emergency power backup service using isolated distribution feeders is to mitigate the individual and collective consequences of large long-duration outages, the WTP estimates in the companion paper are for a 24-hour outage. Hence, we first do the analysis for such a period, and then make assumptions to extend the analysis to longer periods (presented in Section 2.3).

In this first estimate of the benefit from the backup service, we assume that all the residential customers make fixed payments at the time of each outage. Thus, the net revenue that results from implementing the backup service is:

$$\begin{aligned}\text{Total cost} = {} & \text{System upgrade cost}\\ & + \text{Annual O\&M cost}\\ & + \text{Smart meter upgrade cost}\\ & + \text{Total fuel cost} \qquad (1)\\ & - \text{Total service payment,}\end{aligned}$$

where n = number of outages during the lifetime, $Year_i$= year when the i^{th} outage occurs, and

- System upgrade cost = 100,000;
- Annual O&M cost = $\sum_{j=1}^{20} \frac{5,000}{1.03^j}$;
- Smart meter upgrade cost = $2,500 \times 50$;
- Total Fuel cost = $\sum_{i=1}^{n} \frac{2500 \times 9.8}{1.03^{Year_i}}$; and,
- Total service payment = $\sum_{i=1}^{n} \frac{2,500 \times \text{Payment made by each customer per outage}}{1.03^{Year_i}}$.

In the companion paper, the WTP of residential customers for 24-hour partial backup service were found to be lognormally distributed (logarithmic mean=3.4, logarithmic standard deviation=0.84).(7) [6]

The upper parts of Fig. 3 display the results of the 10,000 simulations using the different levels of WTP (x-axis) and the outage frequencies (once every 5, 10, or 20 years on average, from left to right). When we draw realizations using the Poisson arrival model, we encounter some in which no outage occurs, and some in which several occur. To simplify this order of magnitude assessment, we have excluded realizations in which no outage occurs, and cases in which more than

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[5] The use of a Poisson arrival model is a standard way of dealing with the occurrence of random events in which the occurrence of one such event is not affected by the occurrence of other random events, and the events are assumed to occur with a known constant rate ($\lambda = 0.2, 0.1,$ and 0.05). However, climate change is expected to increase the frequency and intensity of severe weather events.(4) In such case, a nonhomogeneous Poisson process or Markovian arrival process could be used to incorporate the time-varying arrival rate.

[6] We used the Kolmogorov–Smirnov (KS) goodness-of-fit test to calculate the maximum difference between the elicited distribution and the lognormal distribution. Since the two distributions do not significantly deviate from each other (KS-D=0.13, p=0.18), we assumed that the fitted lognormal distribution appropriately represents the WTP distribution.(18)

