



RETAIL ENERGY  
PRACTICE BRIEFING SERIES

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**Evolving Business and  
Regulatory Models in a Utility  
of the Future World**

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## RETAIL PRACTICE BRIEFING SERIES

This brief is the first in a series that analyzes potential utility responses to challenges and trends referred to as the “Utility of the Future” (UoF). A new UoF paradigm is emerging as utilities rethink their future business models in response to the expansion of distributed energy resources, decarbonization goals, declining sales growth, and technological developments. While each of these developments has the potential to disrupt the status quo, they could also provide growth opportunities to utilities and new market entrants. They also raise complex questions concerning how and when to modify, or even completely change, long-standing regulatory practices. A lot has been already written on these topics, but, more often than not, each issue is examined in relative isolation. Our briefing series attempts to examine the UoF from an integrated perspective by examining linkages between the financial, technological, strategic, and regulatory dimensions.

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# EVOLVING BUSINESS AND REGULATORY MODELS IN A UTILITY OF THE FUTURE WORLD

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The rapid penetration of distributed energy resources (DERs)<sup>1</sup> into the electric utility market has led many analysts to argue that the utility business model that has been applied for the last 100 years will no longer suffice, and that a new model is inevitable and needed in the very near term. Their concern is not completely without merit: DERs are changing the supply and demand equation upon which the traditional utility business model rests.

In our view, the emergence of DERs will almost certainly require that some changes be made to the way utilities make resource decisions and recover their costs of providing utility services. However, the degree and rapidity of adjustment depends upon the level of DER penetration.

Small-scale penetration of DERs, or even an upward trend in their adoption, does not mean that the current utility business model is unworkable, at least in the short term. More likely, the traditional utility business model can be adjusted to accommodate initially low or modest penetration of DERs. That said, even moderate amounts of DERs change the landscape for utility planning and require some new methods of analysis and changes to status quo policies (especially pricing), so that as DERs become more attractive, they can be assimilated without disruption. And in the long run, high levels of DER penetration may very well sufficiently disrupt the equation to require extensive revisions.

This brief provides our view of how utilities and regulators should prepare for the transition to the “Utility of the Future” (UoF)<sup>2</sup>. We begin with the key issues that we foresee in the short term, and discuss utility actions in a UoF ecosystem in which DER penetration is low to modest. Next, we provide a perspective on how utilities may operate under a longer-term view, on the presumption that DER penetration is higher and the utility facilitates numerous transactions concerning energy and associated services among DERs, consumers, and the utility itself. Finally, we suggest a pragmatic “middle way” viewpoint and approach, which combines a short- and long-term view. Our view is that a futuristic, highly transactive world will not materialize overnight. Rather, the UoF ecosystem will evolve in stages. Accordingly, we conclude with some steps and planning initiatives that utilities should undertake in order to proactively shape their path to the UoF future.

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1. For this briefing series, we define DERs as being primarily “behind the meter” resources that: (1) generate electricity (including solar PV, small wind, combined heat and power, small hydro) and/or (2) alter customer load (energy efficiency, demand response, energy storage, or community microgrids). In other contexts, DERs also include beneficial electrification.
  2. The Utility of the Future is a widely-applied term referring to the evolving roles and business models for the next generation of electric distribution utilities. Other names include Utilities 2020 or Utility 2.0.



## ADJUSTMENTS TO UTILITY PLANNING

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Most discussions about the future of utility business models have concerned revenue recovery and the impact of a potential “death spiral” on distribution utility rates and earnings caused by declining sales via customer- (or third-party) owned DERs. While the term death spiral is effective in dramatically pointing out a negative feedback loop that works against utility financial health, it is more likely that distribution utilities will begin to see a slight erosion of their control of the resource development process long before they experience a death spiral, if that should come to pass at all. However, they will need to adjust their traditional approach to system planning soon, if they haven’t done so already.

In the past, utilities had exclusive responsibility for determining what power and wire resources were deployed and where, and they based those decisions on cost-effectiveness among alternative system expansions or upgrades that were needed to meet specific, traditional performance obligations. Due to DERs, that type of need-based, self-contained analysis is becoming difficult and may become obsolete. For the immediate future, customers will decide how many (and where) DERs will be placed within the system, and they’ll base those decisions on their own benefit-cost calculations, in turn based on the cost of DER assets and prices paid to DERs by the utility. This is quite a change from the model in which the utility was in charge of resource decisions. Such loss of control, even if slight, represents a significant cultural shift for utility managers, who have been trained (and have resource planning systems) to optimize supply to meet expected demand with an emphasis on cost-effectiveness.

While traditional performance requirements will still have to be met, deciding how to support (or participate in) these new technologies requires utilities to modify their traditional cost effectiveness tests with a new benefit-cost analysis (BCA) calculus responsive to regulatory requirements that utilities incorporate customer-sited DERs and customer preferences into their system planning.

