The MIT Utility of the Future Study

White Paper

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The MIT Energy Initiative
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Introduction and Summary[1]

The electric power sector appears poised for transformative change.

Improvements in the cost and performance of a range of distributed energy generation (DG) technologies are creating new options for on-site power generation, driving increasing adoption, and impacting distribution system operations. Increased usage of natural gas fired centralized generation and emerging DG options fueled by natural gas are creating new interplay and competition between gas and electric utilities. Meanwhile, increased energy efficiency and new uses for electricity—including plug-in electric vehicles (EVs)—are altering demands on the electric power system. Distributed energy storage (DS) technologies may also be poised for breakthroughs that could enable widespread adoption and new capabilities. The infusion of new information and communication technology (ICT) into the electric system is enabling the collection of immense volumes of data on power system operations and use; unprecedented visibility and control of generation, networks, and loads; and new opportunities for the delivery of energy services. In particular, new information flows permit a range of demand response (DR) options, making electrical loads more price-elastic and responsive than ever before. Furthermore, these technologies are emerging during a time of increased public, political, and scientific discourse and action on climate change, with growing interest in the potential for these distributed technologies to enable a cleaner, more efficient, and more resilient power sector.

The combination of ICT and various distributed energy resources (DERs) – including DG, DS, EVs, and DR – is enabling the creation and proliferation of new **distributed energy systems or DESs**, from microgrids and virtual power plants to remote aggregation of controllable loads and smart charging systems for electric vehicle fleets. These DESs are enabling a diversity of new business models and have the potential to provide value to end-use energy consumers and upstream electricity industry actors.

To date, the diffusion of DERs and ICTs into power systems has been primarily shaped and propelled by public policy measures. Yet utilities and analysts are increasingly focused on the potential for self-sustaining and disruptive forces to take hold. As technology innovation and industry maturation steadily improve the price and performance of these technologies, many believe that tipping points are possible, after which adoption may proceed quite rapidly.

Together, technological developments, emerging business opportunities, and evolving policies are driving evolutionary as well as potentially disruptive changes to the electric power sector, forcing innovation in power systems design and operation, electricity sector business models, and electricity regulation. The changes facing the power sector over the next decade could be at least as profound as the transformations experienced during the wholesale and retail market restructuring of the past twenty years. While the impacts of these new changes will likely ripple across the power sector, from generation and transmission to distribution and retail, the penetration of DESs will have the most impact on how the distribution and retail sectors deliver electricity services to end-users and service providers.

The future of the power system holds considerable uncertainty. However, it is clear that utilities, regulators, DES providers, and other market actors will need to be prepared for potentially transformative changes in the years

[1] This report, corresponding to the preliminary scoping phase of the Utility of the Future project, was completed in December 2013; however, it was not made public at the time. Since it is being published in July 2015, the authors have introduced a few comments regarding the ongoing, second phase of the project along with a few relevant references made available after December 2013.

ahead. Historically, electric utilities – whether generators, transmission providers, distribution providers, or retailers – have been the sole or dominant supplier of electricity services to end users. However, new technologies and new market actors have the potential to both support and supplant the functions of the traditional electric utility and, at the extreme, may fundamentally redefine the "utility of the future."

This white paper concludes and presents the findings of a **qualitative** scoping phase of the *Utility of the Future* study, a multi-year, interdisciplinary project of the MIT Energy Initiative within the COMITES program.[2] This ongoing project seeks to analyze the future of the provision of electricity services in both centralized and decentralized manners, exploring alternative business models and transformative technologies under diverse regulatory and markets contexts and within the global framework of an increasingly decarbonized power sector. In doing so, we aim to cast light on the likely evolution of the electric power sector over the next decade and beyond, with a particular focus on changes taking place within and adjacent to the electricity distribution system. After this preliminary scoping phase, the subsequent research in the bulk of the project will employ quantitative economic and engineering analysis to assess on which of today's nascent trends are likely to have the greatest impact, which technologies and business models are most likely to proliferate, and how the power system as a whole is likely to evolve.

This report presents the initial qualitative thinking of the *Utility of the Future* research team in three key areas: technology, business models, and regulation. **Section 1** introduces the concept of a distributed energy system (DES), which combines one or more DERs and ICTs into a system that can deliver valued services to electricity end users or upstream market actors. The section also explores a set of key DES component technologies, discusses the likely timing and impact of the adoption of each technology, and evaluates the range of services provided by these technologies. The matrix in Appendix A presents a more extensive representation of the findings of this preliminary technology evaluation. This section also considers the potential for DERs to become "disruptive threats" to electric utilities by sparking a self-reinforcing feedback loop of adoption. Finally, this section describes how individual DERs and ICTs can be combined into larger DESs, and introduces three example configurations of DESs.

Section 2 focuses on characterizing the competitive business models that may take advantage of the new opportunities created by DESs to supply a range of valuable services to power system stakeholders. The discussion introduces a high-level classification of the core attributes of DES-related businesses and uses this attribute framework to analyze both existing (real-world) and prospective DES business models. This section also discusses the opportunities and challenges for the incumbent utility in harnessing DES-related business opportunities before outlining four potential alternative business models for the distribution utility of the future.

Section 3 focuses on two key regulatory policy issues surrounding the large-scale implementation of DESs within the electricity distribution system: the remuneration or cost recovery challenge and the network charge design or cost allocation challenge. The first issue involves updating methods to set the allowed revenues of electric distribution utilities to align incentives for the integration of DERs and DESs and foster system innovation while the second issue involves designing the tariffs charged to users of the distribution system to fairly allocate costs and send efficient price signals as DES penetration increases.

Section 4 concludes by identifying a set of key questions that will help establish the scope of future research for the *Utility of the Future* study.

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[2] COMITES stands for Comillas-MIT Electricity Systems Program, a joint partnership between the MIT Energy Initiative and Institute for Research in Technology (IIT) at Comillas University, Madrid, Spain.

The results presented in this report are preliminary and intended to focus future academic research. Nevertheless, the authors of this report believe we can provide a range of initial findings that can inform participants on the electric power sector.

Key Takeaways

Technology

1. DESs, or distributed energy systems, are comprised of distributed energy resources (DERs) and information and communication technologies (ICTs). New business models for utilities or third parties can be built around DESs. These business models exist within a specific regulatory framework, which is embedded within the boundaries of the broader sociotechnical power system.
2. The core DES component technologies can be classified according to a 3-layer framework: Layer 1 comprises power distribution networks and DER components; Layer 2 consists of ICTs for system monitoring, control, and communication; and Layer 3 encompasses ICTs for data analysis and decision-making.
3. In order to compare the abilities of DES component technologies to deliver a range of services required by electricity end-users and upstream system operators and market actors, sound performance metrics must be developed.
4. A self-reinforcing feedback loop (a "virtuous " or "vicious cycle," depending on the viewpoint) of customer DER adoption is possible, but *not* pre-ordained. Careful examination and analysis of the potential system dynamics at play as DER adoption increases will be essential to determine the ultimate impact on incumbent distribution utilities and others across the value chain.
5. While some DERs and ICTs will prove more disruptive than others, the disruptiveness of technologies will be magnified when individual DERs and ICTs are combined into DESs. DESs are expected to have a greater impact than the sum of the impacts of DER components acting alone.

Business Models

6. DES-related business models will evolve not only because of new value propositions and customer needs but also because of the evolving technological and regulatory conditions that are reshaping the electricity distribution sector.
7. The typical one-directional value proposition in which the utility provides electricity delivery to an end consumer may not always be valid for the utilities of the future. As electricity end-users also become vendors of energy and related services (i.e., ancillary services, capacity, etc.), bi-directional value transactions will become more common, and the utility will need to see end-users as not just customers, but also potential suppliers, partners, and competitors.
8. New DESs have the potential to challenge, and in many cases already are challenging, the core business of the incumbent utilities. At the same time, DESs also create new opportunities for incumbent utilities to meet end-user needs and operate more efficiently.
9. Incumbent utilities have a set of characteristics in common. These characteristics bring both a set of challenges and a set of potential opportunities and competitive advantages regarding the business model attributes of any project in which the incumbent utility might get involved.
10. The business model(s) of the incumbent distribution utility must evolve to capture the opportunities and respond to the threats presented by DESs, and they must do so at an increasingly rapid pace of change.

Regulatory Issues

11. The regulatory framework of the electric power sector must enable and encourage the distribution network operators and the emergent business models to evolve at the pace demanded by changing network uses.

12. If regulatory innovation cannot keep pace with the changing nature of the electric power system, large inefficiencies may result, and network users and new businesses will find ways to arbitrage the growing disconnect between ill adapted regulations and new market and technological realities.

13. The evolution of utility business models can be constrained by the lack of proactive regulatory innovation. Remuneration schemes for regulated distribution utilities must be adapted to better align the incentives with the challenges the utility is going to face, enable the evolution of the utility's business model, and create adequate incentives for long-term innovation.

14. The adoption of DERs and DESs will exacerbate challenges associated with information asymmetry between the utility and regulator during the determination of allowed utility revenues. Regulators should employ an incentive compatible menu of contracts to elicit accurate estimates of expected costs from the utility. Regulators should, in cooperation with utilities, also make use of reference network models or benchmarking to generate their own estimates of efficient network costs.

15. Use of network tariffs must be updated to provide efficient price signals for increasingly diverse system users. The current tariff paradigm, designed for pure consuming agents and a system where DG was considered a minor exception, does not hold anymore. It should be fixed before more substantial distortions occur.

16. Network tariffs should be based on the contribution of each network user to the cost drivers of the distribution system, calculated according to the user's individual profile of consumption, generation, or both.

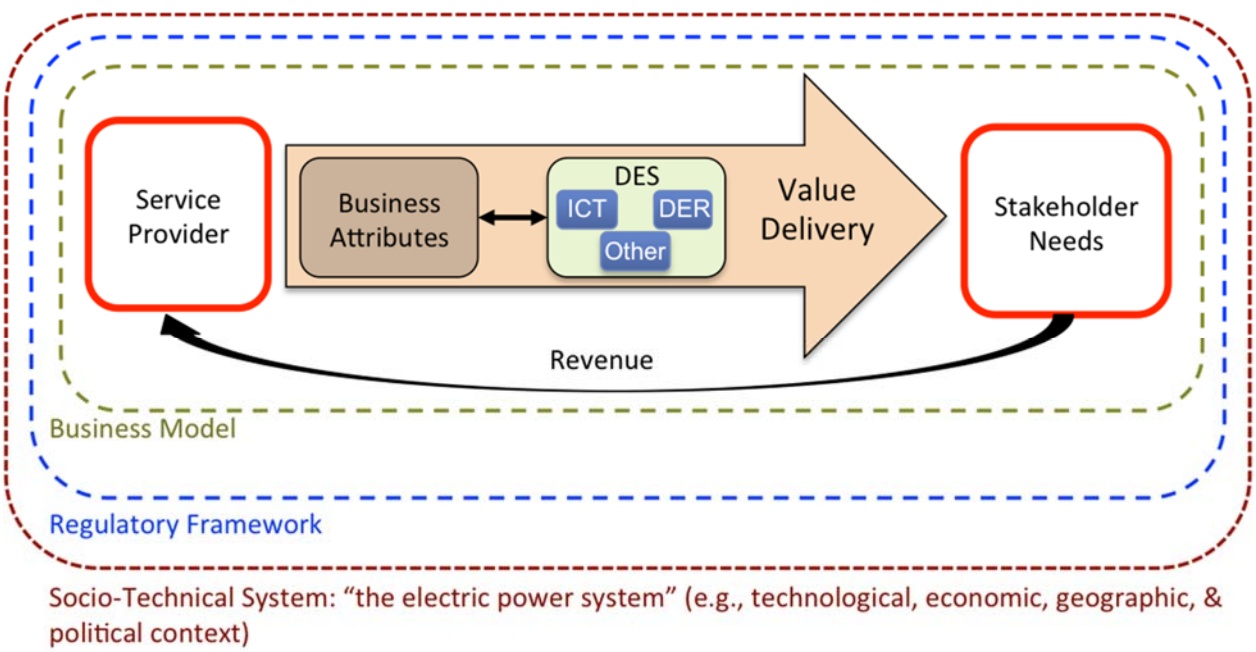
17. The roles and responsibilities of distribution utilities may need to be revisited in some jurisdictions and the ways in which the distribution utility will interact with adjacent market actors, including the transmission system operator and new DES businesses, must be clarified. This also includes defining the way these market actors will interact and coordinate to dispatch DERs and DESs.

Conceptual Framework: A “System of Systems” View

Envisioning the many possible models for the electric utility of the future will require identifying and evaluating new business models that may emerge to redefine the sector. We understand a business model as a framework that presents “the rationale of how an organization creates, delivers, and captures value” (Osterwalder, 2009). A business model “describes a transaction structure that involves stakeholders” (Wei et al., 2013). Business models succeed or fail depending on how well an organization creates value for multiple stakeholders, including, but not limited to, end-use customers (Magretta, 2003).

The following diagram represents the value delivery process in which a Distributed Energy System (DES) (a technical system composed of Distributed Energy Resources (DERs) and Information and Communication Technologies (ICTs)) and a business model deliver value to meet a stakeholder’s needs. An entity may play the role of both service provider and stakeholder in different transactions, as in the case of a distribution system operator that both provides services to an end-user consumer in one transaction while also purchasing system services from that same consumer (e.g., capacity through demand response) in another transaction. All these transactions take place in the context of a particular regulatory framework and are embedded within a particular instance of the larger socio-technical system we call “the electric power system” (including the specific technological, economic, geographic, and political context). See Section 1 for a definition of DESs and for more discussion of DES component technologies.

Figure 1 – A system-of-systems view of DES value delivery



1. Technology Assessment

Improvements in the performance and cost of distributed energy resources, including distributed generation (DG), distributed storage (DS), and demand response (DR), underpin the potential for the growth of distributed energy systems. Innovation in information and communication technologies such as advanced sensing and control devices and communication protocols are also critical to transforming the electricity distribution sector into a more adaptive, responsive system. The first step towards evaluating potential futures that may emerge for electric utilities is identifying and understanding the technologies likely to play a significant role in the evolution of the electric power sector. This includes both technologies likely to drive the shift towards a more distributed paradigm and technologies likely to emerge in response to new needs created by regulatory or business model evolution in the power sector, such as the need for increased system flexibility in response to the increasing penetration of intermittent renewables.

This section introduces the concept of a distributed energy system (DES) by first describing the technological building blocks of these systems in Section 1.1. It then identifies key DERs and ICTs in Section 1.2 and describes the range of services that can be provided by these DES components in Section 1.3. Section 1.4 presents the system dynamics of DER adoption and considers whether these technologies are likely to pose a disruptive threat to incumbent utilities. Finally, Section 1.5 presents three example DES architectures with the potential to substantially impact utility systems.

1.1. What is a Distributed Energy System?

A Distributed Energy System (DES) is a system combining one or more distributed energy resources (DERs), including distributed generation, distributed storage, and/or demand response, with information and communication technologies (ICTs). Figure 2 below depicts four illustrative DES topologies.

Such systems will be distributed throughout the electricity distribution network and adjacent customer properties. Some DESs will be owned or operated by traditional regulated distribution utilities while others will be owned, managed, and operated by end-use electricity consumers and/or by third parties operating in competitive market environments. DESs may enable the provision of a variety of different services, from end-use energy services such as lighting, heating, and cooling to upstream electricity market services such as capacity or ancillary services (see Table 1).

The technologies most relevant to the development of DESs are DERs and ICTs – the DES component technologies. These component technologies are the building blocks of DESs and can be organized according to the three-layer framework illustrated in Figure 3. The framework illustrates the hierarchy of DES component technologies and captures the flow of energy or information between technology layers. For example, information about the state of the system flows from sensors and monitors in the Communications Layer to the Intelligence Layer, where this data is analyzed and interpreted, enabling optimal decision-making. This framework also depicts the relation of DES technologies to technologies that are external to DESs but are critical to DES operation. Such enabling technologies include telecommunications networks and the physical power distribution networks and components.

Layer 1 technologies are the physical components and hardware of the power system and telecommunications network. These components include power electronics devices, transmission and distribution network hardware, and DERs. **Layer 2** encompasses ICTs that enable system monitoring, component control, data collection, and communication. **Layer 3** technologies are those that enable meaningful utilization of the data and information collected by Layer 2 technologies. This includes data analysis, decision-making, and execution of system commands. ICTs will play a critical role in the active management of distribution systems and DESs by, for example, enabling the communication of economic signals to system users and enabling greater control over the use and dispatch of DERs.

