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Reorganizing Power Markets: A Reliability Insurance Business Model for Utilities

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Key Points

A market in which individuals pursue their own self-interest normally maximizes aggregate economic well-being. But households that install distributed energy resources (DERs) in order to obtain savings in their electricity bill impose an external cost on other customers. At scale, their actions can lead to higher electricity tariffs for utility customers and, in the extreme case, a utility death spiral.

In this paper, we propose a market mechanism that may ameliorate this potential distortion based on the creation of a market for risk. Utilities would provide reliability insurance services to households to protect them against the failure of their own DER systems. Creating such an insurance market would allow customers to choose a premium according to their preference for reliability. It could also limit the potential utility death spiral efficiently, as the path would be driven by market mechanisms that arise after reassigning property rights and liabilities between utilities and their customers.

The key findings are:

> Consumers' heterogeneous valuations of risk create the potential to operate a power industry risk market. Regulation can enable this market, removing a utility's obligation to provide uninterrupted services, but only when a customer decides to install DERs. As prosumers, such customers can decide what level of reliability they wish to purchase from the utility.

> A pricing scheme that reflects value creation rather than operational costs could accelerate the transition to a decentralized power system. Such a path would be efficient as it would be market-driven and would reflect consumer preference for reliability.

> High penetration of DER technology could be a reality for Saudi Arabia and its neighbors. Favorable irradiation conditions for solar photovoltaics and phased removal of subsidies for competing fuels may not be sufficient on their own. Developing a regulatory and business model that provides a long-term role for incumbents and others using the utility platform could help avoid the potential for conflicts and disruption in the electricity market.

Summary for Policymakers

The idea that individuals pursuing their own self-interest lead, in aggregate, to maximizing overall economic well-being may not apply in traditional retail electricity markets because of unseen distortions. Households that install distributed energy resources (DERs) seeking to save money in their electricity bill, impose an external cost on other customers. If it is not accounted for, this action can lead to higher electricity tariffs for these other customers and, in the extreme case, a utility death spiral.

DERs – a combination of photovoltaic panels, batteries and demand response – allow consumers to generate, trade, reduce, and shift their electricity consumption, largely bypassing traditional utilities. Regulated utilities recover their costs through tariffs based on a combination of the amount consumed and a monthly charge for recovering the fixed costs plus a regulated profit. This tariff structure, however, is only viable as long as the implicit regulatory compact between utilities and customers holds: the utility has an obligation to provide connection to the grid and supply electricity, and the customer can only buy electricity from the utility. This has allowed redistributive policies to reduce the cost of supply for the lowest consuming, often poorest, customers by passing some of the fixed costs into the variable component and recovering them through a slightly higher price per kilowatt-hour than the true marginal cost of supply.

Installing DERs breaches this arrangement as net-metering consumers are able to reduce their electricity bill by avoiding variable charges. Lower sales reduce that share of the variable charge that 'should have been' in the fixed fee and jeopardize utilities' ability to build and maintain generation, transmission and distribution capacity to provide reliability through the grid.

In this paper we propose a market mechanism that can ameliorate these distortions. We propose the utility can offer 'last resort' power – an insurance – to energy self-sufficient households to protect them against the prospect of a blackout. Creating such an insurance market can limit the potential utility death spiral in an efficient way as the market mechanism would allow the customers to reflect their preference for reliability and pay accordingly. To achieve this, the regulations would need to remove the obligation of utilities to supply those customers that opted out of the 'full service' supply package. This solution can also help to reduce the divide that would exist between those who can afford to adopt these technologies, arguably the well-off, and those who cannot, the economically vulnerable.

Introduction

The fundamental structure of energy utilities and their relationships with their customers have long remained unchanged, even in cases of market liberalization and/or transfer from public to private ownership. However, the emergence of new distributed energy technologies (DERs) (a combination of solar panels, batteries and information technologies) poses a threat to the use of and reliance on centralized generators and the grid – the bedrock of vertically integrated and competitive markets alike. DERs enable consumers to generate and trade their electricity, and to reduce and shift their electricity consumption, giving them the potential to become, in some cases, electricity self-sufficient and even electricity independent.

This paper examines the current organization of the electric power industry and the concern that the rapid and substantial deployment of DERs by consumers pursuing their own self-interest does not necessarily lead to maximizing overall economic well-being. Households that install DERs seeking to lower their electricity bill impose an external cost on others in the system.

Regulated utilities recover their costs through tariffs based on the amount consumed, with a fixed monthly charge for recovering the fixed costs, plus a regulated profit. The variable component of the tariff should reflect the true marginal cost of operation – predominantly fuel – however it is often higher. This creates a redistribution with poorer customers paying a smaller price per kilowatt-hour (kWh) than wealthier, larger consuming customers. DER owners do not pay the utilities for the part of their demand that is met by their own system, enabling highly self-sufficient net-metering consumers to reduce their electricity bill by avoiding paying the component of fixed charges that was included in the variable tariff. If regulators allow these costs to be passed on in higher tariffs, it increases the incentives for more customers to install DERs. However, if the utility is forced to swallow these costs, it can challenge its continued viability.

Wealthier households and commercial customers are in a position to choose to install DERs for their private benefit regardless of their impact on the system. Their action could reduce the volume of utility sales, making it harder for the utility's ability to recover the costs of supplying electricity, to the point where it results in a 'death spiral.' It is possible that electricity tariff schedules would rise to a point where it was cheaper for customers to disconnect entirely, leading to an overall system cost that was higher than the one it displaced. In the absence of a viable business model, utilities would not be able to provide reliability through the grid, which is the lowest cost means of doing so for the vast majority of customers.