New BCAs should directly or indirectly take into account:

- Non-system benefits from DERs as sources of value in evaluations, possibly including positive social externalities such as environmental and macro-economic effects;
- Optimal timing and approach to adopting system improvements, given the ongoing improvements in the costs and performance of both DERs and smart grid platform technologies (i.e., determining when a technology is smart or cheap enough);
- Optionality modeling of how a current upgrade in infrastructure could either enable, or impede, future improvements;
- Constraints based on the incidence of cost shifting from DER-participating customers to non-participants; and
- Consideration for allowable obsolescence and stranded cost recovery of still-viable technologies that no longer provide benefits commensurate with the latest technologies.

The new BCA framework will also need to take geographical differences into account. Inevitably, benefits from DERs will not be uniformly realized throughout the system because they will tend to be local and may be adopted primarily by certain subsets of customers. It is highly likely that DER development will be much more concentrated on subsets of distribution system areas<sup>3</sup> and on certain types of customers or load shapes, more so than addressing all customers or regions equally. This trend conflicts with the past practice of averaging the costs of providing electric distribution services across the system. This approach made sense in the past, but perhaps not so much going forward. Price signals from the utility will be very important in focusing investments in DERs to the geographic areas where they provide the greatest benefit to the system.

## ADJUSTMENTS TO TRADITIONAL REVENUE RECOVERY

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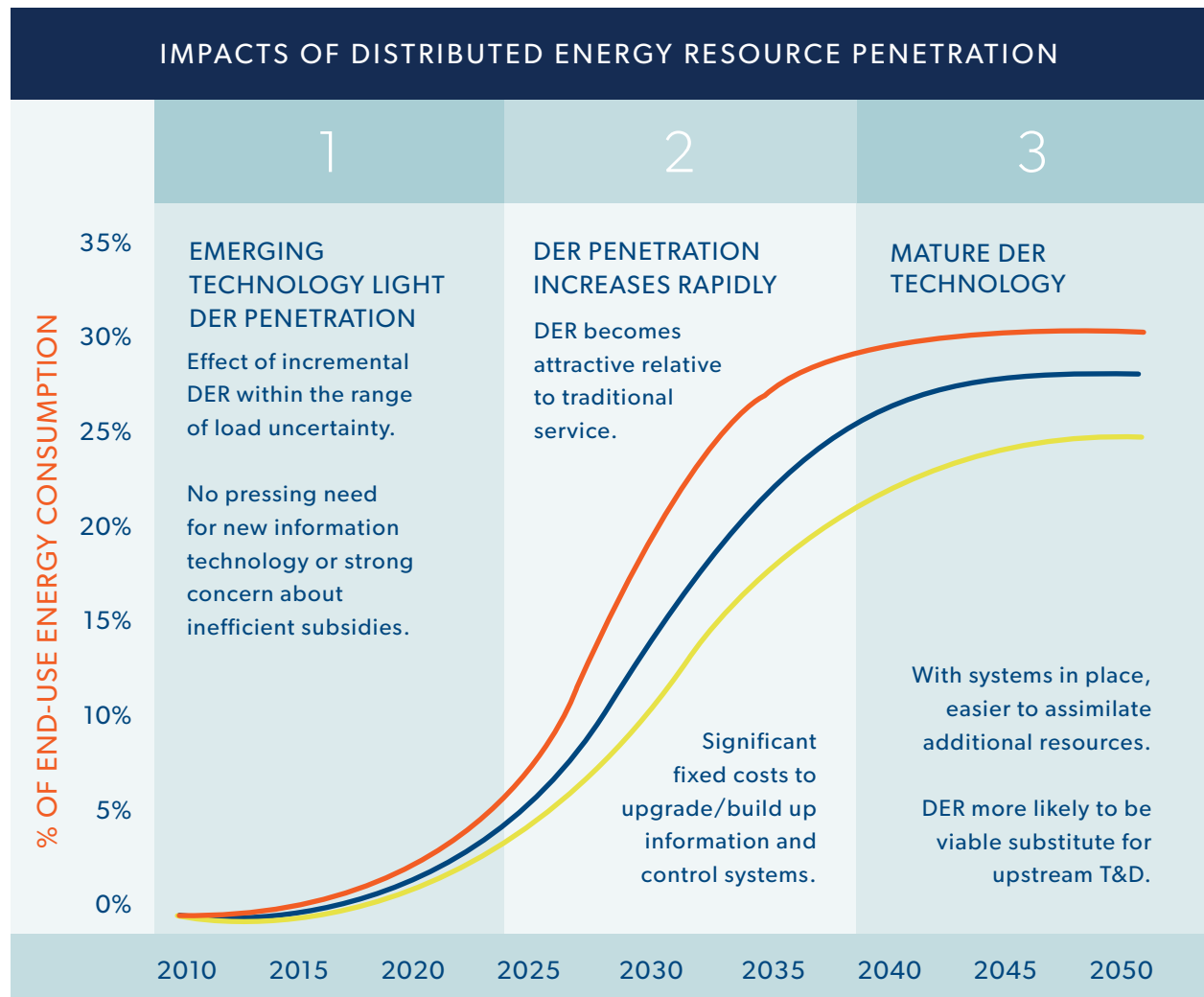
Even very modest levels of DER penetration will test the efficacy of the traditional utility business model, especially in regard to how it recovers costs. The traditional business model applied to electric utilities involves earning a return on the book value of assets prudently used to deploy a reliable electric infrastructure, through billing customers largely volumetrically, based on their average energy use. Distributing costs across all consumers allows economies of scale to be reflected in customer bills, and the expectation that all consumers would remain *full requirement* utility customers provides some comfort that utilities will have the opportunity to reach earnings projections.

