

Appendix B: Summaries of Reports Related to the Future of the Utility Industry

This appendix contains brief summaries of more than 60 reports. We have sorted them into the following categories:

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Within categories, reports are ordered by year of publication and then alphabetically by author.

KEY REFERENCES ON THE UTILITY OF THE FUTURE

EEI (Edison Electric Institute). 2013. *Disruptive Challenges: Financial Implications and Strategic Responses to Changing Retail Electric Business*. January 2013.
<http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf>.

Adapted from the executive summary with permission:

“Recent technological and economic changes are expected to challenge and transform the electric utility industry. These changes (or disruptive challenges) arise due to a convergence of factors, including: falling costs of distributed generation and other distributed energy resources (DER); an enhanced focus on development of new DER technologies; increasing customer, regulatory, and political interest in demand-side management technologies (DSM); government programs to incentivize selected technologies; the declining price of natural gas; slowing economic growth trends; and rising electricity prices in certain areas of the country. Taken together, these factors are potential game changers to the U.S. electric utility industry, and are likely to dramatically impact customers, employees, investors, and the availability of capital to fund future investment.

“The financial risks created by disruptive challenges include declining utility revenues, increasing costs, and lower profitability potential, particularly over the long term. As DER and DSM programs continue to capture market share, for example, utility revenues will be reduced. Adding the higher costs to integrate DER, increasing subsidies for DSM, and direct metering of DER will result in the potential for a squeeze on profitability and, thus, credit metrics.... Without fundamental changes to regulatory rules and recovery paradigms, one can speculate as to the adverse impact of disruptive challenges on electric utilities, investors, and access to capital, as well as the resulting impact on customers from a price and service perspective. Thirty-year investments need to be made on the basis that they will be recoverable in the future in a timely manner. To the extent that increased risk is incurred, capital deployment and recovery mechanisms need to be adapted accordingly.

“There are a number of actions that utilities and stakeholders should consider on a timely basis to align the interests of all stakeholders, while avoiding additional subsidies for non-participating customers. These actions include:

“Immediate Actions:

- “Institute a monthly customer service charge to all tariffs in all states in order to recover fixed costs and eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources
- Develop a tariff structure to reflect the cost of service and value provided to DER customers, [these] being off-peak service, backup interruptible service, and the pathway to sell DER resources to the utility or other energy supply providers....
- Analyze revision of net metering programs in all states so that self-generated DER sales to utilities are treated as supply-side purchases at a market-derived price. From a load provider’s perspective, this would support the adoption of

distributed resources on economically driven bases, as opposed to being incentivized by cross subsidies

“Longer-Term Actions:

- “Assess appropriateness of depreciation recovery lives based on the economic useful life of the investment, factoring the potential for disruptive loss of customers
- Consider a stranded cost charge in all states to be paid by DER and fully departing customers to recognize the portion of investment deemed stranded as customers depart
- Consider a customer advance in aid of construction in all states to recover up front the cost of adding new customers and, thus, mitigate future stranded cost risk
- Apply more stringent capital expenditure evaluation tools to factor in potential investment that may be subject to stranded cost risk, including the potential to recover such investment through a customer hookup charge or over a shorter depreciable life
- Identify new business models and services that can be provided by electric utilities in all states to customers in order to recover lost margin while providing a valuable customer service...
- Factor [in] the threat of disruptive forces in the requested cost of capital being sought”

EFC (Energy Future Coalition). 2013. *Utility 2.0: Piloting the Future for Maryland's Electric Utilities and their Customers*. <http://cleanenergytransmission.org/uploads/Utility%202010%20Pilot%20Project-reduced.pdf>.

Adapted from the executive summary with permission:

“The Energy Future Coalition was charged by Governor Martin O’Malley of Maryland, in response to a recommendation from the Governor’s Task Force on Grid Resiliency, with ‘scoping out a Utility 2.0 pilot proposal and reporting back to the Governor and the Task Force...on a viable method to explore the contours of the utility of the future.’

“This pilot design proposes testing (1) the application of new technologies, strategies, and practices in the day-to-day functioning of electric utility service in a pilot project area; and (2) matching changes in utility business practices and reward structures as well as the regulatory scheme under which Maryland’s utilities operate. It is intended to be incremental to the many progressive policies and tests of new utility technology and regulation already going on today in Maryland.”

EFC outlined six categories in which progress will be essential.

- Reliability and resiliency
 - Ensuring that the quality of electric power remains able to meet demand, as well as better utilizing spare capacity and higher efficiency
- Residential customer optionality
 - Increasing the options, control, and information available to residential customers through the use of smart technologies
 - Facilitating the implementation of distributed generation technologies, increased energy efficiency, and customer self-monitoring of energy usage
- Larger customer optionality
 - Increasing the islanding ability of large customers and groups of small customers through micro-grids, demand response, and distributed generation technologies for economic and reliability benefits
 - Supporting electric vehicle infrastructure for customers with large parking lots
- Utility system upgrades
 - Incorporating smart-grid technologies and infrastructure into the power system
 - Improved grid maintenance, increased investments in reliability, and increased communications infrastructure with customers
- Utility business model changes
 - Adequate returns for utilities on investments in efficiency and improvements to the grid
 - Rethinking outcomes and considering a future where energy efficiency, distributed generation, and micro-grids will be priorities
 - A shift in focus to downstream, demand-side investments with on-bill financing available
 - Transparency to customers
 - Room for reinvention
- Regulatory model adjustments

- Regulatory frameworks that reward utility performance, not necessarily sales volume, in order to incentivize reliability, quality, and security
- Emphasis on reliable, measurable metrics for rating utility performance based on customer satisfaction

Additionally, EFC outlined five core attributes that will be essential to the electric utilities of the future.

- Aligning utility compensation with customers' changing needs and values
 - EFC envisions a system in which electric utilities would be evaluated based on objective metrics to vary the utilities' rate of return on equity by $\pm 1\%$. The degree of variance would be based on cost, reliability, customer service, adoption of smart-grid technologies and services, and support for alternative energy. These metrics would be based on customer rankings of priority.
- Supporting utility investment in an interoperable, integrated suite of smart-grid technologies, not only on its own system, but on the premises of willing customers
- Allowing utilities to finance and customers to repay system-related and efficiency investments on their bills
- Optimizing automated system sectionalizing and reclosing to facilitate micro-grids for areas where customers could safely provide their own energy during an outage and achieve other goals
- Facilitating electric vehicle deployment and utility benefit from utility-controlled vehicle battery charging

Lehr, R. 2013. "New Utility Business Models: Utility and Regulatory Models for the Modern Era." *Electricity Journal* 26 (8): 35–53. <http://americaspowerplan.com/the-plan/utility-business-models>.

The first paragraph is excerpted from the executive summary with permission.

"Because utilities respond first and foremost to the incentives created by the legal and regulatory regimes in which they operate, this paper focuses its recommendations on how utilities are regulated. Regulators must determine desired societal outcomes, determine the legal and market structures under which utilities will operate, and then develop and implement correct market and regulatory incentives. "

In this article, Lehr describes three potential scenarios based on level of utility involvement in transitioning to a renewable-energy-dominated future.

1. A scenario characterized by minimal utility involvement, where utilities act as monopolies and see no need to risk capital on innovative investments
2. A "middle way" scenario, where utilities act as the smart integrator or orchestrator of energy efficiency investments and the shift to a renewable-energy-driven power sector; utilities engage in productive partnerships with third-party innovator firms and use demonstration project findings to inspire new investment at a lower risk to shareholders
3. A maximum utility role where electric utilities act as energy services utilities and the ultimate enablers of innovation; requires a widespread political consensus that could lead a state legislature to mandate a structure in which utilities are primarily in charge, but required to meet certain targets for renewables and energy efficiency

Of these three scenarios, Lehr characterizes the second, middle-way scenario as the most likely to occur, as well as the most conducive to the transitions necessary for survival in an ever-evolving electric power industry.

Lehr indicates there is a need for regulators to align regulatory incentives so utilities can pursue society's broader policy goals in ways that also benefit customers and shareholders. Government mandates should reflect the public demand for a renewable energy future. Regulation must be based on performance rather than sales volume in order to allow utilities to continue to be financially soluble.

Additionally, Lehr outlines three regulatory systems already in place that may serve as examples to draw from for the regulatory scheme of the future.

- The U.K. RIIO (Revenue using Incentives to deliver Innovation and Outputs) model: Utilities are required to meet national climate goals. Rewards and penalties are tied to utility performance on desired outcomes. Utility profits are decoupled from sales volume. Various opportunities to involve third parties in the delivery of energy services exist.
- The Iowa model: This system is based on the settlement process between MidAmerican (a major electric utility) and the Iowa Utilities Board that lessened the

transaction costs associated with a typically adversarial process. Making clean energy goals part of periodic negotiations of shared earnings led to amicable relations between the utility and regulatory agencies, as well as consistent electricity prices for 17 years.

- A grand bargain: This is seen as an alternative to the fragmented rate-making process. The goal of the grand bargain is to produce, through negotiation, a thorough regulatory regime that would address a broad set of issues in a consistent manner.

RMI (Rocky Mountain Institute) eLab. 2013. *New Business Models for the Distribution Edge*.
http://www.rmi.org/New_Business_Models.

Adapted from the executive summary with permission:

“The declining costs and improving performance of distributed energy technologies are expanding the range of options for on-site 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. 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 identifies a number of attributes new business models should provide. Future utility business models will need to ensure the continued efficiency, resiliency, and reliability of the network while also fostering innovation. Transparent incentives and minimal complexity should allow for a more level playing field in competitive energy markets. Regulations should be adjusted to enable a workable transition from current business models, as well as support for the harmonization of business models between regulated and nonregulated service providers.

The paper then discusses four possible business models for the utility of the future.