We propose a market solution to ameliorate these distortions. Removing the utility's obligation to provide services to those who choose to install DERs opens the potential for both parties to negotiate (or more realistically for consumers to choose from an à la carte range of reliability and service offerings. The utility can offer last resort power – effectively an insurance product – to self-sufficient net-metering commercial and household customers to protect them from the prospect of a blackout. Utilities could repackage and reprice those assets that become idle as a result of DER installations as 'reliability insurance' – a service currently embedded in electricity provision and often taken for granted. The idea is that instead of selling commoditized kilowatt-hours (kWh), utilities would sell guaranteed services. Utilities would then charge a fixed fee to guarantee a stable revenue stream, instead of relying on dynamic pricing in which they levy high prices during abrupt demand surges.

Creating an insurance market could limit the potential utility death spiral, and the 'deoptimization' of the energy system that results from deploying DERs behind the meter, by introducing a market mechanism that reflects consumer preferences for risk. This transition would be efficient as it would make most use of the installed infrastructure. The social loss of creating potentially redundant generation and distribution capacity is discounted as a sunk cost. Because the path would be market driven, it would reflect consumers' preferences for reliability, and an equilibrium would, in theory, be reached at the point where installed capacity provided the level of security desired by the market.

Most literature on disrupting DERs focuses on the gradual penetration of new technologies, and incumbent players' attempts to deter the erosion of their market shares. This paper takes a different stance and assumes that this penetration is either inevitable or has already occurred. The value of this approach is to start from the end, see the salient features of the problem and figure out the steps back. Following Baden-Fuller et. al. (2010), the paper presents the architecture of a static insurance business model for utilities in a way that is simple enough to provide insights into a hypothetical scenario. It then analyzes the properties and limitations of the insurance model and provides suggestions on pricing, the role of regulation and possible consumer behavior. To the best of the authors' knowledge, this is the first analysis of this type of business model for utilities.

Context

Currently, electric power utilities have varying structures in different economies. A utility can be publicly (municipal and cooperative) or privately owned. It can have a vertically integrated or liberalized market for generation and retail, and its geographical coverage can be local, regional, or national. The number of utilities in any given country can vary widely: In the United States (U.S.) there are roughly 3,000 utilities, while other countries have only one. Much of the analysis in this paper focuses on vertically integrated, regulated utilities.

These types of utilities are usually regulated as natural monopolies. The key characteristic of a natural monopoly is to have declining average costs – the cost of serving an additional customer or an additional unit of demand is lower than the average cost. If marginal costs are lower than average costs throughout the relevant segment then marginal cost pricing does not lead to cost recovery (Average Costs [AC] > Price [P] when P = Marginal Cost [MC]). Regulators are faced with striking a balance between achieving efficiency (getting closer to P = MC) and cost recovery (getting closer to P >= AC).

In practice, regulation has focused more on adequate utility compensation than efficient pricing. The cost of service regulation focuses on calculating the total utility cost that needs to be covered by rates, given the assumption about the total demand to be met (Q*). To a large extent, this regulation ends up determining a utility's business model. Teece (2010) defines a business model as the way in which firms create and deliver value to customers, and capture part of it to generate a profit. The utilities' value proposition is essentially a commodity sales business model: to sell energy at a higher price than the cost of generation. However, if regulators either overestimate the return on capital used to calculate the price to be paid to the utility or allow more investment in the infrastructure than is required, a utility may over-invest to maximize their return on additional capacity, transforming their business into one of infrastructure. This is the Averch-Johnson effect: any input that is overcompensated will be overused (Averch and Johnson 1962).

New DER systems in the domestic market could reduce the volume of utilities' sales, failing to achieve the desired Q* to cover costs and generate profits. This could result in a 'revenue erosion' effect. Existing research has studied this effect in different ways, from assessing the likelihood of a utility entering into a 'death spiral' due to the penetration of domestic solar panels (Muaafa et al. 2017), to proposing strategies to address the threat of DERs to utilities. These strategies comprise a range of responses, including dismissing the problem, self-cannibalization (establishing a subsidiary to compete directly against the core business), and instituting new roles for the incumbent player, such as orchestrating the deployment of new technologies (KPMG 2015; WEF, 2015; BCG 2016).

These suggestions appear insufficient, however, to solve the problems presented by the disruptive nature of DER technologies and the fundamental changes facing the power sector as a result. Electricity has multiple value streams that are a) difficult to monitor, b) have different significances for different actors, and c) are difficult to capture and compensate the utility for (Foxon et al. 2015). To some extent, disruptive technologies help to overcome the problems associated with capturing and revealing complex values (Hall and Roeslich 2016). Technology may be a more important determinant of business models than regulation. Technology choice and business model design are iterative and interdependent. New utility business models may be based on technological innovation and regulatory adaptation (Fuentes-Bracamontes 2016; Meletiou et al. 2018).

New regulatory and business models focused on services rather than selling commodities have so far been largely conceptual (Satchwell and Cappers 2015). This paper aims to address this gap by leveraging Helms' (2016) asset transformation proposal. Asset transformation shifts tangible assets into intangible assets as major input factors for the value proposition and change in underlying business models. Regulatory and business models within this framework require a fundamental shift in pricing away from commodity sales ($ per kWh consumed). Or, as Lehr (2013, 50) puts it, a move away from the question of "have we paid the correct amount for what we got?" to "are we paying for what we wanted?"

Micro-Foundations of a Service of Last Resort

It is easier to obtain meaningful insights from a model when it is simple enough to be transparent. This paper makes the following assumptions to establish the analytical context (see box 1 for the justification of these simplifications):

Households want to have power provision 100 percent of the time, at the lowest cost to them, while they maximize their level of electricity independence.