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3. One cause of clustered DERs is the imitation effect or “cul de sac” effect, where the existence of a DER on a system makes neighbors more likely to hear about and invest in a DER. Clustering can also be tied to the relative income level for the area; wealthy neighborhoods have a greater ability to invest in DERs.



Having a portion of customers shift away from full requirement status by installing more DERs disrupts this arrangement. In its simplest implication, the loss of megawatt hour (MWh) sales due to shifting customer status requires that rates for existing customers increase in order for the utility to meet its revenue requirement. However, if that shift winds up eroding a sufficiently large percent of MWh sales, the utility may find itself in a reiterating and non-sustainable game of catch up.



Source and Notes: Brattle research and analysis. Indicated penetration rates and time frames are illustrative of a likely general pattern, not the result of a specific empirical study or prediction by Brattle.



The term “death spiral” has become etched into the utility lexicon because the spiral of increasing rates and customer defections (from DER installations) seems to ultimately lead to a permanent and growing under-recovery of costs for the utility. Even if the end state is not quite bankruptcy, a significant shift could result in a kind of financial freeze for a utility where it is unable to raise capital for new infrastructure investments, but also unable to raise rates or raise them rapidly enough to re-equilibrate.

While the death spiral process is mathematically logical, we do not foresee DER penetration being large enough to result in such a vortex. DER adoption as a percentage of total sales is fairly low so far, and there is some evidence that even the deepest possible technical penetration of DERs would not displace the majority of utility supply or involve true defections from the grid to self-sufficiency.<sup>4</sup>

We apply a typical S-shaped adoption curve to demonstrate how long it will take before DERs become a widespread phenomenon. This curve points out that the pace of adoption is likely to accelerate at some point, possibly putting a sudden strain on the ability of the system to integrate, creating a need for significantly upgraded systems. After those are in place, integration becomes easier. It also shows that peak penetration of DERs is not likely to be close to 100% of customers. Many sites are not attractive, and it is hardly ever economical for customers to try to be self-reliant.

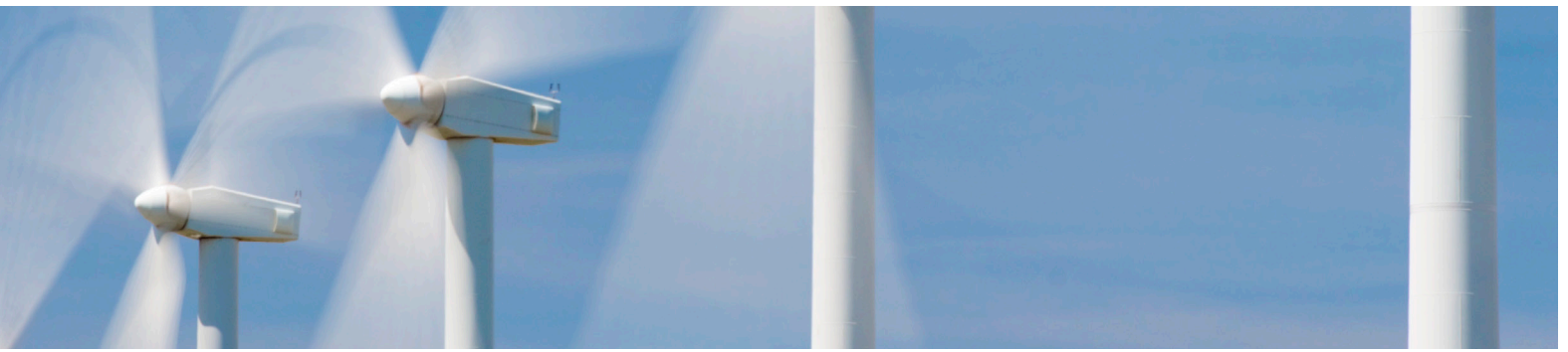
However, there can be financial hardships that are well short of a death spiral if utilities are slow to update their business models and are persistently outpaced by technological advancements in DERs, shifts in customer preferences, and pressures from interveners and politicians to require new kinds of entry. Likely, progress in both declining costs and technology advancements in DERs make it plausible that over time the shift to DERs will be large enough to disrupt the traditional revenue recovery process.

