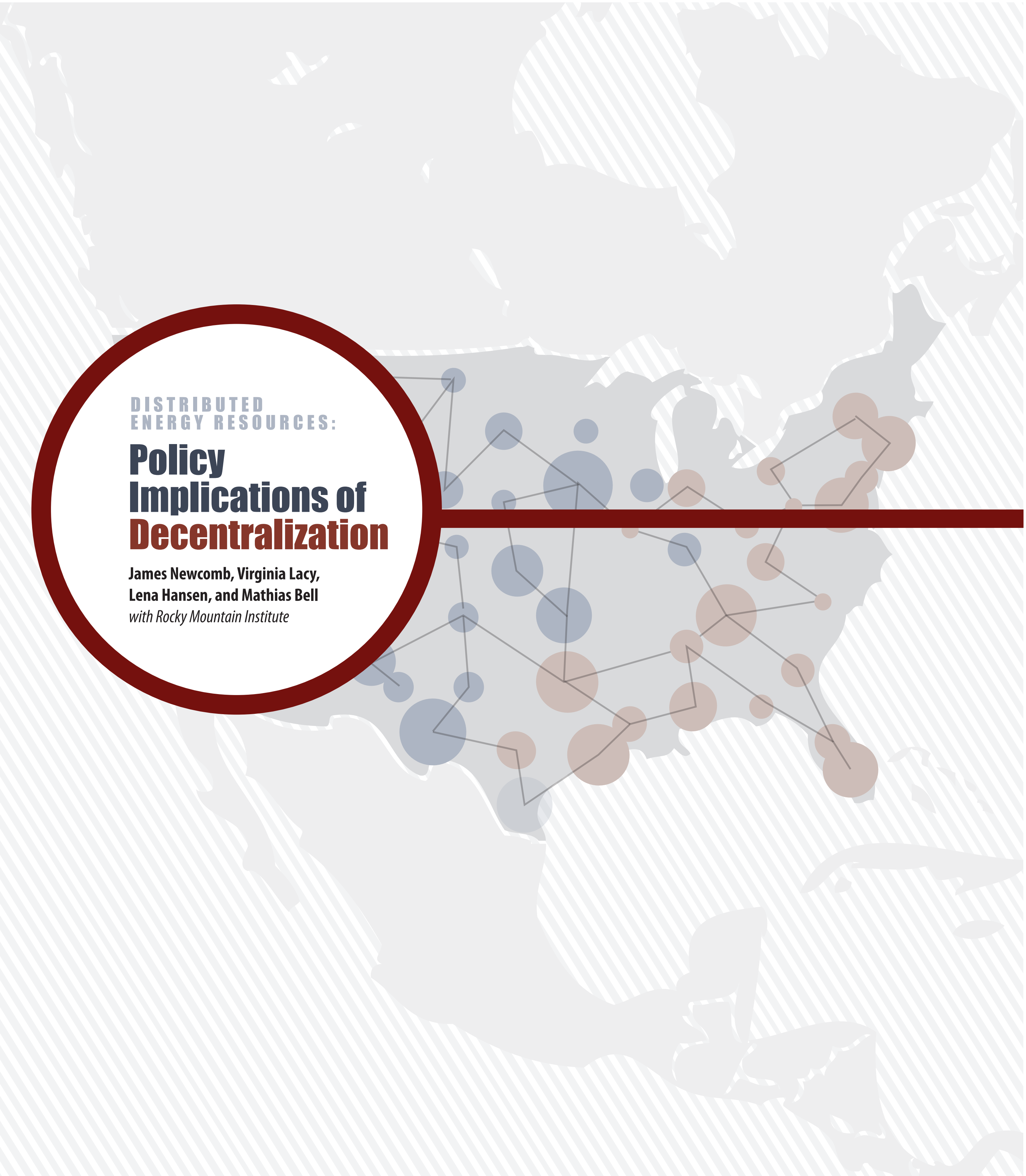
AMERICA'S
POWER PLAN

DISTRIBUTED ENERGY RESOURCES:

Policy Implications of Decentralization

James Newcomb, Virginia Lacy, Lena Hansen, and Mathias Bell
with Rocky Mountain Institute



REVIEWERS

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EXECUTIVE SUMMARY

With smart thermostats, efficient refrigerators, and solar panels all available at the local hardware store, the role of distributed energy resources is growing. Distributed energy resources can deliver clean electricity on site, reduce electricity demand and provide much-needed grid flexibility. Ensuring that policies and markets adequately support distributed resources to keep costs low, enhance reliability, and support clean energy integration, however, will require special attention to:

1. *Measure the full range of costs and benefits for distributed energy resources.* Consistent and comprehensive methods for measuring the costs and benefits of all available resources will create transparency, help deliver reliability, and provide a foundation for designing effective incentives, pricing structures, and markets.

2. *Analyze tradeoffs between centralized and distributed resource portfolios.* New studies at national, regional, and local levels can help to shed light on how to optimize the mix of centralized and distributed renewables.

3. *Integrate distributed energy resources into resource planning processes.* Planning processes at all levels—federal, regional, state, and utility—can be adapted to provide greater visibility into distributed resource options and their implications.

4. *Create new electric utility business models for a distributed-resource future.* New utility business models can be devised that ensure the stability and health of the grid and incentivize integration of distributed resources.

5. *Adapt wholesale markets to allow distributed resources to compete fully and fairly.* With evolved market rules, all kinds of distributed resources could compete to provide a wide range of energy and ancillary services in competitive markets.

6. *Enable microgrids and virtual power plants to support integration and aggregation of distributed resources.* Microgrid control systems enable better integration of local renewable resources and provide greater capabilities to manage these resources in response to grid conditions.

7. *Drive down "soft costs" for solar by streamlining permitting and interconnection procedures.* Regulators and policymakers can help to reduce the costs of permitting, inspection, and interconnection to significantly reduce the costs of distributed solar.

8. *Encourage smart electric vehicle charging.* Smart charging of electric vehicles can help to support the integration of high levels of variable renewable generation into the grid and provide efficiency and environmental benefits in the transportation sector.

Creating a level playing field for centralized and distributed resources will require significant changes in electric utility business models and electricity markets, as well as other changes in regulation and policy to adapt to rapidly evolving technology.

THE ROLE OF DISTRIBUTED RESOURCES IN A RENEWABLE ENERGY FUTURE

Distributed resources* can play a key role in helping to achieve a renewable electricity future in the United States by: (a) providing direct contributions to renewable electricity supply, (b) reducing electricity demand and (c) providing flexibility resources† that allow integration of high proportions of variable renewable supplies into the electricity supply portfolio. In this paper, we identify key opportunities and make specific recommendations for U.S. policymakers and regulators to shape distributed resource development for greatest overall benefit to the nation in line with achieving a renewable electricity supply goal of 80 percent or greater by 2050.

Distributed resources in *RE Futures:* Lessons and limitations

NREL's *Renewable Electricity Futures Study (RE Futures)* analyzes alternative scenarios for achieving 80percent renewable electricity supply by 2050. The study's analysis is largely focused on devising the least-cost portfolio of investments in large-scale renewable supplies, transmission and storage assets to reliably meet electricity demand over the period 2010–2050. Yet, a complementary portfolio of smaller-scale distributed resources, whose market penetrations are determined by assumptions rather than optimized by the study's analysis, play important roles in each of the 80 percent renewable scenarios. These resources and their corresponding assumptions include:

- Investments in **energy efficiency** to significantly reduce electricity use in buildings and industry, allowing room for demand growth from electric vehicles while keeping average annual electricity demand growth to just 0.2 percent. Without these measures, the total present value of electricity sector costs to achieve 80 percent renewable electricity supply would be $844 billion higher, while average retail electricity prices would be 6percent higher (see Table 1).
- Increased **demand-side flexibility**, to reduce the need for grid-scale energy storage and other costly supply-side flexibility resources such as fast-response generation. *RE Futures* assumes demand response reduces peak demand by 16–24 percent in 2050 compared to 1–8 percent today.

* Distributed resources include: energy efficiency, demand response, distributed generation and storage (both thermal and electric), and smart electric vehicle charging.

† Flexibility resources allow electricity supply and demand to be balanced over time. With high penetrations of variable renewable generation, flexibility is especially important. Distributed flexibility resources include demand response, controlled electric vehicle charging, distributed storage and dispatchable distributed generation.

- **Electric vehicle** penetration reaches 154 million vehicles by 2050, with half subject to utility-controlled charging.
- Significantly expanded use of **demand-side thermal energy storage** is assumed to shift load away from critical periods, reducing costs of energy and system capacity.
- **Distributed solar PV** capacity reaches 85 GW by 2050 compared with 4.4 GW installed as of the end of 2012,[1] providing additional renewable electricity supply beyond that provided by grid-scale renewable resources.