All households install large amounts of solar photovoltaic (PV) panels and batteries overnight, which allows them to be power independent. All electric generation capacity would be small-scale DER, with storage at the residential level.

Utilities are entitled to cut households off from their network if they no longer wish to commit to using their services.

The probability that solar-plus-battery systems will fail due to technical or weather-related issues can be anywhere in the range $0<\phi<1$. This risk is inherent to all intermittent forms of generation.

Households cannot buy power on the spot market to fine tune their demand and supply, either from electricity firms or other households. This assumption allows the analysis to focus purely on risk management strategies.

For simplification, the analysis omits commercial and industrial users. These larger-scale users are equally as important as residential users but differ significantly in their needs and possibilities with respect to DER adoption and the ability to participate in wholesale electricity markets.

Box 1. Validating the main assumptions/simplifications

1. A sudden penetration of DERs is not unrealistic. The rapid transformation of industries has occurred in other sectors – consider Uber for the taxi industry, and the iPod for the music sector (CNN 2013). However, there has not yet been a rapid transformation of the power sector (Fouquet 2010). The introduction of Uber and the iPod occurred very fast and made a large portion of the incumbents' business assets obsolete. DERs, if deployed on a large scale, would similarly disrupt the electricity market because they would be installed in addition to the 'formal' sector.
2. Drivers of energy independence include consumer preferences for local renewable energy solutions, independent of the energy industry, and for autarky, perceived or realized (Rickerson et al. 2014). This paper argues that households have a preference for independence, alongside lower cost and greater reliability.
3. Becoming electricity-independent could be possible. Bronski et al. (2015) suggest that PV and batteries together may trigger mass grid defection of customers in the long run. Luthander et al. (2015) find that independent generation for self-consumption can be increased by between 13-24 percent using 0.5-1.0 kWh storage per kW of installed PV capacity.

4. While some households may not be able to install a PV panel because they live in apartment buildings, they could have a stake in pooled/community solar farms and, in that way, the assumptions of this paper would hold.

5. Postulating that utilities are not obliged to provide power once a household is declared independent allows a focus on pure risk management considerations. Households would be forced to reveal their preferences for protection against catastrophic scenarios. The analysis of this paper would have been biased had it assumed that utilities would still be obliged to supply power, as consumers' willingness to pay would be influenced by their initial endowment or property rights (Hanemann 1991).

6. There is a practical reason for not allowing spot market trade from third parties: households' abilities to hedge against catastrophic events is limited because their neighbors face the same profile load. Households could hedge against small variations in their generation but not for the impact of major events.

7. The advantage of transferring risks to a firm specializing in risk management is that they know how to allocate risk better. This transfer of risk would make an efficient distribution of risk throughout society more likely. Risk pooling is what makes an insurance business viable.

Cost structure

The rapid and large-scale deployment of DERs has left utilities with stranded assets, but their cost structures have not changed. Utilities have relatively low variable costs and large capital costs, which are largely sunk costs. For firms whose fixed costs cannot be recovered by some price levels below the minimum of the short-run average cost (AVC), the lost revenue might be greater than the costs that they would avoid if they elected to cease trading. As such, these firms would be better off continuing to operate in the short run.

Alternative models

In this scenario, the utility has to choose between developing a new business model and ceasing to operate. If the utility can reinvent itself by offering new services, it needs to determine the nature of these new services and how they are paid for. A business model is, in essence, the way in which an organization delivers value to customers, encourages customers to pay for value and converts these payments into profit (Casadesus-Masanell and Ricart 2010).

For the sake of argument, assume the utility has two mutually exclusive business model options:

1. The insurance model.

When the utility has no obligation to supply 'independent' customers and suddenly has excess installed capacity, there is a latent market of insurance through which to trade the risk of power outages from households (the pool) and the utility (the insurer). In this option, the utility sells subscriptions for insurance that bundles power and time factors, which would guarantee availability during periods of blackouts.

2. A 'power-only' model.

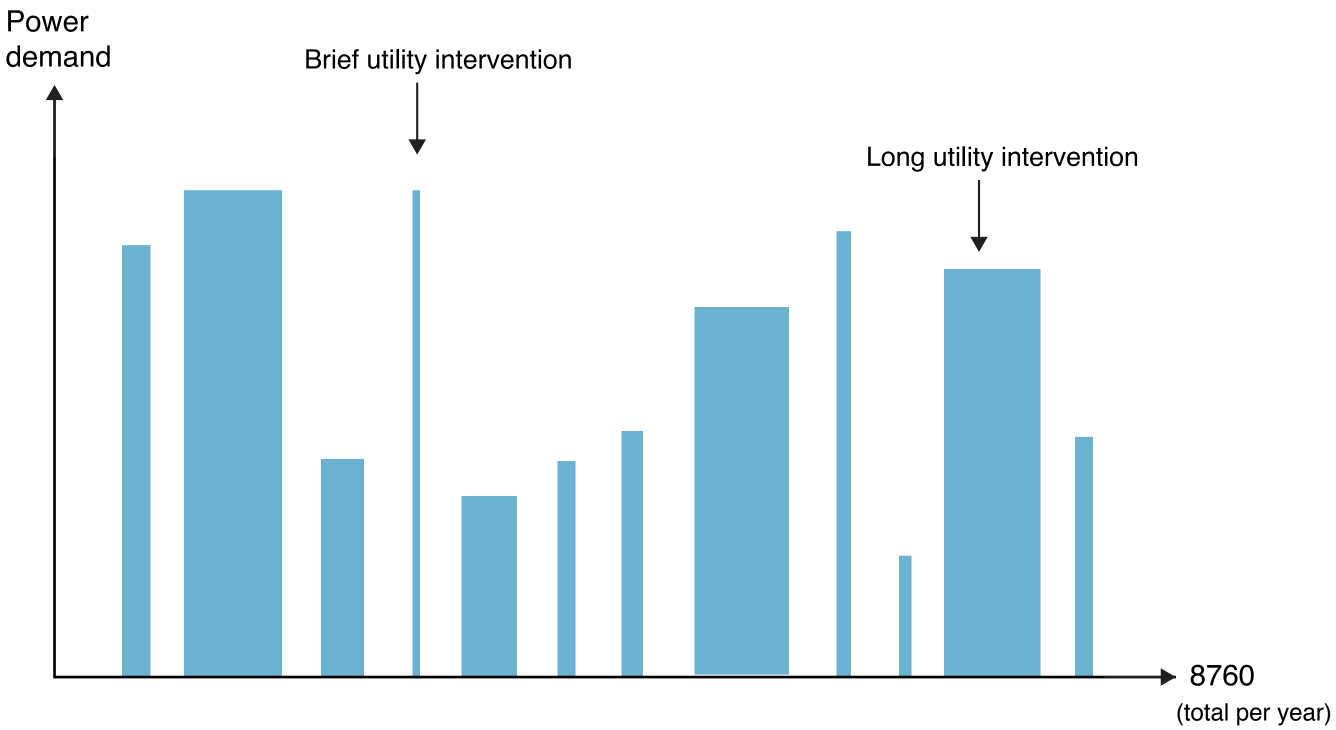
In this model, the utility sells power to households when they face a blackout. If a large number of households demand energy, such as in the case of sudden adverse climate conditions, the utility can charge a high price, while the price would remain low if the aggregate demand of households was low.