How could this be possible? In the past, utilities and regulators were allowed some leeway in setting rates. The rate for a specific customer class or segment did not have to precisely cover the associated costs to serve, because the utility could recover its total costs via alternative rate structures charged to all customers. In fact, rates were frequently designed with deliberate departures from underlying costs (for instance, using variable charges for what are mostly fixed costs) and with cross-subsidies in place to advance social agendas, such as industrial development or income redistribution.

Going forward, however, imprecision in rate design – deliberate or not – will likely mean that the utility is under- or over-recovering its overall cost of service, since some customers will have a means to avoid their shares. In fact, average cost rates likely invite this result, since they often are not reflective of underlying avoidable costs. This also means that the utility is sending the wrong pricing signal to customers making their own DER decisions, which could result in inefficient investment decisions.

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4. To the contrary, there are some intriguing prospects that DER and smart grid technologies could enable material growth, especially if they help usher in an era of increased use of autonomous electric vehicles.



In our view, regulators will have to explicitly address cross-subsidization and rate design efficiency fairly soon in order for DER development to proceed in a fair and beneficial manner for utility customers, and in order to make it possible for utilities to modernize their infrastructure and service menus to foster the new technologies.

First, the predominance of volumetric rates that have been applied historically may need to be modified to incorporate fixed or demand elements. This will enhance utilities' ability to avoid a shortfall in revenue recovery and remain financially viable entities able to develop the new infrastructure, controls, and information systems needed to continue to run the distribution system, and also to manage DER development effectively and fairly. A rate design that corresponds more closely to actual costs will reduce cross-subsidization and ensure that more accurate and informative prices provide the proper signals for investment in DERs, and also for their participation in real-time power system operations. In an ideal scenario, the utility should be able to promote the siting of DERs to locations that provide positive benefits to the system, and discourage them elsewhere (where they might even induce added costs). Finally, one of the main goals and benefits of DER technologies is that they allow customers to differentiate the way they use power and interact with the grid. As customers become more differentiated, pricing should also be modernized and differentiated; "one size fits all" pricing for whole customer classes at a time becomes obsolete.

The idea of differentiating rates more significantly than we do today remains a work in progress. On the one hand, as customer differences become more acute, it may be efficient, and even equitable, to create more classes and subclasses than is the case today in order to send the right price signals to customers and more accurately recover costs. On the other hand, creating more numerous rate classes could lead to a whole host of allocation and other cost assumptions for which there is no single correct answer. For instance, in some cases, it may be more practical and immediate to change backup and ancillary service prices for DER customers rather than redesign all prices more efficiently for all customers.

Modifying rate designs and cost allocations should be worked through progressively over time to deal with modest, but growing, levels of DER penetration and changes in customer views on "prosuming" electricity. This will moderate the detrimental financial effects on both the utilities and customers. However, larger scale penetration of DERs will require more widespread changes to the utility business model, and some of those changes will have to be set in motion early, before deep DER penetration has occurred.



## LONGER-TERM: TRANSACTIONS AND PLATFORMS

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Widespread DER penetration will almost certainly require more than a series of cost-recovery adjustments to the utility business model, both in terms of the way the system is able to accommodate DERs and in the way services are designed and priced.

In the current environment of low to modest DER penetration, DERs are treated as negative load. That is, to utilities, power from rooftop photovoltaics and negawatts<sup>5</sup> from energy efficiency both reduce (and increase the uncertainty of)<sup>6</sup> the demand that must be served through conventional power resources. As such, they also do not yet generally alter the use or requirements of the distribution assets, either positively (avoiding some distribution expansion) or negatively (inducing needs for distribution upgrades).

Using DERs in a more proactive way will require the grid to evolve into a more sophisticated “platform,” a term brought to the fore by the New York Public Service Commission’s Reforming the Energy Vision (REV) initiative and used with increasing regularity throughout the United States. As envisioned in New York, the distribution platform is expected to enable a market-driven ecosystem that includes DERs to be actively used effectively and in combination with centralized power resources to meet system needs in a cost-effective manner. DERs are also to be used as alternatives to conventional distribution system investments when they are cost efficient to do so.