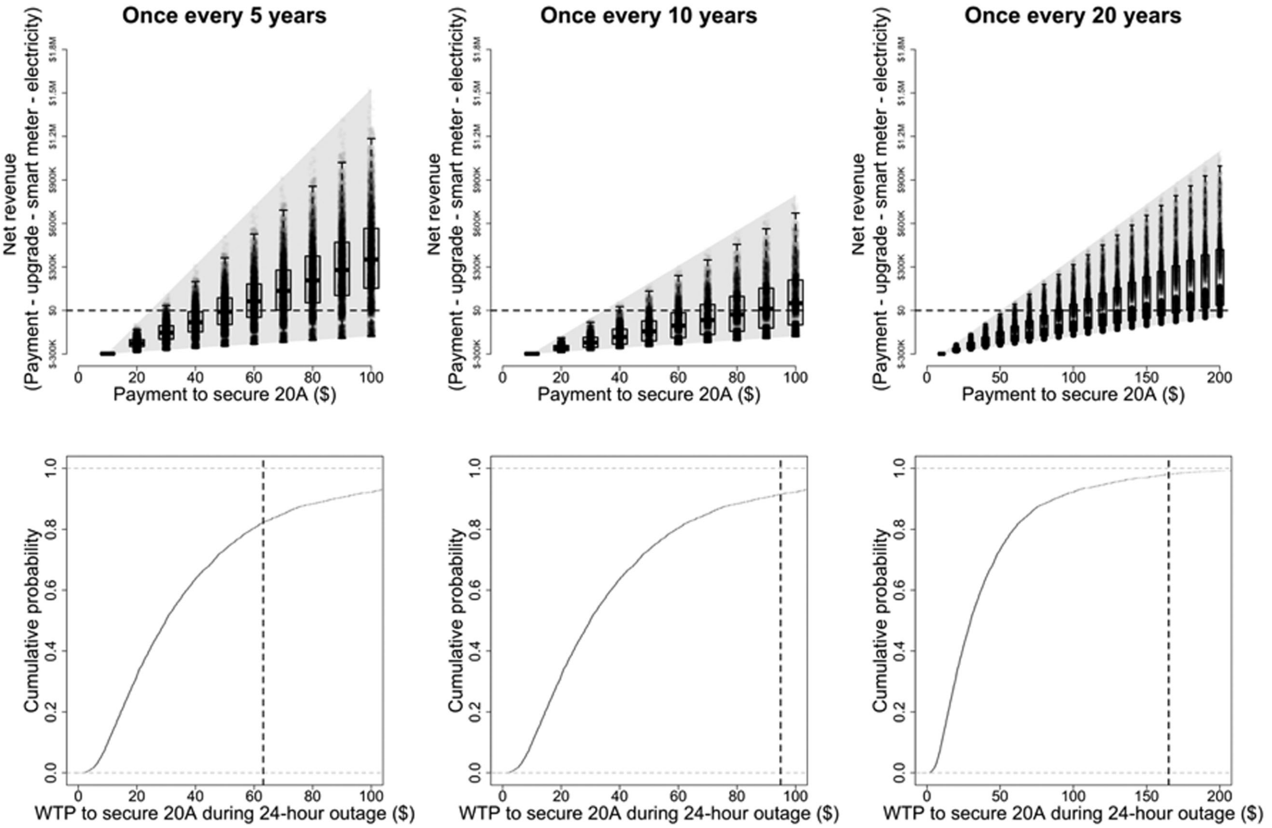

Fig. 3. The upper panel shows the differences between the residential customers' payments to secure the private low-amperage backup service and the actual cost of providing the service for 10,000 realizations of the modeled outages under three different outage frequency scenarios (once every 5, 10, and 20 years). Each point indicates the net revenue when the outages occur according to the Poisson process, and the shaded area indicates the range of net revenue under the assumptions outlined in the text. We assume that upgrading the distribution system requires an initial investment of $100,000 and $5,000 for annual O&M, and an investment of $50/meter to upgrade smart meters when the number of residential customers served by a feeder is 2,500. The lower curve shows the cumulative lognormal WTP distributions fitted to the results reported in Baik *et al.*(7) The vertical dotted lines represent the WTP that would be required to justify the partial backup service if the outage occurs at the mean of the generated Poisson random variables. Upgrades for outages once every 5 years on average can be justified at $63/customer/outage, for once every 10 years on average at $95/customer/outage, and once every 20 years on average at $170/customer/outage.

three times as many occur as expected during the 5-, 10-, and 20-year intervals.[7]

Each point in the upper figure indicates the net revenue (i.e., total customers' payments minus the cost of system upgrades and the cost of electricity) when the outage occurs, and all the customers make the fixed and promised payments right after the outage. A point greater than zero indicates that the investment can be recovered through service payments, whereas a point less than zero indicates that the backup service would require some form of subsidy. The shaded areas are polygons that connect the minimum and maximum net revenue at the given WTP level using the truncation explained above. The bottom part of Fig. 3 displays the cumulative distribution of WTP, with the vertical lines indicating the required service payment per residential customer per outage that is needed to justify the private low-amperage backup service.

If the region suffers a 24-hour outage once every 5 years on average, the backup service can be justified by a relatively low service payment. Assuming that the region is expected to suffer the outages at the

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[7] If the region does not experience any outage during the lifetime, there is no way to recover the system upgrade costs. Also, we do not consider very extreme cases (outages occur three times or more often than the given average). The percentage of realizations that were removed was 36% (once every 20 years on average), 17% (once every 10 years on average), and 9.9% (once every 5 years on average).