Figure 2 – Illustrative DES Topologies

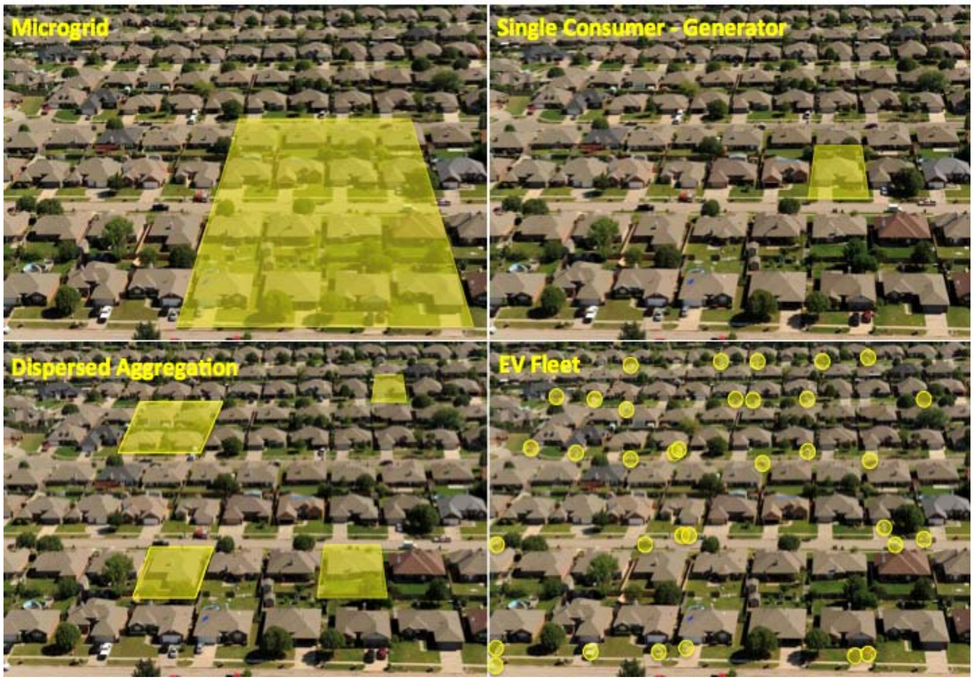
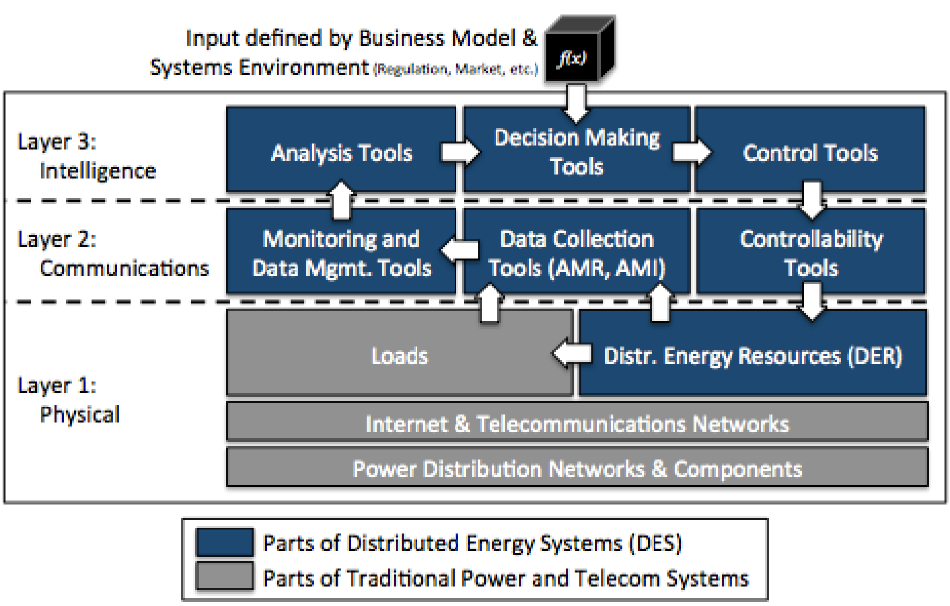


Figure 3 – Technology building blocks of DESs



1.2. Identifying Key DES Component Technologies

Each of the three DES technology layers consists of multiple potential component technologies. **These DES component technologies are the primary agents of change in today's power system.** Prominent DER technologies are listed in the first column of the technology assessment matrix contained in **Appendix A**. These DERs display a range of performance and cost characteristics and have the potential to be disruptive to varying degrees. Figure 4 illustrates a preliminary, qualitative estimate based on literature review of the likely timing and magnitude of the impact of key DERs. In the ongoing *Utility of the Future* project, quantitative analytical modeling tools will be employed to further refine this analysis from a systems perspective.

Technologies grouped according to DER categories—such as DG, DS, DR, and EVs and associated charging infrastructure—are listed along the vertical axes of Figure 4. This figure depicts the potential impact of each technology over the short term (the next five years), medium term (within the next 5-15 years) and long term (beyond a 15-year horizon. For each time period, Figure 4 uses solid lines to indicate high impact and thus greater potential for disruptiveness, dashed lines to indicate lower impact and thus limited disruptiveness, and no line to indicate limited or virtually-zero penetration. A dot-dash line is employed where higher degrees of uncertainty exist.

For each technology, there are a variety of factors that can result in a transition from low impact to high impact. These include changes in the way a technology is employed by system users, advances in the DER technology performance, and/or improvements in the economics of a particular DER. For example, fuel cells are shown to transition from a dashed line to a solid line within the next 5-15 years. This is likely to arise from improvements to the technical and cost performance characteristics of fuel cell distributed generation leading to much greater competitiveness and broader adoption.

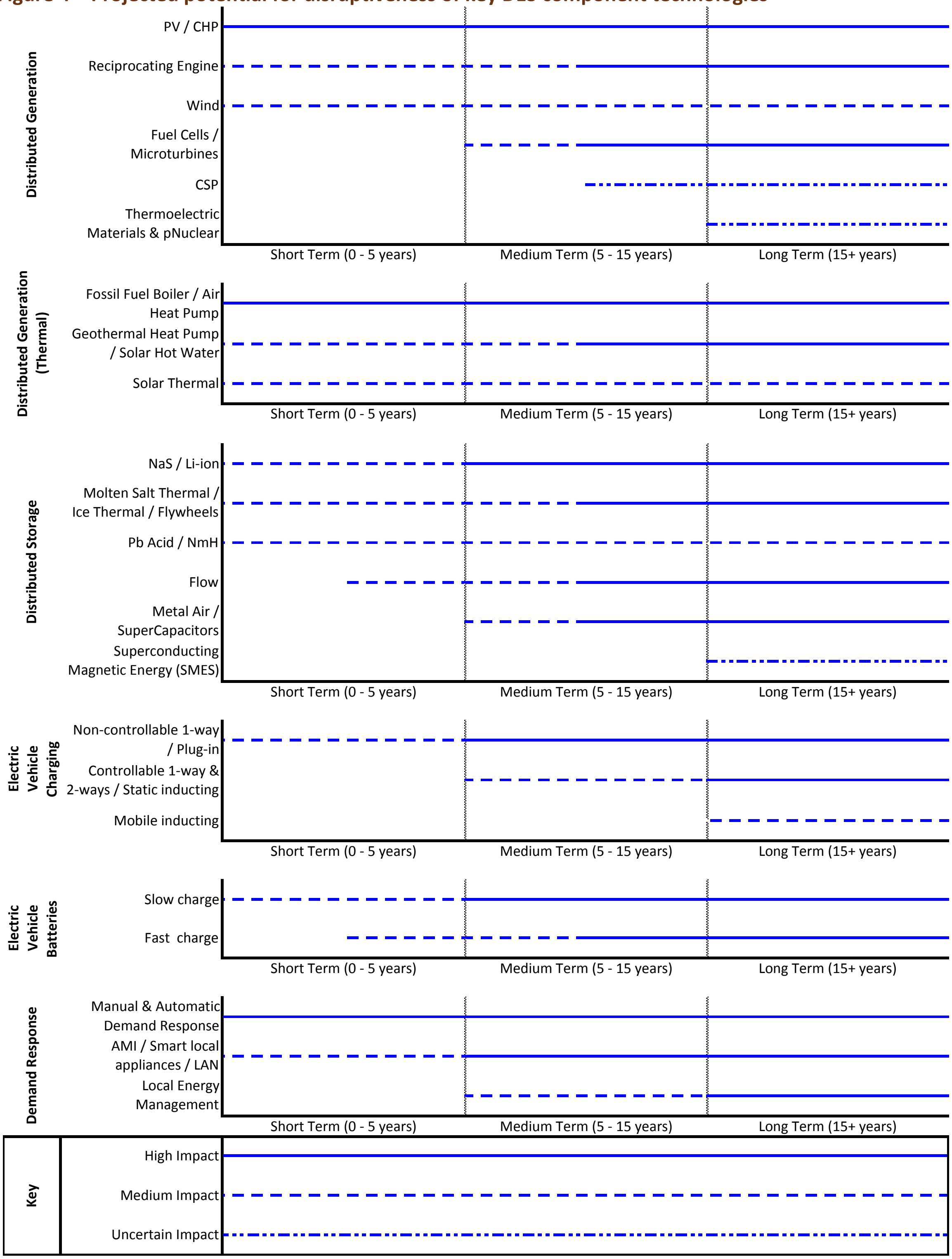
By comparing the timing and impact levels within each DER category in Figure 4, we gain an initial perspective of which component technologies are likely to have the highest impact on the existing distribution sector paradigm. For example, solar PV and combined heat and power (CHP) will likely prove higher-impact amongst distributed generation technologies than distributed wind.

Technologies in Figure 4 are, in certain cases, grouped and listed in the same row entry. These groupings may in fact consist of a diverse set of technologies that are, nevertheless, likely to exhibit similar patterns of impact and development, and thus similar levels of disruptiveness to the existing power sector paradigm. For example, while photovoltaics and CHP are distinct distributed generation technologies, they are grouped together in Figure 4 because they are likely to be high-impact technologies in the relatively short term (within the next five years) and likely to remain high-impact in the medium and long terms. Similarly, while Li-ion and NaS batteries are two distinct battery technologies and may be utilized for different applications, they have not yet reached penetration levels that make them high-impact now and likely will not be high-impact within the next five years. As battery technology improves and costs decline, however, they have the potential to be highly disruptive in the medium and long terms.

Figure 4 and the full technology assessment matrix in Appendix A focus exclusively on DERs. ICTs must also be analyzed in a similar manner. As illustrated in the three-layer DES technology framework, ICTs are typically employed in response to the development of DERs, layered atop DER infrastructure to enhance utilization of DERs. Thus, they are logically the second unit of technology assessment. In addition, while many of the listed technologies may be viable in the long term, this preliminary assessment does not attempt to forecast which technologies will emerge as dominant technologies nor which groups of technologies will coexist on a future grid.

Several of the technologies listed may in fact be in direct competition with one another, and it is unlikely that all will co-exist at high penetrations. Combinations of individual DER technologies and ICTs may form a variety of DESs in the power sector of the future, and Figure 4 does not consider potential synergies created by these DESs.

Figure 4 – Projected potential for disruptiveness of key DES component technologies



1.3. Services Offered by DES Component Technologies

With a clear boundary around the categories of technologies relevant to the evolution of DESs (Section 1.1), and a catalog of the relevant technologies within each category (Section 1.2), DES component technologies can be evaluated according to their abilities to provide the services required by electricity system stakeholders. Identifying the services that can be provided by component technologies then enables the identification of technology *combinations* that yield viable DESs that can provide a range of stakeholder services (Section 1.5).

The two primary categories of stakeholders interested in DES services are:

1. **Electricity end-users**: e.g., residential, commercial, and industrial electricity consumers.
2. **Up-stream system operators and market actors**: e.g., distribution utilities, TSOs, DER aggregators, and wholesale market participants.

Each group of stakeholders has a set of service requirements or needs that may be met by a variety of DES component technologies. The technologies most likely to evolve to a high degree of penetration within the distribution network are those technologies that most effectively provide the services that stakeholders require. Table 1 lists the service requirements of end-users and up-stream actors.

Table 1– Stakeholder needs

End-users	Up-stream Actors
Comfort: heating and cooling	Energy
Mobility	Power / Capacity
Lighting	Voltage control
Other personal energy services	Frequency regulation
Reliability	Increased reliability / Resilience to outages
Control	Black-start / outage recovery
Convenience	Primary reserves
Affordability	Secondary reserves
Variable cost stability	Tertiary reserves
Other concerns (environmental impact)	Flexibility / Integration of intermittent renewables
Other concerns (independence)	CapEx investment deferral
	OpEx reduction
	Reduction of losses
	Risk-mitigation
	Arbitrage of energy price differentials
	Affordability

The DES technology performance assessment begins with an evaluation of *whether or not* a given component technology can provide a particular service. If, in this binary evaluation, a technology can potentially provide a particular service, future quantitative assessment can evaluate *how well* the technology provides that service. If, on the other hand, this binary evaluation reveals that a technology cannot provide a particular service (not every technology category is suitable for providing every service), no further analysis need be completed for that technology-service combination, as it is unlikely or infeasible for a business model to emerge.

The technology performance matrix in **Appendix A** summarizes the results of an initial assessment of the ability of individual DERs to provide a variety of services. Stakeholder service requirements for end-users are listed in the first row of the tables in Appendix A. The particular technologies under evaluation are listed in the first column of the tables in Appendix A. Below are two examples of how individual DERs are evaluated on their abilities to provide any of the key stakeholder needs and services.

Example 1: Distributed generation

DG technologies can be used to meet a variety of stakeholder service needs. For example, Table 2 shows an assessment of solar PV for low voltage or household consumers. Table 2 presents a single row of the full technology performance matrix in Appendix A.

Distributed solar PV can be used to meet end-user needs such as comfort in the form of electricity for cooling or heating, lighting, and other energy requirements – services that are listed in columns A, C, and D, respectively, of the technology assessment matrix. Because of its intermittency, distributed solar is characterized as having low reliability – measured by capacity factor and shown in column E. Solar PV cannot be dispatched by end-users – in contrast to, for example, natural gas fired DG – and thus provides a low degree of control (column F). Since end-users need not actively participate in the operation of distributed PV however, it is characterized by a high degree of user convenience (column G). Column H characterizes the relative present-day affordability of distributed PV as low, medium, or high. Variable cost stability, shown in column J, is primarily tied to input costs, such as fuel for DG units. Solar PV is characterized by high stability since there are no input fuel costs and relatively static operation and maintenance (O&M) costs. Technology performance associated with other concerns such as environmental impact and grid independence are measured in columns K and L, respectively.

Table 2– Example technology assessment for residential, low voltage solar PV

End-User Services										
A	B	C	D	E	F	G	H	I	J	K
Comfort: Heating/ Cooling	**Mobility**	**Lighting**	**Other Personal Energy Services**	**Reliability** [Capacity Factor as a Proxy]	**Control** [High, Medium, Low]	**Convenience** [High, Medium, Low]	**Affordability** [High, Medium, Low]	**Variable Cost Stability** [High, Medium, Low]	**Other concerns (environmental impact)** [High, Medium, Low]	**Other concerns (independence)** [High, Medium, Low]
X	-	X	X	Low (10-22%)	Low	High	U.S.: Low-Medium Europe: Medium-High	High	Low	High

Example 2: Distributed Storage

Sodium sulfur (NaS) batteries are one of numerous battery chemistries under development for grid-scale energy storage that have shown promise. Continuing research and demonstration projects are under way in multiple countries including Japan and the United States. Table 3 shows the technology assessment of NaS batteries for upstream power system stakeholders (e.g., utilities or system operators).

NaS batteries have demonstrated relatively high energy densities (kWh/kg) and are considered to be well suited for grid-scale energy storage applications, as indicated by an 'x' in column A of Table 3. The high operating temperature of NaS batteries requires thermal management equipment that makes NaS batteries more suitable for stationary storage applications than mobile applications. Existing NaS batteries are primarily used for ancillary services such as regulating voltage (column C), providing backup power (column E) or black-start recovery (column F), and providing secondary and tertiary reserves (columns H and I). The batteries experience degradation with frequent charge/discharge cycling at rated power, making them unsuitable for high-power applications (column C), except possibly when controlled in aggregate. Other storage technologies that may be better suited for high-power applications include ultra-capacitors or flywheels. NaS batteries are also utilized for load leveling and peak shaving, thus enabling deferral of network infrastructure investment (column K) and mitigation of cost-of-service variability and risk (column N).

Table 3 – Example technology assessment for NaS stationary storage

Upstream Services								
A	B	C	D	E	F	G	H	I
Energy	Power / Capacity	Voltage control	Frequency regulation	Increased reliability / Resilience to outages	Black-start / outage recovery	Primary Reserves	Secondary Reserves	Tertiary Reserves
X	In aggregate	X (possibly)	X	X	X		X	X
J	K	L	M	N	O	P		
Flexibility / Integration of intermittent renewables	CapEx Investment deferral	OpEx reduction	Reduction of losses	Risk-mitigation	Arbitrage of energy price differentials	Affordability [High, Medium, Low]		
X	X			X	X	Low-Medium		

It is important to note that there does not currently exist a sound methodology by which to compare the performance of various DES component technologies across a wide range of potential services. Developing appropriate methodologies constitutes an active area of research for the *Utility of the Future* project. The most heavily utilized measure of economic performance across energy technologies today is the levelized cost of energy (LCOE). While the LCOE is an informative metric, its utility has significant limitations, and alternative performance measures may be more informative. Furthermore, LCOE provides no information about the relative performance of DERs in providing non-energy services to end-users or up-stream actors, including ancillary services, system balancing, or greater resiliency to supply interruptions. Thus, the development of new metrics or evaluation methods is crucial for assessing the performance of DES component technologies in providing stakeholder services, and to enable comparisons of the abilities of multiple technologies to provide a variety of services.