“Platforms,” as the term is widely used in economics and management literature, refer to mechanisms for serving two-sided markets via networks and information technology that bring together buyers and sellers, both of which can affect the terms of transactions. In connecting these participants, platforms enable growth in the number and variety of new transactions that would not take place without them. For instance, intermediaries such as Amazon and Visa provide platforms for shopping and instantaneous, distributed retail borrowing, respectively. The value of the platform increases as both the number of users and the linkage of the platform to other economic processes (such as compatibility with hardware choices for cellular phones, etc.) increases. These are referred to as positive network effects and economies of scope. For utilities, the grid itself, made smarter with new controls and information support, is envisioned to evolve to a platform of similar character in the future, as more DERs and customer-centric energy management options become widespread.

From a business perspective, making the UoF platform concept work requires new modes of energy usage and new information services amenable to numerous transactions. Services envisioned include highly granular geographic pricing for energy, capacity, and ancillary services, as well as for information-based value-added

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5. An expression representing an amount of energy saved.

6. Even when solar output is relatively reliable, utilities may not be aware of behind the meter resources and therefore not able to include it into their demand forecasting.



services (such as usage patterns for customers or for vendors). UoF platform transactors will include DER-based producers and retail and wholesale electricity consumers. The transformation of the utility distribution system into a widely-subscribed platform (if it were to happen) would completely change the traditional utility business model. As the platform operator, the utility would receive compensation for enabling transactions, just like Amazon and Visa, which are paid as a small percentage of transaction values or a flat fee per transaction. Utility transaction revenues (either their own portion of the value-added or as a kind of transaction wheeling fee) could be sizable if the volume of transactions were sufficiently large, which could offset some of the costs of maintaining and operating the physical grid.

In our view, the only way to realize a high level of transactions over a utility platform would be to substantially, almost radically, change how the distribution grid interacts with societal needs. This will take time and may require the distribution system to be upgraded and modernized as a precondition to attracting those developments. Modern society is evolving towards the “internet of things,” which will need both electricity and widely-shared, coordinated information. Services available over the platform are envisioned to include new information-based services, ranging from smart home and appliance applications to entirely new service segments. In addition, it may be possible to develop new, non-transactional uses for the smart power grid in the future, such as road traffic congestion monitoring, reading meters of other utility services and providing diagnostics (such as water usage), crime monitoring, or other uses. These will also help defray costs of service and may require investment and technology of their own.

Making the platform work will also require a good deal of technical specification and investment. A platform where the utility acts as a Distributed Service Platform Provider (DSP) would involve consumers, prosumers, DER developers, distribution utilities, and power markets interacting with each other over a transaction-based platform that the utility manages and generates revenue from. For this to happen, existing utility controls would need to be upgraded to accommodate complex, possibly ad hoc power flows from DERs, constituting the physical dimension of the platform. On top of that, the platform will also need to define tradable products and prices and act as a financial clearing house, somewhat similar to the function performed by system operators in wholesale markets, who integrate competitive suppliers with net regional demand. It is important to understand, however, that retail transactions may be even more complex and require correspondingly more complex systems, because they may involve more numerous and differentiated locations with fewer existing controllable resources to dispatch or direct to balance the low voltage system. Because the DSP role as a coordinator or dispatcher of DER transactions is so dependent on dynamic system conditions, it is likely that there are informational and operational economies that justify having the utility be the DSP.

## “PLATFORM LITE”

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We believe that the platform concept for electric distribution and distributed energy services is clearly a possibility, but it remains largely unspecified at this time. We do not see the utility business model being turned on its head anytime soon. A more likely case for utilities may be a future ecosystem designed around a scaled-down version of the platform, or “platform lite.”

A full-fledged platform as envisioned for the long term requires specificity concerning the types and extent of services and transactions, which are largely absent for the grid platform at this time. We recognize that innovators may be working through new services and revenue streams, but absent some insight into such offerings, it is difficult to project a transition to a platform-centered world with confidence.

The most dramatic and successful of recent platforms in our economy, such as internet intermediaries and credit card companies, have involved facilitating many new uses with many new users of the underlying network technology, such as the internet or cell phones. For instance, eBay puts millions of buyers and sellers in touch with each other who would otherwise have never overlapped in a brick-and-mortar-based regional market.<sup>7</sup> As a result, eBay and similar intermediaries can charge a small fee on transactions, resulting in a large profit. However, it is less obvious that the new transactions arising from DERs and improved flow of information over the power grid will induce significantly *more* use, as opposed to just increasing efficiency of usage that will still be fundamentally similar in size and purpose to existing energy consumption. Transaction fees may be appropriate for this type of usage, but they are not likely to be sufficient to recover all costs. Therefore, some form of price regulation for core services will persist and may be the mainstay of cost recovery for quite a while.

A transformation of the utility business model – from rate-based to a transactional ecosystem – may not be ready quite yet, and the next iteration of the utility business model may be somewhere in between. Over the past several years, many utilities have invested in advanced metering infrastructure (AMI), which is a platform in its own right, enabled with digital communications and connectivity to customers.