	Low-Demand 80% RE	High-Demand 80% RE	Difference
PRESENT VALUE OF SYSTEM COSTS 2011–2050 (BILLION 2009$)	$4,860	$5,704	+17%
AVERAGE RETAIL ELECTRICITY PRICE, 2050 (2009$/MWH)	$154	$163	+6%

Source: NREL, *Renewable Electricity Futures Study* (2012); Rocky Mountain Institute (RMI) analysis.

Table 1. Comparison of present value system costs and average retail electricity price in low- and high-demand scenarios for 80 percent renewable electricity (*RE Futures*)

The implications for regulators and policymakers are clear: achieving a renewable electricity future is not just a matter of driving new investments in large-scale renewable electricity supplies and transmission assets via supply-oriented policies such as renewable portfolio standards or tax incentives for renewable generation. Distributed resources are key enablers of a high-renewables future in almost any scenario and they may, in fact, provide the engine for a far-reaching transformation of the U.S. electricity sector toward a cleaner, more secure and resilient future.

Indeed, the rapidly falling costs of distributed resources, coupled with shifting customer demands and innovative new business models for delivering distributed resources, could mean that small-scale, local solutions might actually provide a large share of the resources needed to achieve a renewable electricity future. Analysis conducted by RMI using NREL's Regional Energy Deployment System (ReEDS) model suggests that distributed resources could provide half of renewable electricity supply in an 80 percent renewables future, compared with just 3–7 percent in *RE Futures'* core scenarios.

Ensuring that distributed resources are adequately developed to support a high-renewables future will require special attention from regulators and policymakers. In general, existing utility business models typically do not provide a level playing field for investment in distributed versus centralized resources, and distributed resources are only beginning to be allowed to participate in wholesale markets, if at all. Moreover, increased investment in distributed resources 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.

	NREL	*Reinventing Fire*	
	RE FUTURES	RENEW	TRANSFORM
SHARE OF DISTRIBUTED RESOURCES			
Distributed renewable generation as % of total 2050 generation	2.6–5.2%	3.3%	33.8%
Distributed solar PV as % of total 2050 generation	2.6–5.2%	3.3%	23.7%
Demand response: % of peak load, 2050	16-24%	16-24%	16-24%
NPV OF INVESTMENT REQUIRED 2011–2050 (BILLION 2009$, 3% DISCOUNT RATE)			
Conventional	$2,232.49	$2,714.56	$2,178.02
Renewable energy	$2,360.71	$1,774.41	$2,659.20
Transmission	$97.95	$59.79	$54.59
Storage	$168.57	$166.39	$103.57
Total	$4,860	$4,715	$4,995
ELECTRIC VEHICLE PENETRATION			
Total number of EVs, 2050 (million)	154	157	157
Average retail electricity price, 2050 (2009$/MWh)	$154	$129	$134

NREL's *RE Futures* case examines how the U.S. can operate an electricity grid with 80 percent of all generation coming from renewable resources (see RE Futures' 80 percent-ITI core scenario). The "Renew" and "Transform" cases were two of four scenarios RMI evaluated in Reinventing Fire (2011). The "Renew" case explores a future U.S. electricity system in which a portfolio composed of largely centralized renewables provides at least 80 percent of 2050 electricity supply. The "Transform" case assumes aggressive energy efficiency adoption, with approximately half of all generation provided by distributed resources, while still meeting an 80 percent renewable supply goal. All three cases used NREL's ReEDS model for the analysis. The RE Futures study and Reinventing Fire differ in many inputs and assumptions, including energy demand, technology cost reductions and smart grid capabilities.

Source: NREL, *Renewable Electricity Futures Study* (2012); RMI analysis.

Table 2. Comparison of high-renewable-scenario analyses

This paper discusses steps that policymakers can take to unlock the power of distributed resources to support the achievement of a renewable electricity future for greatest societal benefit. These recommendations fall in three major categories:

1. Analyzing the options:

a. *Measure the full range of costs and benefits for distributed energy resources.* Consistent and comprehensive methods for measuring the costs and benefits of different resources will create greater transparency for all stakeholders and provide a foundation for designing effective incentives, pricing structures and markets.

b. *Analyze tradeoffs between centralized and distributed resource portfolios.* New studies at national, regional and local levels can help to shed light on how to optimize the mix of centralized and distributed renewables.

c. *Integrate distributed energy resources into resource planning processes.* Planning processes at all levels—federal, regional, state and utility—can be adapted to provide greater visibility into distributed resource options and implications.

2. Revamping the rules of the game to level the playing field:

a. *Create new electric utility business models for a distributed resource future.* New utility business models can be devised that ensure the stability and health of the grid and incentivize integration of distributed resources in ways that create greatest value.

b. *Adapt wholesale markets to allow distributed resources to compete fully and fairly.* The success of demand response aggregation has paved the way for better integration of distributed resources into wholesale markets. In the future, all kinds of distributed resources could compete to provide a wider range of energy and ancillary services in competitive markets.

3. Encouraging innovative technologies and service models to speed adoption and integration of distributed and renewable resources:

a. *Enable microgrids and virtual power plants to support integration and aggregation of distributed resources.* Microgrid control systems can allow better integration of local renewable resources and provide greater capabilities to manage these resources in response to grid conditions.

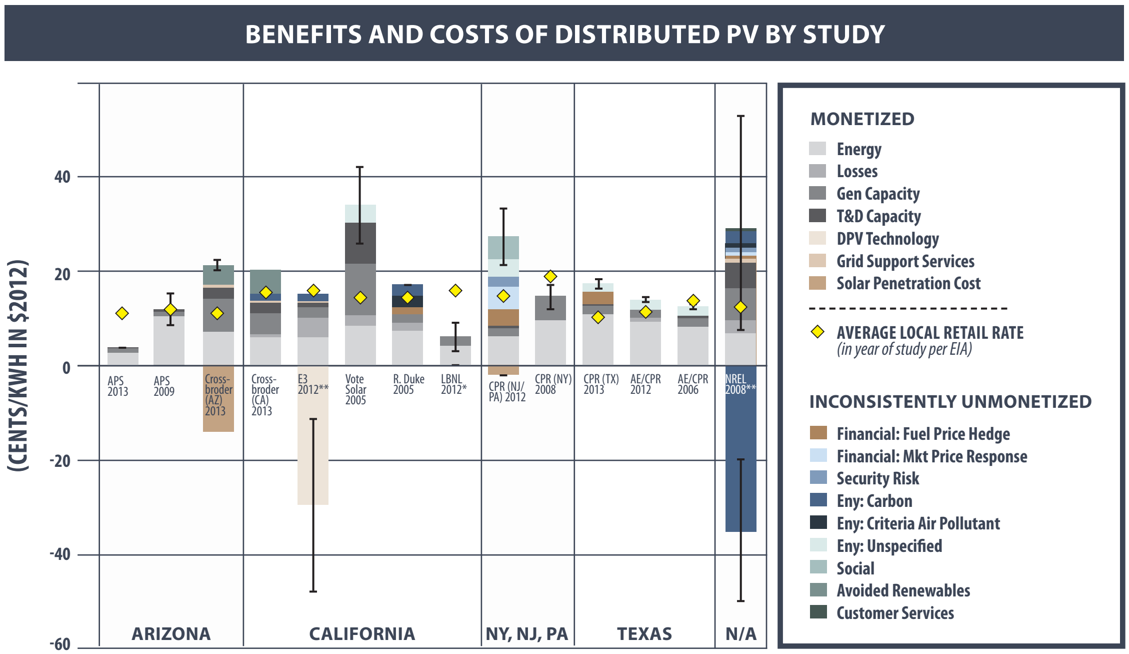
b. *Drive down the "soft costs" for solar PV by streamlining permitting and interconnection procedures.* Regulators and policymakers can help to reduce the costs of permitting, inspection and interconnection by implementing best practices that will significantly reduce the costs of solar PV.

c. *Encourage smart electric vehicle charging.* Smart charging of electric vehicles can help to support the integration of high levels of variable renewable generation into the grid and provide efficiency and environmental benefits in the transportation sector. An integrated view of distributed resource opportunities can help to achieve both goals.