1. Reduce disincentives and reward performance within the existing model. This includes such measures as decoupling revenues from sales so fixed costs are recovered and developing new pricing models and cost-allocation methods to align

- resource investments with system costs and benefits over short-term (operational) and long-term planning horizons.
2. Integrated distributed resource manager. The integrated utility develops a least-cost integrated plan with lots of input from interested parties, including use of energy efficiency and distributed generation. The utility offers incentives, requests for proposals, financing, and direct investments to implement the plan and receives performance incentives based on results.
 3. Distributed resource finance aggregator (finance company). The distribution utility provides on-bill financing for customers to invest in efficiency and/or distributed generation, working with approved third-party service providers. The utility pays service providers based on verified performance for installing and managing resources. The rate structure covers the full cost of distribution services to these customers.
 4. Independent distribution network operator. This is a company that just operates wires and not electricity supply. The wires company is a regulated monopoly subject to performance-based regulation. The distribution utility is encouraged to develop pricing mechanisms and incentives for customers and resource developers in order to develop resources in ways that reduce distribution system costs.

Fox-Penner, P. 2010. *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*. <http://www.smartpowerbook.com/aboutsmartpower.html>.

This edition of *Smart Power* was written in 2009 and published in 2010. While the industry has continued to evolve since its release, Dr. Fox-Penner's discussion of major challenges and the business models he presents are still relevant.

Adapted from the summary on the website:

"A new national policy to address the impact of climate change is under debate in the U.S. and could result in a cap on greenhouse gas emissions, which will significantly impact the energy industry. Regardless of the specific terms adopted, there is no question that utilities will need to shift their focus to the development and acquisition of new sources of renewable energy and low-carbon power.

"Meanwhile, a technical revolution known as the smart grid is underway in the electric power sector, providing dramatic new opportunities for customers to control their power usage and for utilities to change the way they operate. President Obama has declared the smart grid a national priority and expanded funding for pilot programs, creating a wave of interest among utilities, states and municipalities, federal agencies, and private equity firms and venture capitalists.

"There has also been an explosion of interest in transmission and renewable energy infrastructure. There are multiple bills before Congress that address transmission siting and planning, as well as potential legislation for renewable energy standards. The electric industry is planning significant expansion of transmission lines and there is also talk of creating a national transmission superhighway.

"These unprecedented developments will prompt utilities to undergo the largest and most significant changes in their history, transforming them from regulated commodity energy firms to low-carbon network operators. The combination of industry structure, regulation, and business mission that utilities adopted over a century ago must now be retooled for an era with new priorities, goals, and technologies.

"*Smart Power* examines strategies for the development of an energy-efficient business model for the utility industry. It reviews the current prospects for long-term power generation alternatives, from solar panels attached to our homes and offices, to new coal-burning plants that will allow for the capture and sequestration of carbon emissions."

The report proposes two major utility business models for the future.

1. *The smart integrator*. This is a utility that operates the power grid and its information and control systems but does not actually own or sell the power delivered by the grid. The role of the smart integrator utility will be to deliver electricity from a multitude of sources (traditional generators, distributed generators, renewables), at prices set by regulator-approved market mechanisms, to customers who have been empowered through smart-grid technologies to alter their personal energy demand based on price

signals. Smart integrator utilities will own and maintain the physical elements necessary for transmission and distribution, upgrading them to be able to respond to a plethora of information gathered through advanced system-monitoring technologies.

2. *The energy services utility.* An ESU is a regulated electricity-producing entity whose prices and profits are controlled. It is responsible for supplying all retail generation customers demand with high reliability while also providing demand response, energy efficiency, and smart-grid services and technologies to its customers. It can own the generators that provide its supply, whether large upstream plants or small local ones, but it is also required to purchase or transmit power from others attached to its wires. Often, ESUs are incentivized to cooperate with local generators who want to connect and sell power into their smart systems through measures such as energy efficiency profit incentives or revenue decoupling.

Other reports use the same terminology, but *Smart Power* was the first.

ADDITIONAL REFERENCES ON THE OVERALL TOPIC

AEE (Advanced Energy Economy). 2014. *Creating a 21st Century Electricity System for New York State: An Energy Industry Working Group Position Paper*. Advanced Energy Economy. http://www.smartgridnews.com/artman/uploads/2/Creating_a_21stCenturyElectricitySystem_for_NewYorkState.pdf.

From the executive summary with some edits, with permission:

The electricity industry is in the midst of dynamic change, with many of the underlying assumptions that have shaped it for decades in transition. This paper summarizes the collective thinking of an informal Working Group (WG) that was formed to provide input to New York State policymakers, regulators and other stakeholders on potential changes to the electric utility industry that will align the state's utility regulatory framework with the state's energy, environmental, and economic policy objectives while also successfully addressing the underlying technology and market forces shaping the "Utility of the Future." Members of the working group are primarily New York's major electric utilities and private companies who actively sell electric products and services; one environmental group was also represented.

The forces affecting the electric power industry are creating challenges and opportunities. Technology developments include increasing deployment of distributed generation (DG), energy efficiency (EE), demand response technologies (DR), and smart grid technologies, products, and services. Customer needs and expectations are also changing, including the desire for more self-generation, better control over energy use and costs, and expectations for a more resilient system. New York State also has energy, environmental and economic policy objectives that requires a modernized, efficient electricity system.

The WG envisions a future electric industry model in New York in which a modernized grid serves as a platform for enabling new capabilities and customer-driven products and services, and creates value for utilities, non-utility companies, and customers. They claim this vision is one that: aligns the electricity sector with state policy objectives; improves the customer experience and gives customers tools and options for managing electricity costs; creates sustainable utility business models that recognize the value of the grid; improves market design, operation, and coordination; encourages innovation; and moderates future customer bill increases relative to what would otherwise be experienced. To implement this vision, the WG identified three pillars that will serve as the foundation for this new model. These are: (1) customer products and services, (2) the network infrastructure and operational model, and (3) the regulatory framework.

Customer Products and Services

The 21st century electricity system will drive improvements in core functions such as operations and reliability, additional customer services, and greater levels of customer engagement and choice. Grid modernization infrastructure, increased customer participation, and services provided by and to utilities will enhance the core operational capability of the electricity system. Compared to today, basic services will provide incremental capabilities and services to customers and will be included as part of traditional utility rates. Additional value-added products and services will be provided by utilities and/or non-utility companies. Value-added

products and services will allow customers to actively engage more in managing their energy usage or hand off this management to utility or non-utility service providers. Value-added services will typically be market-priced for services. The WG outlined an initial set of basic and value-added services, as follows:

Basic services

- Ensuring access to the distribution system and DG interconnection
- Meeting reliability standards (including EE, DR, and other DER)
- Billing and collection services and customer service relating to utility billing and services
- Metering services and associated data
- Cyber security, data security, and meter data access
- Outage services (restoration and anticipated outages)
- Enhanced customer notifications and energy intelligence
- Buy and sell from the grid, new transactions
- Significant fees and taxes collected by utilities

Potential value-added services

- Billing and collection services relating to utility billing and services
- Billing services for third parties such as ESCOs, as the utility companies do today
- Metering services and associated data
- Enhanced customer and grid management services
- Commodity supply services and behind-the-meter supplies
- Enhanced reliability and resiliency
- Customer-sited energy storage facilities
- Emergency and non-emergency operational services
- Distribution-level ancillary services

However, there are numerous unresolved policy issues that will need to be addressed, including the roles of utilities and non-utility providers, what is included in competitive markets, and how these markets will function. Issues surrounding rate design for regulated services, metering services, and the associated data will also be important.

Network Infrastructure and Operational Model

As New York's distribution utilities plan and invest for the future, their network infrastructure requirements will be shaped by a number of industry dynamics and emerging technologies. The ability of the grid to accommodate a high volume of distributed energy resources (DER), smart grid technologies, demand response, and additional loads from electric vehicles requires an evaluation of necessary network infrastructure and operational requirements. Moreover, certain customers and customer classes will seek increased access to more information and empowerment regarding their energy usage. Reliability and grid resiliency also need to be addressed as a result of changing customer and community expectations as well as an ever-growing reliance on electricity, in light of an anticipated increase in severe weather events. All of these requirements must be delivered while maintaining data security in the face of a rising threat of cyber events. To effectively manage these dynamics, the utility of the future must build out an infrastructure that provides the network operator with a fundamentally new set of functions and capabilities. Managing this complex system will require development or

expansion of two-way, low-latency communication infrastructure and control schemes to integrate distributed resources and controllable loads.

Deploying the infrastructure required to enable the future industry model will entail significant investment over a sustained period of time, which raises questions and considerations with respect to cost recovery and prioritization of which capabilities to deploy first, and to which customers and parts of the network. Valuing DER is a key consideration, as DER is expected to play an important role in providing grid services to the utility. It will be important to assess the costs as well as the direct and indirect broad benefits of this new model, and to move forward in a way that provides net benefits to customers.

Regulatory Framework

Many jurisdictions, including New York, have made adjustments to traditional ratemaking to adapt to the changing industry dynamic with mechanisms such as capital trackers, revenue decoupling, and flexible alternative regulation schemes. To foster increasing investment in grid modernization, these methodologies can be broadened and enhanced. The WG envisions advancing to an increasingly flexible and performance-oriented regulatory system that is designed to accomplish several core objectives:

- Facilitate the attraction of capital and investment in advanced grid infrastructure
- Support continued resource diversity, e.g., demand response, energy efficiency, renewable supply, distributed generation
- Empower consumers with the information and tools to better manage their energy consumption, especially peak demand, and enable value-added products and services
- Enhance the reliability and resiliency of the grid
- Ensure the long-run financial viability of the distribution utility franchise
- Moderate future customer bill impacts through efficient utility investment and operations

The WG recommends that any changes to the regulatory approach in New York should be based on the following guiding principles:

1. Maintain effective aspects of the current regulatory approach that will serve as the foundation for the future
2. Modify the regulatory approach to realize the future model including supplementing traditional cost-of-service regulation with symmetric performance incentives, aligning utility investments to the achievement of state policy objectives, and creating greater clarity for long-term investments and cost recovery
3. Adjust ratemaking, including rate design, to allocate costs equitably, reflect the true value of the grid, and address structural changes in utility load profiles
4. Improve rate design to allow customers to make informed choices to enhance their value of service, aligned with policy objectives

In the future, utilities may be expected to meet a broader range of performance outcomes in order to successfully transition to the evolving utility model. As the industry transforms, today's existing measures can be the building blocks for future measures. Where today the

focus is on maintaining a certain level of service, tomorrow the focus may shift to enhancing that level of service. The WG identified five broad categories of outcomes that may be established: customer engagement; advancement of clean energy goals; operating safe, reliable, and resilient systems; operational efficiency; and innovation.