Customers of utilities that have invested in AMI have noticed charges on their bills for smart meters and have been told that AMI will enable new services that will be of value to them. That is, customer expectations are beginning to expand from reasonable levels of reliability and responsive customer service to also include information, value-added services, and a pay-off (in the form of lower electricity bills) from utility infrastructure investments. Utilities should focus on using their investments in AMI to facilitate more customer benefits as the first stage of a UoF platform.

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7. One important aspect of the Amazon or eBay business model is the discrete, defined, and time-independent nature of their transactions, which differ greatly from the exchange of energy services, which are less discrete and more time-dependent. Adopting a similar model would require much greater automation and communication between energy resources or heavy reliance on DER aggregators.



Increased use of innovative energy efficiency and demand response can head the list of potential new service applications. To some, they may appear less exciting than (yet unspecified) transactional services, but are nonetheless tangible and provide value to customers. Enhanced energy efficiency services can be customized through more detailed, specific usage and load shape information available from AMI statistics. This information can show usage over time, comparisons to other customers, or forecasts and analyses of potential future reductions. It can also be manifested operationally by tying smart appliances to AMI price information.

## WHAT'S NEXT?

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Is there really a new utility business model on the horizon, or will a few adjustments to the current structure suffice? We believe there is a new utility business model coming in the near future, which may look very different than what has been in place for the last 100 years. In our view, however, the path to the new utility business model will be gradual and more evolutionary than revolutionary.

Some degree of change to the traditional model will be required in the very near term to ensure that utilities remain viable and fulfill a meaningful role going forward. This means that utilities and regulators will need to address the incipient problems set off by modest DER penetration under the current business model construct, while also working to more fully structure the model for the future.

Most of these changes can be generally accommodated within the existing framework, but that does not mean they will be easy to implement. It may sound tautological, but it is nonetheless profoundly true that change cannot occur without first making changes that facilitate it, and change is bound to spur still more disruption to the status quo. Thus, it goes without saying that several interrelated changes will be required in order to effectuate a paradigm shift to a UoF ecosystem.

In our view, DER technologies are unlikely to completely or even substantially replace centrally supplied and/or regulated resources. We also believe that regulatory and policy initiatives will likely drive the demand for DERs and new services, well ahead of economic viability. One way or another, DERs will take a bite out of what utilities would normally be expected and authorized to do. The rules and processes for controlling DERs are not part of the current regulatory or utility planning tool kit or experience, so it is important that these be set up to appropriately reflect the economic (i.e., cost and benefit streams) and policy directions.

Understanding costs and benefits is therefore very important. There has been an ongoing discussion concerning the benefits that DERs will provide, but some of them will be outside of the utility system. A “prosumer” or commercial developer investing in DERs will be motivated by his or her own internal costs and benefits (and maybe even societal benefits), but these will inevitably be different than the marginal costs and benefits realized by a distribution utility. As a first step, utilities will need to be conversant on the economics and potential impact of DERs on their systems. They will then need to take steps to make certain that incentives are put in place to ensure efficient placement and deployment of DERs. This may include improvements to their core service design and pricing, as well as enhancements to resource planning and risk analysis tools. Utilities may also need to engage in deployments in cases where DERs are not or cannot be efficiently supplied by (non-utility) market forces; however, defining the boundary of what a utility can (and cannot) do will almost certainly be controversial.

Following from our view that the evolution of DERs will be gradual, we recommend that utilities also proceed gradually because the evolution of DERs will be strongly path dependent. That is, the way DERs are valued and incentivized today will affect how they are viewed and adopted in the future. Furthermore, temporary steps (i.e., viewed by utilities as sub-optimal but tolerable in the short run) may become an irreversible precedent. Thus, it is essential that utilities not “wait and see” to learn how to adjust to DERs until they are widely present. On the contrary, utilities should be proactive in developing and proposing efficient decision processes and pricing for DER adoption and integration. They will also have to be flexible, modifying their initial assessments of winners and losers in DERs as new data and results of pilots come in.

What can be expected in the immediate future? The most prominent DERs are probably right in front of our eyes. Brattle has worked on several scenarios concerning DER deployments and penetration, and the consensus view appears to be that demand-based DERs, notably energy efficiency, will lead the pack, ahead of generation-oriented DERs such as rooftop PV. Energy efficiency also is an ideal application for a lite approach to platform development, i.e., using AMI as a springboard to make it more dynamic and valuable.





Moving hand in hand with modest DER penetration and an enabling platform, we see the need for adjustments to the current revenue recovery framework in order to put appropriate incentives for DERs in place and to ensure that costs are recovered by the utility as it begins to operate in the UoF environment. This will likely result in some changes in the baseline pricing terms and conditions, which may elicit some protesting response ranging from a mild reaction to an outright uproar.

