eLab
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

NEW BUSINESS MODELS FOR THE DISTRIBUTION EDGE

THE TRANSITION FROM VALUE CHAIN TO VALUE CONSTELLATION

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What is e-Lab?

The Electricity Innovation Lab (e-Lab) brings together thought leaders and decision makers from across the U.S. electricity sector to address critical institutional, regulatory, business, economic, and technical barriers to the economic deployment of distributed resources. In particular, e-Lab works to answer three key questions:

- How can we understand and effectively communicate the costs and benefits of distributed resources as part of the electricity system and create greater grid flexibility?
- How can we harmonize regulatory frameworks, pricing structures, and business models of utilities and distributed resource developers for greatest benefit to customers and society as a whole?
- How can we accelerate the pace of economic distributed resource adoption?

A multi-year "change lab", e-Lab regularly convenes its members to identify, test, and spread practical solutions to the challenges inherent in these questions. e-Lab has three annual meetings, coupled with ongoing project work, facilitated and supported by Rocky Mountain Institute.

e-Lab meetings allow members to share learnings, best practices, and analysis results; collaborate around key issues or needs; and conduct deep-dives into research and analysis findings. For more information about e-Lab, please go to: http://www.rmi.org/e-Lab.

About This Paper

This e-Lab discussion paper was prepared to support e-Lab deliberations and discussions and to engender a broader industry-wide dialogue about new approaches to the utility business model ecosystem at the distribution edge.

Principal authors are James Newcomb, Virginia Lacy and Lena Hansen. Mathias Bell provided research assistance. Virginia Lacy directed production and concept design of print publication and webpage. Romy Purhouse, Michelle Fox and Chris Rowe provided graphic design. Peter Bronski provided copyedit. Jamie Moir and Martin Walaszek supported webpage development.

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While e-Lab is a joint collaboration, RMI is solely responsible for the content of this report.

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EXECUTIVE SUMMARY

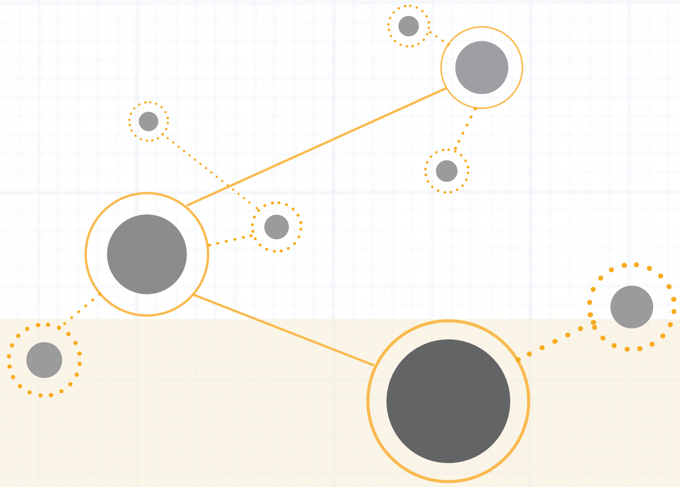
The declining costs and improving performance of distributed energy technologies are expanding the range of options for onsite generation and management of electricity, driving accelerated deployment of these technologies by customers and third-party service providers. Already, the growing role of distributed resources in the electricity system is leading to a shift in the fundamental business model paradigm of the industry. The electricity industry is evolving from a traditional value chain to a highly participatory network or constellation of interconnected business models at the distribution edge, where retail customers interface with the distribution grid.[1] Ultimately, customers that are playing a larger role in producing and managing their energy may also help to provide electricity services to the grid to enable better economic optimization of resource use across the entire system.

Existing electric utility business models, however, are poorly adapted to tap the potential value of distributed resources to meet societal demands for cleaner, more resilient, and more reliable electricity supply. Achieving optimal integration of distributed energy resources will require a versatile and flexible foundation for value-based transactions with and among the many parties. With increased options come increased complexity—and a growing need for better coordination. The regulated distribution utility of the future can be an important partner in helping to coordinate the deployment and integration of distributed resources—investing in grid infrastructure to support this new and more dynamic system, conveying signals about system conditions, and integrating disparate resources to harvest the benefits of diversity for all stakeholders.

Achieving this transition may require transformative, rather than incremental, changes in utility business models. Existing regulatory paradigms and pricing structures can be adapted to provide appropriate incentives for distributed resource deployment, operation, and integration. But they do so by layering new remedies on existing models, adding complexity. At some point, shifting to a new, more customer-centric system may provide a better, simpler, and more elegant solution.

This paper describes 1) how and why the forces changing the electricity system challenge existing pricing and business models, 2) principles that should guide the creation of new business models, and 3) the emerging "solution set" of new business models.

1 See text box "What is the distribution edge"



What is the distribution edge?

The *distribution edge* is the interface between the electricity distribution system operated by utilities and the rapidly growing portfolios of energy assets, control systems, and end-use technologies at or near customers' premises. The distribution edge is a microcosm where fundamental forces changing the economy at large are having transformative impacts on the electricity sector—forces such as digitization, global competition in manufacturing, and intensifying concerns about environmental and cyber security risks.

Distributed energy resources (DERs) include demand- and supply-side resources that can deployed throughout an electricity distribution system to meet the energy and reliability needs of the customers served by that system. This includes targeted energy efficiency, distributed generation and storage, and various forms of demand response, including smart electric vehicle charging. Distributed resources can be owned and operated by customers, utilities, or third parties. The services provided by distributed resources can include energy and capacity, as well as ancillary services such as the provision of reserves, black-start capability, reactive power, and voltage control.

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DRIVING FORCES

Major forces are driving transformational changes in the U.S. electricity sector. At the customer level, advances in communications and controls, distributed generation and storage, electric vehicle charging, and other technologies are opening new avenues for investment and value creation. Third-party providers are stepping in to provide innovative energy services ranging from solar leasing to emergency power systems. Microgrids are being developed to help integrate and manage distributed resources at the local level. New approaches to delivering energy efficiency are yielding deeper savings and, coupled with distributed supply options, are opening the door to achievement of net zero energy buildings and campuses.