A New Benefit-Cost Analytical Framework

The current regulatory framework establishes specific guidance on the rationale for making capital investments: investments are justified on the basis of reliability, risk reduction, safety, and economic and environmental benefits to customers. A broader business case, considering value to customers and societal benefits that meet New York State policy goals, would more fully account for the effects of new technologies and justify support for the investments that may be needed to support overall state policy objectives. Many of the benefits of the investments necessary to realize the vision described in this paper will accrue to others – energy service and technology providers and local economies – and not directly to utilities or the customers they serve. As a result, traditional benefit-cost analysis that compares estimated consumer savings to estimated consumer costs may not capture all of the claimed benefits, thus limiting a utility's ability to justify the investments necessary to make this vision a reality.

The Path Forward

The utility industry model is at a crossroads. A long-term view is essential to maintain the proper alignment and reinforce these elements. It should also set the customer at the center of the new paradigm. The new industry model will need to provide sufficient clarity and certainty such that both utilities and non-utility companies can develop and implement business plans that serve the customer and achieve the desired outcomes.

Aggarwal, S. and E. Burgess. 2014. *New Regulatory Models*. Energy Innovation, America's Power Plan and Utility of the Future Center. http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf.

The report begins by identifying several “disruptive” technologies, such as solar photovoltaics, automated demand-response, and other distributed generation, which are potential threats to current utility business models. Declining sales growth, evolving wholesale markets, and new environmental regulation will also force utilities to adapt. These adaptations are already being experienced largely in the western United States, with residential solar PV costs dropping and utility scale PV growing. These changes to the electric power sector present a massive question to state regulators: “Are there modifications – or more fundamental changes – to traditional cost-of-service regulation that would be beneficial for achieving 21st century goals for the power sector?”

This report has two primary goals:

- To place the discussion of threats to the regulated utility business in context by identifying counterbalancing business opportunities
- To introduce the concept of performance-based ratemaking

Performance-based ratemaking (PBR) looks to move the emphasis of ratemaking to value provided rather than simply the cost of providing a service. PBR is designed to achieve goals that matter to all power-sector industry participants, goals such as minimizing costs, maximizing reliability, and maximizing environmental performance, while operating in an equitable way toward consumers, utilities, and regulators. Under a PBR system, a utility's profits are decoupled from its costs and instead tied to specific benchmarks. These performance benchmarks may be achieved over multi-year periods and measured on the retail or wholesale level. Benchmarks may be based on a number of metrics including equity, innovation, accuracy, and reliability. The authors note that well-designed PBR includes both incentives for over-performance and penalties for underperformance.

Seven case studies are presented, most of which involve just a few aspects of utility goals, but a few of which are more comprehensive. The case studies cover: (a) incentives for nuclear plant performance at the Fort St. Vrain plant, (b and c) revenue sharing for off-system sales involving Xcel Colorado and Mid-American Energy, (d) performance incentives for energy efficiency in Massachusetts, (e) smart-grid investment incentives in Illinois, (f) full-fledged performance-based ratemaking in the United Kingdom, and (g) utility-driven internal measurement at PacifiCorp.

Based on these case studies and other research, the authors suggest ten core principles for designing performance-based ratemaking:

1. Define goals and outcomes, set a quantitative standard of performance with incentives for exceptional performance and penalties for falling short of the standard.
2. Define a clear methodology for measuring performance, as well as a counterfactual, at the beginning of the program.

3. Shift an appropriate degree of performance risk to the utility in exchange for longer-term regulatory certainty and possible incentive compensation. Reward entrepreneurship.
4. Establish a time horizon long enough for the utility and third parties to make sound investment decisions and innovate to meet targets.
5. Structure revenue-sharing programs to align utility performance with customer benefits and give enough upside potential to drive innovation.
6. Build on an existing framework, but aim for holistic solutions that align incentives and simplify regulation.
7. Design single-performance incentives to achieve multiple objectives.
8. Build in mid-course correction, but, to minimize uncertainty, announce the need for changes well before implementation.
9. Engage with customer and power-sector participants early on to learn the outcomes they care about.
10. Learn from prior work with energy efficiency standards and incentive programs, and apply these approaches to achieve further system goals resulting in customer value.

In conclusion, the authors offer several western-U.S.-specific suggestions to aid the State-Provincial Steering Committee and the Committee on Regional Electric Power Cooperation. These recommendations include developing informational materials on PBR to distribute to regulators, surveying stakeholders, and inventorying existing regional performance indicators. The authors also suggest that commissioners open a proceeding on performance measures, and utilities bring together customers and other stakeholders to develop proposals on PBR.

Crane, D. 2014. "Where is the Amazon, Apple and Google of the Utility Sector?" *Green Tech Grid*. March 26. <https://www.greentechmedia.com/articles/read/nrgs-david-crane-where-is-the-amazon-apple-and-google-of-the-utility-sector>.

David Crane is the CEO of NRG Energy, a large independent power company that owns about 50,000 MW of generation and provides competitive power to millions of customers under such brands as Reliant and Green Mountain Energy. This is an early release of his annual letter to shareholders as part of NRG Energy's forthcoming annual report. In this letter he discusses how Amazon, Apple, Facebook and Google are "four companies that will inherit the earth." All four are innovative companies that have achieved ubiquity in the everyday lives of the vast majority of people by offering quality services that connect, relate, and empower. He says no energy company does this, including NRG, but says "we are doing everything in our power to head in that direction, as fast as we can." He sees the future of the utility industry as distributed-generation-centric with an emphasis on a clean energy future featuring individual choice and the empowerment of the American energy consumer. He notes that it is going to take a while to get there and says that NRG is positioning itself to succeed during "a prolonged period through which the traditional centralized grid-based power system co-exists with the fast-emerging high-growth distributed generation sector – much like fixed-line telephony has co-existed with the wireless world for a couple of decades."

He says "we are in the process of reorganizing ourselves from the customer's perspective" including maintaining the NRG generation fleet in top operating condition, but also "repowering select plants with flexible fast-start units located in advantageous positions on the grid." NRG is also expanding its wholesale business in on-site generation for industry and large-scale commercial customers. Crane says that the "cost to our business customer of maintaining localized generation will be defrayed by our ability to sell excess capacity and generation, on behalf of that customer, back into the traditional grid." The retail part of NRG's business is focused on "ensuring that we remain a first mover in bringing technological innovation aimed at the home energy consumer to our customers, on terms that they find attractive." Crane refers to NRG's marketing relationship with Nest as well as plans to offer rooftop solar and other forms of sustainable and clean generation to homes and businesses. NRG will also offer storage and "sophisticated localized automation to balance production and load." They are also exploring fresh water production, waste disposal, and electrified transportation as they strive to be "a leader in the area of renewables-driven ecosystems."

Crane says:

Our goal is to achieve the level of quality and ubiquity of energy outcomes on behalf of our customers that would one day cause us to be mentioned in the same breath as the "four companies who will inherit the earth." And in turn, our customers would have the same kind of experience with us that they have with the four of them, and we can emulate the shareholder value creation of four companies which, at present, have an aggregate market capitalization of over \$1 trillion.

Finally, he says that the next generation very much wants the future to be sustainable, "in every sense of the word, including clean energy." He says we have the technology and "the time for action is now; we have run out of time for more excuses."

Creyts, J. and J. Newcomb. 2014. "Building the Electricity System of the Future: Thinking Disruption, Doing Solutions." RMI Outlet. March 19. Old Snowmass, CO: Rocky Mountain Institute.

http://blog.rmi.org/blog_2014_03_19_building_the_electricity_system_of_the_future .

This summary borrows sections from the original text with permission.

"The speed of disruptive innovation in the electricity sector has been outpacing regulatory and utility business model reform, which is why they now sometimes feel in conflict. That disruptive innovation is only accelerating. RMI's recent report, *The Economics of Grid Defection*, . . . sets a timeline for utilities, regulators, and others to get ahead of the curve and shift from reactive to proactive approaches."

"We used the best available facts to explore when and where fully off-grid solar-plus-battery systems could become cheaper than grid-purchased electricity in the U.S., thus challenging the way the current electricity system operates. Those systems, in fact, don't even need to go fully off grid. The much less extreme but perhaps far more likely scenario would be grid-connected systems, which could be just as or even more challenging for electricity system operation and utility business models.

"The takeaway is this: even under the fully off-grid scenarios we modeled, we have about 10 years – give or take a few – to really solve our electricity business model issues here in the continental U.S. before they begin compounding dramatically. The analysis also suggests we should carefully read the 'postcards from the future' being sent from Hawaii today, and take much more interest in how that situation plays out as a harbinger of things to come."

RMI sees a highly distributed electricity system in the future. "The Transform scenario of our *Reinventing Fire* analysis, the most preferable outcome of the electricity futures we have examined, described a future for the U.S. electricity system in which 80 percent of electricity is supplied from renewable sources by 2050, with about half of that renewable supply coming from distributed resources. Given the current grid is only a few percent distributed and less than 13 percent renewable (counting a generous allotment of hydropower), we have quite a ways to go.

"Achieving that end state requires many changes. Some of those changes already have momentum and likely won't require intervention, but others will need a kick start or some other form of "strategic acupuncture" encouragement. We would certainly prefer that a transition of this scale be orderly and proactive, because having disruption rock the boat of the current system unprepared would undoubtedly leave some combination of shareholders, ratepayers, and taxpayers smarting.