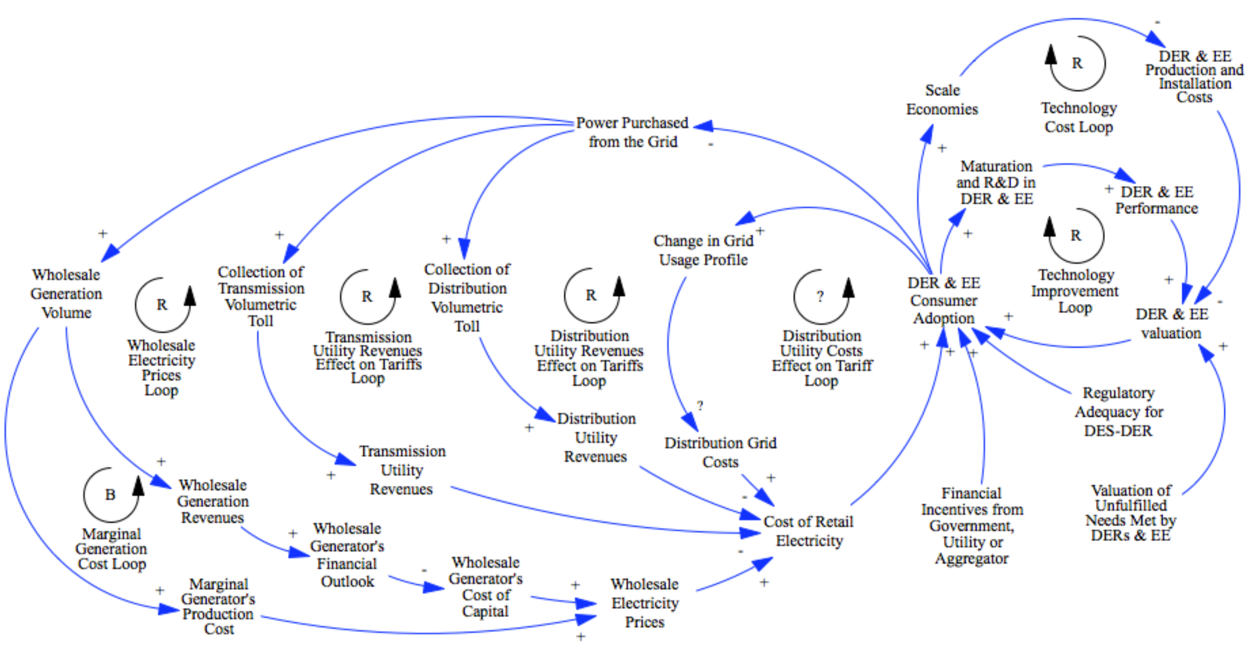
1.4. Distributed Energy Resources: a "Disruptive Threat"?

Faced with the wide range of emerging DERs cataloged above, many electric utilities and industry observers have worried that these new technology trends will prove massively disruptive to the age-old utility business model (see EEI, 2013; Deloitte, 2013). Analogies have been drawn to the deregulation of the airline industries or the overthrow of the landline telephone business by wireless cellular technology, both of which resulted in the widespread bankruptcy of incumbent players. The Edison Electric Institute, a trade group representing the United State's largest investor-owned utilities, describes a "vicious cycle" of "systemic disruptive forces" that could see DER adoption become a self-reinforcing cycle that decimates the incumbent utility's core business (EEI, 2013). In this cycle, improvement in the price and performance of DERs (and end-use energy efficiency) spurs customer adoption, which reduces utility revenues. Reduced revenues then require a rate increase to cover the utility's fixed costs. Higher rates in turn drive even more adoption of DERs and efficiency. Some observers have dubbed this the utility "death spiral" (Lehr, 2013), implying a fundamental incompatibility between growing DER adoption and the financial health of incumbent utilities.

This report agrees that under certain regulatory contexts and at high penetration, the use of DERs has the potential to cause a paradigm shift in the operation of the electric power sector. We similarly argue in Sections 2 and 3 that, under these conditions, the business models and regulation of incumbent utilities will both need to evolve to keep pace with the changing nature of network uses and end-use customer needs. At the same time, our research indicates that the system dynamics or feedback loops associated with adoption of DER are more nuanced and complicated than the simple "vicious cycle" described above.

Figure 5 depicts a broader and more complex description of the system dynamics of DER adoption than has appeared in the literature to date. As indicated in Figure 5, improvements in DER and energy efficiency (EE) performance *are* key accelerators of consumer adoption—as are incentives for adoption provided by governments, electric utilities, or third party aggregators.

Figure 5 – System dynamics of distributed energy resource adoption



Growing consumer adoption of DER and EE will both reduce purchases of power from the incumbent utility and result in important changes in the customer's grid usage patterns. Yet while reducing the volume of energy purchased from external generators and delivered across distribution networks can certainly reduce distribution utility revenues, changing grid usage patterns will have a more ambiguous impact on the costs of the distribution utility. Some technologies, such as dispatchable or peak-coincident DG, smart inverters capable of providing voltage regulation, storage, and DR, may be harnessed by distribution utilities to reduce network costs and defer capital expenditures. Others, including significant generation during minimal load, high-penetrations of EV charging, etc. may substantially increase distribution grid costs.

Figure 5 highlights three important takeaways:

- First, the specific format of network use of system charges, including the proportion of fixed, capacity-based, and volumetric charges, has an important impact on the relationship between reduced grid purchases and declining distribution utility revenues, and thus the potential for a reinforcing feedback loop of DER adoption (see the "Distribution Utility Revenues Effect on Tariffs Loop").
- Second, not all DERs will result in a change in grid usage profile that will drive an increase in distribution network costs; some in fact may decrease distribution utility costs and could increase the utility's profit margins and/or reduce tariff rates under some forms of remuneration (e.g., incentive-based revenue cap) (see the "Distribution Utility Costs Effect on Tariffs Loop").
- Third, the precise balance of these two trends will determine whether or not DER adoption will drive an increase in utility rates.

In addition, Figure 5 depicts the potential impact of this cycle on wholesale markets and transmission utilities upstream. Importantly, this portion of the cycle is also ambiguous.

- Declining wholesale generator revenues could cause increases in the cost of capital for generation owners, which could increase wholesale power prices and accelerate adoption of DER and EE (see the "Wholesale Electricity Prices Loop").
- At the same time, reduced demand for wholesale generation, and in particular any declines in peak demand, could reduce wholesale market prices (see the "Marginal Generation Cost Loop"). This would lower retail prices and potentially slow the reinforcing feedback loop by reducing incentives for DER and EE adoption.
- Finally, declining grid power purchases may also reduce transmission utility revenues, which given substantial fixed costs, could require an increase in transmission network tariffs (see the "Transmission Utility Revenues Effect on Tariffs Loop"). This would potentially reinforce the adoption of DER and EE.

In short, **while a self-reinforcing feedback loop for DER adoption is *possible*, it is *not* pre-ordained.** Careful examination and analysis of the potential system dynamics at play as DER adoption increases will be essential to determine the ultimate impact on incumbent distribution utilities and others across the value chain.

1.5. Identifying DER and ICT Combinations to Form DESs

The component technologies described previously – DERs and ICTs from Layers 1, 2, and 3 of the DES component technology framework – can be combined to form a variety of DESs.

Current applications of DESs tend not to take advantage of the potential synergies between the DES components. For example, existing distributed PV systems rarely provide non-energy services, despite having the capability to provide ancillary services. However, the DESs that will likely emerge as winners will take advantage of the synergies between the various capabilities of the DER and ICT components.

Example 1: Residential solar PV with a smart inverter and energy management system

To illustrate this point, consider a DES combining rooftop solar modules along with a smart inverter and a home energy management system at a single residence. (Aggregation of multiple residences can form a larger DES). Table 4 below illustrates how combining these multiple DES component technologies offers a complimentary set of services that enhances value for both end-users and distribution utilities. For example, a smart inverter can disconnect a distributed PV installation from the distribution network in case of outages, and inverter communication standards can allow a distribution utility to monitor smart inverters, improving visibility of solar output throughout a service area. Smart inverters also enable adjustment of the power factor of the PV system to provide voltage regulation or reactive power services to the distribution utility or a third-party aggregator. With a home energy management system, a residential DG user can monitor and control loads and on-site electricity production and optimize both to best arbitrage differences in electricity prices, avoid peak demand charges, or respond to real-time price signals. Volumetric energy sales from the distribution utility to the end user are likely to reduce significantly. In the case of this DES, residential users can disconnect from the distribution network and gain much greater autonomy and control over their load shape than conventional network users (this option would be significantly enhanced by future installation of a distributed storage system).

Table 4 – Example DES: single end-user DES with solar PV, smart inverter, and energy management system

		End-User Services							
DES Component Technology		Comfort: Heating/ Cooling	Lighting	Reliability	Control	Convenience	Variable Cost Stability	Other concerns (environmental impact)	Other concerns (independence)
	Solar PV ~5 kW residential system	X	X	X				X	X
	Smart Inverter				X				
	Home energy management system					X	X		

		Upstream Services						
DES Component Technology		Energy	Power/ Capacity	Voltage Control	Frequency Regulation	CapEx Investment Deferrals	Increased Reliability/ Resilience to outages	Arbitrage of energy prices
	Solar PV ~5 kW residential system	X	X	X		X	X	X
	Smart Inverter			X	X			
	Home energy management system							

Example 2: Institutional microgrid with local network of intelligent devices

A DES may also take the shape of a commercial campus microgrid – perhaps for a university, hospital, government facility, or data center – that is equipped with a natural gas, biogas, or diesel-fired combined heat and power (CHP) unit (see Table 5). Load is primarily met by onsite generation with supplemental power provided by the local retail company; however, the microgrid may island from the distribution network to ride through outages.

Motivated by the need for reliability of supply or cost savings, microgrids offer end-users flexibility to disconnect from the distribution network, but still require the distribution utility to maintain sufficient infrastructure to accommodate load and excess power supply when the microgrid is connected to the network. Distributed intelligence throughout the microgrid allows supervision and control of equipment such as load shedding and load adjustment, and ensures that all critical loads can be served during outages. Here too, the combination of CHP distributed generation with monitoring and remote control of loads offers greater benefit and value to the end-user and upstream actors than distributed CHP alone.

Table 5 – Example DES: institutional microgrid DES with local network of intelligent devices

		End-User Services						
DES Component Technology		Comfort: Heating/ Cooling	Lighting	Reliability / Resilience to outages	Control	Variable Cost Stability	Other concerns (environmental impact)	Other concerns (independence)
	Institutional-scale CHP	X	X	X	X	X	X	X
	Distributed intelligence and remote control			X	X			

		Upstream Services						
DES Component Technology		Energy	Power/Capacity	Voltage Control	Frequency Regulation	Black start/outage recovery	Reserves	Arbitrage of energy prices
	Institutional-scale CHP	X	X	X	X	X	X	X
	Distributed intelligence and remote control			X	X			

Example 3: Distributed capacity operator (aka "virtual peaker")

Finally, multiple, decentralized units of DG, DS, and DR may be aggregated, remotely controlled, and dispatched to provide capacity or ancillary services (see Table 6). The aggregator or operator of the distributed capacity resources operates a "virtual peaker" that competes directly with centralized power plants in capacity markets. The use of distributed resources for capacity can be highly disruptive to generation utilities if the virtual peaker offers lower-cost capacity than conventional peaking plants.

Table 6 – Example DES: distributed capacity operator or "virtual peaker"

DES Component Technology	End-User Services: Comfort: Heating/ Cooling	Lighting	Reliability	Control	Convenience	Variable Cost Stability	Other concerns (environmental impact)	Other concerns (independence)
Residential solar PV, microturbines, generators	X	X	X	X			X	X
Distributed Li-ion battery storage			X	X		X		X
AMI - remote load control			X	X	X	X		

DES Component Technology	Upstream Services: Energy	Power/Capacity	Voltage Control	Frequency Regulation	Black start/outage recovery	Reserves	Arbitrage of energy prices	Risk Mitigation
Residential solar PV, microturbines, generators	X	X	X	X	X	X	X	
Distributed Li-ion battery storage		X	X		X	X	X	X
AMI - remote load control		X	X	X				

Key Takeaways: Technology

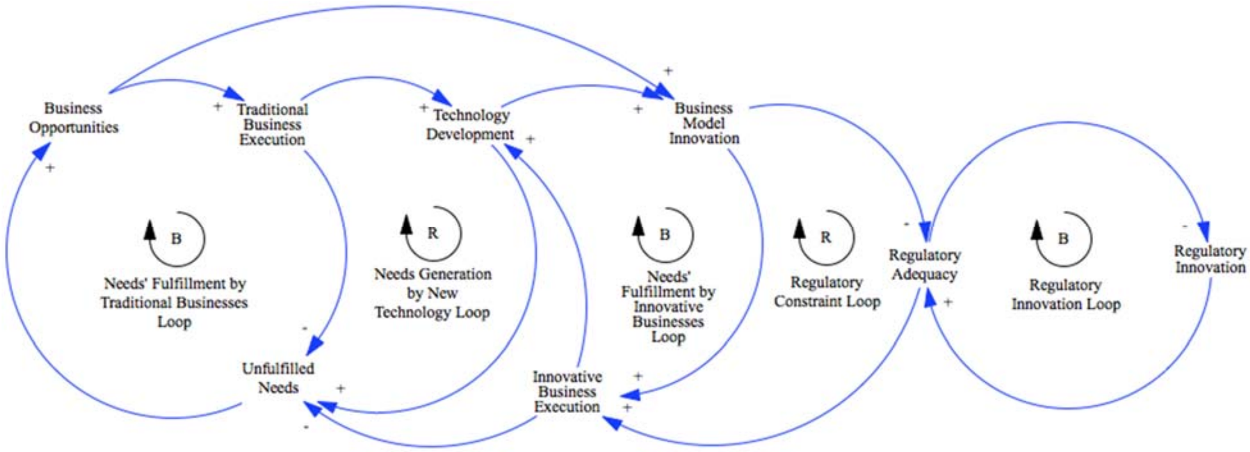
1. DESs, or distributed energy systems, are comprised of distributed energy resources (DERs) and information and communication technologies (ICTs). New business models for utilities or third parties can be built around DESs. These business models exist within a specific regulatory framework, which is embedded within the boundaries of the broader sociotechnical power system.
2. The core DES component technologies can be classified according to a 3-layer framework: Layer 1 comprises power distribution networks and DER components; Layer 2 consists of ICTs for system monitoring, control, and communication; and Layer 3 encompasses ICTs for data analysis and decision-making.
3. In order to compare the abilities of DES component technologies to deliver a range of services required by electricity end-users and upstream system operators and market actors, sound performance metrics must be developed.
4. A self-reinforcing feedback loop (a "virtuous " or "vicious cycle," depending on the viewpoint) of customer DER adoption is possible, but *not* pre-ordained. Careful examination and analysis of the potential system dynamics at play as DER adoption increases will be essential to determine the ultimate impact on incumbent distribution utilities and others across the value chain.
5. While some DERs and ICTs will prove more disruptive than others, the disruptiveness of technologies will be magnified when individual DERs and ICTs are combined into DESs. DESs are expected to have a greater impact than the sum of the impacts of DER components acting alone.

2. Business Models

The business models of electric utilities have co-evolved over more than a century alongside a changing regulatory environment. Over the last two decades, an era of industry and regulatory restructuring saw electric utilities evolve from protected franchise electricity suppliers to a diverse blend of regulated integrated utilities, monopoly network companies, and competitive generators, retailers, and other service providers. Today, the growth of DESs is further accelerating business model innovation in the power sector, as incumbents evolve and new entrants emerge to respond to and take advantage of the new characteristics and services offered by these systems.

As new technologies emerge and existing technologies become increasingly competitive, innovative business models evolve to offer new and improved methods to fulfill customer needs (see Figure 6). At the same time, the capabilities offered by these novel technologies can also create new customer needs or demands, driving further business model innovation. As we discuss in Section 3, the adequacy of existing regulation also often acts as a key constraint on business model formation, particularly in the electric power sector. The emergence of new business models therefore often sparks a corresponding evolution of the regulatory framework, which can proceed in either an anticipatory or reactive manner. Understanding the emergence of new DES-related business models is thus central to analyzing the dynamic evolution of the electric power sector.

Figure 6. Dynamics of technology, business, and regulatory co-evolution



This section presents an initial approach to assessing the emergence of business models incorporating DES technologies within the distribution system, including the role of both incumbents and new entrants. The remainder of the section proceeds in five parts: first, we introduce the concept of business models in the DES context; second, we present a basic, high-level classification of the attributes of DES-related business models; third, we demonstrate the application of our business model attributes framework to analyze both existing (real world) and prospective DES business models; fourth, we discuss the competitive nature of new DES business models; and fifth, we discuss the strengths and challenges for the incumbent regulated utility in harnessing DES opportunities. In the discussion of the incumbent utility, this paper outlines the characteristics of several potential alternative business models for the regulated electric distribution utility that may emerge as DER technologies continue to develop and enter the market.

2.1. Business Models in a Changing Utility World

The term "business model" is used in a number of ways in practice and in the academic literature. The key element in all of them is that **a business model is a method of value creation**. In this document we have adopted the following working definition of business models:

- Business models present the rationale of how an organization creates, delivers, and captures value. This rationale has to cover the four areas of a business: "Value proposition, Customer interface, Infrastructure, and Revenue model" (Richter, 2012).
- A business model "describes a transaction structure that involves stakeholders" (Wei et al. 2013), including both the suppliers/sellers and the consumers/buyers in value based transactions.

It is also important to note that **value migration occurs when incumbents' outdated business models do not meet the evolution of customers needs, creating new business design opportunities.** Incumbents often ignore or overlook these opportunities to address new customer needs, presenting significant openings for newcomers (Slywotzky, 1996).

Utilities will have to acknowledge that the power sector environment is changing and that in this dynamic scenario they must be able to identify and take advantage of the new opportunities arising. The nature of the change is wide, as it does not only involve technology, regulation, and markets. It also considers a redefinition of the electric power sector, including what is beyond the meter. This means adding “Consumption” to the traditional “Generation, Transmission, and Distribution” segmentation of the industry. **Focusing on value creation alone and ignoring the value migration underway from traditional industry segments to the “Consumption” segment and related behind-the-meter focused business models would be unwise**, particularly for an electric distribution utility or retailer.