Together, these changes are creating new possibilities for multi-directional flows of power and information that will empower customers to play a greater role in the future electricity system, a future that is already unfolding today. Recent trends provide evidence of an ongoing acceleration of investment in distributed energy resources:

- Investments in **energy efficiency** by electric utilities and their customers are increasing significantly. Electric efficiency program budgets in the U.S. more than doubled from 2007 to 2011, increasing from $2.7 billion to $6.9 billion per year. Four states—Arkansas, Nebraska, South Dakota, and Wisconsin—more than doubled their electric efficiency budgets in 2012 compared to 2011. Another six—Georgia, Illinois, Maine, North Dakota, Ohio, and Washington—increased their budgets by over 50 percent. Recent projections suggest that electric utilities' annual efficiency program budgets could reach $14 billion by 2025.[i]

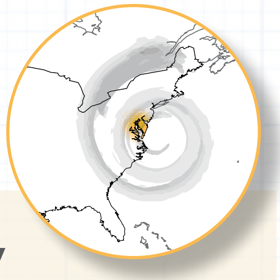
- **Demand response** investments and capacity have increased sharply since 2010. According to an annual demand response survey conducted by the Federal Energy Regulatory Commission (FERC), actual peak reductions from demand response in the U.S. totaled 20.3 GW in 2012, up 27 percent from 2010. Further, the FERC survey estimated demand response's full potential at 72,000 MW in 2012, enough to meet about 9.2 percent of peak demand nationwide.[ii]

- U.S. investments in **solar PV** are surging as system costs continue to fall. In 2012, solar PV installations totaled 3.3 GW, representing an investment of $11.5 billion. In 2013, solar power is projected to be second (behind only wind power) in net additions to U.S. electricity generating capacity.[iii]

- Investments in **on-site combined heat and power generation** are on the rise, stimulated by currently low natural gas prices. An Executive Order issued by President Obama in 2012 established a new national goal of 40 GW of new CHP capacity by 2020—a 50-percent increase from today. Meeting this goal would require $40–80 billion in new capital investment.[iv]

- New options for **emergency back-up** power are proliferating, especially along the East Coast in the aftermath of Superstorm Sandy. Customers ranging in size from households to corporate and university campuses are exploring options for ways to enhance security of supply and service providers are responding with new offerings, some of which integrate distributed resources in new ways. For example, in Connecticut, the state developed the The Microgrid Grant and Loan Pilot Program to develop microgrid solutions that can provide power to critical facilities. The state will invest $1.5 million upfront to fund preliminary design and engineering costs for selected finalists. The state will invest an additional $13.5 million for microgrid projects selected in the final round.

Increased investment in distributed resources, however, could lead to waste or duplication if these investments are not made in ways that integrate with and provide value to both the customer and the electricity grid. Realizing the full opportunity from distributed resources will require new approaches to grid operations and system planning in parallel with new methods for measuring, creating, and capturing value. Together, these changes will have significant implications for the electricity value chain, creating new roles and sources of value for customers, utilities, and new entrants.



Resilience and Reliability in Emergency Conditions: Increased Impetus for Change?

In the aftermath of Superstorm Sandy, much attention has been given to the electricity grid's vulnerability to disruption and the potential contributions of smart grid technologies and distributed generation resources to respond in the event of grid outages. Growing numbers of customers are evaluating the merits of making investments that would give them onsite emergency supply or back-up power. This shift, in itself, could lend additional impetus to distributed resource deployment. The electricity system disruptions caused by Sandy drew increased attention to microgrid systems, such as those at Princeton University in New Jersey and the U.S. Food and Drug Administration's White Oak research facility in Maryland, which were able to island from the larger power grid in the storm's aftermath in order to maintain local power service. Yet, distributed systems are by no means a panacea, since these systems have vulnerabilities of their own and pose cost- and emissions-related considerations that vary widely on a case-by-case basis. For example, blindly expanding the use of diesel back up generators could worsen air emissions problems. As distributed technologies continue to evolve, important questions remain about how investments by customers and utilities can best align to increase the resilience and reliability of the system as a whole. Achieving this goal will require new technologies for grid management and integration, together with innovative business models capable of managing these solutions economically.

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WHY ARE NEW BUSINESS MODELS NEEDED?

Today's electric utility business models reflect the legacy of decades of incremental modifications to structures that were originally designed around technologies, operational strategies, and assumptions about customers' needs that are largely outdated today. For the better part of a century, generation technologies were primarily limited to central thermal power plants with increasing economies of scale: the larger the plant, the more efficient and cheaper the electricity generation. Compared to the capital required to build a power plant, there was comparably little cost to operate it—and therefore a significant economic incentive for integrated utilities to maximize the production and sale of electricity.

Given these characteristics, and the recognition of electricity as a public necessity, the electric utility industry was treated as a natural monopoly. The oft-cited "regulatory compact" connotes an implied agreement between government and the utility that the utility will provide affordable, reliable, universal service in exchange for the exclusive right to serve customers in a geographic territory at an authorized rate of return.

Over the past century, the electricity industry's characterization as a natural monopoly has evolved to become more nuanced. Technological innovation in thermal-powered electric generation plants that occurred over decades in the 20th century brought down the capital cost and investment hurdles for more (and smaller) players to participate. Today, limited segments of the electricity value chain are considered true natural monopolies, principally the role of delivering electricity via transmission and distribution and the role of balancing supply and demand in real time. There is an open debate as to whether other electricity services—including generation and customer-interfacing services—may be better served with more providers competing and innovating to meet diverse demands more cost effectively.

For the majority of retail customers in the U.S., in a given jurisdiction the same provider offers both electricity supply and distribution services. In some jurisdictions, customers can choose their electricity supplier from among competing providers, while receiving distribution services from a regulated distribution monopoly. Additionally, in some parts of the country, the availability of a competitive wholesale electricity market organized by an independent system operator provides another structural layer that delineates the profit opportunities, activities, access, and transparency available to electricity sector players.

Even with this diversity, key tenets of the traditional utility business model remain largely intact:

- **Limited Electricity Service Providers:** Even in "deregulated" retail markets, competitively generated electricity is treated primarily as a commodity delivered over wires owned and operated by regulated monopoly distribution utilities to retail customers in that area.

- **Centrally Controlled System Operations:** A utility or independent system operator centrally dispatches large generators to meet exacting reliability standards by controlling the output of a generation portfolio to match aggregate customer demand.

- **Regulated Rate of Return and Cost Recovery:** Where the monopoly function remains, the utility's return is earned based on invested capital, often recovered through bundled rates that do not reflect temporal or locational differences in cost or value and which were designed to accommodate services provided by central station resources.

Traditional utility business models and institutional structures performed well in times of growing demand, increasing power-plant economies of scale, and an electricity industry dominated by central station resources. Today, however, electricity demand in many jurisdictions is growing slowly or even decreasing due to the combination of slow economic growth and increasingly efficient end-use technologies. A rapidly growing portfolio of energy assets, control systems, and end-use technologies at the customer level—the distribution edge—provides a widening array of options to meet customer demands and, potentially, to respond to system conditions in beneficial ways. For example, customers are increasingly able to:

- Generate electricity via on-site distributed generation,

- Have more control over the timing and the amount of their electricity use, and

- Invest in and manage on-site resources to achieve cost, reliability, and environmental goals.

As technological innovation has fundamentally shifted the ability to meet and provide electricity-enabled energy services, so, too, is the penetration of these technologies creating new business model opportunities or presenting threats to the existing institutional framework that forms the business model ecosystem (Table 1). First, beyond the purview of the utility, entrepreneurial companies or customers can own and provide distributed resources on the customer side of the meter. Second, operationally, distributed energy resources behave differently from conventional, centralized resources; they require new operational strategies for grid operators because they are smaller in size, located closer to load, have traditionally not been set up to enable centralized dispatchability,[2] and to the extent they are powered by variable sources such as solar and wind, their output fluctuates. Finally, distributed energy resources reduce the amount of energy that a customer would otherwise demand from the grid.