The insurance business option becomes more attractive to the utility when the net present value of the revenue from the insurance business stream is equal to, or higher than, the net present value of the revenue stream from the power-only market. If revenues from the two business models are equal, the insurance model would still be preferable as revenues would be paid upfront (see Appendix 2 for a mathematical description).

Characterization of demand

The utility would observe surges in demand on occasions when household power systems failed. Surges could be prompted by individual household system failures or by more systemic events, such as a run of overcast days reducing the effectiveness of storage. Figure 1 shows the annual frequency of such demand surges. The vertical axis shows the amount of power households would demand beyond their independent capabilities, while the horizontal axis represents the total

Figure 1. Blackouts mirror: stylized demand for power of last resort.



Source: KAPSARC.

number of hours during the year. The widths of the columns illustrate the timeframe of power demand: a wider column represents longer periods of demand resulting from increased systemic events, while a thinner column represents shorter periods of demand resulting from more localized events.

This study assumes power surges are independent events (non-systematic risk) so that demand for power from utilities is random. Demand would be unexpected and infrequent, as consumption patterns reflecting usual variations such as day and night, weekday and weekend or the season of the year would not apply. This demand profile would, therefore, be suitable for risk pooling.

Pricing risk

If the utility opted for the insurance business model, electricity would cease to be a commodity, i.e., a generic good traded at the same price to all households. Contracts could be tailored for each household based on their attitude to risk.

Prices would be determined by each household's willingness to pay (WTP) to provide a backup service, as per equation 1.

$$WTP_i < \alpha_i \pi_i * L_i \tag{1}$$

Where L is the potential loss, π_i is the probability of incurring a loss and α is a constant that captures the attitude towards risk. A risk neutral household would have $\alpha = 1$, while for a risk averse household it would be $\alpha \geq 1$. This means that risk averse people would be willing to pay more to avoid the possibility of loss (Einav and Finkelstein 2011).

The risk premium, α, is what the policyholder pays for the transfer of risk to the insurance company. The utility would also need to estimate its own version of equation 1. This study estimates the loss expectancy facing an insurer as the annual rate of incidence of insurance claims (likelihood of occurrence) multiplied by the expected financial value of a single claim during this period (severity of occurrence). The pricing of α, the base (or average) premium, is adjusted up or down depending on the perceived risk of the household.