Table II. The Required Level of Increase or Decrease from the Given Service Payment to Justify the Backup Service (in Percentage)

	Customers' Payments to Secure the Private Backup Service								
	$20	$40	$60	$80	$100	$120	$140	$160	$180
Once every 5 years	220%	58%	5.2%	−21%	−37%	−47%	−55%	−61%	−65%
Once every 10 years	370%	140%	48%	19%	−5.1%	−21%	−32%	−41%	−47%
Once every 20 years	730%	310%	180%	110%	65%	38%	18%	3.2%	−8.3%

mean of the generated Poisson arrival random variables, the backup service can be justified when all residential customers pay $63, which is at or below the value of WTP for 18% of them.[8] When the outage occurs on average once every 10 years or 20 years, the region would suffer fewer outages; thus, a substantial increase in the service payment is needed to justify the backup service ($95/customer/outage for 10 years and $170/customer/outage for 20 years, which is only below WTP for 8.0% and 2.0% of the customers). Still, implementing the backup service is more cost effective than buying a small portable generator and storing diesel or gasoline for fueling (~$280 for purchasing a generator and $52/outage for gasoline if gasoline costs $3/gallon).[9]

2.2. Consideration of Neighbors and Critical Social Services

Power that is supplied to one's own home is not the only thing most people care about. We assume that larger critical social services, such as hospitals, have their own emergency backup power, and the DG capacity exists to sustain other critical social services.(1,8,19) A discussion of critical social services that depend on the availability of electric power (can be found in Chapter 8 of a recent National Academy report).(1) [10]

It is unclear whether WTP would be higher or lower in order to assure some continuing power for neighbors and other local services (emergency services, cash machines, drug and convenience stores, gas pumps, etc.). The answer could depend on both behavioral factors and the outage duration. As Table II shows, even if customers' WTP to secure their private backup service are low, the backup service might still be justified if people attach high values to supplying power for neighbors and other local services. On the other hand, if customers' values for the private backup service are high enough, the distribution utility might also cover the critical social services without additional revenue.

Because we do not know what people's preferences would be, we explore the issue parametrically by assuming, on the high side, that all the customers might be willing to pay 20% more to assure that both their neighbors and critical social services are supplied (i.e., value the social low-amperage backup service as high as 20% of the value of their private demands), whereas, on the low side, they might decrease their WTP by 20% because now they can fulfill some of their private HP demands through the sustained critical social services and/or going to the homes of neighbors with backup power.

Fig. 4 summarizes the cost effectiveness of implementing a private and social low-amperage backup service for 24-hour outages varying WTP by ±20%. The shaded area indicates the range of WTP that would be required to justify the backup service if a 24-hour outage occurs at the mean of the generated Poisson random variables (the left edge is the results when residential customers are willing to pay 20% more, and the right edge is the results when they are willing to pay 20% less). The results are not dramatically different than those for the case of only private backup service. Of course, this thought experiment does not include the nonmonetary community

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[8] In the case of once every 5 years, the average occurrence times of the first, second, third, and fourth outage are year 4.9, year 10, year 15, and year 21, respectively. Since the lifetime of technologies is 20 years, we assume that the region would suffer three outages during the period. Similarly, in the case of once every 10 years, the region will suffer two outages at year 7.1 and year 17, and in the case of once every 20 years, the region will suffer only one outage at year 8.8.

[9] See http://www.amazon.com/DuroStar-DS4000S-4-Cycle-Portable-Generator/dp/B004918MO2 for example. Accessed on July 8, 2016.

[10] Table 8.1 in this National Academy report lists critical social services by category, including: emergency services; medical services; communication and cyber services; water and sewer; food; financial; fuel; nonemergency government services; transportation systems; lighting; and, building operations.(1)