2.2. Business Model Attributes and Opportunities

In order to understand the potential business models that might arise in the evolving electricity sector, this section presents a framework that helps explore and understand the logic of business models. The *Utility of the Future* project will undertake further analysis incorporating detailed techno-economic modeling of various business models’ ability to meet the needs of system actors, in order to identify the most suitable business opportunities in the context of DESs.

Based on the economic activities that exist in electric power systems, we have defined six core “**attributes**” of business models. At the highest level, the attributes of the business model can be characterized by the primary activities of the business, which define how that business approaches each of the four primary areas of business (value proposition, customer interface, infrastructure, and revenue model). Specifically, the business may:

- **Own** assets;
- **Operate** assets and/or systems of assets;
- **Fund** the acquisition or the operation of assets;
- **Provide Information** and related services to asset owners or operators;
- **Build** or manufacture assets; or,
- **Aggregate** with dispersed physical locations and/or disaggregated ownership

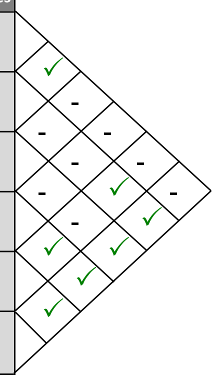
The remainder of this section expands on these six attributes by indicating how they relate to different DES-related business opportunities. As we have mentioned in previous sections, we identify DES implementation as having the potential to drive significant changes in future electricity distribution systems. For that reason, our use of the framework will be focused on business opportunities related to DES component technologies, which are, at the highest level:

- **Distributed Generation** (DG);
- **Distributed Storage** (DS);
- **Electric Vehicles** (EVs) and associated charging infrastructure;
- **Demand Response** (DR); and
- **Information and Communications Technology** (ICT).

The business model matrix shown in Figure 8, illustrates the multiple business opportunities/technologies (horizontal axis: DG, DR, etc.), as well as the core business attributes (vertical axis: own, fund, etc.). Within the main matrix, a green check in a cell indicates a likely opportunity for a business model's main revenue source or value proposition to be structured around the given attribute. A red "X" in a cell indicates that it is unlikely that a business model could be structured such that the given attribute would serve as the business model's main revenue source or value proposition. Finally, a black dash indicates a possible, but not particularly strong or fully developed, opportunity for the given attribute to serve as a business model's main revenue source or value proposition. The half-matrix on the right side identifies with a green check pairs of business model attributes that have high potential for synergy (e.g. the value created by the combination of the two attributes is non-linear), whereas pairs of business model attributes with a black "–" are neutral.

Figure 8. Core DES business model attributes and associated opportunities

Technologies (DES) / Business Models Attributes	Distributed Generation	Distributed Storage	Electric Vehicle Infrastructure	Demand Response	Information and Communic. Technologies	Technologies (DES) / Business Models Attributes
Own	✓	✓	✓	✗	-	Own
Operate	✓	✓	✓	✓	✓	Operate
Fund	✓	✓	✓	✗	-	Fund
Provide Information	✓	✓	✓	✓	✓	Provide Information
Build	✓	✓	✓	✗	✓	Build
Aggregate	✓	✓	✓	✓	✓	Aggregate



2.3. DES Business Models

This section demonstrates the application of the business model attribute framework presented in Section 2.2 in two different contexts. First, Section 2.3.1 uses it to decompose, understand, and characterize two examples of existing U.S.-based companies currently implementing successful DES-related business models: EnerNOC and NRG Solar. This analysis will demonstrate the applicability of the framework to real-world, non-theoretical business models. Next, Section 2.3.2 utilizes the framework to analyze prospective new business models that might arise to accompany the three different DES configurations presented in Section 1.5.

2.3.1 Applying the Framework: Real-world DES-related Business Models

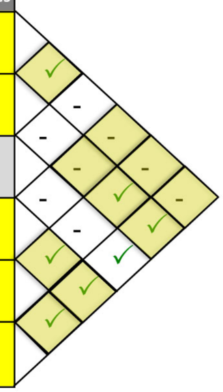
EnerNOC

EnerNOC principally serves as an aggregator and intermediary between electric utilities, transmission system operators and electricity end-users. The company contracts with electricity users willing to reduce their demand during critical periods and sells the resulting demand reductions as capacity, balancing services, or other ancillary services to electric utilities or system operators (Toffel, 2012).

EnerNOC's business model is based on installing ICT infrastructure on the contracted electricity end-user's premises, which enables EnerNOC to remotely monitor—and in many cases remotely control—the end-user's energy usage. This allows EnerNOC to aggregate multiple sources of demand response and, through remote control or manual response, dispatch electricity end-users to meet system operator or utility requirements for capacity, balancing, or other ancillary services. The contract with the electricity end-users states how the profits are shared between the end-user and EnerNOC as the broker and aggregator. In addition, EnerNOC increasingly uses the detailed energy usage data generated for each customer to provide information to end users and identify opportunities for them to optimize energy consumption patterns to reduce demand charges or energy charges.

Figure 9. DES business model attributes: EnerNOC

Technologies (DES) / Business Models Attributes	Distributed Generation	Distributed Storage	Electric Vehicle Infrastructure	Demand Response	Information and Communic. Technologies	Technologies (DES) / Business Models Attributes
Own	✓	✓	✓	✗	-	Own
Operate	✓	✓	✓	✓	✓	Operate
Fund	✓	✓	✓	✗	-	Fund
Provide Information	✓	✓	✓	✓	✓	Provide Information
Build	✓	✓	✓	✗	✓	Build
Aggregate	✓	✓	✓	✓	✓	Aggregate



As we can see in the triangle at the right of Figure 9, there are clear synergies between the Build, Own, and Operate attributes associated with EnerNOC's installation of proprietary ICT systems for energy monitoring, management, and control—although ownership of these assets, rather than lease or sale to electricity end-users, is more a function of the proprietary nature of the ICT systems, rather than a necessity. In addition, there is no conflict (but also no clear synergy) between the Provide Information attribute and the Operate attribute, as in the case when EnerNOC directly operates demand response resources through remote or automated controls and uses energy usage data to provide further information to end users on how to optimize their electricity demand.

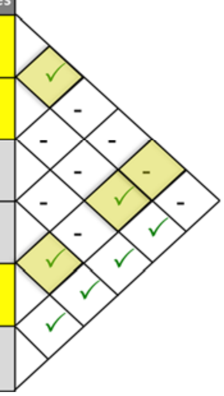
NRG Solar

NRG Energy is one of the largest U.S. utilities with substantial assets in competitive wholesale generation markets across the Untied States. Despite NRG's sizable investment in conventional centralized generation, NRG has developed several new DER and DES-based business models. While the success of these new DES business models may ultimately cannibalize their traditional generation business, NRG seems committed to proactively heading off other potential competitors and exploring opportunities for value creation in this emerging market segment.

In one example, NRG subsidiary NRG Solar installs large-scale solar PV systems on commercial or industrial properties (a Build function). NRG then offers two options to the property owner: purchase the system from NRG directly or allow NRG to continue to own and operate the system and lease it to the property owner. In either case, NRG also typically arranges a power purchase agreement (PPA) with an upstream electricity market actor for any excess energy generated by the solar system after on-site consumption. In this case, NRG must also typically install advanced meter infrastructure (an example of ICT) to monitor energy exported from the site.

Figure10. DES business model attributes: NRG Solar

Technologies (DES) / Business Models Attributes	Distributed Generation	Distributed Storage	Electric Vehicle Infrastructure	Demand Response	Information and Communic. Technologies	Technologies (DES) / Business Models Attributes
Own	✓	✓	✓	✗	-	Own
Operate	✓	✓	✓	✓	✓	Operate
Fund	✓	✓	✓	✗	-	Fund
Provide Information	✓	✓	✓	✓	✓	Provide Information
Build	✓	✓	✓	✗	✓	Build
Aggregate	✓	✓	✓	✓	✓	Aggregate



The NRG Solar business model is thus a Build, Operate, and Own business model, although in the case where the customer chooses to directly purchase the system from NRG, it is a Build only or Build and Operate model. We can see in the triangle at the right of Figure 10 that there is a natural synergy between the Build, Own, and Operate functions, making this a logical business model for NRG Solar.

While to date, NRG Solar has focused on installing a single DER (e.g., solar PV), NRG has discussed plans to expand offerings to aggregate DESs as well as include DESs potentially encompassing solar PV, batteries, and/or natural gas-fueled microturbine, Stirling engine, or fuel cell systems (Maloney, 2013; Martin, 2013).

2.3.2 Applying the Framework: Potential Business Models for Prospective DES Configurations

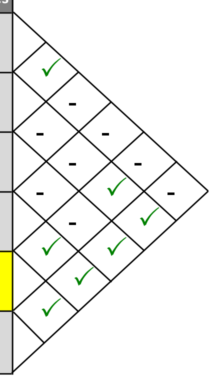
In Section 1.5, three different DESs were presented that spanned a range of possible configurations, including: Single end-user DES, Microgrid DES, and Dispersed DES. We will now apply the business model attribute framework to analyze potential business models for each of those three DESs.

Single end-user DES: Residential solar PV, smart inverter, energy storage, and energy management system

The first DES presented in Section 1.5 is a combination of solar PV, a smart inverter, an energy storage system, and an energy management system in a single residential location. This DES—which is an instance of single end-user DES—primarily aims to address needs of end-use energy generation as well as improved control, reliability, and affordability. A system like this features distributed generation and the capability to isolate from the grid. Those capabilities, which could be used to avoid peak period energy prices or even to isolate in case of blackouts, present many business opportunities. Figure 11 presents the business model attributes of the DES builder/installer offering the full range of DES services as an attractive value proposition to an end-user.

Figure 11. DES business model attributes: single end-user DES with solar PV, smart inverter, energy storage system, and energy management system

Technologies (DES) / Business Models Attributes	Distributed Generation	Distributed Storage	Electric Vehicle Infrastructure	Demand Response	Information and Communic. Technologies	Technologies (DES) / Business Models Attributes
Own	✓	✓	✓	✗	-	Own
Operate	✓	✓	✓	✓	✓	Operate
Fund	✓	✓	✓	✗	-	Fund
Provide Information	✓	✓	✓	✓	✓	Provide Information
Build	✓	✓	✓	✗	✓	Build
Aggregate	✓	✓	✓	✓	✓	Aggregate



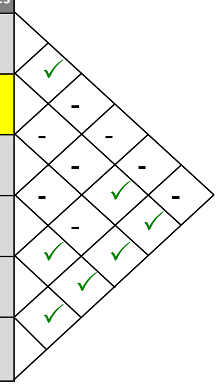
In this model, untapped synergies exist between the build and operate functions as well as build, operate, and aggregate. For example, aggregating single-site DESs and operating them in unison could offer system services and capture value beyond what a single-site system can.

Microgrid DES: Institutional microgrid with local network of intelligent devices for monitoring and control

The second DES presented in this section is an institutional local microgrid including cogeneration and a network of intelligent devices for monitoring and control of DG and loads. This DES—which is an instance of a microgrid DES—usually focuses its design in addressing reliability and resilience needs by giving the institution a certain degree of independence from grid outages and related vulnerabilities. These systems can also contribute to the affordability of the end-user's energy supply. Note that while multiple DESs are deployed within one microgrid, this is not an example of aggregation, as the systems are owned by a single entity and are not geographically dispersed beyond the institutional campus (in contrast, a neighborhood-wide microgrid involving DERs owned by multiple entities would be an example of ownership aggregation). Such a system has a level of complexity which requires some know how regarding distributed resources and power system management, presenting a business opportunity. Figure 12 presents a business model related to the operation of the microgrid on behalf of the institutional end-user.

Figure 12. DES business model attributes: institutional microgrid with local network of intelligent devices

Technologies (DES) / Business Models Attributes	Distributed Generation	Distributed Storage	Electric Vehicle Infrastructure	Demand Response	Information and Communic. Technologies	Technologies (DES) / Business Models Attributes
Own	✓	✓	✓	✗	-	Own
Operate	✓	✓	✓	✓	✓	Operate
Fund	✓	✓	✓	✗	-	Fund
Provide Information	✓	✓	✓	✓	✓	Provide Information
Build	✓	✓	✓	✗	✓	Build
Aggregate	✓	✓	✓	✓	✓	Aggregate



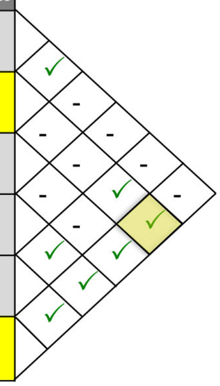
As can be seen in the triangle on the right—where the intersection of "Operate" and "Build" has a green check mark— the business of operating this microgrid could be expanded to the design and installation of new microgrids as well (a "Build" opportunity) or ownership of the microgrid (an "Own" opportunity) and either leasing it to the institution or selling the resulting energy and services to the end user.

Dispersed DES: Distributed capacity operator (aka "virtual peaker")

The third example DES is made up of a set of geographically dispersed DERs (DG, DS, and DR) working as a distributed capacity operator, or "virtual peaker," through remote sensing, remote controlling, and ICT systems. The structure of this DES—which is an instance of a dispersed DES—is commonly associated with aggregation business models, such as the EnerNOC business model described in Section 2.3.1. A business structure similar to that employed by EnerNOC may also be suitable for operating a dispersed aggregation of DG, DS, or EV charging infrastructure, for example, as well as traditional DR resources. We present the virtual peaker business model attributes in Figure 13. As indicated by the half-matrix to the right, potential synergies exist with construction or ownership of the DER and ICT attributes as well.

Figure 13. DES business model attributes: distributed capacity operator or "virtual peaker"

Technologies (DES) / Business Models Attributes	Distributed Generation	Distributed Storage	Electric Vehicle Infrastructure	Demand Response	Information and Communic. Technologies	Technologies (DES) / Business Models Attributes
Own	✓	✓	✓	✗	-	Own
Operate	✓	✓	✓	✓	✓	Operate
Fund	✓	✓	✓	✗	-	Fund
Provide Information	✓	✓	✓	✓	✓	Provide Information
Build	✓	✓	✓	✗	✓	Build
Aggregate	✓	✓	✓	✓	✓	Aggregate



2.4. New Business Models and Incumbent Market Actors

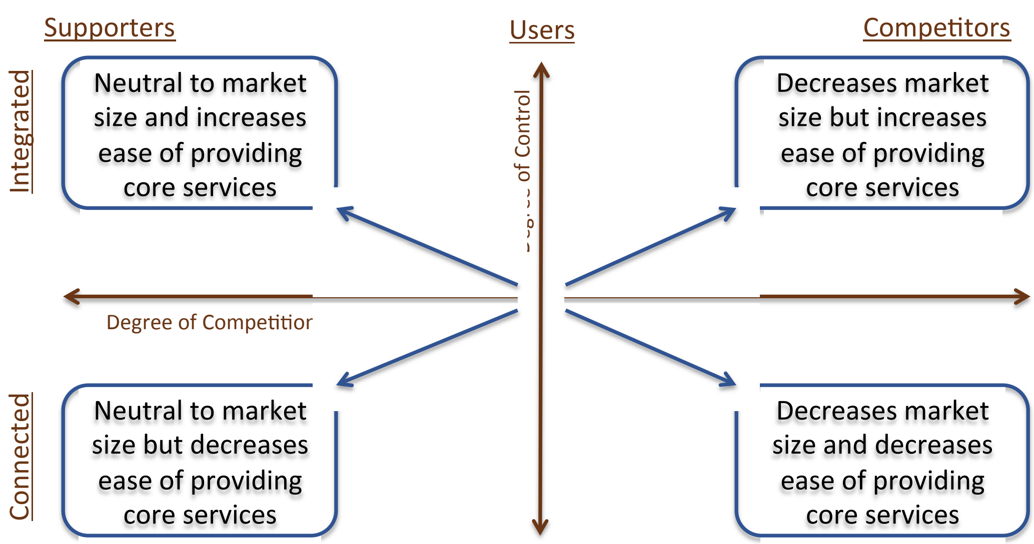
This section provides an initial assessment of how certain DES-based business models will impact incumbent actors in the electric power sector. First, Section 2.4.1 introduces the “Compete, Use, Support” framework and describes how it can be applied to various incumbent players. Section 2.4.2 applies the framework to the incumbent distribution system owner/operator and incumbent flexible generators. Finally, Section 2.4.3 demonstrates how the framework can be used to analyze changes in the regulatory environment.

2.4.1 The “Compete, Use, Support” Framework

As demonstrated above, DES business models can take on a diverse set of attributes and component technologies. As such, new market actors deploying DES business models will have an equally diverse set of impacts on a variety of incumbent utility business models, including generators, transmission system owner/operators, distribution system owner/operators, and retail electricity providers. Understanding the range of impacts of new business models on the various incumbents is critical to the design of effective regulation and can influence incumbent and new market entrant strategy.

The “Compete, Use, Support” framework analyzes the potential effects of new DES-based business models on incumbent market actors. This framework requires two key inputs: the incumbent actor being analyzed and the regulatory framework within which the incumbent actor and new models exist. Using these inputs, DES business models are evaluated based on the degree to which the models inhibit or aid the incumbent in providing its core services (vertical axis), as well as the degree to which the models affect the overall market opportunity or market size for the incumbent (horizontal axis). Figure 14 demonstrates how models are mapped within the framework.