"As we look at the future electricity system – the one we need to be building today – we see five critical differences from the present system. Redesigning our regulatory and market models should reflect these emergent needs.

- **The future electricity system will be highly transactive.** Increasingly, the grid will become a market for making many-to-many connections between suppliers and

consumers, with those roles being redefined on a daily basis as self-balancing systems decide whether to take from or supply to the grid at any given time.

- Correspondingly, **asset and service value will be differentiated by location and timing of availability**, and perhaps even by carbon intensity or other socially demanded attributes. In a system that requires instantaneous load matching at the distribution level, and where virtual and real storage are distributed throughout the system, resource coordination will require transparent markets (with increasing automation) that provide the ability to balance autonomously using value signals. A system historically governed by averages will instead migrate to specific, dynamically varying values.
- **Innovative energy solutions will proliferate.** As a consequence of market forces already unlocked, we are assured to see a regular stream of distributed resource innovations that better meet customer needs at costs comparable to existing utility retail prices. These could be market-based aggregation plays (e.g., demand response) or personal technologies (e.g., a home “power plant” such as solar plus storage or a gas microturbine).
- A consequence of these first three points is that the **rules governing the network must be adaptive to constantly shifting asset configurations, operations, and other factors.** For example, charging EVs may make more sense at night or during the day, depending on the penetration of renewables relative to base needs. There will be lots of inflection points on how and when to encourage the development of different types of assets to reach efficient and stable outcomes.
- Finally, **the customer will be increasingly empowered.** The services of the grid must de-commoditize to deliver against exact customer needs for reliability, “green-ness,” and other attributes. Failure to do so will result in customers finding higher-value alternatives.

“This future still prominently features a robust wires network; defection from the grid would be suboptimal for a number of reasons. We would assert that everyone is better off if we create a future network that is easier to opt in to, rather than opt out of via the risk of defection.

“Moreover, distributed resources – the same ones that could but needn’t threaten defection – have the potential to become a primary tool in the planning and management of grid-based distribution systems. We are exploring new ways to incentivize electricity distribution companies to take full advantage of distributed resources to reduce distribution system costs, increase resilience, and meet specialized customer needs. Good regulation will reveal value and facilitate transactions that tap that value, thereby increasing the benefit of distributed resources for all.”

Denning, L. 2013. "Lights Flicker for Utilities." *Wall Street Journal*, December 22.
<http://online.wsj.com/news/articles/SB10001424052702304773104579270362739732266>.

Denning, L. 2014. "Turning Down U.S. Power's Dimmer Switch." *Wall Street Journal*, January 17.
<http://online.wsj.com/news/articles/SB10001424052702304419104579326811521918006>.

This is a pair of articles. The first discusses how talk of a looming "death spiral" for utilities is "hyperbole...but only up to a point." It notes how the traditional German utilities, E.ON and RWE, have had difficulty adapting to the rising use of solar panels, noting that their combined market value has slumped 56% over the past four years in a rising German stock market. It notes that the U.S. is not nearly as far along. For example, even in California, "the costs shifted onto customers without panels from those with them amounted to just 0.73% of that state's utilities' revenues last year, according to Moody's." Denning goes on to suggest that "despite the perceived threat to regulated utilities, it is actually the merchant generators who look more exposed to distributed solar power for now." Once solar systems are installed, the sun's energy is free, so it will displace more expensive generators, such as gas-fired plants. "Solar power cuts both volume and price for traditional generators." However, for regulated utilities, there is still a need for backup power. "Batteries can help, but ISI Group estimates their price needs to drop by a factor of ten to be competitive with grid power." Moreover, current penetration of distributed generation is low. Denning notes that there are other sources of distributed generation, such as small Stirling engines that can be used alongside solar panels. NRG Energy, a merchant generator, is an example of a company starting to invest in Stirling engines. Denning suggests that "mass adoption is likely years away, but it is no longer over the horizon." "What looks too expensive or esoteric today can quickly make gains: think mobile versus fixed-line phones." He also notes that sales growth has slowed. UBS says, "we do not see the recent slowdown in electric load growth as cyclical anymore; it is a new and permanent feature of modern life." Denning suggests that these trends will mean less utility investment, "and in this business, less investment means less allowed return – and, therefore, earnings." "Even if the sound of bells tolling is faint, the impact on utility stocks will be felt much sooner."

The second article provides some additional information on the points made in the first article, such as falling demand for electricity. It says that electricity charges jumped 36% from 2003 to 2012, twice as fast as the median household income. "That leaves regulators less room to grant utilities the returns on investment that they request.... That puts the onus on utilities to cut costs. Mergers are an obvious way of doing this to support margins in the face of a stagnating top line, and big investment requirements, [just as] big oil companies did in the late 1990s after being whiplashed" by cheap oil.

ENE. 2014. *EnergyVision: A Pathway to a Modern, Sustainable, Low Carbon Economic and Environmental Future*. Rockport, ME: ENE. <http://www.ene.org/resources/detail/energyvision>.

Adapted from the report summary and press release with permission:

This report presents ENE’s suggested overarching framework to guide investment choices and reforms needed in our energy system. If fully implemented, they claim that the approach they outline would achieve key goals for our economic and environmental future: more efficient energy use, accelerated economic development, cleaner air, greater control over consumer costs, and steep reductions in greenhouse gas emissions.

EnergyVision integrates four components in the hope of improving electricity system operations, reliability, and environmental impacts while also maximizing consumer benefit: (i) utilize market-ready technologies to electrify buildings and cars; (ii) modernize the way we plan, manage, and invest in the electric power grid so that it facilitates new technologies, decentralized energy systems, and consumer control; (iii) make continued progress toward a clean electric supply through increased investments in local renewable power; and (iv) maximize investments in energy efficiency so that energy consumption is as efficient as possible while also improving building comfort and reducing unneeded energy demands that waste consumer dollars and act as a drag on the economy.

EnergyVision recommends a variety of reforms that focus on preparing the 21st-century power grid for large-scale adoption of electric vehicles, consumer-centered distribution, renewable generation, and high-efficiency equipment. These are:

Electrifying buildings and transportation

- If all gasoline-powered vehicles and buildings using fossil fuels shifted to electric technologies today, greenhouse gas (GHG) emissions would fall by nearly 50%.
- GHG emissions can be further reduced by 80% or more as additional renewable generation is added to the grid.
- The high cost and market volatility of fossil fuel imports make the Northeast region ideal for widespread adoption of efficient, clean electric space and water heating.
- Electric vehicle and high-efficiency electric heating technologies offer operating costs that are lower by as much as 70% of their traditional fossil fuel counterparts.

Modernizing the grid

- To achieve our climate and energy goals, we must reform the region’s transmission and distribution (T&D) grid to create a renewable-ready energy delivery system.
- The modern grid system should be a multidirectional pathway that uses an array of technologies to meet energy needs.
- Outdated regulations governing energy resource ownership must be revised and a new rate structure considered.

Clean electric supply

- From 2001 to 2012, the share of electricity generated by oil and coal plants in the region fell from 27% of all electric generation to less than 3%.
- The use of clean energy in the Northeast region alone has increased by about 25% since 1990.
- Renewable portfolio standards are catalysts to spur increased generation of renewable power, and higher levels of generation are needed in the future.
- The Regional Greenhouse Gas Initiative (RGGI) should lock in lower emissions to deliver further reductions and extend RGGI targets beyond 2020.

Maximizing energy efficiency

- Massachusetts and Rhode Island are leading the way nationally with energy efficiency savings targets.
- Energy savings from greater efficiency will deliver \$19.5 billion in economic benefits and 51.3 million metric tons of avoided GHG emissions in the Northeast alone.
- Energy efficiency programs can expand to provide more services to the grid and offer additional alternatives to traditional utility infrastructure investment.
- Planning, transportation, and zoning regulations must keep efficiency in mind to cut fuel waste and meet the transportation energy needs of the future.

IHS CERA. 2014. *Fueling the Future with Natural Gas: Bringing It Home*. Prepared for the American Gas Association. Englewood, CO: IHS Inc.
<http://www.fuelingthefuture.org/assets/content/AGF-Fueling-the-Future-Study.pdf>.

Adapted from the executive summary with permission:

“It is called a revolution for a reason. In the span of less than five years, unconventional technologies for natural gas development have changed the outlook for U.S. natural gas supply from scarcity to abundance, from high cost to moderate cost, from import dependence to self-sufficiency. Turning this revolution to best advantage requires both vision and understanding on the part of gas local distribution companies [LDCs], their customers and regulators. Business models, fuel choices, regulation, and energy policy must be reevaluated in light of the new opportunities presented by the unconventional natural gas revolution.