MEASURE THE FULL RANGE OF COSTS AND BENEFITS FOR DISTRIBUTED RESOURCES

Distributed energy resources are dispersed, modular and small compared to conventional power plants, and these different characteristics mean that they incur different costs and create different benefits not typically accounted for and not reflected in simple busbar costs. The "hidden value" of distributed resources can include avoided line losses, reduced financial risk (including fuel price hedge value and increased optionality in investment timing), deferred or avoided generation and delivery capacity, environmental benefits and local economic development. Some of distributed resources' costs and benefits do not accrue directly to the utility or to specific customers but rather to society as a whole, such as environmental benefits, creating a mismatch between who pays and who benefits. Regulators and policymakers should drive for comprehensive assessment of all sources of cost and benefit as the basis for creating a level playing field that takes into consideration the factors that matter to customers and to society at large.

Properly measuring and valuing the full range of costs and benefits is a critical step to enabling the efficient and economic deployment of distributed resources. While methods for identifying, assessing and quantifying the costs and benefits of distributed resources are advancing rapidly, important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees and pricing structures for different types of resources. An RMI assessment of 13 studies conducted by national labs, utilities and other organizations between 2005 and 2013 reveals important differences in assumptions and methodologies, driving widely varying results (see figure 1: Costs and Benefits of Distributed PV by Study).[2]



Source: Rocky Mountain Institute, *A Review of Solar PV Benefit & Cost Studies* (2013).

Figure 1. Costs and benefits of distributed PV by study

The wide variation in analytic approaches and quantitative tools used by different parties in various jurisdictions is inconsistent, confusing and frequently lacking transparency. Regulators and policymakers should raise the bar for cost-and-benefit analyses by requiring that these studies:

- **Assess the full spectrum of costs and benefits,** including those related to risk, resilience, reliability, environmental consequences and economic development impacts; identify unmonetized costs and benefits; and evaluate how costs and benefits accrue to various stakeholders.
- **Standardize data collection and analysis methods** to ensure accountability and verifiability of cost and benefit estimates.
- **Use transparent, comprehensive and rigorous analysis approaches, adopt best practices nationally, and allow expert- and stakeholder-review of analysis methods.**

DECISION-MAKER	RECOMMENDATION
PUCs[3]	Develop and implement a transparent, consistent framework for the evaluation of distributed resources that encompasses the full range of costs and benefits relevant to these resources.
NARUC and/or DOE	Create a multi-stakeholder taskforce to evaluate and establish best practices and guidelines for the evaluation of distributed resources, to create consistency across regions and provide support to individual PUCs and other stakeholders.

Additionally, policymakers can bring greater visibility to distribution system utilization and costs, creating opportunities for cost reductions in high-renewables systems. Evaluating the impacts of distributed energy technologies on the electricity grid is difficult, due in part to the lack of detailed information about capacity utilization for electricity distribution feeders and the timing and capital costs of system reinforcements and expansions. While detailed distribution feeder information resides with distribution utilities, relatively little, if any, of this information is accessible to the public or researchers.

Several significant efforts are starting to address this need. As part of an effort to streamline the analysis required for a distributed PV interconnection request, a collaboration of Sandia National Laboratory, Electric Power Research Institute (EPRI), NREL and other national labs is developing a method to group and classify distribution feeders in a utility service territory to characterize the capacity of individual feeders to accept new PV projects. These efforts will help to simplify and standardize the analysis needed to evaluate the costs and benefits of distributed energy resources in unique electricity system territories.

DECISION-MAKER	RECOMMENDATION
PUCs	Require access to data on distribution system utilization and marginal costs of expansion to support the evaluation of distributed energy resources.
DOE	Support national laboratories' development of new methods that simplify and streamline analysis of distribution feeders.

ANALYZE TRADEOFFS BETWEEN CENTRALIZED AND DISTRIBUTED RESOURCE PORTFOLIOS

While a growing number of studies exist to describe high-renewables electricity futures for the U.S.,[4] surprisingly little research is available to evaluate the tradeoffs between different portfolios of centralized and distributed renewable resources. Deeper analysis of the implications of alternative resource portfolios at the national, regional and local level will help to support better regulatory and policy decision-making and help to find the least-cost ways of achieving a renewable electricity future.

Existing national and regional studies describe an extremely wide range of alternative paths to achieve a high-renewables future. For example, the amount of distributed solar PV deployed by 2050 ranges from 85 GW in NREL's *RE Futures* study to 240 GW in the U.S. Department of Energy's *Sunshot Vision Study* to more than 700 GW in Rocky Mountain Institute's *Reinventing Fire* Transform scenario (see table 2). All three scenarios were analyzed using NREL's ReEds model.

Alternative portfolios of centralized and distributed renewable resources have significantly different attributes, not only in cost, but also in environmental impact, implications for economic development, financial risk, security, reliability and resilience. While policymakers and regulators are often mindful of these attributes in making their decisions, the analytic gaps left by existing studies leaves them shooting in the dark in trying to map a path to a renewable electricity future that delivers the greatest benefits to customers and society.

Six states have incorporated carve-outs into their renewable portfolio standard policies, stipulating that a portion of the required renewable supplies be derived from solar resources[5] and others have created "credit multipliers" that allow distributed resources to earn extra credit toward achieving renewable portfolio requirements. Yet, these approaches are, at best, stopgap measures intended to remedy the lack of a level, competitive playing field, taking into consideration the values that policymakers believe should influence portfolio choices.

Ensuring that centralized and distributed renewable resources compete on a level playing field will be one of the most important challenges facing policymakers, regulators and electric utility planners in the decades ahead. Policymakers at all levels should support the development of better modeling and analysis tools to evaluate tradeoffs between different types of renewable portfolios. In integrated resource planning (IRP)-driven jurisdictions, state PUCs can require that utility planning processes explicitly explore tradeoffs between alternative centralized and distributed portfolios (see recommendations regarding utility resource planning below).

One reason for this important gap in existing analysis is the complexity and difficulty of creating models that can optimize the overall portfolio of distributed and centralized resources. Existing models more easily address utility-scale resources than they do small-scale, heterogeneous, distributed resources. New approaches are now being developed to work through the implications of different combinations of distributed and centralized resources in terms of the needed investments in generation, transmission and distribution grid infrastructure.[6]

But a critical gap still remains: most studies fail to assess the implications of different portfolios for the security and resilience of the grid in the face of natural disasters, physical or cyber attack, solar storms or other threats. *RE Futures* core scenarios for achieving 80percent renewable electricity supply require construction of 110–190 million MW-miles of new transmission capacity and 47,500–80,000 MW of new intertie capacity across the three electricity interconnections that serve the U.S. The average annual investment required for this new infrastructure ranged from $6.4 to 8.4 billion per year.[7]

The increase in transmission and intertie capacity envisioned by *RE Futures* provides for a national grid infrastructure that can take advantage of dynamic fluctuations in variable resource availability on a regional and national basis. But, at the same time, such a grid could be even more fragile and subject to disruption than the existing system. In the aftermath of Superstorm Sandy, policymakers are increasingly looking for ways to reduce the risk of large-scale blackouts. Increased reliance on local renewable resources, integrated with microgrid control systems, holds the promise of providing new ways to manage the risks of major outages.

DECISION-MAKER	RECOMMENDATION
DOE, state governments, PUCs	Conduct modeling and scenario analysis to assess the implications of different combinations of distributed and centralized renewable resources to achieve a high-renewables electricity future.

INTEGRATE DISTRIBUTED ENERGY RESOURCES INTO RESOURCE PLANNING

Resource planning processes provide a view to the future that can help to reveal tradeoffs between centralized and distributed investments and reduce costs on the path to a high-renewables electricity future. In jurisdictions where organized wholesale markets do not exist, regional transmission planning studies and integrated resource plans conducted by utilities will be critical to assessing how best to utilize such resources as demand response, fast-response storage and other options to provide flexibility to match increasing levels of variable renewable generation. Careful resource planning can also reveal opportunities to reduce transmission and distribution costs through targeted investment in distributed resources.

Improved planning processes that properly consider distributed resource options have already harvested significant savings where these approaches have been rigorously applied. In New York, for example, Con Edison reduced its projected capital expenditures on transmission and distribution by more than $1 billion by including energy efficiency and demand response in its forecasting. The company achieved additional savings of over $300 million by utilizing geographically targeted demand resources to defer investments in its distribution system.[8] Similarly, ISO-New England's energy efficiency forecasting initiative led to revised projections of transmission needs for Vermont and New Hampshire, allowing the deferral of ten proposed transmission upgrades totaling $260 million.

Nonetheless, important gaps remain to be addressed to provide a consistently level playing field for competition between centralized and distributed resources at both the transmission and distribution system levels. A recent study by Synapse Energy Economics, for example, highlights weaknesses in ISO-New England's forecasting of distributed generation resources and recommends that the ISO establish a Distributed Generation (DG) Forecast Working Group in order to develop a DG forecast that can track existing installations and project future installations.[9] In New England and elsewhere in the country, critics complain that ISOs and RTOs fail to adequately consider distributed resource alternatives and lack the expertise to do so. ISOs and RTOS, on the other hand, argue that uncertainties about the amount and location of distributed resources that can be expected to be installed, together with the difficulties of anticipating the behavior of variable distributed resources, makes it impossible to rely on them in developing future plans.