However, the conventional approach for pricing the electricity service a customer receives is to bundle all of the costs—fixed and variable—into a relatively simple cost per kilowatt hour or only a slightly more sophisticated approach. In that case, reducing the number of kilowatt hours purchased from the grid may also reduce necessary recovery of fixed costs. Similarly, innovation in distributed technologies can be stifled when utility prices fail to provide customers with an economic benefit when they are able to self-provide a service such as storage or power quality services.

In an industry where new investment and service opportunities are rapidly proliferating at the distribution edge, new regulatory and business structures will be required to better align incentives for utilities, customers, and distributed resource developers. This will require: 1) greater transparency with respect to the services provided to and by distributed resources and the ability to fairly and objectively quantify their respective value, 2) pricing models or incentives that more accurately reflect the operational needs of the system, possibly including timing and location, and 3) new utility business models adapted to create and sustain value through integration of economically deployed distributed resources.

2 However, that does not mean that distributed resources cannot be centrally dispatched today with the right coordination equipment and "smart grid" investments.

Electric Utility Business Model Challenges and Opportunities

ISSUE	CHALLENGE TO EXISTING BUSINESS MODELS	OPPORTUNITY FROM NEW BUSINESS MODELS
Social priorities	Society values the potential environmental and innovation benefits that distributed resources could provide, but the utility may have little incentive to encourage distributed resources if those resources will reduce utility revenues or create cross-subsidies among customers.	New business models can potentially better align the profit-making incentives of utilities with social priorities, leading to reduced environmental impact and increased innovation.
Operations	Providing reliable power requires grid flexibility and predictability. The variability of supply from distributed renewable resources may require smart grid investments to better integrate these resources' output with the grid. Better price signals or incentives may be needed to ensure the highest-value deployment of distributed resources.	New business models can potentially send signals to customers to encourage deployment of resources when and where they are of most benefit to the grid and with equipment that does not require grid upgrades to ensure power quality. For example, utilities could charge customers for the power quality and storage services they receive, providing customers with an opportunity to save money by investing in distributed storage and/or smart inverters. At the same time, customers could be compensated for services they are able to provide to the grid based on cost savings the grid operator is able to realize.
Cost allocation & value recognition	To the utility, revenue from customers with distributed resources may not match the cost to serve those customers. Mechanisms are not in place to value or reward service that distributed resources provide, nor is there currently the ability to easily quantify their value.	New business models can potentially reflect more accurately the costs to serve customers with distributed resources, and the values that those resources can provide. This would create a more level playing field where utilities and customers can make smart choices.
Social equity	Existing rates may not adequately reflect the costs and value of services that distributed resource customers receive or provide. Where they do not, they create problems of fairness, since one class of customers will wind up subsidizing another. If customers with distributed generation pay less than their "fair share" for the grid services they receive, those costs are covered by the rest of the customer pool. Alternatively, where distributed resource customers are undercompensated for the value of services they provide, they subsidize other customers.	New business models can better allocate costs between customers and customer classes based on the services they receive and the costs utilities incur to provide those services. To the extent that incentives are necessary to achieve short-term policy goals with regard to distributed energy resource deployment, they can be clearly identified, equitably allocated, and adjusted as market conditions change to ensure achievement of those policy goals.
Service innovation	Existing utility business models limit the ability of utilities to generate profits through innovative deployment of distributed resources.	New business models could create new avenues for service integration and value creation at the retail customer level, potentially including utility ownership of on-site distributed resources.

PERSPECTIVES

What is the role of the utility at the distribution edge?

The utility will be needed to play a critical coordination and stewardship role–which will require new regulatory incentives. The provision of electricity is a business "affected with the public interest," roviding essential services for the benefit of our society and economy. By interconnecting producers and consumers with diverse supply resources and varying electricity demands, the electricity grid reduces risk, enables greater economic efficiency, and lowers costs for all. The historical role of the utility to coordinate operations and planning does not fade away but rather grows in importance as distributed resources proliferate. Further, there will be a continued and growing need to ensure that low-income or disadvantaged customers—who may not have the income, opportunity, or desire to operate their own virtual power plants—can still access affordable electricity.

The traditional electricity grid is becoming increasingly vulnerable to bypass; its importance will diminish as growing numbers of customers seek alternative supply options. Distributed generation, electricity storage, and energy management technologies are advancing rapidly and will eventually give large numbers of customers options to unplug from the grid. As this occurs, the role of the traditional utility monopoly will shrink. This is a natural and perhaps inevitable transition as competitive forces play out in the electricity sector. Regulators should prepare to manage a diminishing role for regulated utilities rather than trying to maintain the status quo. The needs of low-income customers, renters, and other "disadvantaged" customers with respect to distributed energy resources can be met through universal access charges, third-party finance, community solar, and other innovative mechanisms.

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WHAT ATTRIBUTES SHOULD NEW BUSINESS MODELS PROVIDE?

The increasing role of distributed resources in the electricity system is leading to a shift in the fundamental business model paradigm of the industry, from a traditional **value chain** to a highly participatory **network** or **constellation** of interconnected business models at the distribution edge. In this context, regulators and policymakers must redesign the structure and form of the regulated monopoly utility's functions in a way that provides a **platform** for the economic and operational integration of distributed resources. Today's business models largely fall short of this aspiration, and often do not provide a level playing field for making trade-offs between distributed and centralized resource options.

By "platform," we mean a system that supports value-based interactions among multiple parties and a set of rules—including protocols, rights, and pricing terms—that standardizes and facilitates transactions among multiple parties.[v] The New York Stock Exchange is a platform, as are Apple's iTunes and App stores and PJM's capacity market. A platform can increase innovation and competition by: 1) reducing transaction costs, 2) increasing transparency in relating or comparing the value of services provided by different types of assets, even where the underlying assets are very different in character, and perhaps most powerfully, 3) enabling and empowering the creation of integrated solutions that are built up from readily combined but heterogeneous modules—a stock portfolio, an iTunes playlist, or a portfolio of assets to meet electricity capacity needs or voltage requirements. In the electricity system, a more open platform will require greater transparency of information about costs and benefits of the services that are or could be provided by utilities, customers, and other agents at the distribution edge. Here, two layers of market or platform structure are closely interwoven: technical standards and economic standards. Technical standards, ranging from voltage specifications to the nuances of IEEE-1547 and California's Rule 21, define the "rules of the road" for interconnection to the electricity grid. Economic standards, including rules for value determination, pricing, and market structure, define the terms for value-based transactions. In both cases, many of today's rules are archaic.