“These opportunities are both immediate and far-reaching, as evidenced by the current natural gas surplus and the view of many that the domestic natural gas resource base will be sufficient for domestic needs for many decades. A visionary response to these opportunities must therefore encompass both the near- and long-term perspectives. This report seeks to begin this process by evaluating the opportunities to leverage customer-based knowledge, critical infrastructure, regulatory and policy relationships, and the extraordinary natural gas resource availability to realize the benefits of natural gas for gas LDC customers and the nation as a whole:

- “Technology, efficient applications, and economic opportunity have dramatically altered the outlook for domestic natural gas for decades to come. Once considered in imminent danger of depletion, the U.S. natural gas resource base is now widely accepted to be robust and recoverable at a lower cost than could have been imagined even five years ago.
- Extensive volumes of natural gas can be economically developed in the United States with prices of less than \$4–5 per million Btu, making supply response to demand increases highly elastic. Domestic and international oil prices are expected to remain three to four times higher than the Btu equivalent price of natural gas for many years into the future. Also, new high-efficiency natural gas technologies and a widening gap between retail prices of electricity and natural gas in many U.S. regions give natural gas the competitive edge for many residential and commercial applications.
- Increased use of natural gas in the national energy economy will help achieve national goals of energy efficiency, environmental protection, and energy security.
- Unconventional oil and gas activity and energy-related chemical manufacturing, directly or indirectly, are expected to contribute 3.9 million jobs, \$533 billion (constant 2012\$) in value added to gross domestic product..., and \$138 billion (constant 2012\$) in government revenues by 2025.
- Growing natural gas use in the United States is not just about using more. The efficient use of natural gas and other forms of energy should continue to be a policy imperative. Cost-effectively increasing overall energy efficiency throughout the economy will require that energy policy, regulation, and consumer fuel choice be grounded in a full fuel-cycle analysis of energy requirements and costs. In many

- cases, increased use of natural gas to displace less efficient sources of energy may improve the overall energy efficiency of the economy.
- For many decades, natural gas regulation was based on an assumption of resource scarcity. These regulations need to be reevaluated in light of new realities. An opportunity now exists to redefine business models, regulatory policies, financial outreach, and technology innovation from a position of strong supply and expectations of long-term market price stability.
 - Significant regional diversity across U.S. energy markets precludes a one-size-fits-all approach to energy policy, regulation, and business models. Opportunities to increase natural gas's market share will vary by region and by state.
 - Bringing the benefits of natural gas to new markets will require investment in gas LDCs and their customers. In some cases, significant up-front costs may be required in order to realize fuel cost savings over many years into the future. New policies and regulations may be required to assure that gas LDCs recover their prudent investment costs and that high up-front costs do not deter consumers from making prudent fuel choices."

Source: IHS Inc. This content is extracted from IHS Energy *Fueling the Future with Natural Gas: Bringing It Home*. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content was approved in advance by IHS. Any further use or redistribution of this content is strictly prohibited without written permission by IHS. All rights reserved.

Utility Dive. 2014. *The State of the Electric Utility 2014*. Washington, DC: UtilityDive.com.
<http://app.assetdl.com/landingpage/siemens-2014-electric-utility-survey>.

A survey of more than 500 people in the utility industry was conducted in early 2014.

When asked what their three most pressing challenges were, 48% said old infrastructure, 32% said the current regulatory model, 31% listed an aging workforce, 30% said distributed generation, 28% indicated flat demand growth, 23% said smart-grid deployment, and 21% listed grid reliability. Other items listed were coal plant retirements (17%), renewable portfolio standards (17%), energy efficiency mandates (16%), emission standards (12%), and cybersecurity (11%).

In terms of electricity demand growth over the next five years, 7% expect a decrease in demand, 17% expect level demand, 55% expect minimal growth, and 21% forecast significant growth.

If there was low-to-no growth in electric sales in coming years, 65% said their utility would develop a new business model, 43% would invest in distributed generation, 33% would seek decoupling of electricity sales from profits, 26% would seek rate loss recovery mechanisms, and 4% would do nothing.

Eighty-three percent of respondents said their utility is planning to grow its energy efficiency programs over the next five years, whereas 81% said they plan to grow their demand response programs.

When asked what technology provides the most disruptive potential to your utility's business model, 53% listed distributed generation, 28% listed demand-side management, and 19% listed energy storage.

Regarding their views on distributed generation, 57% see it as an opportunity for utilities, 38% see it as a threat to utilities, and 5% see it as ultimately unimportant to utilities.

Regarding electric vehicles, 46% think utilities are missing an opportunity to deploy public charging stations, 37% feel that the opportunity is there and will not be missed, and 17% see no opportunity for utilities.

Finally, when asked if they anticipate their utility's regulatory model to change over the next ten years, 57% said yes, significantly; 38% said yes, minimally; and 5% answered no.

AEE (Advanced Energy Economy). 2013. "21st Century Electricity System CEO Forums."
<https://www.aee.net/initiatives/21st-century-electricity-system.html>.

Advanced Energy Economy and the MIT Industrial Performance Center have held a series of three forums so far to discuss the 21st-century electricity system. The forums have included some utility executives, but also many executives of other companies that are interested in doing more in the utility space. The overarching theme that has emerged is that utility business and regulatory model changes will be necessary to accelerate innovation and advanced energy deployment in order to meet the multiple challenges facing the industry.

Some of the suggestions that emerged were:

- Help advanced energy companies better understand the taxonomy of utility needs
- Assist regulators in encouraging innovation in the electric power sector. However, it was also noted that each state will decide its own path. "We're 50 different countries here," stated one participant. It was agreed that it will be much more feasible to align particular regions around common goals than to achieve national uniformity.
- Align business models and incentives so that innovation can create value for the full range of stakeholders and utilities can embrace it. It was noted that major mismatches currently exist between the low-risk, steady-return investment environment of the traditional utility and the higher-risk, higher-return requirements of innovative ventures. Returns are often too low to attract traditional venture capitalists, and risks are too high to attract traditional institutional investors. There is a need to identify new business models that can result in a win-win for advanced energy companies as well as utility companies. For example:
 - Explore the removal of caps on utility profits from advanced energy investment
 - Consider shared-savings models for new investments
 - Promote more opportunities between incumbents and innovators for profitable partnerships, including:
 - Risk sharing between load-serving entities and providers of new technologies and services
 - Ways for new ventures to access low-cost utility capital
 - Ways to address other regulatory barriers to innovation, such as requirements for nondiscriminatory rates and services and regulations governing market entrance

As a starting place, it may be useful to develop a shared strategic vision that enables load-serving entities, other market participants, and regulators to work toward solutions to well-defined challenges. Among the potential services discussed were:

- Innovation in retail services to meet differentiated customer needs. For example, will some customers pay more for higher-quality power, reduced risk of interruptions, or reduced emissions?
- Further (utility?) investments in solar and combined heat and power
- Services based on access to real-time customer end-use data

One view noted was that the challenges to utilities posed by distributed energy resources (DER) will not be addressed effectively by regulatory approaches such as decoupling and performance-based regulation, nor will forward integration by regulated utilities be an effective strategy with DER rolled into the rate base along with conventional assets. None of these approaches can solve utilities' basic dilemma of escalating costs and declining sales. In this view, what is needed is a right-sized (that is, smaller) core of regulated assets – primarily network assets – that can ensure universal service and enable the development of a vibrant competitive market in DER. In this model, utilities will retain opportunities for growth through their unregulated arm's-length affiliates.

In general, it was suggested multiple times that pilot projects be used to field-test new ideas and concepts, including new services, regulatory reforms, and so on.

a Paris, J. 2013. "The Economic and Political Consequences of the Last Ten Years of Renewable Energy Development." The Oil Drum. <http://www.theoil Drum.com/node/10227#more>.

This synopsis on renewable energy development in Europe over the past ten years found that high subsidies in the early years helped jump-start the market in Europe, but as subsidies were dropped, the industry was able to lower costs through new technology and a brutal price war. More recently, the costs of increased renewables have largely been absorbed by incumbent utilities, who are finding that their conventional power plants are being dispatched much less often due to the widespread presence of renewables, which have low operating costs and tend to set spot-market prices. Many intermediate and even baseload plants made money during the daytime when spot-market prices were high, but now that spot prices are down, the economics of conventional plants are weaker. Many utilities underestimated the amount of renewables available when they made decisions to build baseload or midload plants. In other words, the market changed in ways they did not foresee. A capacity market such as the one that exists in California will be needed to address this problem. Such a capacity market will help ensure that enough balancing capacity is built.

The author concludes:

- "Renewable energy is reaching the scale where it has an impact on the overall system; the effects are irreversible, and highly damaging to incumbents
- The net cost to get there has been relatively low, and largely paid for by utilities, which have constantly underestimated the ongoing changes, even as they were both (wrongly) dismissing them and (relatively ineffectively) fighting them
- There are legitimate worries about the way to maintain the fleet of flexible plants that was required in the past and will continue to be needed in the new paradigm, but can no longer pay its way under current market arrangements....
- The solution is not to fight renewables (it will not make the existing fleet go away), but to ensure that the right services (megawatts on demand) are properly remunerated
- The shale gas revolution will have a limited impact in this context...and does not change the economics of gas-fired plants to the point that they can be competitive in a system dominated by renewable energy production capacity
- More generally, the future for gas suppliers is bleaker than for gas turbine manufacturers – there will be a need for a lot of gas-fired plants, but they will not be burning a lot of gas (they will be selling megawatts rather than megawatt-hours)
- Overall, a future with high renewable penetration is not only possible, but increasingly likely."

Bazilian, M., M. Miller, R. Detchon, M. Liebreich, W. Blyth, M. Futch, V. Modi, L. Jones, B. Barkett, M. Howells, I. MacGill, D. M. Kammen, T. Mai, M. Wittenstein, S. Aggarwal, M. O'Malley, J. P. Carvallo, M. Welsch, G. Pugh, R. Weston, and D. J. Arent. 2013. "Accelerating the Global Transformation to 21st Century Power Systems." *Electricity Journal* 26(6): 39–51.

In this article, the authors stress the interconnectedness of global socioeconomic phenomena with the evolution of the technical needs of electric power systems, stating that "the socio-technical systems that comprise the electricity industry often evolve at a slower pace than other industrial sectors."

Investments in clean energy and end-use efficiency are viewed as key to improving grid resiliency. However, the electric power industry tends to prioritize least-cost, lowest-risk investments, which is currently a significant impediment to power system transformation. In developing economies, environmental quality, power quality, and fuel price volatility are often sacrificed in an effort to meet rapidly growing demand for infrastructure and services. This creates a growing need for the prioritization of "social objectives beyond those that have historically driven the development of the power sector."

The article predicts that future power systems will be particularly affected by the pace of technological and systemic innovation. The future low cost of renewable generation technologies, deep end-use efficiency measures, and major increases in the implementation of distributed generation will dramatically reshape the utility of the future. The electricity demand of industrialized nations will continue to level off. Conversely, demand for electricity and power system infrastructure in developing nations will undoubtedly increase. The proliferation of electric vehicles will also play a role in shaping the future electric utility landscape.