Building the capabilities to answer these questions will take better analysis and new institutional alignments. ISOs and RTOs have expertise and vested interest in transmission, but relatively little experience in evaluating diverse portfolios of distributed resources that they are now being asked to evaluate. One way or another, credible, rigorous and independent analysis of distributed resource options will need to support transmission planning processes.

The Federal Energy Regulatory Commission (FERC) Order 1000 requires that all transmission providers develop regional transmission plans that give "comparable consideration" to non-transmission alternatives (NTAs) such as energy efficiency, demand response, distributed generation, storage and microgrid deployment. Despite FERC's aspirations, however, today's industry practice often falls short of creating a level playing field for consideration of non-transmission alternatives.[10] Existing rules require only that transmission planners consider NTAs brought forward by participants in transmission planning processes, instead of requiring that transmission providers search for and assess such alternatives even if no other party proposes them. Even where NTAs are estimated to provide the least-cost solution, cost recovery may be a problem:

> "If a transmission proposal serves regional needs, the provider can allocate and recover the costs regionally through a FERC-jurisdictional tariff. There is no comparable opportunity for regional cost allocation of an NTA because an NTA, by definition, is not 'transmission' subject to FERC jurisdiction."[11]

Addressing these problems will require several different actions. At the federal level, FERC could require that regional transmission providers examine all feasible NTAs. To do so, RTOs will need to develop new capabilities for evaluating NTAs and projecting their potential impact even when there is not a specific transmission project to compete against. At the state level, PUCs can create open competition for NTAs and facilitate cost recovery for these measures and PUCs can require utilities to report distributed-generation interconnections and net-metering activities to increase access to this data for planning purposes.[12] Finally, Congress could amend the Federal Power Act to allow cost recovery for NTAs through a FERC-jurisdictional rate where these measures are found to provide lower-cost alternatives to transmission.[13]

At the distribution level, new planning approaches, known as integrated distribution planning (IDP), hold promise to create more streamlined and coordinated approaches to distribution planning and distributed generation interconnection.[14] Such approaches could provide the foundation for targeted deployment of distributed resources in ways that minimize system costs, manage load shapes and provide valuable ancillary services to the grid. Eventually, greater transparency with respect to marginal capacity costs on the system could support some form of locational marginal pricing targeted incentives for distributed resources within the distribution system (see the New Business Models section of this paper for further discussion of these options).

Improved transparency of the distribution system: The size of the prize

Studies over the last decade have illuminated the potential size of prize when taking a step beyond average distribution rates and examining distribution investments on a more granular scale. For example, a study by the Regulatory Assistance Project included a review of the marginal cost of transformers, substation, lines and feeders for 124 utilities, finding, "On a company-wide basis, the marginal costs are high and variable. For the entire group of 124 utilities, the average marginal cost for transformers, substations, lines and feeders exceeds $700 per kW."[15] In another example, cited in Small is Profitable, "PG&E found that very locally specific studies often disclosed enormous disparities: marginal transmission and distribution capacity costs across the company's sprawling system (most of Northern California) were found to vary from zero to $1,173/kW, averaging $230/kW. The maximum cost of new grid capacity was thus five times its average cost."[16]

For vertically-integrated utilities, IRP can reveal tradeoffs between centralized and distributed resources. IRP has been used in some parts of the country since the late 1980s, and Congress included a provision in the 1992 Energy Policy Act encouraging state public utility commissions to implement IRP processes.[17] In practice, however, IRP processes across the U.S. are extremely varied. As of 2013, 34 states require that electric utilities conduct integrated resource plans.[18] Where organized markets do not exist, state PUCs could reinvigorate IRP planning processes, taking them to the next level required for planning a renewable electricity future, by strengthening requirements for these plans to assess distributed resource alternatives to major investments in utility-owned infrastructure. This, coupled with changes in business models that allow utilities to benefit from greater investment in distributed resources (as discussed below), could open the door to a wider range of solutions to meeting future needs for generation, transmission and distribution capacity in a high-renewables future.

Innovative approaches to integrating distributed resources into resource planning

HAWAII'S PROACTIVE APPROACH

In March 2013, the Hawaiian Electric Company (HECO) and several collaborators, including representatives from the solar industry, presented a proposal for consideration by the Hawaii PUC that would integrate HECO's interconnection and annual distribution planning processes. Termed the Proactive Approach, the proposal outlines several steps that HECO would undertake annually to "identify opportunities where infrastructure upgrades can accommodate both DG and load." The process includes: projecting the likely distributed generation growth based on the interconnection queue and other data, evaluating generation production data in comparison to the capacity of the distribution infrastructure, and planning distribution system upgrades accordingly. If approved, HECO plans to start implementing the planning approach in 2013.[19]

CONEDISON'S SOLAR EMPOWERMENT ZONES

Since 2010, a partnership task force between ConEdison, New York City's Department of Buildings and New York State Energy Research and Development Authority (NYSERDA) has identified five solar zones that could benefit from solar development. Each zone was selected on the basis of energy use profile coincident with solar production, likely distribution system capacity upgrades needed to meet load growth and available roof space. Within zones, ombudsmen facilitate customer installation of solar PV by helping customers navigate through red tape to receive incentives and permits, provide free data monitoring devices and provide technical assistance.

DECISION-MAKER	RECOMMENDATION
PUCs	Require utilities to implement IDP to provided transparency with respect to planned distribution network costs and allow competition from distributed resources.
PUCs	Require utilities to regularly issue public reports on planned transmission and distribution upgrades. Plans should include cost per kW, the characterization of reductions for deferral and by date.
FERC	Direct RTOs and ISOs to develop capabilities to evaluate NTAs and require that regional transmission planning processes entertain NTAs even when there is not a specific transmission project to compete against.
PUCs	Facilitate cost recovery for NTAs on a coordinated utility, state and regional basis.
Congress	Amend the Federal Power Act to allow cost recovery for NTAs through a FERC-jurisdictional rate where these measures are found to provide lower-cost alternatives to transmission.

CREATE NEW ELECTRIC UTILITY BUSINESS MODELS

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 and will become increasingly so in an 80 percent renewable future. Another paper in this series, *New Utility Business Models: Utility and Regulatory Models for the Modern Era,* explores the question of new utility business models, especially within the vertically integrated environment, in depth. As a complement, this section focuses specifically on business models issues stemming from the growth of distributed resources, which present particular challenges to the current utility business model. Our focus in this discussion is on laying the foundation for taking full advantage of distributed resources over the decades ahead on the path to 80 percent renewable electricity and beyond.

The need for change

Conventional utility business models have evolved based on the control, ownership, scale efficiencies of centralized supply, transmission and distribution. For the better part of a century, generation technologies were primarily limited to supersized thermal power plants with increasing economies of scale: the larger the plant, the more efficient and cheaper the electricity generation. In times of growing demand and passive customer engagement, these conventional utility business models worked well. These traditional approaches, however, are poorly adapted to an environment of up to 80 percent renewable energy predicated on a widening array of distributed energy resource options to meet customer demands and to respond to system conditions in beneficial ways. Many utilities are unable to capture or optimize the value streams associated with distributed energy resources and instead see these resources as threats associated with revenue loss, increased transaction costs and challenges to system operations.

The diversity of utility business models in the U.S.

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., the same company provides 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.

The situation is further complicated by prevalent rate structures and incentive mechanisms that are not easily adapted to the more temporally and geographically diverse value of renewable and distributed resources. For example, a predominant pricing structure for residential and small business customers features a bundled, volumetric charge by which the utility recaptures most of its costs — including both fixed and variable elements — via a single kilowatt-hour-based price. While this approach provides customers with simple bills and an incentive for efficiency, it starts to break down with significant percentages of customer-owned generation. In combination with retail net metering, such bundled, volumetric pricing may not recover the costs of a customer's use of the grid, and conversely, may not compensate the customer for the services they are providing to the system. Further, customers do not receive incentives to invest in technologies that can benefit both them and the larger system, such as smart appliances that can help the system adapt to more variable supply or thermal energy storage that can take advantage of low-cost energy during times of energy surplus. As more investment is made outside of the utility's control, new rate structures, price signals and incentives will be critical for directing that investment for greatest system benefit.