Figure 14. The “Compete, Use, Support” Framework



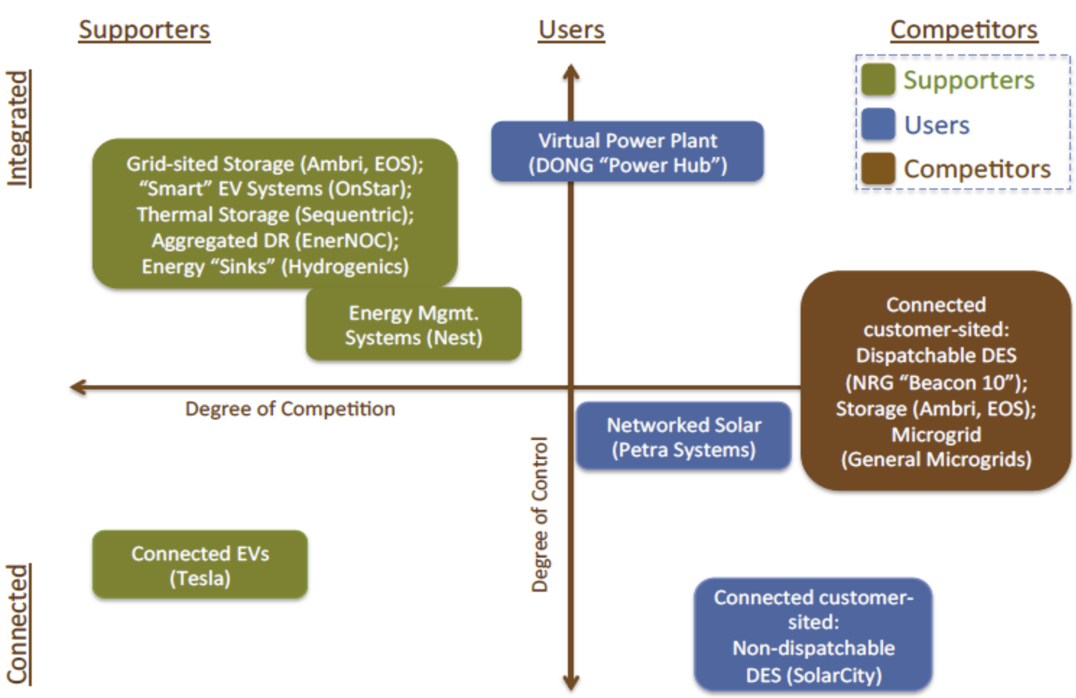
By mapping new DES business models onto the above framework, we can identify three broad categories of models: “Supporters,” “Users,” and “Competitors.” Supporters are models that either sell services directly to, or purchase services directly from, the incumbent in order to create economic value for themselves and the incumbent. Users are models that depend on the services provided by the incumbent to fulfill their business functions, but primarily provide economic value to non-incumbent actors such as end-users. Finally, Competitors are models that largely create economic value independent of the incumbent and in a manner that reduces the economic value captured by incumbents.

2.4.2 Applying the Framework: the DSO and the Flexible Generator

The main task of the distribution system owner/operator (referred to herein as the DSO) is to ensure that the distribution system can securely, efficiently, and economically distribute electricity to end users. In order to accomplish this task, the DSO makes investments in network infrastructure. In the regulatory framework used as an input in this analysis, it is assumed that the DSO primarily recuperates costs through volumetric tariffs (e.g., tariffs that depend primarily on the amount of electricity transmitted across the distribution network; this concept will be further discussed in Sections 2.5 and 3). As such, business models that are deemed "competitive" with the DSO are largely those that diminish the amount of electricity transmitted across the DSO's network and reduce end-user dependence on the DSO. Similarly, business models that have the potential to create disruptions in the reliable operation of the distribution network are deemed to challenge the DSO's ability to provide its core services (for example, a business model that creates rapid, unpredictable, or uncontrollable changes in network usage would fall in this category).

Figure 15 maps many emerging DES business model categories (e.g., "Microgrid") and example real-world models (e.g., General Microgrids) onto the "Compete, Use, Support" framework, using the DSO and a hypothetical cost-of-service-like regulatory scheme (such as those found in many areas of the U.S.) as inputs. It is assumed that under this hypothetical regulation, the DSO recuperates its costs through volumetric network tariffs, that incentives for efficiency in operational expenditures are greater than incentives for efficiency in capital expenditures, and that the DSO is not incentivized to engage in Active System Management (the purpose of this section is not to discuss these issues directly; these regulatory issues and alternative regulatory frameworks will be further developed in Section 2.5 and 3).

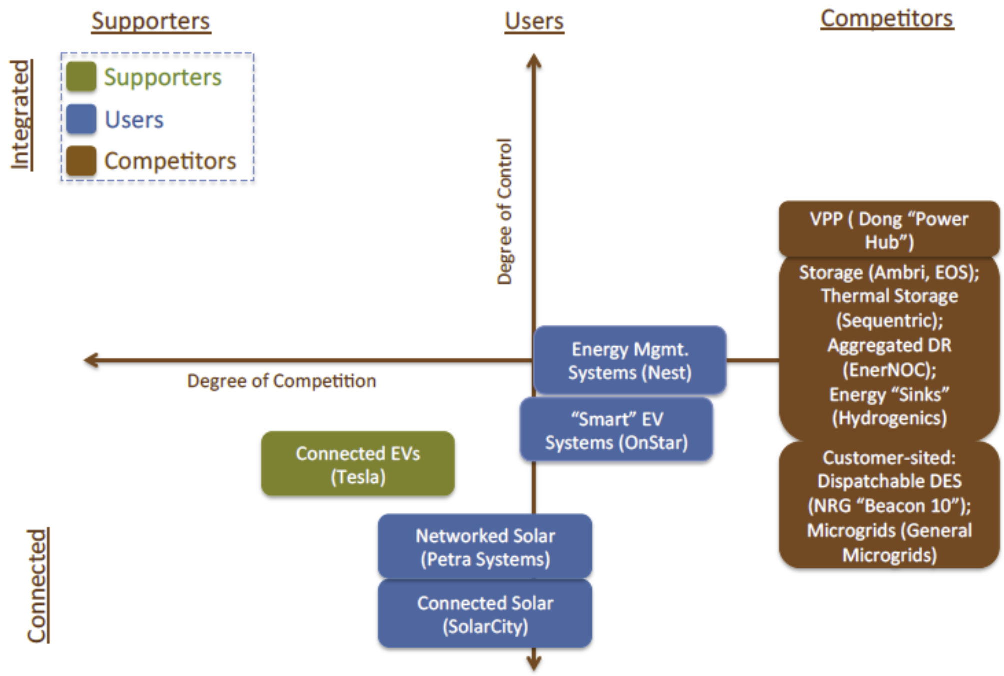
Figure 15. DES Business Models and the DSO



Business models that rely on solar PV systems that are connected to the distribution network but not integrated into system operations are referred to as DSO "Users" because they rely on the DSO to gain access to electricity markets but do not offer services directly to the DSO. Specifically, customer-sited solar PV business models typically sell power to the end-customer or back to the system through net-metering or feed-in tariff rules, requiring the larger electric grid to export PV production and import energy when PV production falls; however, these models provide only indirect services such as loss reduction (in some cases) to the grid. Alternatively, a grid-sited energy storage system (e.g. located at a distribution substation) creates economic value by, for example, providing capacity during peak consumption periods and selling frequency regulation services to the DSO or TSO (the TSO is the typical purchaser of these services, although the DSO could procure these services on behalf of the TSO). This business model is therefore referred to as a "Supporter." A set of business models intended to provide much or all of an end-users electricity while significant reducing that user's dependence on the distribution network are all labeled "Competitors," including customer-sited dispatchable distributed generators (i.e., fuel cells or microturbines), energy storage devices, and microgrids.

The same methodology used above can be applied to other incumbent actors. A flexible generator, for example, is a wholesale generator that can ramp or curtail generation rapidly in response to changing system conditions (for example, an open cycle or combined cycle gas turbine or hydropower facilities). Figure 16 maps DES business models within the "Compete, Use, Support" framework with cost of service regulation and flexible generators as inputs. Flexible generators typically earn profits during peak demand hours or by providing system services that leverage the ability to rapidly change output (e.g., reserves). A variety of DES business, including virtual power plants, energy storage, and aggregated demand response, also have the capability to offer peak capacity, reduce system peak demand, or provide similarly flexible generation. These business models could all diminish the market opportunity for flexible generators and are therefore "Competitors." DES business models that create more variability within the system may be classified as "Users" of flexible generator services, as they increase the market opportunity for flexible generators while also decreasing the predictability of generator dispatch and increasing wear and tear on generators. For example, business models for solar PV deployment will increase demand for flexible generators by creating periods of more rapid ramps in generator output (California ISO, 2013). Finally, uncoordinated EV charging may increase peaks in system demand, supporting the business models of incumbent generators.

Figure 16. DES Business Models and Flexible Generators

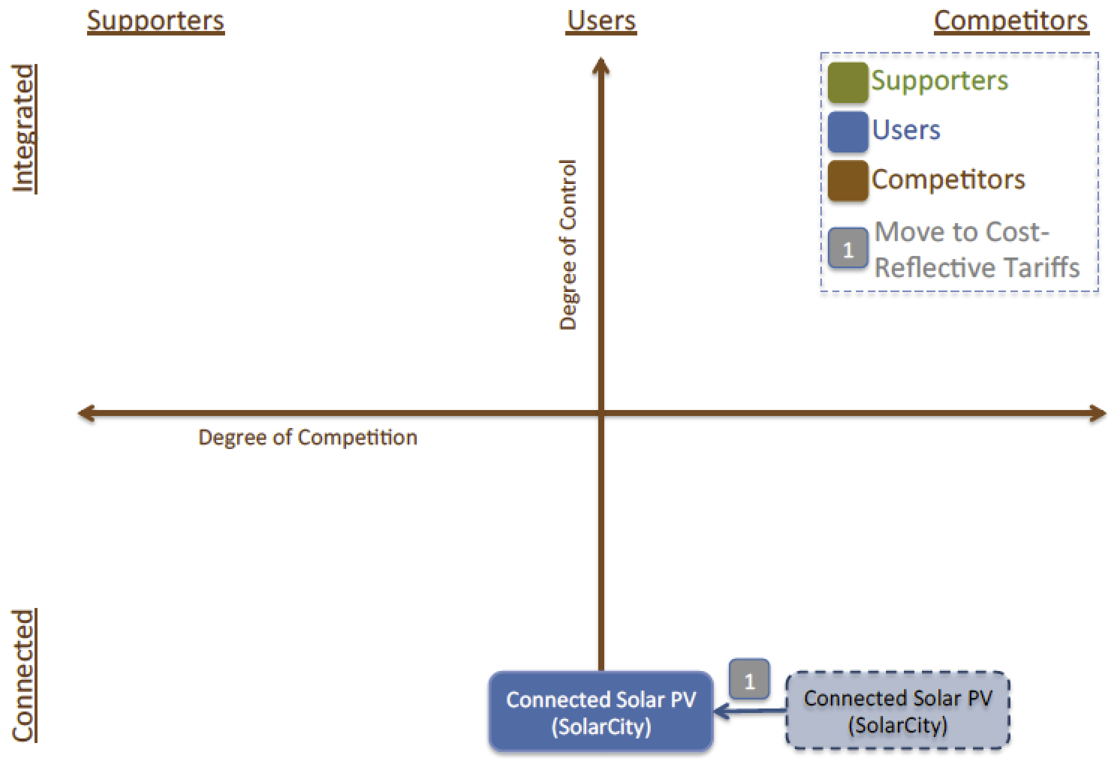


As Figures 15 and 16 demonstrate, business models, such as grid-sited storage, that are very supportive of DSO activities can also be very competitive to other incumbents, such as flexible generators. As such, policy or regulation that encourages or incentivizes the deployment of these technologies requires recognition of these tradeoffs between market actors.

2.4.3 Applying the Framework: the DSO Cost-Reflective Tariffs

As shown above, the "Compete, Use, Support" framework can give valuable insight into the effects of various business models on different incumbents in a static regulatory environment. The framework can also be used to visualize the impacts on incumbents under varying regulatory environments. For example, as shown in Figure 15, in a regulatory environment in which the DSO recuperates costs through largely volumetric use of system charges, business models based on solar PV are seen as competitive with the DSO. However, as discussed in detail in Section 3.2, it is possible to design cost-reflective tariffs such that business models that decrease the net volume of energy distributed over the DSO's network are not viewed as competitive in nature to the DSO. Figure 17 demonstrates how the DSO would view the competitiveness of a customer-sited, non-networked solar PV business model with cost-reflective tariffs in place.

Figure 17. Customer-Sited, Non-Networked Solar PV, the DSO, and Cost-Reflective Tariffs



2.5. The Future of the Regulated Utility?

As Section 2.3 demonstrates, emerging DESs may give birth to a diversity of new business models. Many of these DES business models will be active in competitive, unregulated markets. These models may represent either new opportunities or new competitors for non-regulated utility businesses, including generators, retailers, and energy services companies. But what will the growth of DESs entail for the business model of regulated utilities?

The electric utility sector has historically responded well to the demands of its customers for the provision of reliable power at either regulated or competitive market prices. In either market environment, large generation plants connected to the transmission network have overwhelmingly dominated the supply of electricity. Distribution network activities have been traditionally remunerated in some proportion to the volume of energy distributed and the network charges or tariffs were computed in a simple fashion, since all network users were consumers and large classes of customers could all be safely assumed to have similar demand profiles.

Today, as many utilities and industry observers across Europe and North America have argued (Deloitte, 2013a, 2013b; Eurelectric, 2013b; EEI, 2013; PwC, 2013; RMI, 2013), **the proliferation of DERs and DESs could reshape this familiar utility business landscape.**

The traditional utility business model has revolved around the commodity delivery of electricity—sending kilowatt-hours to end consumers. If DESs successfully break down the barriers between electricity providers and end-users and create new options for the delivery of energy services, network utilities could be asked to take on a very different role. The relationship between existing utilities and their customers and stakeholders is likely to become much more complex. Today, network users increasingly generate their own electricity, take greater control over their consumption, and even become potential suppliers of services to the utility. Incumbent utilities will be expected to maintain reliability of supply while providing the network infrastructure that simultaneously facilitates many of the new functions that are eroding their core business. Furthermore, if DERs reach high penetration levels, distribution network costs can no longer be recovered on a fully volumetric basis (i.e., in proportion to the volume of energy distributed to end-users). Network charges thus have to be fully redesigned to fairly allocate costs amongst an increasingly diverse range of network users connected at distribution level (see Section 3).

In many jurisdictions, the growth of DG combined with improving end-use energy efficiency is also leading to stagnant or declining demand for energy purchased from wholesale generators and delivered across transmission and distribution networks. Network utilities can no longer necessarily rely on load growth to finance necessary capital investments. Owners of central station power plants may be particularly at risk: in European markets, flat load growth and rising DG and central-station renewable energy penetration is squeezing market share and reducing profit margins for this traditional “cash cow” of the electric utility value chain (Eurelectric, 2013b). Eurelectric projects earnings before interest and taxes (EBIT) from conventional generation assets in Europe, responsible for nearly half of all electric utility sector revenues in 2012, will decline by 11 percent (or €13 billion) by 2020 (ibid.).

As the utility business landscape rapidly evolves, the challenge for incumbent utilities is to find innovative ways to retain the value proposition of their assets while capturing the opportunities presented by new DESs and their component technologies.

Electric utilities today have a set of common characteristics that in many ways make them ill prepared to accept this challenge.

Innovation in the electric utility sector has traditionally focused on provision of the same service, but better—e.g., reducing costs via economies of scale and scope—rather than on product and service innovation to meet the expanding range of customer needs and demands that are now causing an upheaval in the distribution system.

Utilities are also capital-intensive, asset-heavy businesses structured around building and maintaining large, lumpy investments that can last for decades. In contrast, PV systems, programmable thermostats, and even electric vehicles are beginning to look more like consumer electronics or appliances than traditional utility assets. Likewise, DER and ICT technologies are improving quickly, driving rapid investment turnover that contrasts with the decades-long life of typical utility investments. At the same time, investors have traditionally perceived utilities as stable, long-term investments with a very low risk profile. In contrast, the companies developing competitive services in the distribution system are generally asset light, higher-risk, and evolve more rapidly to match the pace of technology evolution and changing customer demands.

Incumbent regulated utilities must therefore evolve their business models to succeed in an environment where DESs may become ubiquitous. The value proposition for the utility need not be in competition with the value proposition of the consumer or "prosumer." The common characteristics of incumbent electric utilities may make them relatively slow to react to disruptive threats. However, these characteristics also bring a potential set of opportunities regarding the business model attributes of any new DES-related activities in which the utility might get involved. Figure 18 presents preliminary insights on what should be the opportunities and challenges of a standard electric distribution utility that aims to get into DES-related business models. This framework is adapted from the business model matrices above. In this context, green shading indicates that this attribute is a core business attribute for a traditional distribution utility, while yellow and orange shading indicate that this is a neutral or non-core attribute respectively.

Figure 18. Business model attributes, opportunities, and challenges for the regulated distribution utility

	Regulated Distribution Utility's		
Business Models Attributes	Opportunities	Challenges	Business Models Attributes
Own	As an asset heavy company, its financial profile won't be affected by the addition of new DER or ICT assets		Own
Operate	As a company that has the know-how of electricity distribution network operation, it might have an advantage when operating DESs		Operate
Fund	As a long-term and stable investment class, it could rather easily get capital to fund DESs	Funding is a business attribute that is not in present utilities, and they would probably face competition from financial industry	Fund
Provide Information	As a company interfacing directly with end-users and transmission companies/system operators, it could obtain valuable information	Utilities are not well suited to manage large amounts of information (compared to Amazon Web Services, or other Big Data companies)	Provide Information
Build	If dedicated to it, it might be suited to design and implement the system integration of DESs, as a small version of electric power systems	It is not suited to be a manufacturer of DES components and might face challenges keeping the fast pace of technology changes in this sector	Build

In the context of new business models derived from the integration of DESs, special attention should be centered on the right-hand triangle, which depicts the existence of synergy between two business model attributes. For example, utilities have traditionally managed data from SCADA systems and high and medium voltage networks. However, new technologies are unleashing orders of magnitude more data than has traditionally been processed by utilities. We can conclude, therefore, that from a business model attributes' standpoint the present capabilities of utilities do not position them to manage the magnitude of information produced by distribution networks and distributed systems. Utilities may therefore want to think twice before getting into an information provision business model. At the same time, despite the lack of clear synergy, incumbent utilities may want to take on the role of data manager or data hub in order to prevent a rival from capturing that opportunity.