The authors state that these factors will empower customers to affect their energy consumption, as well as reduce geopolitical tension as competition for resources becomes less essential. Globally, health will improve as carbon emissions are reduced.

In order to accelerate power system modernization, the authors recommend the widespread adoption and implementation of these best practices:

- Self-tightening standards to improve energy efficiency (efficiency standards based on the best available technology)
- Government-run utility financing programs for investments in energy efficiency
- White certificates schemes and other market mechanisms to inspire energy efficiency
- Incentives for the installation of smart appliances
- Increased use of energy management systems
- Third-party markets for demand response
- Decoupling
- The adoption of market rules that encourage system flexibility
- Government renewable energy directives
- Implementation of smart-grid technologies
- Smart meters
- Advanced communication infrastructure between utilities, customers, and regulatory agencies

- Adoption of a systems approach to utility planning
- Transparency of model results and methods to increase trust
- Factoring in of risk calculations
- Improved power system governance and multilateral collaboration
- Balancing short-term operational changes with long-term power system dynamics, as well as interaction with other critical infrastructure, information systems, and social considerations
- Involving developing countries with international energy organizations
- Decentralizing decision making

Citi. 2013. *Energy Darwinism: The Evolution of the Energy Industry*.
<https://www.citivelocity.com/citigps/ReportSeries.action?recordId=21>.

In Citi's view, the global energy industry has been transformed in the last five years:

- The United States boasts \$3 shale gas.
- In Germany, leading utility owners have issued profit warnings as solar has driven some gas-fired power stations to run for less than 10 days a year.
- Japan has become the world's number-two solar market with the most attractive solar subsidies as gas is burning at \$16-17/million Btu.
- Uncertainty over commodity pricing and future utilization rates are leading developed markets to spend more on renewable capital expenditures than on conventional generation.
- But some markets are seeing greater demand for flexible gas-fired power plants due to renewables' intermittency.

Citi finds that large, capital-intensive, long-life conventional generation is not likely to be built under current remuneration structures. Utilization rates and prices cannot be counted on. Citi predicts continuing declines in utility electricity sales due to energy efficiency and more distributed generation, and suggests that these together could bring about more than a 50% decline in utilities' available market. Given this changing landscape, remuneration structures will likely need to be altered, and utilities probably will have to evolve into new types of companies. Utilities' options will depend on how they position themselves within a changing value chain.

Upstream, they could become decentralized energy and independent power producers. Distributed resources (solar, CHP, wind) could constitute 30-40% of residential and industrial demand. Renewables (onshore and offshore wind, biomass, hydroelectric), could become a large portion of centralized energy, perhaps covering 30-40% of demand. The remaining 20-40% of demand (some baseload and some for system backup) may be covered by conventional generation (nuclear, combined gas cycle turbines, coal).

Midstream, new opportunities lie in a super-smart grid. These include system stabilization (e.g., through battery storage), expanded e-mobility, district heating and local distribution networks, and common-interest initiatives (e.g., interconnections). For gas, opportunities include storage, interconnections, and liquid natural gas terminals.

Downstream, utilities may offer a variety of new services. They may:

- provide energy solutions (design, plan, install, operate, and/or maintain residential and industrial energy systems)
- install and maintain distributed generation
- maintain electric vehicle charging points
- contract as energy efficiency managers

Department of Energy (DOE). 2012. Visioning the 21st Century Electricity Industry: Outcomes and Strategies for America. Presentation to National Electricity Forum. February.
http://www.pserc.wisc.edu/documents/general_information/presentations/ofinterest/DRAFT%20DOE%20Vision%20of%20a%20Future%20Grid%20as%20of%2011.29.2011.pptx.

DOE's Grid Tech Team developed the following draft vision of the future grid (latest version at <http://www.doe.gov/oe/services/doe-grid-tech-team/vision-future-grid>).

A seamless, cost-effective electricity system, from generation to end use, capable of meeting all clean energy demands and capacity requirements, will include:

- Significant scaling up of clean energy (renewables, natural gas, nuclear, clean fossil)
- Universal access to consumer participation and choice (including distributed generation, demand-side management, electrification of transportation, and energy efficiency)
- Holistically designed solutions (including regional diversity, AC-DC transmission and distribution solutions, micro-grids, energy storage, and centralized-decentralized control)
- Two-way flows of energy and information
- Reliability, security (cyber and physical), and resiliency

DOE is working on the following issues:

- Renewables integration
- Smart grid
- Advanced modeling
- Cybersecurity
- Energy storage
- Power electronics and materials
- Institutional and market analyses

A March 2012 PowerPoint presentation summarizes work in each of these areas:

<http://energy.gov/sites/prod/files/Presentation%20to%20the%20EAC%20-%20Visioning%20the%2021st%20Century%20-%20William%20Parks.pdf>

Executive Office of the President. 2013. *A Policy Framework for the 21st Century Grid: Enabling Our Secure Energy Future*. Washington, DC: Executive Office of the President, National Science and Technology Council.

<http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf>.

From the foreword, with the addition of key actions within each pillar:

“A smarter, modernized, and expanded grid will be pivotal to the United States’ world leadership in a clean energy future. This policy framework focuses on the deployment of information and communications technologies in the electricity sector. As they are developed and deployed, these smart-grid technologies and applications will bring new capabilities to utilities and their customers. In tandem with the development and deployment of high-capacity transmission lines, which is a topic beyond the scope of this report, smart-grid technologies will play an important role in supporting the increased use of clean energy.

“A 21st-century clean energy economy demands a 21st-century grid. Much of the traditional electricity infrastructure has changed little from the original design and form of the electric grid as envisioned by Thomas Edison and George Westinghouse at the end of the 19th century. In a 21st-century grid, smart-grid technologies will help integrate more variable renewable sources of electricity, including both utility-scale generation systems such as large wind turbines and distributed generation systems such as rooftop solar panels, in addition to facilitating the greater use of electric vehicles and energy storage. Moreover, such technologies will help enable utilities to manage stresses on the grid, such as peak demand, and pass savings on to consumers as a result.

“The evolution toward a 21st-century grid is already taking place, such as a Recovery Act investment of \$4.5 billion for electricity delivery and energy reliability modernization efforts. In addition, policy direction was set forth in the Energy Independence and Security Act of 2007. This policy framework is designed to chart a path forward on the imperative to modernize the grid to take advantage of opportunities made possible by modern information, energy, and communications technology. This framework is premised on four pillars with several key actions within each pillar.

“1. Enabling cost-effective smart-grid investments

- a. States and federal regulators should continue to consider strategies to align market and utility incentives with the provision of cost-effective investments that improve energy efficiency
- b. The federal government will continue to invest in smart-grid research, development, and demonstration projects
- c. The federal government will continue to support information sharing from smart-grid deployments to promote effective cost-benefit investments and remove information barriers

“2. Unlocking the potential for innovation in the electric sector

- d. The federal government will continue to catalyze the development and adoption of open standards

- e. Federal, state, and local officials should strive to reduce the generation costs associated with providing power to consumers or wholesale providers during periods of peak demand and encourage participation in demand-management programs
- f. Federal and state officials should continue to monitor smart-grid and smart-energy initiatives to protect consumer options and prevent anticompetitive practices

“3. Empowering consumers and enabling them to make informed decisions

- g. State and federal policymakers and regulators should evaluate the best means of ensuring that consumers receive meaningful information and education about smart-grid technologies and options
- h. Building on recent efforts, state policymakers and regulators should continue to consider how to develop policies and strategies to ensure that consumers receive timely access to, and have control over, machine-readable information about their energy consumption in a standard format
- i. State and federal regulators should, in instances where a utility deploys the relevant infrastructure, consider means of ensuring that consumer-facing devices and applications make it easier for users to manage energy consumption
- j. State and federal regulators should consider, as a starting point, methods to ensure that consumers’ detailed energy usage data are protected in a manner consistent with Fair Information Practice Principles...and develop, as appropriate, approaches to address particular issues unique to energy usage
- k. State and federal policymakers and regulators should consider appropriately updating and enhancing consumer protections for smart-grid technologies

“4. Securing the grid.

- l. The federal government will continue to facilitate the development of rigorous, open standards and guidelines for cybersecurity through public-private cooperation
- m. The federal government will work with stakeholders to promote a rigorous, performance-based cybersecurity culture, including active risk management, performance evaluations, and ongoing monitoring

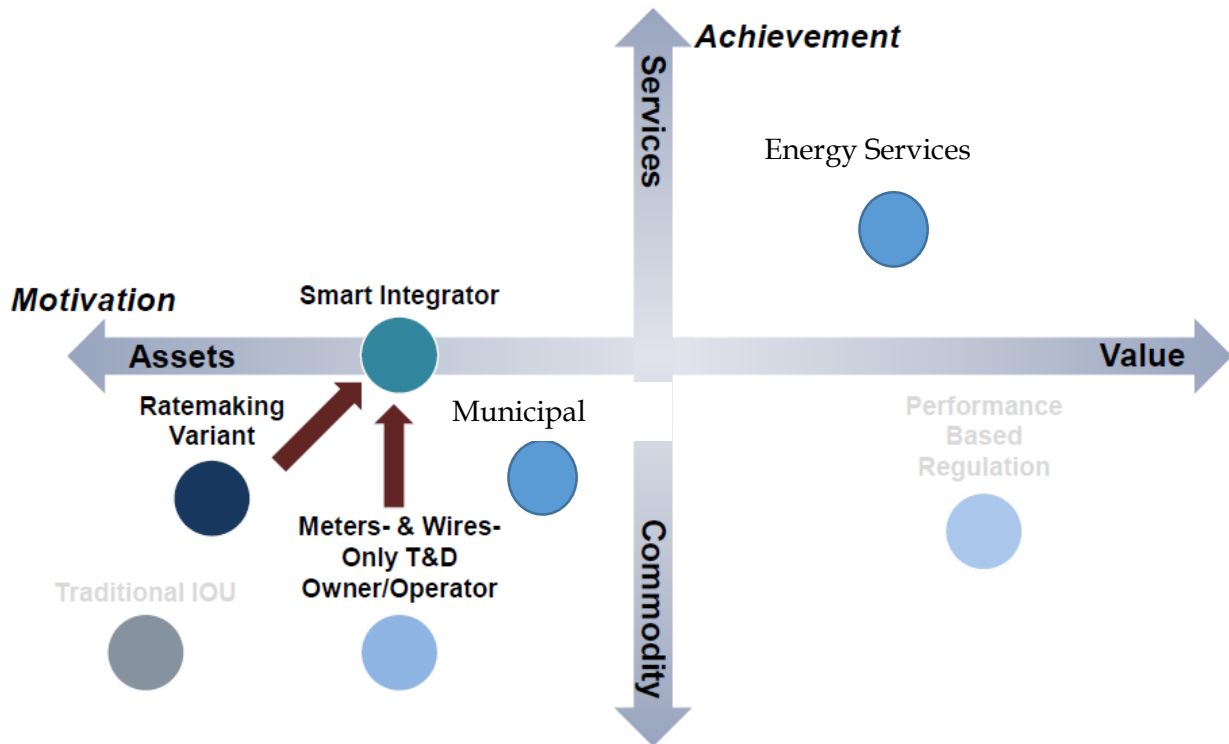
“Progress in all four areas, as part of an overall grid modernization effort, will require sustained cooperation between the private sector, state and local governments, the federal government, consumer groups, and other stakeholders. Such progress is important for the United States to lead the world in the 21st-century economy, be at the forefront of the clean energy revolution, and win the future by encouraging American innovation.”