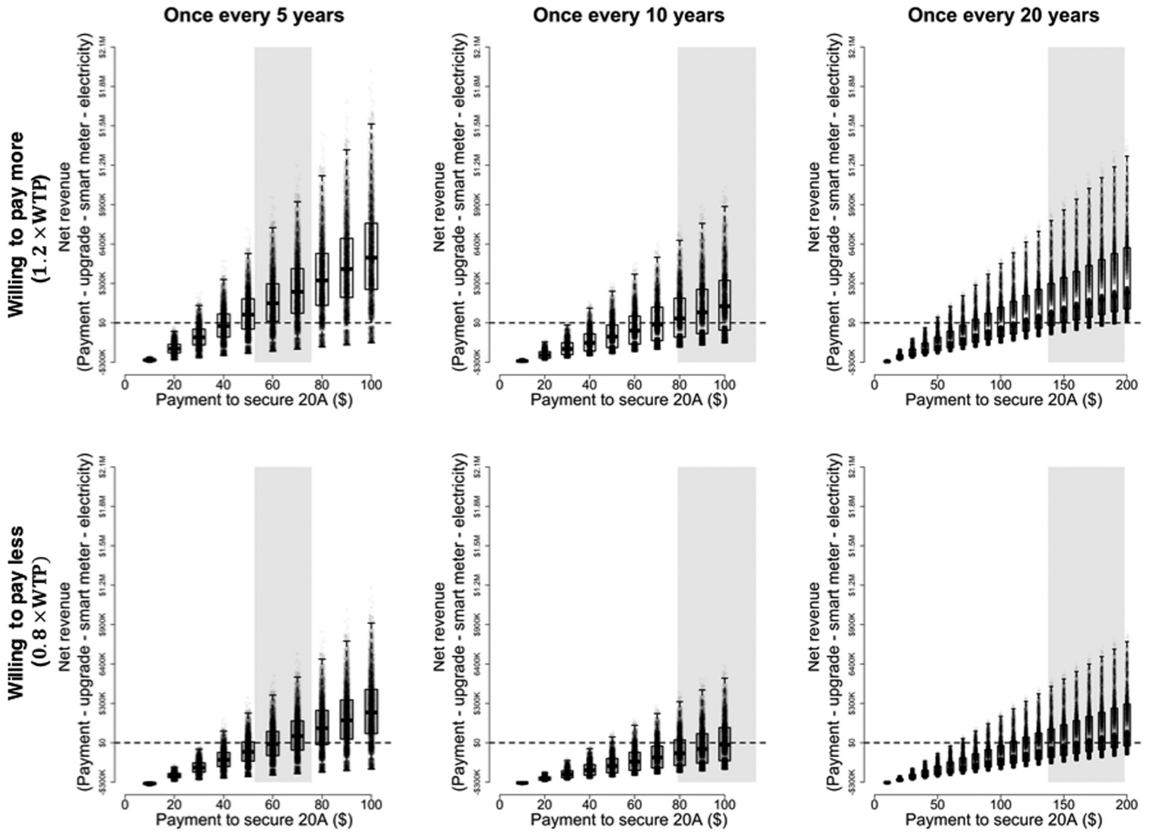

Fig. 4. Results similar to those shown in the upper portion of Fig. 1 in which WTP values are increased by 20% (above) and reduced by 20% (below) given the possibility that the power to neighbors and to local critical social services without emergency power can both increase and decrease individuals' preferences. Here we use the generated Poisson random variables and the truncation explained in Section 2.1. The boxplots show the median, interquartile range, and whiskers at 1.5 times the interquartile range. If a region suffers a 24-hour outage once every 5 years on average, the backup service can be justified at $53–76/customer/outage; for the case of once every 10 years, it can be justified at $79–110/customer/outage; and, for once every 20 years at $140–200/customer/outage.

benefits, which might be large, especially as the duration of an outage increases.

From the forgoing, we conclude that in some communities, a low-amperage backup service can be cost effective if a 24-hour outage occurs at least once every 20 years. Implementing a low-amperage backup service appears to be more cost effective (and certainly safer) than having each homeowner buy a ~$280 portable or standby generator and refuel the generator ($52/outage), even in the case of decreased WTP due to sustained critical social services. As might expected, the results changed when we explored the sensitivity of these findings to the assumptions made to the number of residential customers served by a feeder, the distribution system upgrade cost per feeder, and the cost of advanced smart meter.

2.3. Order of Magnitude Estimates for Longer Outages

In the absence of WTP estimates for longer outages, we can perform a simple order of magnitude calculation to see how the results of Section 2.1 might change for longer outages. For purposes of illustration, we examine an outage lasting 5 days (120 hours), roughly the mean of the large-scale and severe outage durations affecting more than one distribution utility or more than one state (Fig. 1-b).