We've compiled a list of key analytic initiatives that utility managers should begin to address to prepare for and participate in the UoF ecosystem.

THE BASIC UoF READINESS CHECKLIST	
1	Develop cost of service (and marginal cost) analyses in order to better understand geographic and other differences in costs and benefits of integrating DERs
2	Gradually replace "make-whole" lost-revenue recovery mechanisms with more efficient cost recovery and rate designs
3	Add incentives to the traditional rate of return framework as a transition step and to encourage utilities to integrate DERs and platform functionality
4	Determine applications where the non-utility market can provide DER-based incentives and where applications are best provided by the utility
5	Reformat traditional benefit-cost analyses to incorporate the scope of DER benefits
6	Evaluate growth opportunities, particularly in beneficial electrification, such as the electrification of transportation

Source: The Brattle Group



## THE MODELING CHALLENGE

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The checklist certainly covers the basics, but most utility managers will also need to link the disparate pieces together in a model that allows communication and risk analysis of the alternative approaches. Modeling of electricity markets, customers, and finances is a staple of utility planning, and scenario analysis has taken on the role of workhorse.

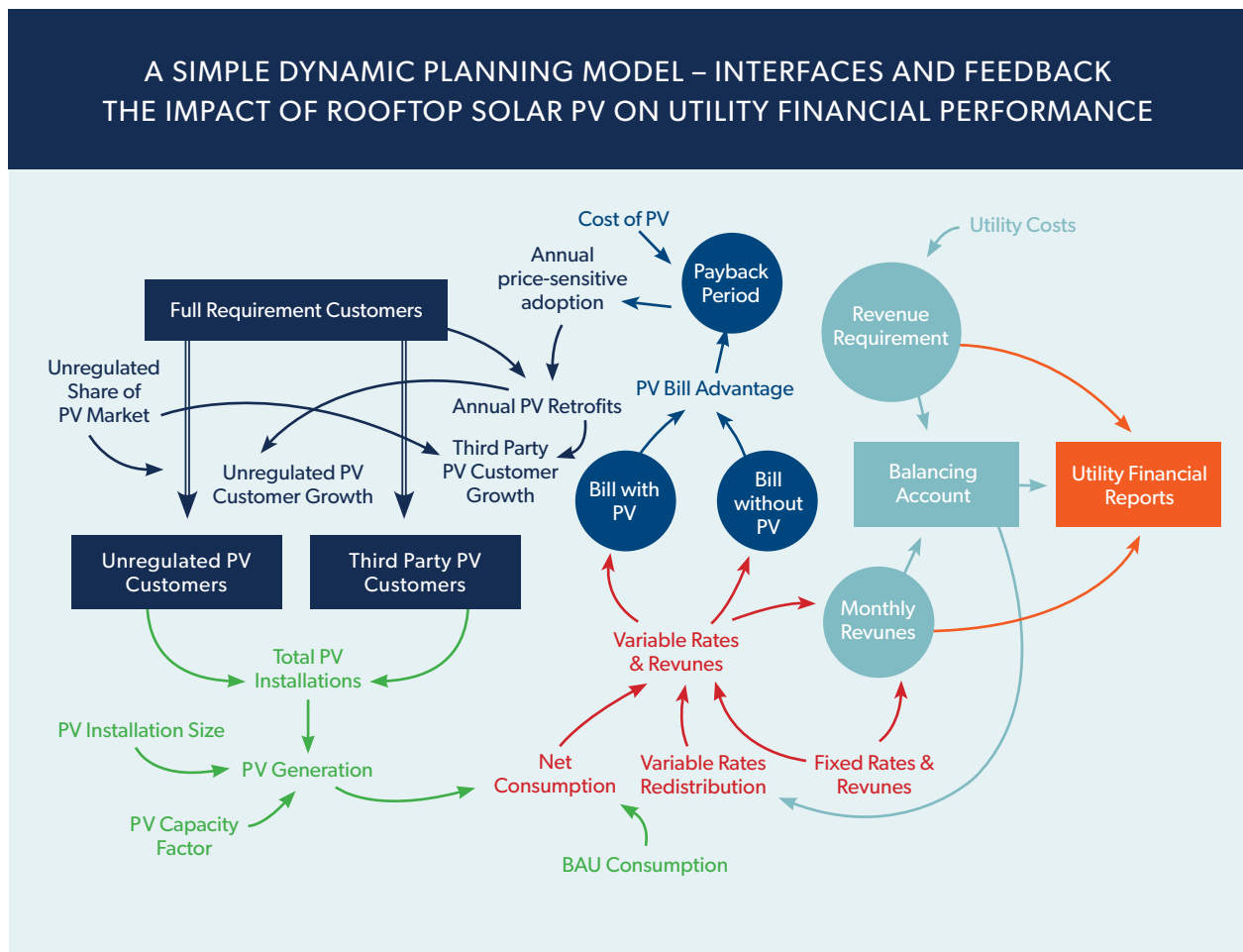
The essence of the technique is to project market conditions and then evaluate how your organization might perform under those conditions, typically under alternative strategies. Scenario analyses have been widely applied and work best when our understanding of the future is shaped by modest variations on the past. It is also particularly effective when the relationships among variables are fairly well-known and deterministic. As the saying goes, however, the future may not be what it used to be, and this is especially likely as DER penetration becomes more attractive. This means that models have to rely less on extrapolation and more on dynamic relationships.