Note: A February 2013 progress report on implementation of the framework can be found at http://www.whitehouse.gov/sites/default/files/microsites/ostp/2013_nstc_grid.pdf.

Goldman, C. A., A. Satchwell, P. Cappers, and I. M. Hoffman. 2013. *Utility Business Models in a Low Load Growth/High DG Future: Gazing into the Crystal Ball? PowerPoint Presentation*. April 10. Berkeley, CA: Lawrence Berkeley National Laboratory.

<http://emp.lbl.gov/publications/utility-business-models-low-load-growth-high-dg-future-gazing-crystal-ball>.

In this PowerPoint presentation, the authors note the growth of renewable generation and increased demand-side management (for example, projected savings of 0.76% per year by 2025 in Lawrence Berkeley National Laboratory’s medium case). The authors project that electricity rate increases are likely in the near future. They list a variety of organizations that are working on business model proposals, including proposals that are position driven, investment driven, and crisis driven. Several possible business models are discussed and presented along two continuums, as shown in the chart below.



Options for utility business models that were discussed in the presentation include:

- Rate-making variant: Implement lost revenue mechanisms to eliminate the “throughput incentive”; apply shareholder incentives to create positive profit motive
- Meters- and wires-only transmission and distribution owner/operator: Removing generation assets from the utility portfolio means the utility is indifferent to policy that affects the timing and quantity of generation expansion. Otherwise, it is same as traditional regulation.

- Performance-based regulation: Provides stronger incentives for cost containment and innovation, but can lead to dissatisfaction with audits and prudence reviews. The authors noted the new approach being used in the United Kingdom.
- Smart integrator: The utility is responsible for creating the infrastructure so all entities can readily integrate into all aspects of the smart-grid network. The smart-grid network should be open to all other service providers to maximize the value of the grid. It is unclear how the business model should be changed to motivate the utility to play this role.
- Energy service utility: Involves a fundamental pricing shift away from commodity sales (cost per kilowatt-hour) and toward services (for example, cooling). Services are priced to ensure an adequate rate of return on investments required to provide those services
- Fundamental shift in ownership to municipalization

In the presentation the authors state, “Utilities [are] likely to pursue other (incremental) strategies to mitigate ‘threats’ to their business model/revenues (for example, high customer charges, limit net metering) before proposing fundamental changes to regulatory compact.”

Harvey, H. and S. Aggarwal. 2013. *Overview: Rethinking Policy to Deliver a Clean Energy Future*. America's Power Plan. <http://americaspowerplan.com/the-plan/overview/>.

In this article, Harvey and Aggarwal stress the primacy of a clear policy signal in inspiring innovation in response to the rapidly changing face of the electric power industry. The authors submit that government regulation focused on adapting to the changing face of power system technologies is “required to drive efficiency and then switch to ever-greater proportions of clean power.”

As the nation's electric power system evolves, utilities will have more control on the demand side and less on the supply side. In order to ensure that this transition is functional, Harvey and Aggarwal assert that demand and supply resources must be optimized by rethinking system planning, investment, electricity markets, and system operations.

Supporting policies of this new policy signal must be “investment grade” to ensure affordability. This involves shifting risk to the parties that can best manage it. In addition, creating long-term certainty through policy supports investment, ensures stable prices, and allows open market access. Contract sanctity with creditworthy utilities, as well as timeliness and efficiency in system operations, are also mentioned as necessary attributes of an investment-grade policy scheme.

Regardless of what structure is created through a new or amended regulatory framework, the authors believe that system planners have three main tenets to uphold: high system reliability, reasonable costs, and strong environmental performance.

What is necessary to support these three tenets is policy designed with long-term signals in mind, structured to be transparent, and fostered along strong lines of communication between regulatory agencies and utilities. Long-term planning is indispensable to offering utilities confidence in their investments. Additionally, regulations should be drafted to incentivize innovation and efficiency, while also properly valuing both generation and demand-side resources to determine the right mix for system optimization. Harvey and Aggarwal also state that new ancillary services must be valued as the grid modernizes (non-energy grid services).

In order to ensure that the regulatory framework addresses the needs of an ever-evolving power industry, the authors suggest the following eight policies:

1. “Move away from rate-of-return regulation; use performance-based regulation that gives utilities the freedom to innovate or call on others for specific services. Separate the financial health of the utility from the volume of electricity it sells.
2. Create investor certainty and low-cost financing for renewable energy by steadily expanding renewable electricity standards to provide a long-term market signal.
3. 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. Set a clear methodology for allocating all costs and benefits.
4. Ensure that all markets (such as energy, ancillary services, capacity) and market makers (such as utilities) include both demand- and supply-side options. All

- options—central and distributed generation, transmission, efficiency, and demand-response—should compete with one another to provide electricity services.
5. Employ electricity markets to align incentives with the desired outcomes, such as rewarding greater operational flexibility. Open long-term markets for new services such as fast-start or fast-ramping.
 6. Before investing in technical fixes to the grid, first make operational changes that reduce system costs, enable more renewables, and maintain reliability. For example, coordinate between balancing areas, dispatch on shorter intervals, and use dynamic line rating to make the most of existing transmission lines.
 7. Mitigate investor risk by adopting stable, long-term policies and regulations with low impact on the public budget. Financial policies should be predictable, scalable, affordable to public budgets, and efficient for investors.
 8. Reduce siting conflicts by using explicit, preset criteria; ensuring access to the grid; respecting landowner rights; engaging stakeholders early; coordinating among regulatory bodies; and providing contract clarity.”

Hogan, M. 2013. "Aligning Power Markets to Deliver Value." *Electricity Journal* 26 (8): 23–34.
<http://www.sciencedirect.com/science/article/pii/S1040619013001930>.

This report was written with the express intention of laying out an array of measures market authorities can take to enable markets and market institutions to deliver gains in energy efficiency, higher shares of renewable electricity, and the system services required to support a modern electricity mix.

Drawing from the National Renewable Laboratory's *Renewable Electricity Future Study*, Hogan outlines five "critical success factors that can be facilitated by changes to markets and market institutions." These key factors are necessary to enable a smooth transition to the electric power sector of the future, one in which renewable energy makes up 80% of the electric power sector:

1. Increased investment and deployment of energy efficiency: Low-cost, supply-side energy efficiency measures will drive the cost-effective implementation of renewable energy. In order to be effective, energy efficiency must be driven by policy and programs.
2. Reduce market area fragmentation: The benefits of balancing supply and demand over larger regions far outweigh the costs of integration. These benefits include better access to high-quality sources of renewables, less aggregate variability in supply and demand, lower integration costs due to better use of transmission, and risk mitigation from both resource and market diversification.
3. Improve operational flexibility: Flexibility can reduce the need for backup capacity and transmission expansion. Also, operational flexibility reduces the need to curtail renewable production during periods of low demand and high renewable supply.
4. Invest in greater resource flexibility.
5. Make way for continued deployment of commercial renewable energy technologies.

Additionally, Hogan delineates three categories of market design adaptations that can be implemented to allow the market to evolve with the implementation of increasing renewable energy technologies:

1. Recognize the value of energy efficiency: Wholesale markets should drive energy efficiency by rewarding more efficient production and system operations. Hogan suggests factoring transmission and distribution losses into delivered energy prices. Energy efficiency should play a role in capacity markets and standard capacity values should be set for a menu of standard energy efficiency measures.
2. Upgrade grid operations to unlock flexibility in the short term: Grid scheduling, dispatch, and weather forecasting should all be upgraded to allow for more flexible and reliable system operations. The consolidation of balancing areas will be necessary, as well as expanding the role of demand response.
3. Upgrade investment incentives to unlock flexibility in the long term: It will be pertinent to develop tools to better forecast net demand and the value of various forms of flexibility. In regulated markets, existing generators' flexibility should be surveyed, and, when it becomes valuable to do so, investments should be made in low-cost options to increase the flexibility of existing generation. Hogan suggests adapting forward investment mechanisms to capture the value of certain resource

capabilities. Also, forward markets for specific system services and time shifting services should be adopted, and new market entrants should be encouraged whenever possible.

IEI (Institute for Electric Innovation). 2013. *Innovations Across the Grid; Partnerships Transforming the Power Sector*. Washington, DC: Edison Foundation Institute for Electric Innovation. http://www.edisonfoundation.net/iei/Documents/InnovationsAcrossTheGrid_LoRes_InstElcInnv.pdf.