While the growth of DESs may challenge existing utility business models, they also present new business opportunities for incumbent utilities. DG owners will rely on the distribution network to sell excess electricity into energy markets, representing both a new cost driver and potential revenue source for network companies. EV charging systems may also become significant new users of distribution systems. ICT platforms are enabling more active coordination and dispatch of both DG and loads (i.e., DR), creating new tools for distribution network operators to manage system congestion, losses, and voltage and reactive power as well as the potential to aggregate ancillary services from DESs within their service territory for sale to transmission system operators. As active system management and bidirectional electricity flows and financial transactions become the norm, the regulated network utility's role is thus likely to evolve in fundamental ways.

New market entrants and diversifying DES activities at the distribution edge may also create new challenges for the existing industry structure. As new DES business models proliferate, how will regulators ensure markets are open to new entrants and entrepreneurs? What should the regulated utility's role be in "down-stream" markets for end-use energy services, such as the installation, finance, and operation of customer-sited distributed generation, energy efficiency retrofits, and charging networks for electric vehicles? What market and industry structures and regulated utility business models will best promote flourishing innovation in product and service delivery and system-wide efficiency while maintaining system reliability and robustness?

Given this confluence of forces, it is no surprise that 94 percent of utility executives surveyed in 35 countries predict "complete transformation or important changes to the power utility business model" (PwC, 2013). In short, **the business model for the regulated network utility of the future is likely to be quite different than today**.

The regulated distribution utility business model of the future will need to:

- Find a way to turn DER from a threat into an opportunity—e.g., as a new source of network use charges and as a tool to improve system operation efficiencies or reliability;
- Master new and evolving technologies;
- Become more customer-facing and respond adroitly to evolving customer needs and uses of the system;
- Develop new products and services that deliver value to network users and utility stakeholders; and
- Comply efficiently with a changing regulatory and policy environment.

In the remainder of this section, we present four potential prototype models for the evolution of the regulated distribution utility.[3] In each of these models, the utility remains responsible for efficient construction, operation,

[3] These models are based in part on similar discussions of potential business models contained in RMI (2013) and Lehr (2013).

and maintenance of a safe, reliable, and affordable electric distribution network within their service territory. Where these models become differentiated is in their primary interaction with and value proposition towards end-users and new DESs. Other structural or regulatory features may follow from these primary differences. We do not attempt to describe here which of these models may be winners or losers. That type of projection requires further techno-economic analysis, as well as consideration of regulatory and social objectives, and is currently being undertaken by the *Utility of the Future* project.

Model 1: Cost of Service+ (aka the "California Model")

The utility (here we refer to a distribution utility, although it may be part of a larger company also involved in electricity generation or other activities) still primarily operates as a **supplier of commodity electricity** (kWhs) via safe, reliable, and efficient operation of the distribution network. Cost-of-service regulation would evolve to better align utility incentives with the evolving nature of customer needs and growth of energy efficiency (EE) and DG and to place more emphasis on "non-wires" solutions to network management (e.g., procurement of system services from DESs). Non-utility actors would continue to have access to customers to provide a range of customer-sited DES/DER and EE services. DES/DER on the utility-side of the meter remains the responsibility of the utility, although they may also procure these solutions from third parties. This model could also be an incremental stage of evolution (for traditional cost-of-service regulated utilities) towards one of the following three models.

Key questions: Is this model viable for the utility in the long-term, or simply a stopgap measure to "stop the bleeding" caused by the growth of DERs/DESs and EE? Is this an intermediate step on the path to one of the other models discussed below? Even if the utility can be made neutral to DG and EE investments (e.g., through decoupling of revenues), will they face adequate incentives to truly pursue innovative solutions making use of these resources or pursue innovation in product and service delivery in these areas?

Model 2: Independent Distribution System Operator (aka "the UK Model")

The utility becomes an **open-access network owner & operator**, similar to an ISO/TSO, and invests in the technology and infrastructure necessary to provide "plug-and-play" network access to a growing variety of network users with more differentiated needs—i.e., conventional electricity consumers, but also aggregators, DES operators, DG owners, etc. This role may include open access to data and data services associated with the growth of "smart grid" advanced metering and system component monitoring systems. Ideally, the utility would be an independent "wires company" separated from both the upstream wholesale electricity generation and downstream retail supply businesses. Given the diversity of starting structural conditions of distribution utilities around the world and the central role of the DSO as the integrator and access point for network users and services, uncompetitive practices would have to be watched carefully by the regulatory agency, which could adopt any necessary measures to guarantee a true level playing field for all actors involved.

Key questions: Do the benefits of this model (e.g., open competitive markets, a neutral DSO facilitator, open access for DERs/DESs) warrant the industry restructuring that may be required to make this model viable in many jurisdictions or the restrictions on the role of the regulated utility? Can markets be trusted to deliver the services and outcomes needed without direct regulatory oversight? Will less lucrative customer classes be "left behind" and thus under served by competitive markets, and if so, what provisions may be needed to prevent this? Will the DSO act as the aggregator of ancillary services provided by DESs within their territory for sale to the TSO/ISO, or will independent and competitive aggregators be expected to provide those services directly to the TSO/ISO? What are the proper boundaries for the DSO in regards to electric vehicle charging infrastructure? Do they provide infrastructure and services for EV charging or does this put them too far “downstream” in this emerging market segment?

Model 3: Integrated Electricity Services Provider (aka “the Subscription Cable/Internet Model”)

The utility integrates downstream to become a **provider of end-use electricity services**. The utility’s value proposition/revenue model could be based on a monthly subscription fee in exchange for bundled energy services (i.e., heating and cooling, lighting, etc.). These service packages could be further differentiated by offering different levels of peak capacity or guaranteed reliability. The utility would be in active competition with other non-utility providers of end-use services. Regulators would have to be vigilant to avoid abuse of market power given the utility’s position as network owner/operator. Market access could be further opened to entities not affiliated with the incumbent utility by requiring open and transparent bidding and procurement of non-wires services (on either side of the meter), allowing the regulator to ensure that the utility is considering the full range of options and not privileging traditional build-and-own options only. The utility may also serve as an aggregator between network users and the TSO/ISO (for example, in procuring and aggregating DERs to provide capacity or balancing services for the TSO/ISO).

Key questions: Can the regulated utility be expected to deliver sufficient innovation in product differentiation and service delivery? Would end-use service innovation be better served by competitive markets? Can regulators sufficiently ensure that a forward-integrated utility does not abuse the market power afforded by control of the distribution network to shut out competitors or privilege their own service offerings? What regulatory methods can be used to ensure adequate performance and reasonable “value for money” for ratepayers?

Model 4: Financial Intermediary Company (aka “the FinanceCo model”)

The utility becomes a **provider of financing for customer & non-utility investments in DERs and DESs**. By offering on-bill financing for DERs and DESs, the utility leverages its lower cost of capital and its existing billing system for lower risk of non-payment. The utility may also act as an interface and intermediary between DER/DES and EE providers and network users, using their existing relationships with customers to help market the services of approved suppliers in exchange for a portion of revenues. This model may be compatible with other models above.

Key questions: Does the utility deliver enough value added in this model to continue to have profitable growth opportunities? Will investors perceive these new activities as suitably low-risk to continue offering the low cost of capital regulated network utilities traditionally enjoy? With bond ratings for many utilities already declining due to evolution/disruption in the power sector, will utilities retain sufficiently low capital costs to pursue this model? There are two key risks here: risk of non-performance related to the technology/service and risk of non-payment related to the customer. Are there workable partnership arrangements between the “FinanceCo” utility and the third party service/technology providers such that these two risks can be separated, with the utility taking on the risk of non-payment and the technology/service provider taking on the full risk of non-performance? Would investors, capital markets, and regulators understand this separation of risk and price the utility’s level of risk accordingly? Would the utility want to take on this role, or would they see this strategy as enabling their competitors (this is likely affected by whether or not the utility also owns upstream generation assets)?

Key Takeaways: Business Models

6. DES-related business models will evolve not only because of new value propositions and customer needs but also because of the evolving technological and regulatory conditions that are reshaping the electricity distribution sector.
7. The typical one-directional value proposition in which the utility provides electricity delivery to an end consumer may not always be valid for the utilities of the future. As electricity end-users also become vendors of energy and related services (i.e., ancillary services, capacity, etc.), bi-directional value transactions will become more common, and the utility will need to see end-users as not just customers, but also potential suppliers, partners, and competitors.
8. New DESs have the potential to challenge, and in many cases already are challenging, the core business of the incumbent utilities. At the same time, DESs also create new opportunities for incumbent utilities to meet end-user needs and operate more efficiently.
9. Incumbent utilities have a set of characteristics in common. These characteristics bring both a set of challenges and a set of potential opportunities and competitive advantages regarding the business model attributes of any project in which the incumbent utility might get involved.
10. The business model(s) of the incumbent distribution utility must evolve to capture the opportunities and respond to the threats presented by DESs, and they must do so at an increasingly rapid pace of change.

3. Regulatory Issues

The regulation of the electric power sector has historically co-evolved with the underlying technical and economic characteristics of the electricity system. Economies of scale and scope driven by the particular engineering characteristics of conventional thermal and hydro power plants and electricity transmission and distribution gave rise to a regulatory compact that was ubiquitous for many decades. This compact viewed the generation and delivery of electricity as natural monopolies. Over time, a number of technological changes occurred, including the advent of less capital intensive and smaller scale natural gas-fueled power plants, much stronger and more interconnected transmission networks, computerized handling of consumer information, industrial co-generation opportunities, and renewable energy technologies. This new portfolio of technologies lowered barriers to entry and made more competitive wholesale generation markets possible, sparking a wave of industry restructuring and liberalization in numerous jurisdictions. Simultaneously, regulators sought new ways to introduce greater incentives for economic efficiency for regulated transmission and distribution companies, leading most notably to a range of incentive-based regulatory frameworks.

Today, a new era of technological innovation, in particular at the distribution network level (see Section 1), requires a corresponding anticipative response from regulatory institutions. In the past, regulatory reforms have focused on market designs (particularly for wholesale generation and retail supply) and regulatory incentives for the network-related activities (transmission and distribution) to improve economic efficiency, affordability, and quality of supply. This new era of reforms must continue to address these ongoing objectives while also addressing the evolving uses of distribution networks and fostering technological innovation and the efficient evolution of electric power systems and markets.

As discussed in Sections 1 and 2, a broad range of DERs and ICTs are enabling the emergence of innovative business models utilizing DESs to deliver new value to electricity end-users, upstream market actors, and system operators. These emerging technologies and associated business models have the potential to drive several paradigmatic shifts in the planning and operation of power systems and electricity markets:

- The traditional top-down power flow from centralized generation sources connected to the high voltage transmission grid through lower-voltage distribution to end consumers is challenged by local distributed generation (DG), requiring changes to distribution infrastructure and operations. Multi-directional power flows across distribution networks may soon be the norm, and new opportunities are emerging for local means of electricity trade, including microgrids and on-site DG, that directly compete with wholesale generators.
- Distributed storage (DS) could entail profound changes to the real-time operation of electric power systems, offering a buffer between system supply and demand, new ways to provide ancillary services to network operators, and opportunities to temporally shift energy supply to maximize the value of energy production and meet peak demands. At the same time, cost effective storage combined with on-site generation may also reduce electricity end users' reliance on distribution networks.
- Demand response (DR) makes electricity loads far more responsive to economic and operational signals than ever before. Conversely, the proliferation of customer-owned DG, particularly variable distributed solar and wind technologies, may make generation less controllable and predictable for system operators.
- Widespread adoption of electric vehicles (EVs) would constitute an important new class of electricity system users and loads. EVs also hold the possibility of injecting power back into the grid, delivering

so-called "vehicle-to-grid" (V2G) services. Efficient price signals and/or new control systems will be essential to manage and coordinate EV charging and V2G services, while new network investments must accommodate and enable EV users. The role of the distribution utility in enabling this new market segment must also be defined.

- Last, but perhaps most significantly, a cost-effective combination of DG, DS, DR and EVs—whether in the format of an autonomous or semi-autonomous physical microgrid or as a virtual decentralized aggregation of each of these components—could challenge the current centralized paradigm of the electric utility, potentially initiating a transition towards a more decentralized structure and organization of the power sector.

These potential paradigm shifts bring new challenges and opportunities for electricity distribution utilities and their regulators alike. Today, some of these shifts are only a possibility and might arise once technologies mature and are more widely deployed. Other important changes, foremost related to distributed solar, are already established facts and concern distribution utilities and regulators in many jurisdictions today. Regardless, **the evolution of new DESs and the changing needs of network users are proceeding at a pace that could easily outstrip the rate of regulatory innovation—*unless* proactive reforms are taken.**

These dynamics lead to several key implications:

1. **The regulatory framework must create a level playing field between distributed and centralized energy resources while allowing the distribution system and the regulated utility's business model to evolve at the pace demanded by changing network uses.**
2. **If regulatory innovation cannot keep pace with the changing nature of the electric power system, large inefficiencies will result.** Network users and new businesses will find ways to arbitrage the growing disconnect between old regulations and new market and technological realities. These issues are already beginning to arise in some jurisdictions, and many of these issues are much more difficult to fix retroactively.
3. **The evolution of utility business models can be severely constrained by the lack of proactive regulatory innovation.** If this is the case, regulated utilities will be severely challenged by the growth of DES-related business models and the adoption of DERs.

In short, regulation must lead, not lag behind the evolution of technologies, business models, and customer needs.

In particular, regulation of distribution utilities must be proactively assessed and, whenever appropriate, reformed in order to:

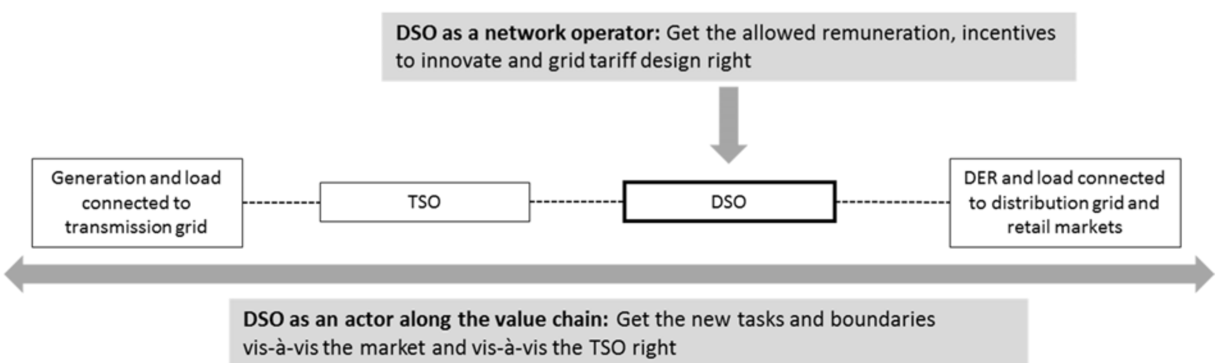
1. **Enable distribution utilities to more rapidly evolve to meet the changing needs of network users.** This requires addressing the remuneration or cost recovery challenge by updating methods for establishing the allowed revenues of regulated distribution utilities to better align incentives for the integration of distributed resources and enable the evolution of the utility's business model. Distribution utilities must be adequately compensated for investments required to accommodate new DERs and DESs and incentivized to make efficient use of these same resources to improve system reliability, reduce losses, and defray unnecessary capital expenditures. Incentives to innovate may also be considered to allow distribution utilities to take on the long-term challenges of developing and adopting novel technologies and services necessary to accomplish their evolving role as a dynamic system operator.

2. **Provide efficient price signals for an increasingly diverse range of system users.** Regulators must rethink the design of network tariffs to ensure that these charges fairly allocate network costs despite changing cost structures, and that appropriate price signals incentivize the efficient location and operation of DERs. Network tariffs should provide incentives for network users to evolve business models and network-use practices that add value to the system and prevent users from arbitraging weaknesses in market or regulatory design.

3. **Define the proper industry structure and responsibilities of the distribution utility and clarify the ways in which the distribution utility will interact with adjacent market actors**, including the TSO and new DES businesses. This also includes defining the way these market actors will interact and coordinate to dispatch DERs and DESs.

The preliminary research conducted for this report focuses on the first two key areas of necessary regulatory innovation and reform: the remuneration or cost recovery challenge and the tariff design or cost allocation challenge. For the research team's current thinking on regulatory issues involving appropriate market structure and the roles and responsibilities of market actors, see Pérez-Arriaga, Ruester, Schwenen, Batlle, and Glachant (2013).