The UoF ecosystem is characterized by an increased number of players and decision makers (DER developers, customers, regulators, policymakers, and other utilities), most of whom operate independently of the host utility's economics and system interests, and make self-promoting decisions based on their own economic perspectives. Future decisions will interact and respond to other policy decisions in more dynamic and significant ways than third-party decisions may have in the past.




In addition, future customer reactions are becoming more difficult to extrapolate due to heightened customer awareness of technological improvements and alternatives that have been excluded from past observations. This means that future conditions may be less linearly dependent on traditional risk factors than in the past, and what were previously second-order interactions of influences may reach levels where they are primary. It also means that building credible scenarios (or knowing what weight to put on them) may be more difficult than in the past.

Depicting a planning model has traditionally involved circles and arrows, but effective modeling has become decidedly less linear in our view, as exemplified in the simple dynamic planning model diagram.



Source: The Brattle Group



The sheer number of interfaces and feedback loops lends itself more to a “systems-based” approach to modeling than to linear scenario analysis, as depicted in the diagram. Technically, systems dynamics uses numerous equations for how one variable or market factor influences another (or several others) to model complex systems over time using stocks, flows, feedback loops, and time lags. More simply put, it focuses on how marginal change relationships will play out once set in motion, rather than trying to identify plausible combinations of assumed market outcomes. The analytic essence of system dynamics is to develop very detailed, functionalized influence diagrams of how the factors at play in the market interact.

A model can readily be developed for the decision process for a range of participants in the UoF ecosystem that are also each connected through relationships and iterations. Scenarios then unfold in unpredictable ways based, for example, on how changes evolve with respect to customer adoption rates of DERs, technology improvement (in terms of effectiveness and costs), changes in utility rate designs (and the impacts on cost shifting and recovery), new usage patterns (by consumers), and altered risks and opportunities for the utility. It allows testing of what-if conditions that might create a “death spiral” or nonlinear “tipping points” where old paradigms suddenly become obsolete, albeit not necessarily fatal.

The diagram also reflects a segment of a full systems model, focused on how rooftop PV penetration may upset the traditional utility business model. The same set of interactive systems can be applied to the impact of community choice aggregation, changing customer behaviors, regulatory incentives and pricing policies, and/or evolving DER applications upon utility operations and finance.

We have found that the systems dynamics tool has invigorated some areas of the utility strategic planning process. First, it has helped to highlight the path dependencies in strategies; that is, understand the impacts of today’s decisions on future outcomes.



We have also found that it helps in consensus building exercises. For instance, we often find that utility managers in the same organization have material differences of opinion about whether the UoF outlook is a threat or an opportunity, as well as the degree and timing of its impacts.

A systems model is well-suited for testing competing hypotheses in real time. We also believe that a model with a wide web of interconnections can be used to facilitate dialogue among utilities, industry participants, and regulators.

Understanding the pace of change within the industry and developing appropriate modeling techniques to capture new interdependencies are just two aspects of UoF planning facing utilities. Moving forward, utilities would be wise to address the challenges they face with an integrated business and regulatory strategy that considers all aspects of their operations. In further installments of this briefing series, we will address the financial, technological, strategic, and regulatory facets that impact future business models.



## ABOUT BRATTLE'S RETAIL ENERGY PRACTICE

As distributed energy resources (DERs) become more widespread and utility managers and regulators look toward incorporating new business models, the “retail” side of the electric utility industry is receiving increased attention. The Brattle Group’s Retail Energy Practice helps clients address the critical issues that impact the utility industry at both the distribution system and retail service levels.

Brattle’s Retail Energy team has extensive experience developing benefit-cost analyses for next generation investments in smart grid, system reliability and resilience, and overall grid modernization, as well as for investments at the system edge, such as electrification opportunities. We have also worked extensively on assessing business and financial models applicable to the evolving electricity market ecosystem, and are at the forefront of marginal cost and benefit analyses that are becoming increasingly important in determining efficient and equitable pricing constructs and incentives for DER compensation. Our expertise is grounded in foundational principles of economics and finance, in order to better align load forecasting, rate design, and risk management with industry trends and developments.

For more information on our expertise and services, please contact:

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