Looking ahead, these two sets of rules will have to become more readily adaptable, and they will inevitably become more closely linked to each other. New technical standards will define ways to measure value more precisely—for example, defining voltage support or rapid-response flexibility services—in relation to markets or pricing structures that break out these sources of value in economic terms. Clearer and more highly differentiated technical and economic rules for interconnection to the grid will open greater opportunities for new business models to emerge by providing the basis for buying, selling, and recombining different types of services. Finally, there is the challenge of addressing the potential conflicts and trade-offs between solutions that optimize economic benefits at the individual customer level versus those that create benefits through aggregation or socialization of costs.

Some of the changes possible at the distribution edge could be analogous to those already taking place at the wholesale market level where organized markets, managed by Independent System Operators such as PJM Interconnection, have created new markets for demand response and other services. But major challenges exist in developing such models at the distribution level. These challenges include:

- **Operational challenges of managing large numbers of interactions** among customers and other parties,
- **Issues of equity, fairness, and social impact** that could emerge from a shift away from traditional pricing approaches that socialize most costs across large customer classes, and
- **Challenges of engaging customers,** or the service providers representing them, to respond to price or market signals.

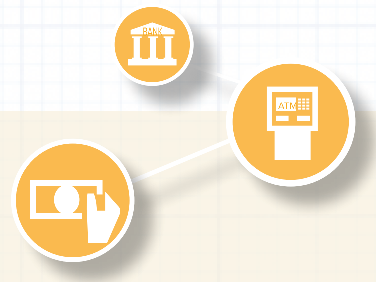
In view of these challenges, new business models that begin to make the transition to providing a platform for value-based transactions at the distribution edge will likely need to evolve in a step-wise fashion, allowing time for new service provider business models to evolve and for customers to learn and adapt to new rates and rules.

PERSPECTIVES

How should rates be structured to send appropriate price signals, reflect true costs, and ensure simplicity that customers can understand?

Rates must be restructured to provide clearer signals about the costs of electricity service. Rates are price signals that drive customer behavior and communicate the needs of the grid. Average volumetric prices, which bundle fixed and variable costs of service into a single price per unit of electricity ($/kWh), were adequate when first promulgated more than 100 years ago when utilities provided integrated service from generation to delivery. Today, however, customers of all classes—industrial, commercial, *and* residential—are investing in the ability to produce their own electricity. They still need the grid and grid services to export and import power, but some need less total grid-supplied energy overall. One size fits all no longer fits. In order to progress to a future where distributed resources can provide real value and reduce costs of electricity service overall, we must transition to refined pricing structures that reflect diverse service needs and offerings.

Simplicity is the key to successful retail ratemaking. Volumetric pricing with minimal fixed charges provides the strongest possible signal for customers to use electricity conservatively and efficiently. Energy efficiency investments remain the least cost and most beneficial distributed resource available today and volumetric prices strongly encourage these investments. For distributed generation, volumetric pricing coupled with net energy metering provides simplicity and certainty that is unmatched by more complex pricingand has become an industry standard for solar integrators providing third party finance. Further, fixed customer charges disproportionately penalize low-income customers.



ATM Networks and the Future of the Electricity Grid

Today, we take for granted the fact that we can put our bankcard into an automated teller machine (ATM) in virtually any major city in the world and discharge cash from our account in local currency. Behind the scenes is a highly robust interbank data network that allows real-time data flows to support ATM transactions. It took years to evolve the data systems, cooperation agreements, and protocols that support this system. By comparison, the systems that would be needed to support point-of-use transactions in the electricity system are far more complex. For electricity, the value of a transaction that provides electricity or other ancillary services to or from the grid depends not just on where and when the transaction takes place, but on system conditions that may be changing significantly in real time. While the technology to support sophisticated transactions over the electricity grid is emerging rapidly, the institutional and customer-related changes necessary to support such transactions could require a lengthy transition. Yet, the longer the delay, the greater the market dislocation from cost shifts and inaccurate market signals. New business model strategies may speed this transition by “hiding” the complexity of the system from most customers while sophisticated intermediaries or intelligent agents take advantage of signals that allow them to optimize the system behind the scenes.

In evolving new utility business models, it will be useful for regulators and policymakers to consider a set of attributes that the ideal distribution edge platform should be designed to meet. Clearly, it will be necessary to make trade-offs among some of these attributes and to adapt business models to particular regulatory and market contexts, but a high-level set of attributes can be described generally nonetheless. These include:

- Ensure **network efficiency, resilience, and reliability.** From both economic and technical perspectives, it is important that the integration of distributed resources should not only “do no harm” in terms of the efficiency, reliability, and resilience of the electricity system, but that these resources are deployed in ways that enhance these attributes.

- **Create a level playing field** for competition between all resources.

- **Foster innovation** in energy services delivery to customers to minimize energy costs. This requires an ability to evolve or adapt the platform structure over time; it points toward modularity, allowing separable services that can be bundled together.

- Provide **transparent incentives,** where necessary, to promote technologies that result in social benefits such as job creation and local economic development, financial risk mitigation, or environmental attributes of different resources, and properly allocating those costs.

- **Minimize complexity** that customers face in dealing with the electricity system.

- Enable a **workable transition** from traditional business models to new structures.

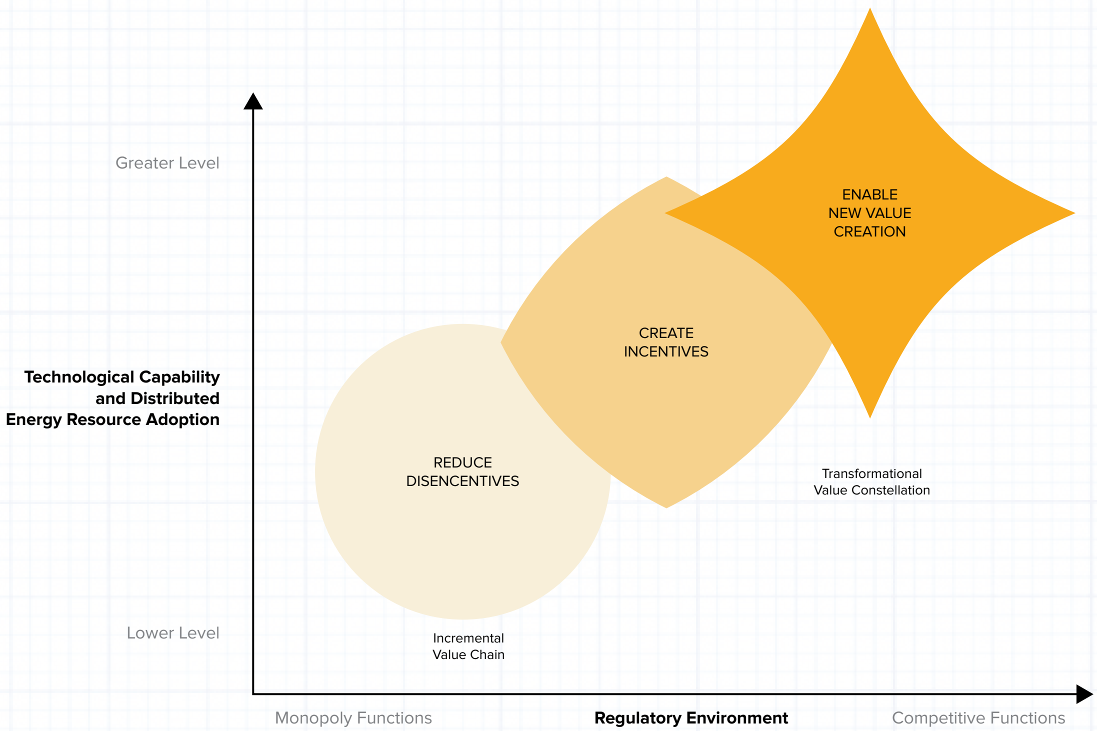
- Support the **harmonization of business models** of regulated and non-regulated service providers.