Figure 19: Relevant areas of regulation



(Source: Pérez-Arriaga, Ruester, Schwenen, Batlle, and Glachant 2013)

3.1. Remuneration of Distribution Utilities: New Cost Drivers and Incentives for Innovation

Large-scale penetration of DERs within distribution networks will likely increase the total costs of business-as-usual management of the distribution system (that is, a continued "fit-and-forget" grid management strategy). Substantial future investments will be required to fulfill the distribution utility's "open access" requirements and connect all new DER system users as well as to enable the system to deal with bidirectional load flows, potentially increased volatility in peak demand, and new DG-related system peaks at various voltage levels. **Remuneration schemes must account for these new DER and ICT-related cost drivers and provide adequate incentives for distribution utilities to facilitate the penetration of DERs.**

Distribution utilities can also achieve important cost savings by adopting an active system management approach, especially as DG shares increase (Cossent, Gómez and Frías, 2009; Cossent, et al., 2010). Setting up ICT and advanced grid management infrastructure that allows distribution utilities to more actively manage distribution network configuration and make use of DESs for their daily grid operations will entail substantial upfront capital expenditures (CAPEX) but can also improve system operating efficiency and reduce operational expenditures (OPEX). Likewise, coordination and management of EV charging within an active system management approach is essential to avoid heavy investments into low- and medium-voltage lines to compensate for local peak demand resulting from high penetration of EVs (Pieltan Fernández, et al., 2011; Gómez, et al., 2011). **Remuneration must provide the right incentives for distribution utilities to manage important tradeoffs between CAPEX and OPEX and find the efficient balance between these expenditures.**

In addition, utilities must become much more agile and adept at responding to changing network uses and customer needs. To date, incentive-based regulation has focused on generating incentives for short-term cost efficiencies while maintaining adequate system performance. While short-term efficiency and performance will remain key regulatory objectives, **remuneration must also facilitate the more rapid evolution of the distribution network and provide adequate incentives for distribution utilities to engage in long-term innovation.** Utilities should be encouraged to take on the challenges of developing, demonstrating, and adopting novel technologies and practices that can reduce costs and improve system performance in the long-term as well as the short term (see Bauknecth, 2011; Eurelectric, 2013b; Lo Schiavo et al, 2013; and Ofgem, 2010a, 2010c).

To accomplish these objectives, regulators will need to adopt new tools and methods.

- **First, new regulatory techniques are needed to overcome information asymmetry, assist in benchmarking expected costs, and set allowed remuneration levels**. As the power system evolves more rapidly, negotiating and benchmarking CAPEX and OPEX will become more complex for regulators due to the proliferation of new costs drivers (i.e., DER connections, ICT infrastructure, new markets and platforms to procure system services, etc.). These new challenges will likely exacerbate existing informational asymmetries between regulators and utilities. State of the art methods to address these regulatory challenges include the use of an incentive compatible menu of contracts to elicit accurate information from the utility on their expected costs (see Ofgem, 2008, 2009, 2010b; Cossent, 2013; Cossent and Gómez, 2013; Jenkins & Pérez-Arriaga, 2014) and the use of a reference network model (RNM) to generate engineering estimates of efficient network costs taking into account new cost drivers and network uses (see Mateo, et al., 2011; Gómez, et al., 2013; Cossent, 2013; Jenkins & Pérez-Arriaga, 2014). These methods can identify new cost drivers related to DER connections and help formulate adequate remuneration mechanisms for the evolving distribution utility of the future (for more, see Jenkins, 2014).

- **Second, remuneration mechanisms must ensure that distribution utilities are incentivized to pursue long-term innovation and the efficient evolution of the distribution system to accommodate changing network uses.** A range of regulatory incentives for innovation have been proposed in various jurisdictions and should be explored, including: prolonging revenue control and regulatory review periods; an increased focus on measurable output metrics and associated distribution utility performance indicators; explicit incentives or full or partial "pass-throughs" to compensate distribution utilities for a higher DER penetration in their grids; input or output based incentives for research and development investments and the implementation of innovative demonstration or pilot projects; and competitive network innovation funds (many of these measures are discussed in Ofgem, 2010a, 2010c, 2013).

3.2. Distribution Network Tariff Design: Getting Incentives Right for Network Users

The allowed remuneration discussed above is collected from network users through distribution network use of system (DNUoS) charges. The efficiency of cost allocation depends upon the degree to which distribution charges send sound economic signals to network users (Rodríguez Ortega, Pérez-Arriaga, Rivier-Abbad, and González, 2008). Well-designed network charges are essential both to promote efficient short-term usage of the grid and to guide efficient long-term network development, as well as to provide a level-playing field for competition amongst emerging DES-based business models and between distributed and centralized resources.

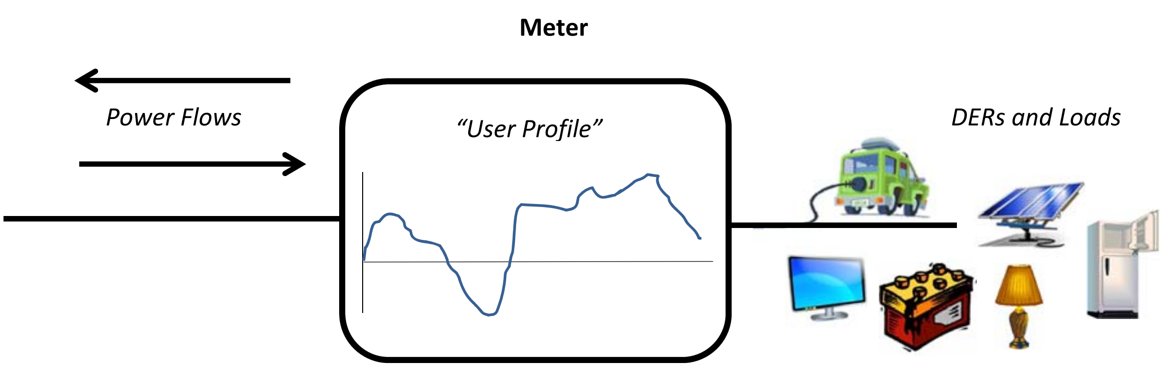
At present, electricity rates and network charges are often ill suited to accomplish any of these objectives, particularly as diverse new uses for the network proliferate. Existing rate structures or network tariffs typically charge customers for their use of the distribution network through volumetric ($/kWh) rates that are uniform across time and across broad classes of customers assumed to have similar network use patterns. Such tariffs attempt to allocate on a per-kWh basis network costs that are not driven exclusively by volumetric energy consumption. With growing penetration of DER, net energy metering (NEM) and volumetric distribution rates will lead to growing cross-subsidization between network users or inadequate recovery of essential network costs. Business models exploiting economically inefficient arbitrage opportunities caused by differentiated treatments of different DER technologies, or of different types of producers and consumers, are likely to flourish in the absence of sound network charge design (see Perez-Arriaga et al., 2013).

In short, the current distribution network charge paradigm, designed for broad classes of electricity consumers assumed to have similar network use patterns, in a system where DER are considered a minor exception, no longer holds. The power system of the future (or of the present in many jurisdictions) will be much more complex, and the DNUoS charge design paradigm should be proactively reformed before more substantial distortions occur. Many utilities and regulators are attempting to address the challenges posed by outdated or poorly designed network tariff structures. The box below — "Alternative Network Charge Proposals"— outlines a few examples of recent efforts by utilities and commissions to develop alternatives to net metering and volumetric rates and to redesign existing approaches to electricity rate design.

Typically, a distribution utility has limited visibility over and control of DERs in its network. As distribution network operation becomes more dynamic – with greater injection of power from DG and DS and with new and more responsive loads from DR and EVs – more refined and dynamic locational and temporal price signals are required. These price signals should indicate the value or cost of injection or withdrawal of power in order to ensure that increasingly sophisticated network users can operate efficiently and help distribution utilities minimize system costs (Cossent, Gómez, and Olmos, 2011). The distribution network charge is *one* component of the final retail bill seen by system users. An unbundled retail bill includes multiple price signals, or components, corresponding to multiple components of electricity service provision – namely: an energy or generation charge, transmission charge, distribution charge, and additional retail charges. Each component signals the cost and value of providing each service, is computed according to different **cost drivers** (as described below for DNUoS charges), and is best communicated in a variety of formats. For example, incentives to reduce overall volumetric energy consumption are best communicated in volumetric ($/kWh) energy charges. Time-varying electricity rates incentivize users to shift consumption and production to off-peak periods and help reduce overall generation costs. A capacity component of the distribution network charge signals users to shift their network use to off-peak periods and helps reduce the magnitude of distribution investments (Rothstein, Besser, & Jenkins, 2014). DNUoS charges should be designed in a manner that does not interfere with energy prices signals. Using the drivers of distribution costs to compute network users' DNUoS charges accurately signals to network users how their consumption and production behaviors impact distribution costs.

As grid users become more sophisticated by introducing various DERs, it is no longer possible or meaningful to understand network users according to the existing classifications of "producers" and "consumers." Network users' activities behind the electricity meter often are – and ought to remain as far as possible – a black box to distribution utilities (see Figure 20). In order to compute users' contributions to total distribution network costs, the distribution utility need only know each user's contribution to the drivers of distribution costs. It is immaterial to the DSO if a user's contribution to peak load is reduced via efficiency, DR, or DG. Creating **network use profiles** for each user and allocating shares of total distribution costs to users according to the contribution of their profiles to distribution cost drivers obviates the need to define customer classes. Profiles permit distribution utilities to understand grid users' contributions to network costs (whether positive or negative) without requiring detailed knowledge of which customers in a DSO's service area own and charge EVs, operate battery storage units, utilize backup diesel generators, or operate any other combination of DERs.

Figure 20. What the distribution utility sees of a network user's behind-the-meter activity is a user profile



Allocating distribution system costs according to network use profiles consists of the following steps:

1) Identify the ***cost drivers***, or primary variables that drive the total cost of the distribution network. Once the cost drivers have been identified, the network use profile can be defined. The cost drivers of focus in preliminary analysis (building upon earlier work in Rodríguez Ortega, Pérez-Arriaga, Rivier-Abbad, and

González, 2008) are: *connection*, or the need to provide each user with a connection to the distribution network; *capacity*, or ensuring network capacity to accommodate peak load and injection, *reliability,* or ensuring continuity of supply, and *losses*, or minimizing distribution network losses (Pérez-Arriaga & Bharatkumar, 2014).

2) Determine the contribution of each cost driver to the total distribution network cost. Then, if appropriate, allocate the total cost associated with each cost driver at each voltage level of the network amongst homogenous network zones.

3) Compute each network user's DNUoS charge. Determine each user's share of the total cost associated with each driver in the user's network zone. The user's share of the total coat associated with each driver is determined by the user's profile. The final DNUoS charge is the sum of the charges assigned for each driver.

4) Choose an adequate format for presenting the final distribution network charge on network users' electricity bills. Traditional formats such as $/kW or $/kWh rates will not provide efficient signals for network users since users' charges are based upon cost allocation to network zones and then to individual users. Presentation of DNUoS charges as lump monthly charges, possibly specified by cost driver, provides a transparent and understandable billing format.

In order to determine the contribution of each cost driver to the total distribution network cost and to identify network users' cost causality, a reference network model (RNM) can be utilized. For more detailed discussion and demonstration of how an RNM can be used in conjunction with network use profiles to compute DNUoS charges see (Pérez-Arriaga & Bharatkumar, 2014) and (Bharatkumar, 2015).

Alternative Network Charge Proposals

California

California leads the U.S. in solar PV capacity. Its 687.4 MW of residential solar* have been at the center of discussion about changes to residential retail rate structures. In 2013, AB327 was signed into law, opening the door for comprehensive rate redesign. The law requires California utilities to continue offering net energy metering (NEM) until NEM program limits set by the California Public Utilities Commission (CPUC) are reached or until 2017. After that time, utilities must offer a CPUC-determined standard contract or tariff to DG customers (Durkay, 2014).

Italy

The Italian power sector has an installed capacity of 17 GW of solar PV, second only to Germany's installed capacity of 32 GW. Current regulation provides for net metering of solar PV systems with capacities below 200 kW. Utility customers are granted credits on their utility bills for electricity sold back to the distribution company. The network tariff for household customers includes an energy charge (€/kWh) and a capacity charge (€/kW) (Eurelectric, 2013c).

Arizona

With 1,250 MW of installed capacity, Arizona has the second-highest penetration of solar PV in the United States (SEIA, 2013). In 2013, Arizona Public Service Company (APS) proposed two alternatives to the existing arrangement of net metering and volumetric tariffs. One proposal remunerates owners of distributed PV at the retail rate and charges DG owners a network use fee. This network fee is computed on the basis of each customer's volumetric energy consumption. The second APS proposal – called a bill credit – remunerates DG owners for excess production at the wholesale market rate. In November 2013, the Arizona Corporation Commission made a decision to preserve net metering and apply *a network use charge* of $0.70/kW on new rooftop solar installations – a fraction of the $3.00/kW-$8.00/kW charge proposed by APS and other parties (Durkay, 2014).

Spain

With over 4 GW of installed capacity of solar, Spanish utilities are grappling with the challenge of a high penetration of solar PV and significant reductions in volumetric energy sales. In July 2013, a *backup charge* for owners of rooftop PV installations was proposed. The volumetric fee is applied to each kWh of energy production by DG owners/operators in the low voltage network in order to help utilities recover their costs and resolve mounting debts (Robinson, 2013).

Texas

In 2012, Austin Energy – a municipal utility in Austin, Texas – proposed a *Value of Solar Tariff* (VOST) as an alternative to net metering. This proposed payment to customers aims to capture the net value delivered by distributed PV to the electricity system. The tariff defines the value of solar as the net of: loss reductions, capacity requirement reductions, emissions reductions, and other costs and benefits. Customers receive a credit on their electricity bill for their contributed value of solar during each monthly billing period. In August 2014, changes were proposed to the existing VOST, introducing a price floor and eliminating size restrictions for PV systems eligible for the VOST (see NCSU, 2014). Other states including Minnesota and Colorado have proposed or similar value of solar tariffs.

*California has over 2 GW of solar installed capacity. This figure refers only to residential solar PV and was obtained from the California Solar Initiative solar statistics: http://www.californiasolarstatistics.ca.gov/

Key Takeaways: Regulatory Issues

11. The regulatory framework of the electric power sector must enable and encourage the distribution network operators and the emergent business models to evolve at the pace demanded by changing network uses.
12. If regulatory innovation cannot keep pace with the changing nature of the electric power system, large inefficiencies may result, and network users and new businesses will find ways to arbitrage the growing disconnect between ill adapted regulations and new market and technological realities.
13. The evolution of utility business models can be constrained by the lack of proactive regulatory innovation. Remuneration schemes for regulated distribution utilities must be adapted to better align the incentives with the challenges the utility is going to face, enable the evolution of the utility's business model, and create adequate incentives for long-term innovation.
14. The adoption of DERs and DESs will exacerbate challenges associated with information asymmetry between the utility and regulator during the determination of allowed utility revenues. Regulators should employ an incentive compatible menu of contracts to elicit accurate estimates of expected costs from the utility. Regulators should, in cooperation with utilities, also make use of reference network models or benchmarking to generate their own estimates of efficient network costs.
15. Use of network tariffs must be updated to provide efficient price signals for increasingly diverse system users. The current tariff paradigm, designed for pure consuming agents and a system where DG was considered a minor exception, does not hold anymore. It should be fixed before more substantial distortions occur.
16. Network tariffs should be based on the contribution of each network user to the cost drivers of the distribution system, calculated according to the user's individual profile of consumption, generation, or both.
17. The roles and responsibilities of distribution utilities may need to be revisited in some jurisdictions and the ways in which the distribution utility will interact with adjacent market actors, including the transmission system operator and new DES businesses, must be clarified. This also includes defining the way these market actors will interact and coordinate to dispatch DERs and DESs.

4. Key Questions for Future Work

Technology

This report primarily focuses on identifying key DERs that may form core components of DESs (Section 1.2 above) and carrying out a preliminary qualitative assessment of the ability of DES component technologies to provide a range of valuable services to meet key electricity sector stakeholder needs (Section 1.3 and Appendix A). Future research must examine the range of ICT technologies that form Layers 2 and 3 of potential DESs. In addition, a more quantitative and rigorous measurement and comparison of each DER or ICT component technologies' abilities to deliver stakeholder services is necessary to identify the most likely components of viable DESs. That effort will also require the identification or development of a range of performance metrics or methodologies by which to assess the abilities of component technologies to provide each key stakeholder service. The evolution of the performance characteristics of DES and related power sector technologies will have a significant influence on the system impacts of DES-based business models and will be studied accordingly.

Finally, this report only offers a framework by which to identify and describe potential DESs. We provide but a brief set of illustrative DES examples (Section 1.5). Future research could thus productively identify a diverse range of combinations of component technologies that could form DESs and evaluate the relative performance of these complete systems in a more quantitatively rigorous manner.

Business Models

Section 2 introduces the attributes and business opportunities within the DES environment (Section 2.2). The frameworks included in this report represent a high level of abstraction but nonetheless, offer a point of departure for further detailed analyses that could lead to the identification of implementable DES business models and strategies. Further business model attributes and the interactions of the various attributes must be explored. We also demonstrate the applicability of this model to explore both existing real-world DES business models and prospective new DES business models (Section 2.3). Furthermore, we apply the business attributes framework to assess the opportunities and challenges facing incumbent regulated utilities (Section 2.4) before identifying four prototype business models for the distribution utility of the future (Section 2.4). Alternative frameworks for analysis should be explored to enable a broadly applicable and quantitatively rigorous analysis of business models.

Future research could develop a more detailed assessment of the specific DES-related business opportunities underlying the high-level framework presented in Section 2. Section 1 and Appendix A of this report provide an initial identification of the key services that could be provided by various DES component technologies. Future research should focus on enhancing this work further and exploring how these component technologies interact in a system to provide a level of service greater than the sum of individual components. The aim of this research should be to lead to the identification of a set of DES business opportunities that are likely to prove particularly viable in the near to medium term. This research should consider and evaluate these business models within a variety of regulatory, social, technological, political, and economic contexts.