Finally, with a dwindling share of total investment in the electricity sector made by utilities, the decisions and actions of all these interconnected actors — utilities, customers and non-utility providers — will need to be harmonized. Managing the increased complexity of system operations, both technically and transactionally, means that operational management will need to depend less on hierarchical command-and-control and more on responses to signals indicating the state of the system. Successful business models in this environment will transcend the traditional utility versus non-utility framework, creating a conduit of value and service for customers, regardless of supplier.

The path forward

The increasing role of distributed resources in the electricity system will start to shift the fundamental business model paradigm of the industry from a traditional value chain to a highly participatory network or constellation of interconnected business models. In this context, regulators and policymakers should start to consider how the utility's business model could serve as a platform for the economic and operational integration of distributed resources and the ability to make fair tradeoffs between distributed and centralized resources.

Myriad pathways exist toward such a future. In supporting the evolution of new utility business models, regulators and policymakers should consider a set of attributes that the utility platform should be designed to meet. Clearly, it will be necessary to make tradeoffs among some of these attributes and to adapt business models to particular regulatory and market contexts, but a high-level list of desired attributes includes:

- Ensure network efficiency, resilience and reliability. The integration of distributed resources should not just "do no harm" to the efficiency, reliability and resilience of the electricity system, but should actually be deployed to enhance these attributes.
- Create a level playing field for competition between all resources, regardless of their type, technology, size, location, ownership and whether or how they're regulated.
- 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.
- Minimize the 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.

Business model solutions designed to meet evolving needs on the path to an 80 percent renewable future that optimize distributed resources will not 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. 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.

Already, various new alternatives are beginning to emerge in the U.S. and around the world that represent solutions to different aspects of the challenge. Some solutions include:

a. New pricing and incentive approaches.

b. Opportunities to explore new value creation such as financing through on-bill repayment.

c. Reducing disincentives and rewarding performance.

The remainder of this section explores some of the 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.

a) Pricing and incentive approaches

Retail rate designs, and the resulting prices that they create, simultaneously reflect the underlying costs of production, indicate the value of services provided between suppliers and customers, serve as signals to communicate the needs of the grid system and directly influence customer behavior. The importance of pricing grows significantly in an 80 percent renewable world, where there is an increasingly dynamic grid that incorporates a high penetration of variable renewable energy and a corresponding need for distributed control and intelligence throughout the system. Today, however, existing rates and policies obscure the costs and benefits of various resources to the grid, limit the ability to add better integration technologies that could add value and restrict signals to customers that would enable them to make mutually beneficial decisions.

In a more highly renewable and distributed future, prices and/or incentives need to provide more accurate signals that reflect the actual costs and values in the electricity system, thereby sending appropriate signals to customers and fairly compensating utility service. At the outset of considering new rate designs, regulators must consider: Can the pricing model pay for operational services, properly capture and promote value to the system and be implemented effectively with the flexibility to accommodate further market changes?

Key approaches include:

- **Itemize and value core service components separately.** By separately measuring service components, costs and value can be more accurately reflected (see, also, the cost and benefit section earlier in this report) enabling the service provider — utility or customer — to be compensated fairly for the value they provide. Overall, mechanisms should be promoted that drive unit prices toward the long-run marginal costs of system operation in order to send correct price signals and promote economic efficiency.
- **Determine the appropriate recovery mechanism for disaggregated components.** While important to transparently quantify the underlying cost drivers and recognize whether they are fixed or variable costs, there is still flexibility in the type of mechanism used to recover that cost in the price to customers. For example, a fixed cost, such as a distribution line expansion, does not necessarily need to be recovered through a fixed charge, such as a straight fixed variable rate structure.
- **Incorporate time- and/or location-varying prices or incentives at the retail level**. While many utilities already have some (often very simple) form of time-varying prices, the widespread implementation of dynamic pricing, supported and enabled by advanced communications and controls, will be a key enabler in allowing distributed and renewable resources to provide needed system flexibility.
- **When appropriate, transparently add policy-driven incentives that are not captured strictly by costs.** Better understanding the utility's avoided costs and determining the difference between the cost of stated policy objectives empowers regulators to achieve policy goals, accurately inform customers and achieve policy goals at a lower societal cost.

"Getting the price right" is not the only consideration. Rate design must also strike a balance between the interests of traditional customers and customers with distributed generation, while remaining simple enough to be understood. There can be significant tension between rate simplicity, the need to support energy efficiency and customer generation and the need for accurately allocating benefits and costs. For example, California has a volumetric tiered rate structure for residential customers with a primary goal of encouraging energy efficiency. Thus, the price of electricity increases as the amount of electricity a customer uses increases over a billing period. Accordingly, reductions in electricity consumption will be valued at the marginal tiered rate, and higher electricity consumers will have a larger incentive to invest in distributed energy resources. California's volumetric tiered rate structure and decoupling of rates and sales have helped keep per-capita electricity use flat for the past 30 years and made California the largest energy-efficiency market in the country. However, this rate structure could also contribute to shifting costs to non-participating customers as distributed energy resources and zero-net-energy buildings become more prevalent. Yet wholesale replacement could have the unintended consequence that energy efficiency becomes less attractive for customers. Strict cost-of-service rates and socialization of the "cost shift" must reach an appropriate balance.

Emerging rate design ideas

As part of its General Rate Case in October 2011, San Diego Gas and Electric Company (SDG&E) proposed modifying its residential electric rates to include a "Network Use Charge," which would bill customers for the costs associated with all network use, including electricity exports. Proponents of the Network Use Charge note that it would allow SDG&E to ensure that net energy metering (NEM) customers contribute to their fair share of distribution system costs when exporting power, while reducing the inequitable cost shifts that result from retail NEM. However, the measure met with fierce opposition from the solar industry, consumer advocates, environmentalists and NEM customers. These groups argue that the Network Use Charge does not account for the benefits that DG systems provide to the network, that it runs contrary to California's renewable energy goals by discouraging solar, and that it does not send price signals that encourage reduction in coincident peak demand — rather, it pushes PV owners to shift their demand to times when their system is producing, i.e., midday.

In the first of its kind, Austin Energy proposed a residential solar rate to replace conventional net energy metering in its territory, the Value of Solar Tariff.[20] Based on the distributed costs and benefits study completed for Austin's territory in 2006, the rate is designed to include an annually adjusted value for distributed solar energy to the grid, which includes calculations that estimate savings from avoided losses, energy, generation capacity, transmission and distribution capacity and environmental benefits. The approach attempts to address unintended consequences of net energy metering, such as reduced incentives for energy efficiency, by decoupling the customer's charge for electricity service from the value of solar energy produced.

Outside the U.S., distribution companies in Germany, New Zealand and the United Kingdom use new forms of pricing or incentives to foster deployment of distributed generation in ways that will reduce distribution system costs. For further information see: New Business Models for the Distribution Edge, an eLab discussion paper.[21]

The role of aggregators in delivering distributed resource value to the grid

As the electricity system becomes more distributed, millions of devices could be connected to the system with each capable of making a small contribution to respond to system conditions. ISOs and RTOs have enabled many more devices to participate by reducing sizing requirements. Still, minimum size requirements are no smaller than 100 kW. So what is to be done about all of the devices that are much smaller than 100 kW? Should they just be considered noise on the system? Many service providers are trying to find ways to aggregate small, distributed resources in order to maximize their impact.

Take the Nest smart thermostat as an example. The company has been hailed for its hardware design and simple, easy-to-use interface. The smart thermostat has been very effective in providing utility bill savings. Nest though has been ambitious in terms of maximizing the value of its thermostat. Rather than being complacent with only delivering efficiency savings, the company is now starting to work with utilities to reduce peak demand.

In April 2013, Nest announced new partnerships with NRG, National Grid, Austin Energy and Southern California Edison to enable more participation in demand response programs. Rather than calling it a demand response, Nest has cleverly coined its newest feature "Rush Hour Rewards." As part of the program, Nest raises its customers' thermostats by up to four degrees during peak hours between 12 and 15 times each summer.[22] In Austin, several thousand Nest thermostats delivered average reductions of 40–50 percent in air-conditioner run time when the program was triggered on hot days in June 2013. The utility partners see value in the device, offering customers rebates on the smart thermostats and giving bill credits to customers who participate during "rush hour." While these partnerships are just pilots for now, both Nest and its partners see sizeable opportunities ahead.