We consider the three cases: (1) people find strategies to adapt, so that the WTP for a five-day outage is only four times that for a 24-hour outage (Low case); (2) the WTP for a five-day outage is five times that for a 24-hour outage (Middle case); and (3) because it becomes increasingly inconvenient the

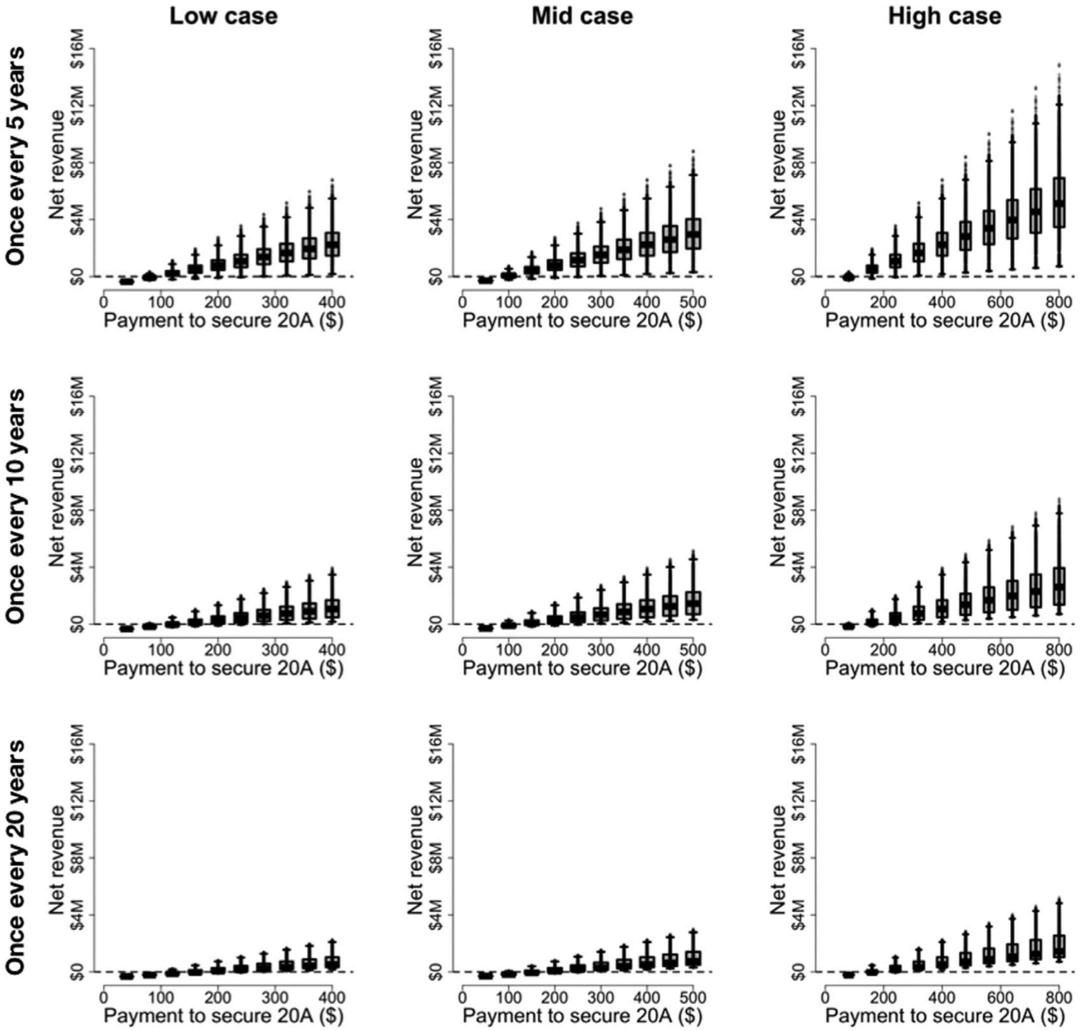

Fig. 5. Plots similar to those shown in Fig. 3 for three outage frequency scenarios for outages of five days assuming low (×4 one day), middle (×5 one day), and high (×8 one day) values of WTP.

longer the outage persists, the WTP for a five-day outage is eight times that for a 24-hour outage (High case). We generate three different sets of lognormal random variables for each case by multiplying the WTP results in the companion paper by 4, 5, and 8 and then refit the lognormal distributions.