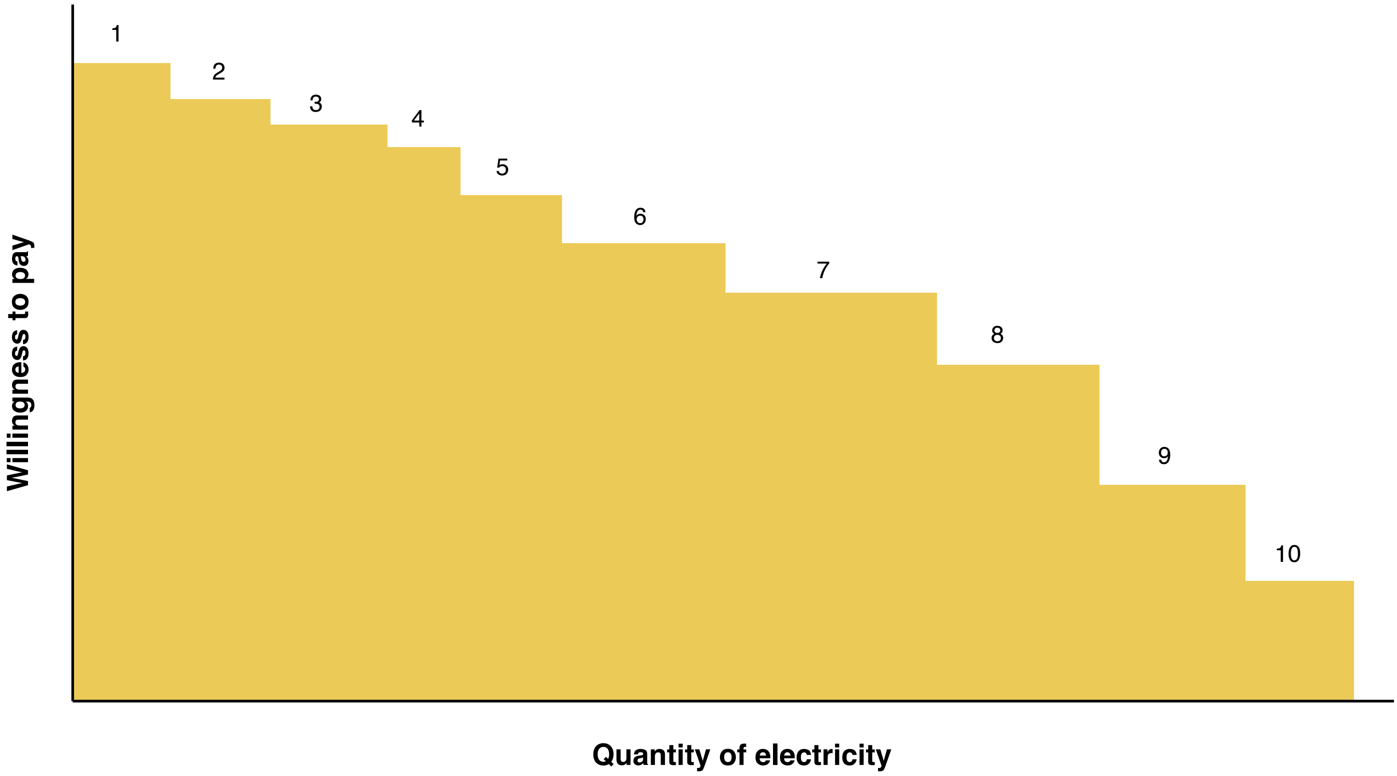
Thus, as long as $WTP_i < AVC_t$, there is a market for insurance in electricity, as the willingness to pay represents demand and the variable cost represents supply. All households could be ranked according to their willingness to pay for electricity insurance, creating a demand curve with a negative slope. This finding is consistent with a Coasian approach to market design, in which a reassignment of property rights can create a market (Coase 1981).

Figure 2 presents this idea for 10 heterogeneous households, showing that each household has a different willingness to pay and a different electricity-of-last-resort demand, depending on its preferences and income.

Budget constraints and household preferences

This section examines why an independent household would pay for a service of last resort. Risk aversion is not the only variable required to determine the demand for coverage against a power shortage. Even if a household were risk-averse, a new insurance contract would compete against other goods and services for budget allocation. This section illustrates how wider preferences and budget constraints determine insurance demand, using the word 'welfare' instead of the economic concept 'utility' to avoid any confusion with electricity utilities.

Figure 2. Illustration of potential demand from 10 households for electricity insurance.



Source: KAPSARC.

As an example, the representative household has an income of \$100 and spends \$90 on consumption *(C = 90)* and \$10 to generate electricity through the DER system *(E = 10)*. The electricity is used for air conditioning, heating and cooking, among other uses, and has a positive impact on the welfare of the household.

Weather conditions constrain power production from the DER system, lowering the total welfare of the household. This is an inherent risk associated with all intermittent forms of generation. This analysis assumes that this credible contingency event has a probability of 10 percent. As a result, the expected welfare of the representative household is a weighted combination of two situations: the welfare in 'normal conditions' and the welfare in 'bad times,' when the DER fails to deliver sufficient power.

In other words, the expected welfare, $\mathbb{E}\overline{W}$, of the household is the following:

$$\mathbb{E}\overline{W} = 90\% * \text{welfare in ideal operating conditions} + 10\% * \text{welfare in constrained operating conditions} = 90\% * \text{welfare} (C = 90, E = 10) + 10\% * \text{welfare} (C = 90, E = 0) \quad (2)$$

DER households may have four broad options to deal with this risk in a liberalized market environment:

- Over-invest in PV and/or batteries.
- Sign a backup contract with a third party.

- Opt to live with power shortages during constrained operating conditions.
- Buy from the spot market.

The household will compare each alternative and will opt for the one that maximizes its welfare, subject to budget constraints. In practice, this may involve a combination of any of the four options. The challenge for the household, then, is how to balance exposure to an uncertain power supply with the cost of managing that uncertainty. The first option would imply an inefficient allocation of resources in cases where there are less expensive options to mitigate against this risk. In the second, the household has to reduce its consumption of other goods in order to buy insurance. In the third case, household welfare is reduced in the event of a power shortage. In the fourth option, households may have insufficient flexibility at the time to manage a substantial shortage of power, or limited capacity to reduce their electricity consumption over time. This insufficient flexibility reflects the associated financial costs and relative inelasticity of demand.

If uncertainty were eliminated actual welfare would be:

$$W^* = 100\% * \text{welfare } (C = 90 - \text{insurance cost}, E = 10) \tag{3}$$

How much is the household willing to pay to avoid the costs related to a failure in their DER system or bad weather conditions? To evaluate both alternatives, the household would be expected to make decisions consistent with applying equations 2 and 3. This analysis assumes that the household has no preference for either of the two alternatives ($E\bar{W} = W\hat{}^*$) if the cost of the insurance is \$5. If the cost of the insurance is below \$5 then $E\bar{W} < W\hat{}^*$ and the household would find it more attractive to buy it. In this situation, an opportunity exists to develop a new product or service to help meet this latent demand. This may prove profitable for incumbent utilities or other market participants. The example given here assumes that the household is willing to allocate up to \$5 of its income to electricity insurance, at the expense of general consumption which is reduced to \$85.