Nest is one of many companies trying to figure out how to aggregate distributed resources. Utilities themselves are bidding electric efficiency program savings into forward capacity markets. Demand response service providers—such as Enernoc, Comverge and Viridity—continue to hone their offerings and control rapidly growing portfolios. As the grid transitions to a more distributed one, those that understand the benefits of aggregating distributed resources stand to capture some promising opportunities.

b) Opportunities to explore new value creation such as financing through on-bill repayment

New opportunities to offer new services in these emerging markets could likewise incent utilities to support and encourage this transition. On-bill financing (OBF), in which a utility loans capital to a customer and the customer pays the loan back on the utility bill, has been an effective vehicle for customers to pay for energy-efficiency improvements for decades — usually at a lower cost of capital. More recently, distributed generation has been included within some OBF programs. While some OBF programs have featured bank lending, with the utility as a servicer to its customers, OBF has otherwise been limited in engaging with third-party financiers. OBF has customer acquisition benefits, as the customer does not have to pay a second bill and is familiar with the utility as a reliable electric services provider. The downside of many OBF programs is that they are not well marketed by the utilities, who are not adept at driving new customer uptake and whose business is not heavily predicated on the success of OBF programs.

With on-bill repayment (OBR), the utility enables third-party financiers, as equity and/or debt providers, to provide loans, leases, power purchase agreements and other repayment structures to the customer, with the repayment held on the customer's bill. The OBR solution is particularly valuable with solar PV, as third-party equity can lower the cost of solar below what a homeowner (restricted by inability to monetize solar's accelerated depreciation), a regulated utility (required to monetize investment tax credit over rate-basing period instead of first year) or a municipal utility (ineligible to receive tax benefits) can otherwise achieve. For all technologies and financing types, however, there is generally stronger business drive to market intelligently and energetically to potential customers and to ensure reasonable transaction costs and customer experiences in OBR than in OBF. In addition, the inherent benefits of OBF (one bill and a reliable, known "face" of the program) are still present.

OBR is most beneficial when there exists a strong relationship between utility and third-party financier. Aligning interests between these parties is essential. Utilities must not see third-party financing as simply diminishment of revenue, weakening investor returns and the safety of creditor obligations. Equally, the third-party financier does not want damaging rate changes or strategic defaults by the utility to disrupt their cash flows. Balancing interests in OBR is a ripe electric regulatory policy opportunity space.

c) Reducing disincentives and rewarding performance

While the steps described above address misalignments in existing institutional and pricing structures, they are not sufficient to provide a long-term, sustainable foundation. The key drivers that are transforming the electricity industry will continue to alter revenue streams, sources of value and operational requirements for electric utilities. This, in turn, will necessitate further evolution and adaptation of utility business models and new thinking about the role of the utility in the future. Should the utility be allowed to own and operate distributed resources on its customer's premises? What incentives should the utility have to ensure that distributed resources are fully deployed to minimize costs for the system as a whole? If the utility is allowed a more expansive role in owning and/or managing distributed energy assets, will this unfairly crowd out other competitors?

No doubt, incremental steps can be taken to start to shift the rules and reward structures to recognize the costs and values of service provision, whether they are met by distributed or conventional resources. Taking a long-term view, however, it is important to recognize that the underlying system architecture — not only physical, but economical — is changing. Localized generation, responsive demand and energy efficiency coupled with distributed communication and coordination can enable the economic optimization of resource use across the entire system that has not been possible before. Equally important, it dramatically opens the potential for demand diversification and the creation of new value.

In the vertically-integrated utility environment, new types of incentive regulation may provide mechanisms to create a more level playing field between centralized and distributed resources. A majority of vertically-integrated utilities and distribution-only utilities in restructured environments 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. 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. Key business model changes could include:

- **Reducing disincentives.** Decoupling the recovery of fixed costs from sales can be an important first step. 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. This mechanism addresses some, but not all, of the criticisms lodged against traditional revenue recovery approaches. For example, it does not protect non-participating customers from cost shifts and does not create the price signals necessary to support long-term distributed resource development and innovation in new technologies.
- **Rewarding performance.** 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.
- **Enabling new value creation.** 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. The utility could also more actively direct investment and siting for distributed resources.

DECISION-MAKER	RECOMMENDATION
PUCs	Encourage distributed generation by acknowledging customers' right to generate their own energy, by charging them a fair price for grid services and by paying them a fair price for the grid benefits they create. Use net metering, or set a clear methodology for allocating all costs and benefits.
PUCs	Work with appropriate stakeholders to develop a pathway to more unbundled, time- and location-varying prices that 1) balance needs for simplicity, accuracy and fairness, and 2) collectively send appropriate behavioral and value signals to customers.
PUCs	Actively explore new utility business models that reward desired performance and enable new value creation.

ADAPT WHOLESALE MARKETS TO ALLOW DISTRIBUTED RESOURCES TO COMPETE

RE Futures calls attention to opportunities for improvements in electric system operations that will enhance flexibility in electricity generation and end-use demand to enable more efficient integration of variable-output renewable electricity generation. Organized wholesale markets can provide a crucial link to allow distributed resources to compete to provide energy, capacity and ancillary services in a high-renewables electricity future. Already, organized wholesale markets serve two-thirds of electricity customers in the U.S.[23] Well-structured organized wholesale markets can allow distributed resources to compete with grid-scale energy storage and flexible generation to provide needed flexibility resources to support grid operations. Market mechanisms that allow demand response aggregators to compete in capacity markets have already demonstrated the feasibility of rules that provide for aggregation of distributed resources to the scale needed for wholesale market transactions.

Another paper in this series, *Power Markets: Aligning Power Markets to Deliver Value,* provides details about how wholesale markets can be utilized to accommodate higher levels of renewables. In this section, we focus specifically on how markets can incorporate higher levels of distributed resources to support achievement of a renewable electricity future. Still, we recognize that organized wholesale markets do not serve some regions of the country. For these regions, while they could begin participating in organized wholesale markets over the next 40 years, other means may be necessary to coordinate and encourage the development of distributed resources.

Today, distributed resources are able to bid into wholesale power markets in some parts of the U.S., including the PJM Interconnection (PJM) and ISO–New England (ISO-NE), to help meet load requirements and support reliability. In PJM, more than 14,000 MW of demand response and energy efficiency have cleared in the forward capacity market auctions over the past five years.[24] In ISO-NE, distributed resources are set to defer the need for transmission lines, saving customers over $260 million.[25] FERC's recent rulings, including Orders 719 and 745, support continued engagement of demand-side resources in organized wholesale markets.[26]

With continued technological improvements, the ability for distributed resources to provide value will increase. For instance, in a recent PJM vehicle-to-grid (V2G) pilot, electric vehicles were used to provide ancillary services to the grid, including real-time frequency regulation and spinning reserves.[27] With proper control and communications capabilities, distributed resources may be used to increase the reliability of the electricity system by providing enhanced flexibility and, in some cases, deferring the need for expensive upgrades to transmission and distribution systems.[29]

Compensation for the value provided by distributed resources is crucial. Forecasts show increasing levels of adoption of energy efficiency, distributed solar PV and electric vehicles over the decades ahead. If markets provide a price signal for what attributes are most highly valued, technology developers can adapt their technologies to help meet these needs. And if distributed resources are compensated for these attributes, there could be a "virtuous cycle" that improves the economic returns and further increases the adoption of distributed resources.

Although specific rules, requirements and market structures vary among RTOs and ISOs, there are three general types of markets that distributed resources can or could participate in:

- **Energy**. Electricity generators bid into these markets to sell energy. These transactions typically take place in day-ahead and real-time markets, with settlement based on locational marginal prices.[29] Already, distributed resources are playing a significant role in energy markets in PJM, ERCOT and New York ISO (NYISO). Electricity is sold to consumers at retail prices that include the costs of transmission and distribution services.
- **Capacity**. There is an ongoing debate whether energy-only markets are sufficient to provide price signals to encourage long-term investments. In order to provide incentives for power plant operators to build new capacity, forward capacity markets have been created in some jurisdictions. Every resource bids into the market at the total cost of operation to provide service at future date, typically three to four years in advance.[30] Aggregations of distributed resources can be assigned capacity values and then bid into those markets along with much larger generators.
- **Ancillary Services**. Ancillary services are provided to help ensure the operational stability and reliability of the electricity system. These services include regulation, spinning and contingency reserves, voltage support and system restart capabilities. Like energy markets, ancillary service transactions take place in day-ahead and real-time markets.[31] Today, market-based mechanisms designed to support ancillary services are the least mature. However, studies and pilots, like the PJM V2G demonstration project, have been promising and distributed resources could start to become an important contributor of ancillary services.[32]

Several of the RTOs and ISOs have already begun leveling the playing field and incorporating distributed resources into their markets. The changes to the rules in these markets can serve as a blueprint for beginning to unleash market forces to encourage more development of distributed resources while also staying technology neutral. These changes include:

- **Ensure pricing signals encourage mid- and long-term investments.** Not all ISOs and RTOs employ capacity markets, but some have done so with varying degrees of success. PJM, NYISO and ISO-NE are notable among these. These forward capacity markets have created a clear price signal to direct future investments for both large, utility-scale generators as well as smaller, distributed resources. Some of ISOs and RTOs have debated the need for capacity markets and whether their markets are currently sufficient to encourage future investments.[33] In the move to a high-renewables future, it will be important to make sure that markets adequately compensate the value of all mid- and long-term investments, including investments in demand-side capacity resources.