Following the same procedure outlined above, Fig. 5 reports the results for a private 20A backup service against longer five-day outages. Compared to the 24-hour outages (Fig. 3), implementing the backup service for longer outages can be justified in more scenarios, and becomes more affordable. If the five-day outage occurs once every 5 years on average, even a service payment around $100 per outage per residential customer (which is the same as $20/residential customer/outage-day) can justify the low-amperage backup service, and includes between 56 and 84% of the residential customers without subsidies. If the outage is expected to occur once every 10 years, a residential customer would need to pay slightly less than $130 per event (i.e., around $26/residential customer/outage-day), and between 43 and 75% of the customers would be willing to use the backup service without subsidies. However, if the outage occurs only once every 20 years on average, each residential customer would have to pay $200/outage (i.e., $40/residential customer/outage-day), and in such case, the service is affordable between only 25 and 56% of the residential customers without subsidy.

Table III. Two Methods to Subsidize the Required System Upgrade Costs to Implement a Low-Amperage Backup Service and the Estimated Electricity Cost per Residential for 24-Hour and Five-Day Outages; the Costs for System Upgrades and Annual Operation and Maintenance are Covered by Tax Revenues, and the Backup Service Provider Only Charges Residential Customers to Cover the Electric Costs; the Electricity Cost is \$9.8/Residential Customer/Day and Each Residential Customer will Pay when there is an Actual Outage at the Interest Rate of 3%, and the Outages Occur at the Mean of the Generated Poisson Random Variables

	Once Every 5 Years	Once Every 10 Years	Once Every 20 Years
Monthly backup service insurance charge	\$0.66/month	\$0.66/month	\$0.66/month
Required subsidy per residential customer (if instead of monthly insurance it is covered as a one-time fee for installation at the beginning of the lifetime)	\$120	\$120	\$120
Expected value of total electricity cost per residential customer during the lifetime (for 24-hour outages)	\$7.6	\$14	\$22
Expected value of total electricity cost per residential customer during the lifetime (for 5-day outages)	\$38	\$69	\$110

In summary, as one might expect, implementing a low-amperage backup service becomes more economically feasible if the region is expected to suffer widespread outages of longer duration. While not reported here, it appears that implementing a backup service to serve both social and private HP demands can be justified without subsidies in most cases. In addition to the monetary benefits, the value of sustaining HP loads for longer outages would be even greater than that for shorter outages. Across most of these scenarios, the 20A backup service is still more cost effective, and certainly much safer than having each individual homeowner buy a small portable generator (~\$280) and fuel (~\$52/day). While the backup service becomes more affordable for residential customers, the payment (from \$75 to \$130, depending on the outage frequency and how much more the residential customers are willing to pay) still imposes a financial burden on low-income households, which are likely to be the most vulnerable segment of the population.

3. EQUITY AND OTHER IMPORTANT CONSIDERATIONS

3.1. Questions of Equity

While some of the variation in WTP in the companion paper is likely due to different assessments of the degree of inconvenience that an outage would produce, some is likely related to ability to pay.(7) Understanding private WTP is important in assessing the viability of backup service; however, an approach that provides a service only to those prepared to pay for it raises issues of social equity. If a community were to implement a system of the sort discussed here, it should cross-subsidize service to very low-income individuals and families that would likely be among the most vulnerable segment of the population.

Here, we consider two different methods to recover the system upgrade costs. Under the first option, the backup service provider adds a very small (<\$1) monthly backup service insurance charge to all customer bills. For some low-income households who are already covered under various financial assistance programs for energy bills, we assume that those programs would also cover the costs for the insurance. The second option is to cover the incremental cost of the upgrade with general tax revenues on the grounds that much of the benefit will accrue to the community as a whole. In such cases, the equity issue is automatically resolved to the extent that taxes and subsidies are roughly proportional to individuals' incomes and wealth levels. In either case, each residential customer would be responsible for paying for power he or she consumes during outages (in our example assumed to be \$9.8/residential customer/day).

Under these assumptions, we conduct a back of the envelope calculation for the low-amperage private backup service against outages. As Table III shows, the system upgrade requires an initial subsidy of \$120 per customer (a one-time installation fee) or \$0.66 per month per customer during the entire 20-year system lifetime. Given that the utilities' fixed customer charge associated with cost of providing grid services for residential customers is ~\$10 per month on average, most would probably view an additional \$0.66 per month to implement a low-amperage backup service to be acceptable.(20)

The table also reports the customer charges for the emergency electricity consumed if the outages occur at the mean of the generated Poisson random variables.