WHAT TYPES OF NEW SOLUTIONS COULD EMERGE?

Business model solutions designed to meet evolving needs at the distribution edge will hardly develop under a one-size-fits-all approach. Instead, many different types of models are likely to emerge and evolve in different regulatory and market contexts. Already, various new alternatives are beginning to emerge in the U.S. and internationally. Two key factors are likely to influence the types of solutions that are adopted over time in different regions or jurisdictions:

1. **The technological capability** of the electricity system in question, reflected in the level of adoption of distributed energy resources and the capabilities of the grid to integrate these resources.

2. **The regulatory environment,** characterized by the degree to which various types of services are considered monopoly functions.



These factors are likely to drive a spectrum of business model options, ranging from incremental approaches, which address discrete problems or opportunities while leaving the fundamental utility model largely unchanged, to transformational ones, which shift the electricity distribution sector towards a more complex value constellation. Myriad pathways exist.

The remainder of this section explores some of the alternative utility business model options that are or could be considered in vertically integrated and retail competition environments. Since these new models are still nascent, many questions remain about how they might actually be implemented, whether they are practical and workable, and what economic impacts they would have on utilities and other stakeholders. Nonetheless, it is valuable to float some “trial balloons” to stimulate dialogue about a range of new possibilities.

THE VERTICALLY INTEGRATED UTILITY ENVIRONMENT

In the vertically integrated environment, the utility is permitted to own or contract for services all along the value chain, including generation, transmission, and distribution, and it is typically granted an exclusive right to sell bundled electricity services to retail customers. In this environment, the growth of distributed energy resources owned by customers or other non-utility service providers represents a significant departure from the existing business model ecosystem. If an increasing share of the total investment in electricity assets is being made by non-utility actors, then utilities have less control over the evolution of the system. Equally, regulators and policymakers, who have used utility pricing and incentive structures as tools of social policy, must become increasingly aware of the possible unintended consequences of these policies insofar as they affect the investments and behaviors of a widening array of economic actors in the system.

Not surprisingly, the misalignments of incentives with respect to distributed resource deployment can be significant under this structure because the utility’s business model—including cost structure, revenue streams, key activities, and customer relationships—is predicated on the provision of all services along the value chain. Customers’ adoption of distributed resources may encroach on the utility’s conventional role (and revenue streams) as an integrated service provider. This evolution also represents a shift away from the centralized control model to which a vertically integrated utility, its regulators, and customers are acclimated.

Can these two seemingly contradictory worlds coexist? What changes can utilities and their regulators make in the vertically integrated environment to better integrate distributed resources? The evolution could include: 1) correcting existing misalignments in pricing and other incentives, 2) ensuring a level playing field for distributed energy resources in resource planning and investment, and 3) enabling the utility to capitalize on the opportunities presented by distributed energy resource adoption through direct investment or other means.

Reducing Disincentives and Rewarding Performance

A majority of vertically integrated utilities, whether publicly or privately held, are regulated under rate-of-return regulation that determines the amount of the utility’s return based on the amount of capital invested “prudently” to maintain service.[3] Most utilities’ financial health, in turn, depends directly on the volume of retail sales, because their fixed costs are recovered through charges based on how much electricity their customers use. This creates little incentive for utilities to promote distributed energy resources, such as efficiency or distributed generation, or to experiment with new service and price models.

Decoupling allows automatic adjustments in utility rates so that utilities are ensured the ability to recover their fixed costs regardless of fluctuations in electricity sales.[vi] Decoupling holds the fixed-cost revenue requirement constant and allows the rate charged per unit to vary (up or down) to account for a change in sales. Accordingly, decoupling “allows utilities to receive no more and no less than the

3 Between rate cases, the utility has a strong incentive to increase profit margins by increasing sales or decrease operating costs, although opportunities for short-term cost reduction can be more constrained than other industries given the higher proportion of fixed costs.

fixed-cost revenue requirements that their regulators have reviewed and approved."[vii] By the end of 2012, 25 states had adopted decoupling for at least one electric or natural gas utility; 24 electric utilities were operating under decoupling rules.[viii]

While decoupling addresses some of the important business model issues related to distributed resources, other challenges remain. For example, if utility rates increase automatically as sales decline, this could, under some circumstances, drive increased adoption of efficiency or distributed generation, thereby further increasing rates and further accelerating adoption, ultimately destabilizing the economic model that supports grid operation. While these mechanisms attempt to address revenue risk from a utility shareholder point of view, they leave some problems unresolved. For example, they do not protect non-participating customers from cost shifts and do not create the price signals necessary to support long-term distributed resource development and innovation in new technologies. Thus, decoupling addresses some, but not all, of the criticisms lodged against traditional revenue recovery approaches.

In an environment with more distributed resources—whose value is temporally, operationally, and geographically specific—new pricing models and methods of cost allocation may be needed to communicate the needs of the grid system and align resource investments with system costs and benefits over short-term (operational) or long-term (planning) horizons. The issue will become increasingly important as more capacity investment is made outside of the utility's control and more energy is supplied at the distribution level. Examples include unbundled pricing for reliability, standby, and power quality services; temporally or locationally differentiated prices for energy or distribution services; price structures that reflect how costs are incurred (e.g. fixed, demand-based, energy-based, etc.); and incentive payments for dispatchable demand response or ancillary services to the grid. Examples of new tariff structures that have been proposed or implemented in recent years that take a new look at the "cost to serve" include:

- **San Diego Gas & Electric's Network Use Charge Proposal**—would have charged customers for the costs associated with network use based on measured demand for distribution service, regardless of whether that service is required for importing or exporting power.