In addition, much work remains to be done to further explore and analyze several potential business models for the regulated distribution utility of the future. This work should be closely related to the development of new regulatory frameworks for power systems with high penetration of DERs and DESs (see below).

Regulatory Issues

This report identifies a range of key regulatory issues and sketches a preliminary framework for regulatory innovation to accommodate the emergence of DESs and the evolving nature of the electric power system (Section 3), including: design of adequate remuneration mechanisms for distribution utilities to facilitate DER and DES adoption and encourage more rapid innovation and evolution of the distribution system (Section 3.1); and new tariff designs to accommodate DERs and DESs and provide efficient price signals to network users (Section 3.2).

To further develop and demonstrate the application of new remuneration mechanisms that provide appropriate incentives for the efficient evolution of the distribution system, deeper analysis must identify the ideal use of both incentive compatible menus of contracts and reference network models to overcome information asymmetries and assist regulators in benchmarking efficient utility expenditures and setting revenue caps. The most effective incentive mechanisms to encourage utility innovation should also be explored.

Subsequent analysis must demonstrate the use of network profiles and a reference network model to compute DNUoS charges. Alternative DNUoS charge designs can be evaluated according to their impacts on DES business models, distribution utilities, and wholesale and/or ancillary services markets.

The regulatory challenges associated with the utilization of DESs in the provision of system energy services, particularly with respect to Active Network Management as defined by Pérez-Arriaga, et al. (2013), requires further analysis. This analysis should involve further definition of the roles and responsibilities of the DSO with respect to the TSO and other market actors.

Future research should also identify and assess elements of the regulatory framework that will be required to stimulate DSOs to engage in long-term innovative activities. While a well designed remuneration scheme can itself incentivize short- to medium-term innovation in relatively low risk technologies and processes, additional regulatory elements will be required to stimulate DSOs to deploy innovative technologies and processes over longer time horizons. Examples of such elements could include the creation of a competitive network innovation fund, a mechanism for DSOs to pass the costs of research and development (R&D) activities onto consumers, a mechanism to reward DSOs for successful innovation activities by increasing DSO revenue caps, and other approaches. Research will be required to identify where such regulatory elements have been implemented and to what degree they have been successful.

Additionally, while this report has primarily focused on regulation of distribution utilities, the penetration of DESs entails broader regulatory and market design implications for other actors in the electricity supply chain. For instance, the anticipated reduction in the volume of wholesale energy contracted could bring regulatory changes in wholesale market design, as well as much stronger interaction between retail and wholesale levels. Likewise, the growth of DESs will impact the roles and responsibilities of TSOs and may require regulatory adjustments there, as well. Future research should therefore address the broader regulatory implications of the growth of DES-related business models as well. Systems-level analytical and engineering modeling will likely assist in identify these larger system-wide implications.

Ongoing Research

The *Utility of the Future* project is continuing to analyze the questions highlighted in this report. The project's researchers rely upon quantitatively rigorous technical and economic models in order to interrogate the questions proposed herein. The project plans to identify theoretical "first best" approaches to key regulatory and market design questions and then adapt these approaches to suit real-world conditions. Tremendous uncertainty remains today over which technologies, business models, and regulations will enable the future of the provision of electricity services. The *Utility of the Future* study will make an important contribution towards answering these key questions.

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Part 1: Electricity End User Services

		Service										
		A	B	C	D	E	F	G	H	I	J	K
		Comfort: Heating/ Cooling	**Mobility**	**Lighting**	**Other Personal Energy Services**	**Reliability** [Capacity Factor as a Proxy]	**Control** [High, Medium, Low]	**Convenience** [High, Medium, Low]	**Affordability** [High, Medium, Low]	**Variable Cost Stability** [High, Medium, Low]	**Other concerns (environmental impact)** [High, Medium, Low]	**Other concerns (independence)** [High, Medium, Low]
Technology	***Distributed Generation***											
	HV/MV Distribution / Industrial											
	Small wind turbine (5kW <X< 100kW)	X	-	X	X	Low	Low	Medium	Medium	High	Low	High
	Med. wind turbine (100kW <X< 2MW)	X	-	X	X	Low	Low	High	Medium-High	High	Low	High
	Solar PV (< 1 MW capacity)	X	-	X	X	Low	Low	High	U.S.: Low-Medium Europe: Medium-High	High	Low	High
	CSP (< 3 MW capacity)	XX	-	X	X	Low	Low	Medium	Low	High	Low	High
	CSP + TER	XX	-	X	X	Medium	Medium	Medium	Low	High	Low	High
	CHP (Industrial)	XXX	-	X	X	High	High	Low	High	Low	Medium	Low-Medium
	Biomass CHP (Industrial and District Heating)	XXX	-	X	X	High	High	Low	High	Medium	Low	Low-Medium
	Thermoelectric generator	X	-	X	X	High	High	Medium	Low	High	Low	Medium
	LV Distribution / Household (Europe <110KV)											
	Household wind turbine (0.1kW <X< 5kW)	X	-	X	X	Low	Low	Medium	Medium	High	Low	High (although note that for safety reasons, grid-tied units will go offline in case of power failure unless equipped with remote disconnect from the grid)
	Solar PV	X	-	X	X	Low (10-22%)	Low	High	U.S.: Low-Medium Europe: Medium-High	High	Low	High (although note that for safety reasons, grid-tied units will go offline in case of power failure unless equipped with remote disconnect from the grid)

		Service										
		A	B	C	D	E	F	G	H	I	J	K
		Comfort: Heating/ Cooling	**Mobility**	**Lighting**	**Other Personal Energy Services**	**Reliability** [Capacity Factor as a Proxy]	**Control** [High, Medium, Low]	**Convenience** [High, Medium, Low]	**Affordability** [High, Medium, Low]	**Variable Cost Stability** [High, Medium, Low]	**Other concerns (environmental impact)** [High, Medium, Low]	**Other concerns (independence)** [High, Medium, Low]
Technology	Micro CSP	X		X	X	Medium	Low	Medium	Low	High	Low	High
	Solar stirling engine	X	-	X	X	Low	Low	Medium	Low	High	Low	High
	Geothermal heat pump	XXX	-	-	-	High	Medium	High	Medium	High	Low	Medium
	Biomass CHP	XX	-	X	X	High	High	Low	High	Medium	Low/Medium	Low
	Diesel generators	X	-	X	X	High	Medium	Medium	Low-Medium	Low	High	Low
	Natural gas-fired stirling engine (1-25 kW) and reciprocating engines (1-5000 kW)	X	-	X	X	High	Medium	Medium	Low	Low	Medium	Low
	Fuel Cell Micro-CHP (Residential)	X	-	X	X	High	High	Low	Low	Low	Low	Low
	Microturbine Micro-CHP (MCHP) (> 30 KW)	XXX	-	X	X	High	High	Low	Low-Medium	Low	Medium	Low
	Stationary Storage											
	KWh-scale "household/community" storage							X (depends on how much end-user operation and maintenance is required)		X (reduces risk from use of intermittent generation)	X (if used in conjunction with renewable generation; disposal/end of life may be of concern)	XX (Increases self-sufficiency, particularly when paired with DG)
	Sodium-sulfer (NaS) batteries		X	X	X	X	X	-	Low-Medium	-	-	-
	NiMH batteries		X	X	X	X	X	-	Low-Medium	-	-	-
	Lead acid batteries		X	X	X	X	X	-	Medium	-	-	-
	Zn-Br (flow battery)		X	X	X	X	X	-	Low	-	-	-
	Zinc-air (Zn-air) batteries		X	X	X	X	X	-	Low-Medium	-	-	-
	Lithium-ion batteries		X	X	X	X	X	-	Low-Medium	-	-	-
	Frozen air (liquid nitrogen) batteries		X	X	X	X	X	-	Low	-	-	-
	Thermal storage		X	X	X	X	X	-	Medium	-	-	-

		Service										
		A	B	C	D	E	F	G	H	I	J	K
		Comfort: Heating/ Cooling	**Mobility**	**Lighting**	**Other Personal Energy Services**	**Reliability** [Capacity Factor as a Proxy]	**Control** [High, Medium, Low]	**Convenience** [High, Medium, Low]	**Affordability**	**Variable Cost Stability** [High, Medium, Low]	**Other concerns (environmental impact)** [High, Medium, Low]	**Other concerns (independence)** [High, Medium, Low]
Technology	***Electric Vehicles & Charging Infrastructure***											
	Plug-in vehicle		X				X (greater control over charging/fueling)	X (no need to go to gas station)	? (possibly; upfront capital costs higher, cost of ownership lower)	Possibly (electricity relatively less volatile than oil/gasoline prices)	X (environmental concern; energy security concern)	
	"Dumb" uni-directional flow (charging only)		X				X (greater control over charging/fueling)	X (no need to go to gas station)	? (possibly; upfront capital costs higher, cost of ownership lower)		X (environmental concern; energy security concern)	
	"Smart" uni-directional flow (smart/automated charging)		X				X (greater control over charging/fueling)	X (no need to go to gas station)	? (possibly; upfront capital costs higher, cost of ownership lower)		X (environmental concern; energy security concern)	
	Bidirectional flow / Full V2G		X				X (greater control over charging/fueling)	X (no need to go to gas station)	? (possibly; upfront capital costs higher, cost of ownership lower)		X (environmental concern; energy security concern)	
	Electric Vehicle Supply Equipment (Charging)		Enabling			Need reliability metrics	Possible with right embedded ICT	Need charging speed metrics for each	Need affordability metrics for each			
	Residential Charger		Enabling					X	Low upfront cost, medium variable cost	Medium (High relative to gas prices)		
	Charging Station		Enabling						No upfront cost, medium variable cost	Medium (High relative to gas prices)		
	3-Port Hybrid Converter		Enabling					X	High upfront cost, low variable cost	High		
	Interchangeable EV battery		Enabling			If charged and kept at home			Medium upfront cost, medium variable cost	Medium (High relative to gas prices)		
	Stationary Inductive charging		Enabling					X (High convenience)	High upfront cost, medium variable cost	Medium (High relative to gas prices)		
	Mobile Inductive charging		Enabling					X (Very high convenience)	No upfront cost, medium variable cost	Medium (High relative to gas prices)		

		Service										
		A	B	C	D	E	F	G	H	I	J	K
		Comfort: Heating/ Cooling	**Mobility**	**Lighting**	**Other Personal Energy Services**	**Reliability** [Capacity Factor as a Proxy]	**Control** [High, Medium, Low]	**Convenience** [High, Medium, Low]	**Affordability**	**Variable Cost Stability** [High, Medium, Low]	**Other concerns (environmental impact)** [High, Medium, Low]	**Other concerns (independence)** [High, Medium, Low]
Technology	***Demand Response***	May help improve comfort					X		May help improve affordability			
	Advanced metering infrastructure ('smart meters')						?					
	Energy Management Systems/Home energy report platform	May help improve comfort					X		May help improve affordability			
	"Smart" uni-directional flow (smart/automated charging)	May help improve comfort					X		May help improve affordability			
	Bidirectional flow / Full V2G	May help improve comfort					X		May help improve affordability			

Part 2: Upstream System Operator and Electricity Market Services

		Service															
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Technology		Energy	Power / Capacity	Voltage control	Frequency regulation	Increased reliability / Resilience to outages	Black-start / outage recovery	Primary Reserves	Secondary Reserves	Tertiary Reserves	Flexibility / Integration of intermittent renewables	CapEx Investment deferral	OpEx reduction	Reduction of losses	Risk-mitigation	Arbitrage of energy price differentials	Affordability [High, Medium, Low]
	Distributed Generation																
	HV/MV Distribution / Industrial																
	Small wind turbine (5kW <X< 100kW)	X	X	Can, by adding electronics	Can, by adding electronics	-	-	-	-	-	-	-		-	-	-	Medium
	Med. wind turbine (100kW <X< 2MW)	X	X	Can, by adding electronics	Can, by adding electronics	-	-	-	-	-	-	-		-	-	-	Medium-High
	Solar PV (< 1 MW capacity)	X	X	Can, by adding electronics	Can, by adding electronics	-	-	-	-	-	-	-		-	-	-	U.S.: Low-Medium Europe: Medium-High
	CSP (< 3 MW capacity)	X	XX	X	-	-		-	-	X	-	-		-	-	-	Low
	CSP + TER	X	XXX	XX	X	-	X	X	X	X	X	-		-	X	X	Low
	CHP (Industrial)	X	XXX	XXX	XXX	-	X	X	X	X	X	-		-	-	X	High
	Biomass CHP (Industrial and District Heating)	X	XXX	XXX	XXX	-	X	X	X	X	X	-		-	-	-	High
	Thermoelectric generator	X	XXX	XXX	XXX	-	X	X	X	X	X	-		-	-	X	High

		Service															
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
		Energy	**Power / Capacity**	**Voltage control**	**Frequency regulation**	**Increased reliability / Resilience to outages**	**Black-start / outage recovery**	**Primary Reserves**	**Secondary Reserves**	**Tertiary Reserves**	**Flexibility / Integration of intermittent renewables**	**CapEx Investment deferral**	**OpEx reduction**	**Reduction of losses**	**Risk-mitigation**	**Arbitrage of energy price differentials**	**Affordability** [High, Medium, Low]
Technology	**LV Distribution / Household (Europe <110KV)**																
	Household wind turbine (0.1kW <X< 5kW)	X	X	?	?	X	-	-	-	-	-	-		X	-	X	Medium
	Solar PV	X	X	-	-	X	-	-	-	-		-		X	-	X	U.S.: Low-Medium Europe: Medium-High
	Micro CSP																Low
	Solar Stirling engine	X	X	-	-	X	-	-	-	-	-	-		X	-	X	Low
	Geothermal heat pump	X	-	-	-	-	-	-	-	-	-	-		-	-	-	Medium
	Biomass CHP	X	X	?	?	XXX	-	-	X	X	X	-		X	-	X	High
	Diesel generators	X	X	?	?	XXX	-	-	X	X	X	-		X	-	X	Low-Medium
	Natural gas-fired Stirling engine (1-25 kW) & reciprocating engines (1-5000 kW)	X	X	?	?	XXX	-	-	X	X	X	-		X	-	X	Medium
	Fuel Cell Micro-CHP (Residential)	X	X	?	?	XXX	-	-	X	X	X	-		X	-	X	Low
	Microturbine Micro-CHP (MCHP) (> 30 KW)	X	X	?	?	XXX	-	-	X	X	X	-		X	-	X	Low

		Service															
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
		Energy	**Power / Capacity**	**Voltage control**	**Frequency regulation**	**Increased reliability / Resilience to outages**	**Black-start / outage recovery**	**Primary Reserves**	**Secondary Reserves**	**Tertiary Reserves**	**Flexibility / Integration of intermittent renewables**	**CapEx Investment deferral**	**OpEx reduction**	**Reduction of losses**	**Risk-mitigation**	**Arbitrage of energy price differentials**	**Affordability** [High, Medium, Low]
	Stationary Storage																
Technology	**MWh-scale "distributed" grid-connected storage**																
	"Fast" batteries (high power throughput)																
	Flywheels		X	X	X		X	X		X	X	X					Low-Medium
	Super-capacitors		X	X	X		X	X		X	X	X					Low
	Fast-charging Li-ion		X	X	X		X	X		X	X	X					Medium
	Superconducting magnetic energy storage (SMES)		X	X	X		X	X		X	X	X					Low
	"Slow" batteries (lower power throughput, high energy capacity)																
	Sodium-sulfur (NaS) batteries	X	In aggregate	X (possibly)		X	X		X	X	X	X			X	X	Low-Medium
	Zinc-air (Zn-air) batteries	X	In aggregate	X (possibly)		X	X		X	X	X	X			X	X	Low-Medium
	Lithium-ion batteries	X	In aggregate	X (possibly)		X	X		X	X	X	X			X	X	Low-Medium
	Frozen air (liquid nitrogen) batteries	X	In aggregate	X (possibly)		X	X		X	X	X	X			X	X	Low
	Flow batteries	X	In aggregate	X (possibly)		X			X	X	X	X			X	X	Low
	Zn-Br (flow battery)	X	In aggregate	X (possibly)		X	X		X	X	X	X			X	X	Low
	KWh-scale "household/community" storage	X (aggregated)	X (aggregated)	X (possibly with right power electronics)	X	X	X				X	X			X	X	Low-Medium

		Service															
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
		Energy	**Power / Capacity**	**Voltage control**	**Frequency regulation**	**Increased reliability / Resilience to outages**	**Black-start / outage recovery**	**Primary Reserves**	**Secondary Reserves**	**Tertiary Reserves**	**Flexibility / Integration of intermittent renewables**	**CapEx Investment deferral**	**OpEx reduction**	**Reduction of losses**	**Risk-mitigation**	**Arbitrage of energy price differentials**	**Affordability** [High, Medium, Low]
Technology	***EV Charge Control Methods***																
	Smart Unidirectional flow			X	X						X (Downramping)						
	Bidirectional flow / Full V2G		X (aggregated)	X	X	X	X	X			X	X				X	
	Demand Response		X	?	?			X	?		X	X		X			X
	Advanced metering infrastructure ('smart meters')		Possibly enabling					Possibly enabling			Possibly enabling	Possibly enabling		Possibly enabling			Possibly enabling
	Energy Management Systems/Home energy report platform		Possible					Possible			Possible	Possible		Possible			Possible
	Grid-friendly appliances(GFAs)/ automated controllable loads		Possible					Possible			Possible	Possible		Possible			Possible
	Local/Home Area Networking of "smart" devices		Enabling					Enabling			Enabling	Enabling		Enabling			Enabling

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