The other alternative is a flexible backup contract that enables power to be purchased as required. The household faces two mutually exclusive situations: 'normal conditions' when the DER system functions well and 'bad times' when there is no electricity due to adverse weather conditions or technical problems. This analysis assumes no uncertainty. In bad times welfare would be:

$$W^F = 100\% * \text{welfare } (C = 90, E = 0) \tag{4}$$

In this case, the utility could offer electricity to the household. However, the household would only buy that electricity if welfare was higher than W^F. This situation is expressed as follows:

$$W^{**} = 100\% * \text{welfare } (C = 90 - \text{cost of electricity in spot market}, E = 10) \tag{5}$$

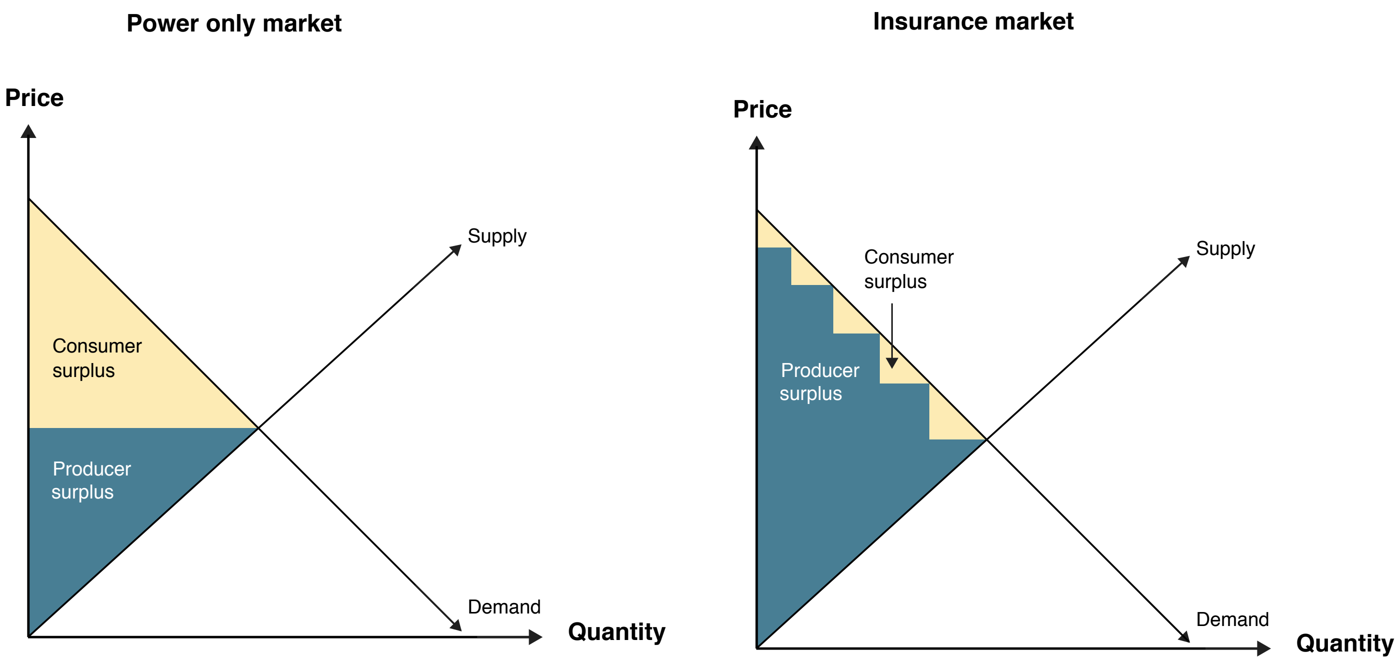
Again, the household will use the information from equations 4 and 5 to evaluate both alternatives. Assuming that the cost of electricity that makes both equations identical $W^F = W^{**}$ is \$15, the household would buy electricity in the market if the spot price fell below \$15, again creating an opportunity for the utility. This implies that the household has no preference between a scenario where it consumes \$90 and gets no electricity and a scenario where it consumes $75 and gets the same amount of electricity from the grid as it would have obtained from the DER in normal conditions.

The utility-insurer profit maximization strategy

To maximize its revenues, a utility would need to identify a household's attitude to risk to be able to charge higher prices to those willing to pay them. For example, a financially strong and risk-averse household could be expected to buy a more comprehensive insurance package than a weaker, risk-averse or risk-neutral household. The utility's profit in this case depends on its capacity to capture higher shares of the consumer surplus (see Figure 3 – note that the *y* and *x* axes represent different goods and prices).

The utilities would initially have enough capacity to accommodate any sudden surge in demand from households. Since an insurance contract is based on expectations, not actual power delivered, the utility would need to estimate its annualized expected losses. For a utility offering an insurance service to supply households in case of power failures, this means collecting and modeling, during the period of interest, all data describing every claim (drawing power from the grid), including date, duration, location, amount of power and household characteristics. It would then use the annualized expected loss, which is given by the mean of the distribution, to calculate the base or average premium that households need to pay to be insured. The process would be repeated every year to recalibrate and refine the models, as the utility accumulates historical data.

Figure 3. Consumer and producer surplus under two market arrangements.



Source: KAPSARC.

Contracts

Households can select their risk category where the utility offers contracts with a two- (or multiple-) part tariff that includes a fixed entry cost plus variable incremental coverage (Veiga and Weyl 2016; Weyl 2010). Hence, this model contract uses a fixed access fee and variable fees for extra coverage. Brousseau and Glachant (2002), Ho and Zhang (2008), Richter and Pollitt (2016) and Harford (2017) discuss these types of two-part tariffs and their economics.

A contract with a low fixed fee and high extra costs would possess similar characteristics to an energy-only spot market, while a contract with a high fixed fee with low extra costs would look more like typical insurance. If the events are frequent or predictable, the insurance business model would resemble an energy-only business model where the utility charges very high prices for an expected number of events.