- **Austin Energy's Value of Solar Tariff** designed to reflect the net value of distributed solar power to the grid, including net impacts on line losses, energy, generation capacity, transmission and distribution capacity, environmental benefits, risk mitigation, or other factors.[ix]

In addition, transitioning the utility business model to one designed to support new technologies, by allowing utilities to charge for services they provide that support those technologies, could incentivize innovation. Such a business model could also alleviate concerns over cost shifting among customers while ensuring the achievement of short-term policy and market penetration goals through transparently identified incentives that could be adjusted as market conditions and policy goals warrant. New opportunities to offer new services in these emerging markets could likewise incent utilities to support and encourage this transition. Performance-based regulation could also tie utility revenue growth to a set of performance-related metrics, providing the utility with opportunities to earn greater profits by constraining costs rather than increasing sales.[x] Performance incentives, including shared net benefits (sometimes referred to as "shared savings"), or cost capitalization for distributed resources,[xi] can be used to reward utilities for achieving the least-cost system by enabling distributed resource investments to defer or displace more costly infrastructure needs.

Enabling New Value Creation

Utilities can only start to embrace new roles and revenue streams that enable greater profitability and high levels of distributed resources once an evolved business model removes disincentives and establishes fair and objective cost allocation. The utility could likely fill a number of clear roles. For example, the utility could continue to maintain its role of

1) distribution system operations coordinator, 2) provider of reliability/standby and power quality services for customers that do not self-provide these services, and/or 3) integrator of large-scale supply resources, distributed energy resources, and storage, all under circumstances in which regulation creates a level playing field for the utility to combine these resources for least cost overall.

MODEL 1

THE INTEGRATED DISTRIBUTED RESOURCE MANAGER (DER DISPATCHER)

DESCRIPTION

The integrated utility conducts an open-platform, peer-reviewed, and integrated least-cost planning process to evaluate alternative options to meet system requirements and select solutions. Based on a preliminary characterization of where and when investments in the utility system would be required and what needs these investments meet, third parties such as distributed resource providers, trade associations, customer advocates, or other outside experts are encouraged to propose alternative solutions based on distributed resources. An independent team of expert peer reviewers reviews these proposals and decides which of them requires full review and analysis by the utility. Where distributed resources are determined to provide the least-cost option, the utility is required to develop programs to support the development of these resources. The utility's options could include: 1) incentive payments to participating customers, 2) issuing RFPs for third parties to aggregate and deliver the required resources, 3) providing pooled financing for distributed resource development by third parties, or 4) directly investing in owning and operating distributed resources on the customer's side of the meter. The utility's bill could unbundle charges for distribution services from energy-related charges through some form of network use charge, paving the way for more highly differentiated pricing to accurately reflect costs and benefits of distributed resources. On-bill financing could fund distributed resource investments that meet certain requirements. Utilities would earn performance incentives, based on shared savings, for delivering distributed resources to meet system needs.

PROS & CONS

This model uses incentive regulation within the existing integrated utility business model construct, so the transition path to implementation is simpler than other alternatives. With an appropriate array of incentives and flexibility in developing new types of rates, the integrated utility could, in principle, incentivize the deployment of distributed resources for greatest system benefit. On the other hand, creating adequate transparency about distribution system costs and trade-offs among alternative solutions (especially between a distribution system asset and distributed resource alternatives) would remain a challenge.

QUESTIONS

1. Is such a model of distribution system planning workable given the constantly changing nature of system needs?
2. Would this model limit innovation on the part of distributed resource developers relative to more market-based approaches?
3. Can regulators really level the playing field between distributed resources and distribution system investments that meet the same need?

MODEL 2

THE DISTRIBUTED RESOURCE FINANCE AGGREGATOR (DER FinanceCo)

DESCRIPTION

The distribution utility provides on-bill financing for customers choosing to invest in certain types of qualifying distributed energy resources, coupled with a new tariff structure that applies to participating customers. The new rates are designed to ensure that the costs of distribution services provided to customers are recovered even if these customers implement distributed generation or become net zero energy customers. The rates also provide special incentives, such as those provided by today's "value of solar tariffs," for customers to deliver value to the system through deployment of distributed resources. Customers participating in the program can choose from among any of the energy services provided by a group of qualified "preferred service provider installers." The utility could help third parties market these services; for example, utilities could advertise third-party offerings on their website on a non-discriminatory basis, earn a commission on sales, and make necessary data available to third parties with customer consent. This helps to reduce customer acquisition costs and reduces barriers to entry into these emerging markets while encouraging the utility to support development of innovative services.

The energy services provider could either deliver an integrated bundle of energy services to the customer or an "a la carte" menu of options, potentially including energy efficiency retrofits, energy control systems, distributed generation, storage, and other options. With the customer's permission, the utility provides detailed customer information to qualified service providers, including: customer billing and usage data, information from satellite surveys of roof potential for solar PV, results from energy audits, and other information. The customer can choose from among alternative service packages—composed from a portfolio of approved, measureable, and verifiable investments—offered by competing providers. The service providers themselves could provide financing by agreement with customers or, for qualified sets of measures, through the utility via on-bill financing.

Preferred service providers are compensated by the utility on a verified performance basis for installing and managing distributed resources. The preferred service providers' customer acquisition and finance costs are lower because: 1) they receive a select customer list, 2) they receive data about each customer that facilities development of service proposals, 3) they benefit from pooled, low-cost finance backed by on-bill cost recovery, and 4) they benefit from increased scaling and geographic concentration in the utility's service territory.

PROS & CONS

This model could operate within the conventional structure of integrated utilities and could be especially attractive to municipal utilities. Making arrangements to support the flow-through financing model, while attractive for many reasons, could be difficult to implement.

QUESTIONS

1. Can an opt-in tariff be designed with minimal risk of cross-subsidy between participating and non-participating customers?
2. Can appropriate structures be created to support pooled financing of distributed resource development with on-bill repayment?

PERSPECTIVES

Can distributed energy resources deliver cost savings in the electricity distribution system?

Yes, distributed energy resources' capacity can reduce distribution system costs in a variety of ways. Increased distributed supply can prolong lifetimes of transformers and other equipment on the utility system by regularly reducing loads during peak periods. Where solar PV supply is reliably correlated with peak demand, distributed supply may allow utilities to avoid or defer capacity expansion in parts of the distribution system. In the long run, if there are appropriate incentives, distributed generation—coupled with electricity storage and necessary communications and control equipment—may be able to provide increased capacity value to the electricity grid. Eventually, with advanced inverters, distributed generation may even help to provide voltage regulation and reactive power on distribution system feeders.

No, all the assets on the distribution system are needed to serve electricity customers. The most common type of distributed generation, rooftop PV, provides little or no offset to the amount of distribution capacity that the utility must provide, since the utility must stand ready to provide electricity supply to customers when those distributed resources fail or are not available. Solar power supplies may not correlate well with system peak electricity demand, so capacity requirements on the utility system may not be reduced even under the best of circumstances. In some cases, high penetrations of distributed solar power may necessitate making additional investments in the distribution system to handle the power exported by solar systems at periods of peak supply.