While there are minor differences between the methods of financing the system upgrades and who is directly responsible for supporting low-income and vulnerable people, both methods can be implemented without excessive burden to either residential customers or the region without raising a serious equity issue. A low-amperage backup service can generate nonmonetary benefits that we do not consider in the assessments, which would make backup service more feasible and more advantageous.

Some especially disaster-prone regions might be able to secure funds from federal stimulus and disaster relief programs to cover upgrade costs. For example, in the past, the American Recovery and Reinvestment Act invested $400 million to develop energy assurance plans for natural disasters (Enhancing State Energy Assurance Planning and Enhancing Local Government Energy Assurance program), and the Disaster Relief Fund from the Federal Emergency Management Agency (FEMA) has funded disaster support and mitigation activities.(21,22)

3.2. Other Considerations Relevant to Valuing of Backup Service

Because we adopted the results from the companion paper,(7) all of the preceding discussion assumes that outages occur under circumstances that, while they may be inconvenient and uncomfortable, do not pose a serious risk of death or major property losses. However, there are situations in which such risks do exist.

The WTP values that we employed in this article came from respondents in southwestern Pennsylvania, where electric power is fairly reliable, and only few respondents have experienced long power outages. Results from regions that have suffered more frequent and longer outages (e.g., New Jersey shore, parts of Florida, etc.) might be quite different.

Moreover, outages in extreme winter weather can cause deaths and major property damages (e.g., frozen water pipes). The 1998 ice storm in Québec, Ontario and the northeastern United States blacked out 2.3 million customers (some for many weeks), caused damages of $4.4 billion, and 44 deaths (mostly because of carbon monoxide poisoning).(23) Similarly, extreme heat waves of the sort that hit Chicago in 1995 can be catastrophic. The Chicago event resulted in 700 deaths, mostly among vulnerable populations that did not have air conditioning or could not afford substantially increased electric costs.(24,25) In these and similar situations, such as after a major hurricane, the WTP values discussed above are almost certainly lower bounds since supplying a limited amount of electricity can determine the life and death and the level of injury of people, especially from the vulnerable population groups.

Second, in the companion study, we found that the survey respondents had relatively imprecise preferences, and the information and exercises we provided helped them better translate those into values for WTP. However, in many cases, uncertainty and inconsistencies persisted throughout the study.(7) There are two possible explanations for the respondents' uncertainty: (1) incomplete understanding in the current survey design, and inferences about the scenario beyond what we provided; and (2) a mismatch between a respondent's perceptions and actual situation (such as how extreme they perceive the scenario to be and how different the external environment is compared to what they expected) can also affect their numbers. While we may be able to further reduce some of the cognitive challenges and uncertainty by providing additional help, we cannot completely eliminate uncertainty. Instead, incorporating the inherent uncertainty in respondents' preferences into the analysis and understanding when and how much the uncertainty can change the cost effectiveness of the investments would be helpful to develop resilient decisions.

4. LIMITATIONS OF THIS ANALYSIS

We have assumed that the distribution utility has already implemented a full suite of intelligent distribution automation and that there is already a significant amount of connected DG, some of which can be freed up for emergency use in the event of a large blackout of long duration. In distribution systems for which those assumptions are not true, costs could be considerably higher if needed upgrades are allocated against the emergency backup service. Because of the limited nature of the WTP data available from the companion study our analysis has focused on the choices of individual customers. However, the primary motivation for implementing the system we have outlined is not to deal with the sorts of brief outages that occur regularly in many distribution systems but rather to address issues of individual and collective social vulnerabilities that can result from large long-duration outages in the bulk power system. While we have discussed some of the relevant issues in Section 3, before any community choose to implement such a system, these issues should receive considerably more consideration and elaboration.

5. CONCLUSION

The order of magnitude estimates we have outlined in this article suggest that implementing the ability to provide a low-amperage backup service via islanded distribution feeders may make sense in some regions that face a significant risk of frequent or long outages. While not considered in the analysis, a low-amperage backup service can generate substantial nonmonetary benefits, the value of which will grow as outages becomes longer. However, even in systems that already have smart meters, distribution automation, and DG, upgrades will require investments of ≥$300,000 per feeder. Thus, it will be important to consider the best and most equitable way to cover costs and adequately address equity and ethical issues. Spreading those costs over time in the form of a monthly backup service insurance charge may be one attractive way to cover costs, when such retrofits appear to be desirable.

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