Just like an insurance company that offers cover for unanticipated economic and non-economic losses, ranging from car and home insurance (property damage or loss), to life and health insurance (death and illness) and even retirement income (guaranteed pension annuities), there is a range of value of loss loads for domestic customers based on the timing of the hypothetical outage. Therefore, extra coverage could include:

- Time of day when the electricity has to be supplied.
- Season of the year.
- Number of events per year.
- Fixed quantities per event or variable quantities.

Implications

Regulatory

This analysis provides several insights for policymakers. The first is that this market can be created using a Coasian approach where the regulator assigns — or in this case, reassigns — property rights from the consumer (the right to be connected) to the utility (no longer any obligation to connect). A household's 'independence' from the utility breaches the implicit social compact between electricity consumers and utilities (Boyd 1998). This social contract is premised on the understanding that utilities meet consumers' energy needs — whatever they are and whenever they arise — and consumers in aggregate pay for this. This contract applies to vertically integrated utilities and firms in liberalized markets. Power generators are not obliged to bid to the system operator in liberalized markets but customers are still entitled to connect to the grid, and the distribution company has to serve them. When the extent of free-riding on the system's ability to provide reliability by those who have installed intermittent DERs gets too high, the social compact is at risk. Customers who cannot afford to avoid the variable portion of the electricity tariff may decide they will not pay to subsidize the wealthier consumers and demand a change.

A new social compact between utilities, regulators and the public needs to be forged (Lehr 2013) but would be difficult to achieve. Consumers generally feel entitled to secure supply and many may oppose the idea of having to pay extra for it. Value of lost load (VoLL) calculations demonstrate this: The maximum consumers are willing to pay for more reliable services is less than the minimum they are willing to accept in payment for a less reliable supply (OFGEM 2013).

The proposal of this paper, however, is for the creation of appropriate property rights that can drive efficient and innovative behavior consistent with the governance of the sector. This means clarifying roles, responsibilities and accountabilities within a legal framework that provides comprehensive coverage and enables effective enforcement. Prior to the Public Utility Regulatory Policies Act (1978) in the U.S., U.S. utilities were not required to provide standby power services to self-generators, and it was unclear whether utilities were obliged to interconnect consumer-owned generators to the distribution grid at all (Wellinghoff and Weissman 2015).

Wellinghoff and Weissman (2015) argue that individuals have the legal right to generate electricity on their property for their use while still being connected to the utility's local electric distribution system. They base their argument on the common law tradition that property owners have the right to utilize the benefits of their property so long as, by doing so, they do not cause third-party damage or inflict a cost on society. Moreover, U.S. regulation mandates utilities to provide services at the lowest feasible costs and to take advantage of all available cost-saving opportunities. The proposed insurance business model is an attempt to address the costs that such self-generators impose on the system and society in general, in a way that is equitable.

The problem arises when lowering private costs does not necessarily translate into lower system costs, as one would expect in a centralized system; lower household electricity bills do not automatically translate into a more efficient electricity sector. A higher penetration of DER technology raises the cost of maintaining a high-capillarity electricity network and makes universal access to electricity more expensive. Increasing penetration of DERs might, therefore, create a technological divide in which wealthier customers enjoy the benefits of these technologies, placing the burden of maintaining demand from the grid on poorer consumers. Such a shift would challenge the ability of utilities to provide electricity reliably through the grid.

Based on the Coase theorem, parties can achieve an efficient outcome if they can negotiate among themselves, regardless of the source of the externality (Coase 1981). They would therefore achieve efficient levels of reliability, measured as the cost/value ratio, regardless of who has the property rights. This argument would justify the creation of a reliability (insurance) market in the electricity sector.

The second implication for policymakers is that creating an insurance market could accelerate the transition to a distributed power sector efficiently, if that is the policy objective. Bardt et al. (2014) argue that the economic potential of independent generation for self-consumption strongly depends on the regulatory framework, including market rules and related governance incentive structures. This transition would be efficient once the social loss of having redundant capacity is discounted. The market would reflect consumers' preferences for reliability and equilibrium would be reached at the point where installed capacity provides the level of security the market desires. The potential drawback, however, is that markets could underprovide reliability products or services due to the public good and free rider characteristics associated with the provision of electricity security. This may imply some limitations on the role of markets in this space.

Industry

Electricity can learn from industries such as telecommunications. Offering many options that reflect the heterogeneity of consumers' preferences can be incorrectly misinterpreted as beneficial for consumers. This is apparent in mobile phone packages and remedied through telecommunication regulation (Ayal 2011; Bar-Grill and Stone 2012; Bar-Grill 2006; Oseni and Pollitt 2017; Ulset 2002). Firms could potentially abuse their position of power, given that one important enabler of this market is the ability to discriminate demand. Contracts could be designed to shift a share of the consumer surplus to the producer. In the power-only market all consumers face the same price for one product, but in the insurance market consumers pay different prices for differentiated goods. Figure 3 illustrates this point.

Electricity firms could also borrow some elements from the insurance industry. Insurance companies have to be able to distinguish between systematic (global) risk and non-systematic (local) risk if they are to be profitable. This is because only non-systematic risk is diversifiable and can therefore be pooled. Utilities will need to consider all potential sources of systematic risk, including those that arise from operating in a small geographical area (e.g., weather conditions affecting all households equally). Local or regional utilities could pool together into a wider geographical area to diversify these risks. Alternatively, a national system operator could act as a 'reinsurer' to the local utilities in a similar way that insurance companies pool together and transfer the pooled risk to reinsurance companies (see IEA/OECD 2005 for more discussion on the system risk associated with greater regionalization of power systems and markets).