Sometimes. Distributed energy resources deployed in the "right place at the right time" can create value for the distribution system. The value of distributed resources is affected not only by timing and location, but also by the flexibility, predictability, and controllability of the resource. For example, the capacity value of distributed energy resources, especially distributed generation, is highly geographically specific and varies by distribution feeder, transmission line configuration, and composition of the generation portfolio. Capacity investments, such as transmission upgrades or centralized generation plants, are "lumpy" in nature; therefore, it is necessary to determine the sufficient capacity demand reduction to avoid or defer such investments. Capacity costs and benefits are highly variable in nature, with the greatest value accruing in places of high system congestion and at times of peak demand.

The utility could also more actively direct investment and siting for distributed resources. In this role, the utility could manage deployment through price signals, ensuring that the resources provide the most value to all customers at the lowest cost. This is a significant departure from today's incentive programs in which the utility plays little role in providing clear value signals as to where distributed resources are deployed.[xii]

THE COMPETITIVE RETAIL ENVIRONMENT

Currently, more than 13 million customer accounts in the U.S., representing about 18 percent of total U.S. electricity load, are served in markets that provide for competitive retail electricity choice.[xiii] Twenty-one states allow retail competition for at least some electricity customers. In the retail competition environment, the distribution company—still a regulated monopoly—could provide the platform for distributed resources to conduct value-based transactions over the grid, given appropriate regulatory incentives. Distribution network operators can be regulated in ways that sever the volumetric incentive that can otherwise stifle distributed resource development. Moreover, distribution operators could provide incentives or price signals to customers and distributed resource developers to promote the development of these resources in ways that create the greatest value to the grid.

Reducing Disincentives and Rewarding Performance

Many of the solutions that apply in the integrated utility environment, such as decoupling, performance targets, and innovative pricing models, can be used to ensure that the distribution utility can profit from distributed resource deployment where those resources reduce the cost of providing distribution services. Indeed, in Europe, where stand-alone distribution network companies are more common than in North America, an array of new regulatory and pricing tools is rapidly evolving (see page 22).

Enabling New Value Creation

Utilities can only start to embrace new roles and revenue streams that enable greater profitability and high levels of distributed resources once an evolved business model removes disincentives and establishes fair and objective cost allocation. The utility could likely fill a number of clear roles. For example, the utility could continue to maintain its role of 1) distribution system operations coordinator, 2) provider of reliability/standby and power quality services for customers that do not self-provide these services, and/or 3) integrator of large-scale supply resources, distributed energy resources, and storage, all under circumstances in which regulation creates a level playing field for the utility to combine these resources for least cost overall.

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Transactive Grids for Distributed Resource Integration

In Denmark and the Netherlands, pilot projects are demonstrating how electricity distribution network companies can create peer-based transactive energy grids that allow distributed resources to interact directly with each other through network-based local energy markets in close to real time. In both countries, electricity distribution companies are prohibited from involvement in electricity production, trading, and supply, so they operate as "pure" distribution network companies. Enexis, an electricity and gas distribution company that serves 2.5 million households in the Netherlands, is using smart grid technologies to create a peer-based energy grid in a pilot program called PowerMatchingCity. The project encompasses 25 residential homes in the city of Groningen equipped with micro combined heat and power (CHP) equipment, smart appliances, smart meters, electric vehicles, and rooftop solar PV.[xviii] PowerMatchingCity's "real-time" market functions in 5-minute intervals, using a market platform software system to balance supply and demand in distributed clusters with the help of intelligent "agents" that manage the energy devices owned by customers. A similar experiment is being conducted at a larger scale on the Danish island of Bornholm, using the same platform and 5-minute interval market structure, but involving 28,000 customers with an energy portfolio that is 50 percent renewables. The Scandinavian and Dutch experiments are enabled in part by the restructuring of electricity distribution functions, which has removed conflicts of interest for distribution system operators, allowing distributed resources to deliver a widening range of energy and ancillary services to the grid.

Distribution Network Charges in Europe and Beyond

While locational and temporal pricing is an elegant and logical approach to managing distributed resource development within distribution networks, implementing such pricing regimes would be challenging. Nonetheless, some European countries are experimenting with new forms of pricing or incentives to foster deployment of distributed generation in ways that will reduce distribution system costs.

In **Germany**, distribution network operators are allowed to charge distributed generation customers for "**contributions to connection and construction costs**," thereby allocating a part of the connection or construction costs to the customer. Regulators require that these contributions be cost-oriented, non-discriminatory, transparent, and proportionate. Contribution to connection costs may only be charged for network investments that are not "economically feasible" otherwise. The contributions to construction costs open the possibility of more highly differentiated network charges. Further locational and time differentiation of contributions to construction costs, as well as inclusion of other incentives related to network conditions and costs, could give network operators more freedom to encourage targeted distributed resource development.[xiv]

In addition, distribution network operators in Germany are allowed to implement flexibility agreements, called "**call and return agreements,**" as a part of an individual network tariff or as a separate contract for flexibility services. These agreements allow the network operator to contract for dispatchable flexibility resources that are available during critical periods.

German network companies can negotiate **specialized contracts** for individual users that are expected not to add to system peak (e.g., customers that are providing power to the grid near load centers during periods of peak demand). This allows the network company to share savings provided as a result of distributed generation with the customer. The tariff must reflect the actual cost savings from deferred or avoided network investment, but cannot be less than 20 percent of the standard tariff. Similarly, distribution network operators in **New Zealand** employ very diversified contracts with network customers based on the customer's utilization patterns and the controllability of loads or curtailability of generation.[xv]

In the **United Kingdom**, so-called distribution use-of-system charges are based the "**distribution reinforcement model,**" whereby network operators estimate the cost of network development based on expected growth of distributed generation and load. These costs are the basis for the determination of network charges, which are socialized among network users with no location specific components. The U.K. model does, however, allow for differentiation between supply- and load-dominated network areas. Accordingly, distributed generation interconnection in areas where it relieves system stress and avoids network expansion may receive lower, or even negative, distribution charges. The practical workability and effectiveness of the U.K. system, however, is still criticized by some observers.

Some analysts have proposed that distribution network operators in Europe be given greater flexibility to design and execute "**smart contracts**" with customers to provide special incentives for distributed generation deployed in ways that create greatest system value. In such circumstances, standard regulatory terms would provide the default or backstop payment terms that are always available to any customer that chooses to opt out of the smart contract. Allowing distribution operators the flexibility to create smart contracts, some argue, would be easier to implement than system-wide locational and temporal energy and network pricing, but still allow distribution companies and customers to capture and share some of the benefits of targeted distributed resource development.[xvi]

MODEL 3

THE INDEPENDENT DISTRIBUTION NETWORK OPERATOR (DNO)

DESCRIPTION

The utility's distribution wires function is separated from the electricity supply function; the former remains a regulated monopoly business. The wires company is subject to performance-based regulation that provides it with strong incentives to earn higher rates of return by minimizing costs. The distribution utility is encouraged to develop pricing mechanisms and market-based incentives for customers and distributed resource developers to develop these resources in ways that reduce distribution system costs.