- **Allow distributed resources (or aggregations thereof) to bid into markets**. Demand-side resources such as energy efficiency and demand response have been able to bid into PJM and ISO-NE for several years. These resources have reduced the peak demand on the system and prices to consumers. While efficiency acts as a passive resource (it cannot be turned on and off), demand response provides additional value to the system because operators can choose to dispatch it. Furthermore, electric vehicles, distributed storage and solar PV with smart inverters should be able to bid into markets if they are able to meet the necessary technical and physical requirements.

- **Allow smaller resources to compete**. Many markets have rules that only allow large generators to compete (e.g., greater than five MW standard). In order for many distributed resources to bid into these markets, rules will have to be modified to allow these resources to compete. PJM is notable for allowing resources as small as 100 kW to compete.

- **Enable aggregation**. Some resources won't be able compete even at lower sizing requirements. However, service providers can aggregate these resources to provide value to the system. ISO-NE and PJM allow efficiency program administrators to bid their savings into the forward capacity market.

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs	Create capacity markets where they are necessary.
PUCs, ISOs/RTOs, NERC	Create a platform for all distributed resources to register and allow participation in capacity, energy and ancillary service markets on the same footing as supply-side resources.
ISOs/RTOs	Allow smaller resources to compete.
PUCs, ISOs/RTOs	Allow third-party aggregators full access to markets.
PUCs, FERC, ISOs/RTOs, NERC	Assess the need for new services that may arise as renewable production grows (e.g., capability markets or alternative dispatch rules).

These are promising first steps that we recommend other RTOs and ISOs begin to adopt. In addition, there are other opportunities on the horizon that no U.S. market has fully implemented.

As the system changes from one in which thousands of devices operate to one where millions could operate, this will create a plethora of new opportunities and challenges. Overall, the intention should be to ensure all resources are recognized for their ability to provide value from a locational and temporal perspective as well as improve reliability. As markets continue to allow more distributed resources to compete, additional considerations will include:

- **Improving responsiveness and visibility.** Having potentially millions of devices on the system responding to price signals will mean that there will be even greater need for responsiveness and visibility. Multi-stakeholder working groups, which should include utilities, service providers, ISO's and others, will have to decide the appropriate response-time and telemetry requirements for resources. These requirements will have to balance the need to ensure that these resources are providing the services that they are supposed to provide while also minimizing the transaction costs that could prevent service providers from participating.
- **Connecting wholesale markets to retail rates.** Many distributed resources could be on the electricity system in the future without bidding into power markets. In order to maximize the value of these resources, the proper pricing signals will be important, perhaps coupled with customer-choice automation or remote load control. There has already been significant work done piloting and establishing rate structures that more accurately reflect the wholesale market environment, like critical peak pricing and real-time pricing. These rate structures could further incentivize higher levels of adoption of distributed resources by aligning compensation with the value the distributed resources provide.

ENABLE MICROGRIDS AND VIRTUAL POWER PLANTS TO SUPPORT INTEGRATION AND AGGREGATION OF DISTRIBUTED RESOURCES

Microgrids[34] and virtual power plants[35] can facilitate the achievement of a renewable electricity future by integrating distributed renewable resources locally while providing greater flexibility for managing resources to respond to varying grid conditions. In addition, microgrids can protect customers from outages and support the security and resilience of the larger system by isolating and containing problems, providing ancillary services including black-start services and reducing the risk of cascading outages.

In Denmark, where renewable and distributed resource penetration levels are already among the highest in the world, grid operators have begun to fundamentally shift grid architecture toward a new system of "cellular control" that aggregates distributed resources into blocks of supply that behave like virtual power plants, allowing them to provide grid support services. By design, these "cells" that support the larger grid can isolate from it, withstanding major system disturbances. Meanwhile, market mechanisms, aided by digital communications and real-time feedback, determine the least-cost ways to generate power and provide grid support services.[36]

Today, the U.S. has nearly 1,500 MW of generation operating in microgrids, but substantial growth is expected. Navigant projects the global microgrid market could surpass $40 billion by 2020 and over 60 percent of this market resides in the U.S.[37] The opportunity for capturing value to the grid and the customer from current and future microgrid deployment will be shaped by the policies and regulations that determine the viable business models.[38] In this section, we identify a set of principles for consideration that can help policy makers and other relevant stakeholders navigate the regulatory juggernaut and speed the advance of rational microgrid development.

There are multiple considerations that shape the opportunity for all players and determine whether and how new business models will emerge. These include rate design (e.g., how microgrid costs and benefits are assigned, where the capital comes from, what types of performance incentives exist, how to manage legacy grid costs), provider participation rules (e.g., who is allowed to own the microgrid, what products and services are allowed, how are they governed in the market), customer eligibility (e.g., which customers are allowed to microgrid in the first place, what rights do they have in secondary markets), how to plan around microgrids (e.g., optimizing parallel investments, role in delivering "smart grid of the future") and interoperability rules that define the technical aspects of islanding. While this is quite an array of considerations, several guiding principles can help minimize unnecessary friction in the alignment process between stakeholders on all sides of the issue:

- *Define microgrids, and clarify how existing policies apply to them.* Job number one for regulators is to determine a clear definition (or definitions, plural, if a one-size-fits-all approach proves insufficient) for a microgrid. Should a microgrid be categorized as a distributed energy resource, an independent power producer, or something completely different? How big or small can a microgrid get before it ceases to be a microgrid? Only after such questions are answered can the regulator, utility, customer and private developers make sense of how existing rules and regulations inhibit or incent microgrids in places where sound business cases exist. In addition to clarifying how existing rules apply, the regulator must clearly articulate the type of treatment legacy utility assets will receive.

- *Adopt and enforce a grid-wide interoperability standard.* Safe and beneficial linking of micro- to macro-grids requires adoption of standard protocols that ensure physical integrity of the system and allow for joint optimization of the independent and combined system's economic, environmental or operational performance. IEEE 1547.4 is one promising option for standardization, though there may be additional requirements to be codified in this or other protocols over time.

- *Strive to reasonably value microgrid costs and benefits, and price accordingly.* The foundation for microgrid business models is premised in part on the costs and benefits this technology offers to the grid. These include services such as black-start capability, frequency regulation and an ability to shift from energy sink to source at a moment's notice. But these services should be weighed against any additional infrastructure or operational costs associated with integrating many semi-autonomous microgrids into the macrogrid. An initial effort at evaluating the size of these costs and benefits and finding ways to monetize them through existing or new pricing approaches is critical to encouraging microgrid development in situations that make the most sense for the grid, while also providing fair compensation for customers investing their own capital in microgrids.

- *Remove the delivery utility's disincentive, and consider performance-based incentives to stimulate development.* As another technology that stands to reduce demand serviced by the distribution utility, there is a potential disincentive for the utility to pursue or support investment in microgrids. However, microgrids present real opportunities to deliver system benefits to customers in the form of cost savings and improved reliability and power quality. Where evaluation and planning reveal these opportunities, the utility should be permitted to pursue and invest in them. Beyond freeing the utility up to invest in microgrids, establishing and strengthening performance-based incentives for cost, reliability and power quality can provide the carrot that some utilities may need to explore microgrid opportunities. And just as the utility is incentivized to make targeted microgrid investments through performance-based incentives, more highly differentiated pricing can signal to customers and developers where microgrid investments will minimize distribution system costs.