Utilities would need to monitor the behavior of households to avoid adverse selection and moral hazard. Adverse selection happens when observed risk (utility perspective) and actual risk (household perspective) do not match. As a result, utilities will be unable to distinguish between either risk accepting or risk-averse households who hold different expected losses and preferences, leading to high-risk households paying lower premiums than they should. This would occur if households changed their behavior so that it altered the frequency of risk events, for example by saving on maintenance or deliberately cutting off their local electricity supply. To minimize moral hazard, the utility, as an insurer, could include deductibles and limits to coverage and sell insurance policies that incentivize households who can demonstrate that they regularly maintain their electricity system.

How Has the Industry Managed Risks so Far? What Is New?

Traditional electricity markets have dealt with uncertainty in different ways. Capacity payments are arguably a system-wide type of insurance in some liberalized markets. Governments decide how much total grid-system connected capacity is required to meet peak load, taking into account the risk of the wind not blowing and the sun not shining. Consumers' perceived VoLL, an economic value of a non-market good, and their willingness to pay for secure electricity are inputs likely to factor into the calculation of security of supply. This calculation could be used for setting capacity levels and calculating costs in and cash out. The literature on VoLL, however, recognizes the practical difficulties and the theoretical limitations associated with the public good character of reliability and the incentives it gives to free ride. It is difficult to identify those customers who experience an outage by their willingness to pay more for a secure supply. The unwanted effect of this way of dealing with reliability is that risk-averse planners are incentivized to set prices high enough to overprotect the system and consumers end up purchasing overpriced electricity. Our proposal is different to capacity payments in two ways: it is, firstly, distributed insurance rather than system-wide insurance. Instead of utilities deciding the VoLL, the insurance market allows consumers to reflect their own VoLL. This proposal is therefore based on consumer choice being influenced by price signals.

Another way to deal with reliability in electricity markets is through 'flexibility markets.' Industry and existing literature have proposed such markets to deal with the situation where intermittent marginal cost renewables replace baseload units. This paper's proposal differs from these markets in three ways. First, its flexibility follows the natural increase in the share of renewables. The second difference is the treatment of time. An insurance market detaches power prices from their time variable, increasing time lags for transactions by charging fixed prices for longer periods of coverage. This decreases the number of transactions and extends the period in which they take place. Conversely, a flexibility market demands more granular decisions, with shorter delta times (Fuentes 2016). Premiums are likely to have a delayed response to changes in the cost of disturbances, which will be influenced by prevailing power prices. The third difference has to do with the starting point. In flexibility markets, utilities are willing to pay customers to increase their flexibility and customers expect coverage all the time. In this scenario, customers would need to reveal their level of willingness to accept occasional service disruptions or pay to avoid them.

An alternative insurance approach, more suitable for wholesale markets rather than for the domestic sector, would be to change the current rules for renewable technology generators, making them fully responsible for managing their intermittency. This approach could be the foundation for an insurance market in which fossil fuel generators secure renewable generators in the case of insufficient clean power generation.

Conclusion

New DERs could reduce the reliance on centralized generators and the grid, challenging the fundamentals of the current paradigm. This paper set out to address questions about the future of the electricity industry: What will its products be? How should they be priced? And how might the relationship with customers change? The proposed insurance market switches the focus from system reliability, where the desired reserve marginal is a technical decision, to a household's valuation of preferences and risk aversion (an economic matter). This market would change the business model for utilities, from providing a commodity to providing a service.

Further issues not analyzed in this study that may have relevant policy implications include the following:

> The utility would end up with stranded assets, generation and networks. These assets belong to a different part of the value chain. The impacts of DERs are likely to differ and therefore different solutions are needed to address these impacts. While more granular analysis is needed in this area, insurance implicitly bundles both assets into the same service, so the business model and regulation need not be separated, just as the inputs in other service industries are not accounted for separately.

> This business model assumes that a static number of households are connected to the grid. It does not deal with issues such as refinancing infrastructure or building new infrastructure. Further work could add a dynamic element to this analysis.

> The analysis presented in this paper is more suitable for a vertically integrated utility operating as a monopoly. There would arguably be more incumbent electricity firms willing to engage in asset transformation if DER penetration occurs in a liberalized market.

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Appendix 1: Microeconomic Foundations of the Insurance Business Model

Indifference condition for business model choice

$$NPV\ Revenue\ energy\ only \leq NPV\ Revenue\ insurance \quad (6)$$

The power-only spot market revenue stream

$$Revenues\ energy\ only = \sum Spot\ Price_t * Quantity_t\ , \quad (7)$$

where

$$Spot\ Price_t = f\ (fixed\ costs, variable\ cost)$$

$$Spot\ Q_t = f\ (installed\ PV, Batteries, risk)$$

Insurance business model revenue stream

$$Revenues\ insurance = Price\ insurance_i * (n * Quantity\ insurance_i\ ) \quad (8)$$

$$Revenues\ insurance = \begin{bmatrix} P_{Neutral} \\ P_{Averse} \end{bmatrix} * [n * Q_{Neutral}\ (1\text{-}n) * Q_{Averse}\ ] \quad (9)$$

Ideal condition for demand discrimination

$$P_i = WTP_i$$

Condition for an insurance market to exist

$$Price_s \geq Variable\ cost \quad (10)$$

Notes

Notes

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About the Project

The Utilities of the Future project focuses on how new distributed energy resources (DER) technologies are transforming customer/provider relationships. Advances in DER and associated costs reductions are providing customers with potentially attractive alternatives to standard electric utility service, perhaps turning them into “prosumers”. Utilities around the world are re-evaluating their business model, and regulators are considering multiple market reforms. The project aims to develop analytical tools and techniques to help address the key market, regulatory and energy policy issues in a power sector with high penetration of DER.

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