If the utility is able to reduce capital investments or other costs of distribution system operation by inducing distributed resource investments at lower cost, it is rewarded through regulatory incentives. These incentives could be structured in ways that are analogous to "shared savings" incentives provided to electricity companies today for delivering savings through energy efficiency programs. Such measures, if they prove to be workable, could level the playing field between investments that the utility would make in distribution infrastructure and alternative investments in distributed resources that avoid or reduce the need for certain distribution system investments.

The distribution company might also be required to make incentive payments for verified renewable energy supplied by solar PV or other renewable sources based on regulators' determination of the added value provided by these resources, taking into consideration environmental goals, local economic development, grid resilience and reliability, or for demand response that reduces distribution system costs. The cost of these incentives would need to be transparent, and passed through to all consumers without opportunity for bypass. Alternatively, the pricing of distribution system services could reflect some form of locational marginal pricing. Either way, the distribution network operator's structure and function could be considered analogous to an ISO at the distribution level.

PROS & CONS

The shift to an independent distribution system operator model, achieved through unbundling electricity distribution functions from electricity supply functions at the retail level, would require far-reaching structural change in most regulatory jurisdictions in the U.S. While similar changes have been made in New Zealand and some European countries, results have been mixed. Experience with this model in Europe and New Zealand shows that this approach can support high levels of innovation in creating new methods for distributed resource integration and the integrated delivery of distributed energy services to customers.

QUESTIONS

1. Are the advantages of such an approach enough to justify the major structural changes necessary to implement it?
2. Why has this model produced so little innovation in distributed resource delivery in the Texas market?
3. Will customers rebel against increasingly complex rate structures where prices vary based on location and time for reasons that are not readily understood?

06

LOOKING AHEAD

Technological innovation has vastly increased the options by which utilities, end users, and non-utility energy service providers can meet demand for electricity-enabled energy services. These options present new opportunities to reshape a $400 billion industry by unlocking opportunities on the customer's side of the meter. Distributed generation, responsive demand, and energy efficiency—enabled by distributed communication and coordination systems—could enable better economic optimization of resource use across the entire system, if the utility business models can be realigned to embrace these opportunities.

In the near term, incremental steps can be taken to begin to adapt utility business models in jurisdictions where penetrations of distributed resources are already rising rapidly. A longer-term view, however, suggests that the underlying system architecture—not only physical, but economic—is changing in ways that are being led by changing technology. By unleashing new paths for innovation at the distribution edge, the level of customer participation and the numbers of transactions and activity will multiply exponentially. With increased options come increased complexity and rapid evolution of commercial relationships and business structures.

While incremental steps will smooth the early stages of transition, the industry is at a crossroads in which it must ask if holistic, structural change will ultimately better align the regulatory and economic structures that frame the set of opportunities for utilities, customers, and other service providers. This paper outlined a few hypotheses that represent that transformational change. Taking the leap to reach these visions would mean "reframing the idea of 'the public interest' away from its current narrow focus on low, stable retail prices to include environmental benefits and other more general concepts of consumer choice, product availability and consumer empowerment."[xviii] While this is no small feat, the rewards associated with the long-term health and stability of a thriving, adaptive electricity system that can meet diverse energy service demands at least cost and risk to the entire system could be well worth the challenge.

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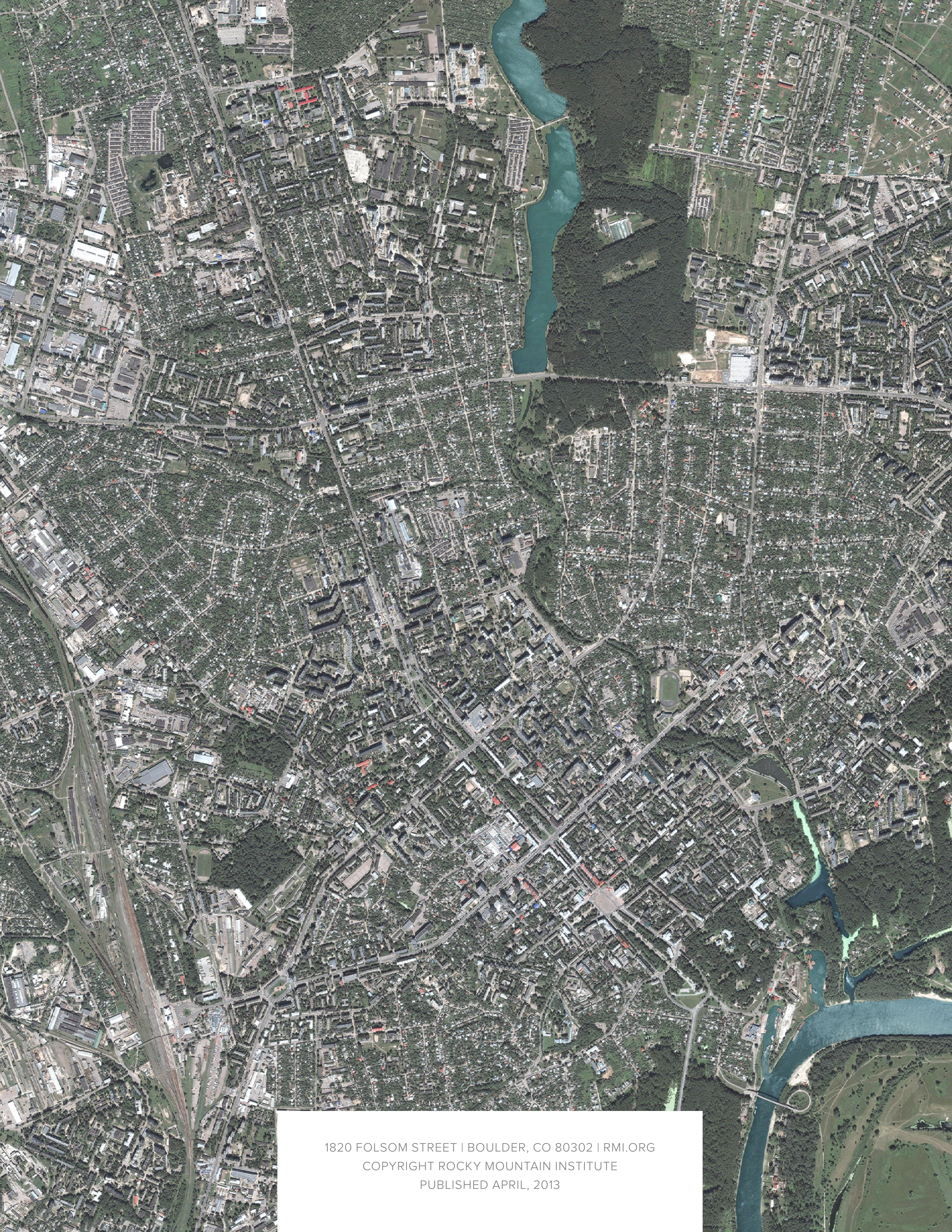

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