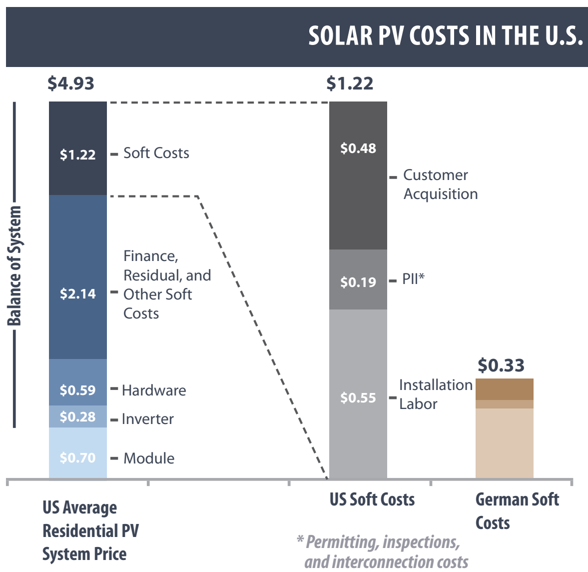
- *Allow broad-based microgrid participation in wholesale markets.* In some cases it will make the most sense for microgrids to participate and provide services in the wholesale markets. To facilitate customer participation, clear operational and market-based standards need to exist without limiting customer access to develop a microgrid. In markets like California, the path to participation for a microgrid connected at the transmission level is clear enough, but the situation grows more complex and nuanced when a microgrid is connected to the distribution system and wants to participate in wholesale markets. In this instance, the customer must navigate between the ISO and the distribution utility. Simplifying and reducing barriers to wholesale market participation for microgrids, both big and small, that are connected at the distribution level increases competition in the markets, improves the economic case for microgrids and provides the grid operator with new resources to balance the system. In Denmark, on the island of Bornholm, the municipal utility is testing a market that encourages participation from many small customers. In this market prices change every five minutes, there is no limit on the size of demand or supply resources that can participate and participants do not need to bid into markets to participate, vastly simplifying the task for small residential and commercial customers.[39]

- *Incorporate microgrids into broader grid-planning processes.* Both distribution and transmission system planning represent important opportunities for evaluating microgrid options and incorporating them into system design. These resource planning processes can provide the foundation for targeted deployment of microgrids in ways that minimize system costs, manage load shapes and provide valuable ancillary services to the grid. Transmission planning processes typically include NTAs, of which microgrids should be included. Although the consideration of NTAs is far from perfect, it represents a clear entry point for consideration of microgrids. Incorporating microgrids as potential assets for optimization in other integrated grid-planning exercises (either traditional Integrated Resource Plans done by electric utilities in 34 states,[40] or alongside the emerging discipline of IDP[41]) presents an opportunity to evaluate and implement least-cost distribution alternatives, such as energy efficiency, distributed energy resources and microgrids.

DECISION-MAKER	RECOMMENDATION
PUCs	Ensure interconnection rules allow and conform to intentional islanding standards set per IEEE 1547.4. Enable and encourage delivery utility support and investment in microgrids that offer grid benefits.
PUCs/RTOs/ISOs	Define microgrids, and clarify how existing policies apply to them. Incorporate microgrids into utility and ISO/RTO grid-planning processes. Allow microgrids to transact with wholesale markets and provide services at a single point of interconnection with the microgrid.

DRIVE DOWN "SOFT COSTS" FOR SOLAR PV BY STREAMLINING PERMITTING AND INTERCONNECTION PROCEDURES

Regulators and policymakers can help to reduce the costs of permitting, inspection and interconnection to significantly reduce the total cost of distributed solar PV. Module costs, which have historically dominated the cost of PV systems, declined 80 percent between 2007 and 2012 and are continuing to fall. Given this steep decline, the remaining "balance of system" (BOS) costs — all cost components *other* than the module —now constitute 80 percent or more of total system cost. "Soft costs" — which include customer acquisition; installation labor; and permitting, inspection and interconnection costs — can be dramatically lower where procedures are streamlined, as evidenced by experience in Germany, where soft costs are 73 percent lower than in the U.S. (figure 2).



Source: RMI Analysis based on GTM / SEIA Solar Market Insight Q1 2013 (available: http://www.seia.org/research-resources/us-solar-market-insight-q1-2013); Goodrich et al. Residential, Commercial, and Utility-Scale Photovoltaic System Prices in the U.S.: Current Drivers and Cost-Reduction Opportunities. February 2012; Friedman et al. Second Annual Benchmarking Non-Hardware Balance of System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey. NREL. August 2013; Seel et al. "Why are residential PV prices so much lower in the U.S.?" LBNL / NREL. February 2013.

Figure 2. Residential Solar PV Costs in the U.S. and Germany

Government agencies with responsibilities for permitting solar systems can help to reduce soft costs by streamlining and simplifying permitting procedures consistent with best practices, including adopting the recommendations of the Solar America Board for Codes and Standards' *Expedited Permit Process and Emerging Approaches to Efficient Rooftop Solar Permitting*[42] and IREC's *Sharing Success: Emerging Approaches to Efficient Rooftop Solar Permitting*. Further, local and state governments can help drive the development of more efficient local installation and support installer training to reduce installation costs.

In permitting, current best practices include:

- Over-the-counter, same-day permit review.
- Clear, well-organized webpages focused on the solar permitting process, including recent changes in codes, where applicable.
- Exempting building permit review altogether for small systems.

Inspection processes can be streamlined with the following approaches:

- Self-inspection (of certain types of systems) by certified PV installers.
- Simplifying requirements for site plans.
- Specifying how much of a project must be complete for interim inspections.
- Providing a tight time window for inspection appointments.
- Providing consistent and current training for inspectors so that installers receive actionable and reliable guidance, including training inspectors on advances in the solar installation hardware and practices and how they relate to permitting codes.
- Combining all required inspections into one onsite visit.

DECISION-MAKER	RECOMMENDATION
Local governments	Streamline permitting procedures to match best practices.
PUCs	Require utilities to simplify and speed inspection and interconnection processes subject to meeting safety requirements.

ENCOURAGE SMART ELECTRIC VEHICLE CHARGING

The electrification of light-duty vehicle transport is an important complement to increasing the share of variable renewable generation in the electricity sector. In *RE Futures'* 80 percent-ITI scenario, 40 percent of the passenger vehicle transportation fleet (about 154 million vehicles) is assumed to be electrified by 2050. Of the assumed 356 TWh of electric vehicle load in 2050, 165 TWh are charged under utility control, which allows vehicle charging to be interrupted by the utility within certain boundaries. In *Reinventing Fire,* the share of the vehicle fleet that is electrified by 2050 is approximately the same (157 million vehicles), with similar shares of utility-controlled charging, but with a total of 26 million vehicles capable of providing active vehicle-to-grid (V2G) services for voltage regulation, ramping and other purposes.[43]

The proliferation of electric vehicles connected to the grid means that a significant amount of battery storage capacity could be available, if equipped with proper controls and communications capabilities, to help to ride through short-term fluctuations in system conditions and manage load shapes in response to price signals. Electric vehicle manufacturers, electric utilities or other intermediaries could aggregate electric vehicles with charging controls to provide services to the grid. Based on some estimates of the value of grid-control services, the upfront cost of an electric vehicle with full V2G capabilities could be $10,000 less than that of an electric vehicle without such capabilities if vehicle manufacturers or other intermediaries were to monetize the lifecycle value of services provided to the grid.[44] On the other hand, unmanaged electric vehicle loads could present challenges for grid planners and operators if their use contributes to peak period demand and increases burdens on constrained parts of the distribution system.

Regulators and policymakers can help to pave the way toward a high-renewables future by promoting the integration of electric vehicle charging into the grid. This could occur through:

- Encouraging utilities to provide special incentives to customers in return for utility-controlled or V2G charging.
- Allowing aggregators to manage vehicle charging in order to provide services to utilities or directly to wholesale markets. In February 2013, the University of Delaware and NRG Energy began providing frequency regulation services to PJM Interconnection under a pilot program that allows aggregations of as little as 100 kW to provide such services to the grid.

DECISION-MAKER	RECOMMENDATION
PUCs	Encourage utilities to provide special incentives to customers in return for utility-controlled or V2G charging.
RTOs/ISOs	Allow aggregators that manage electric vehicle charging to compete to provide ancillary services to the grid.

CONCLUSION

Distributed resources can play a crucial role in the transition to a renewable electricity future by adding to renewable electricity supply, reducing demand and providing flexibility to integrate variable renewable resources. Creating a level playing field for centralized and distributed resources will require significant changes in electric utility business models and electricity markets, as well as other changes in regulation and policy to adapt to rapidly evolving technology.

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3 See Appendix A for a list of acronyms.

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34 A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.

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43 Another important difference is that those vehicles are several times as efficient (thanks to ultralighting, better aerodynamics and tires, more-efficient accessories, and better-integrated design) as in *RE Futures* — a vital step in making electric vehicles rapidly affordable by eliminating half to two-thirds of their costly batteries. DOE is adopting this fewer-batteries-before-cheaper-batteries strategy, and so are several influential automakers. The result will presumably be faster adoption of electric vehicles but with smaller charging loads, lower electricity consumption, and smaller sellback and regulation potential per vehicle than most analyses assume.

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APPENDIX A. ACRONYMS

DOE	Department of Energy
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NTA	Non-Transmission Alternatives
PUC	Public Utilities Commission
RTO	Regional Transmission Organization