This book, published by the Edison Foundation's Institute for Electric Innovation, details nearly 70 projects led by utilities and technology companies that are transforming how we deliver, manage, and use electricity. The focus of the book is to illustrate how putting entrepreneurial thinking, new technology, and engineering know-how to work are optimizing grid resources on both the supply and the demand sides of the electric meter. Case-study projects referenced in the book are placed into one of seven categories:

1. "Grid edge optimization: Increasing visibility at the edges of the traditional electricity distribution network to improve service reliability and increase grid efficiency." Includes Volt/VAR optimization and conservation voltage reduction.
2. "Grid resiliency, reliability, and restoration: Making the grid less vulnerable to weather-related outages and reducing the time it takes to restore power after an outage does occur." Includes distribution automation equipment that reroutes the flow of electricity and isolates an outage to a small line section so that fewer customers are disrupted.
3. "Grid visibility and asset management: Deploying distribution automation and advanced metering infrastructure, and linking systems to improve asset management and the operational efficiency of electric distribution systems.
4. Grid analytics: Using information from smart meters, grid sensing devices, and asset monitoring for end-to-end data analytics to optimize the transmission and distribution systems and improve grid performance.
5. Renewable energy, distributed generation, and storage integration: Integrating distributed generation resources into the power grid, deploying micro-grids, and utilizing electrical energy storage devices effectively in a robust, flexible, and reliable grid.
6. Customer engagement: Educating and empowering electric utility customers to manage their energy use more strategically and efficiently.
7. Demand response and energy management: Using technology to simplify and automate customer involvement in peak demand response events, and using demand response to manage renewable energy integration."

Scalise, J. 2013. "The Business Model for the Electric Utility of the Future." Presentation to the California Public Utilities Commission, San Francisco, Ca., October 8, 2013.
<http://www.cpuc.ca.gov/NR/rdonlyres/932AC939-CAC7-43E3-BF06-61D5E90FCC25/0/1ScaliseCPUcCenbanc1082013.pdf>

This presentation, delivered at a California Public Utilities Commission workshop, discusses the current California utility industry and the disruptive forces it faces. In the presentation, three possible business models for the future are considered, which are summarized in the slide below. Scalise said he preferred the last model.

Comparative business models

	VERTICAL INTEGRATION	DECOUPLED MONOPOLY	RETAIL COMPETITION
	Utility as single generator and deliverer of energy to captive ratepayers	Utility as deliverer of competitively sourced energy to captive ratepayers	Utility as grid operator with both wholesale and retail competition
<i>Economics</i>			
Competition	<i>Lowest system cost</i>	<i>Wholesale market; artificial at retail</i>	<i>Where technology allows</i>
Choice	<i>Constrained output</i>	<i>Commission designed</i>	<i>Increased 'output' at lower prices</i>
<i>Equity</i>			
Customers	<i>Commission controlled cross-subsidies</i>	<i>Rational to defect</i>	<i>Explicit incentives</i>
Competitors	<i>Non-franchise capital prohibited</i>	<i>Discrimination across participants</i>	<i>Free enterprise access</i>
<i>Robustness</i>			
Disruption	<i>Socialized responsibility</i>	<i>Fragile to regulatory risk</i>	<i>Private sector assumption of risk</i>
Innovation	<i>Commission driven</i>	<i>Commission as referee</i>	<i>Commission (grid) and market (energy) driven</i>

UBS Utilities. 2013. *Renewables: Threat to Traditional Gen.* UBS Investment Research: Electric Utilities. November 15.

UBS Utilities. 2013. Email: "EEI 2013: Full Takeaways." November 13.

UBS predicts significant growth in renewables and the widespread adoption of energy efficiency and renewable energy initiatives. Contributing factors include:

- State renewable portfolio standards (RPSs)
- A rush to meet wind production tax credit grandfather requirements by end of 2013
- Continued improvement of dispatch factors on new wind technologies
- Continued sharp decline in cost of solar voltaics

According to UBS, growth in wind and solar will offset coal retirements and will lower wholesale power prices. Renewable growth to meet RPSs will exceed demand growth by 62 TWh. Due to RPSs and energy efficiency initiatives, this supply/demand imbalance will lead to increased pressure for baseload coal and nuclear retirements.

UBS suggests that energy efficiency initiatives have broken the historical link between electric load demand and economic growth. Annual load growth has declined to 1.0-1.5% as compared to the 3% of GDP growth typical since the 1970s. UBS expects this slowdown in load growth to continue.

According to UBS, almost all companies at the 2013 Edison Electric financial conference planned to significantly expand their involvement in electric transmission. Another theme was the potential for rising rates and cautious optimism about rising returns on equity. Many attendees were focused on proactively addressing their rate tariffs in light of distributed generation developments. UBS is surprised that more utilities are not pursuing renewable investments.

World Energy Council. 2013. *World Energy Scenarios: Composing Energy Futures to 2050*. <http://www.worldenergy.org/publications/2013/world-energy-scenarios-composing-energy-futures-to-2050>.

This is a set of worldwide scenarios and is not focused on utility issues, but some of their broad findings and insights are applicable to the future of the utility industry. In this study, they construct two scenarios that they title “jazz” and “symphony.” These are summarized as follows:

Jazz	Symphony
World where there is a consumer focus on achieving energy access, affordability, and quality of supply with the use of best available energy sources.	World where there is a voter consensus on driving environmental sustainability and energy security through corresponding practices and policies.
Main players are multi-national companies, banks, venture capitalists, and price-conscious consumers.	Main players are governments, public sector and private companies, NGOs, and environmentally minded voters.
Technologies are chosen in competitive markets.	Governments pick technology winners.
Energy sources compete on basis of price and availability.	Selected energy sources are subsidised and incentivised by governments.
Higher GDP growth due to faster convergence across countries, higher international competition, and low environmental constraints.	Lower GDP growth due to less convergence, more environmental constraints and a more capital-intensive growth pathway
Free-trade strategies lead to increased exports.	Nationalistic strategies result in reduced exports/imports.
Renewable and low-carbon energy grows in line with market selection.	Certain types of renewable and low-carbon energy actively promoted by governments.
In the absence of international agreed commitments carbon market grows more slowly from bottom up based on regional, national and local initiatives.	Carbon market is top down based on an international agreement, with commitments and allocations.

They find that economic growth is likely to be a little higher under jazz (3.54% vs. 3.06% compound annual growth rate to 2050), but that energy use and carbon emissions will also be higher. Under jazz, new energy supplies will be mostly gas and other conventional supplies.

Under symphony, with more government support, there will be more nuclear, renewables, carbon capture and storage, and use of energy efficiency.

Key messages from the scenarios are:

1. Energy system complexity will increase by 2050.
2. Energy efficiency is crucial in dealing with demand outstripping supply.
3. The energy mix in 2050 will mainly be fossil based.
4. Regional priorities differ: there is no “one size fits all” solution to the energy trilemma (which is how to balance energy security, energy equity, and environmental sustainability)
5. The global economy will be challenged to meet the 450-parts-per-million target for CO₂ concentrations in the atmosphere without unacceptable carbon prices.
6. A low-carbon future is linked to not only renewables; carbon capture and storage is important and consumer behavior needs to change.
7. Carbon capture and storage technology, solar energy, and energy storage are the key uncertainties up to 2050.
8. Balancing the energy trilemma means making difficult choices.
9. Functioning energy markets require investments and regional integration to deliver benefits to all consumers.
10. Energy policy should ensure that energy and carbon markets deliver.

Lacy, V., R. Matley, and J. Newcomb. 2012. *Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future*. Snowmass, CO: Rocky Mountain Institute.
http://www.rmi.org/Knowledge-Center/Library/2012-02_PGENetZero.

Adapted from the executive summary with permission:

“Based on publically announced power purchase agreement (PPA) contracts, the California Solar Initiative goals, and Gov. Jerry Brown’s targets for distributed renewables, one-fourth of the total new investments in generating capacity in Pacific Gas and Electric’s service territory between 2012 and 2020 could come on the customer’s side of the meter, largely in the form of rooftop solar photovoltaic (PV) systems. In parallel with these trends, growing numbers of buildings, campuses, and communities will be exporting and importing electricity to and from the grid, bringing fundamental changes to the relationship between these customers and the utility.” In addition, the state has long been a leader in investments in energy efficiency, as well as smart-grid deployment.

“If this emerging system is to sustainably achieve societal goals for the electricity system – providing reliable and resilient energy services at reasonable cost while meeting standards for fairness and environmental stewardship – then the decisions and behaviors of utilities and their customers must be harmonized to an unprecedented degree.... Overall, the effectiveness of a utility’s role in conducting the orchestra of distributed energy resources that interact with its system will be a critical factor in achieving favorable outcomes for all stakeholders. And the long-term health and stability of the electricity grid will be essential to making such a system work.

“Existing utility rate structures and business models...are poorly adapted to this new environment.... Rate structures and incentives designed to stimulate the early adoption and scale-up of rooftop solar systems, electric vehicles, and other new technologies and design approaches will need to be modified over time, as adoption rates increase. New technologies and design practices call for new approaches to managing utility operations and pricing electricity services to accurately reflect benefits and costs of distributed resources and provide a sustainable path for the increased deployment of these resources....

“Rocky Mountain Institute and PG&E convened a roundtable composed of leading policy experts and industry and customer representatives.... [The] participants agreed that three key building blocks will be essential in developing solutions to the challenges discussed.

1. *“Identify and measure impacts, costs, and values of distributed energy resources.*
 Building a shared understanding among stakeholders in the electricity industry of the full range of costs and benefits of distributed resources is an essential first step toward devising the business strategies, rates, and incentives that will create the greatest benefit for all.... Experience with high penetration of distributed generation, especially solar PV, is limited, and many questions remain about (a) the types of costs and benefits that may be incurred, (b) the magnitude of these costs and benefits, and (c) the degree to which these costs and benefits may be influenced by utility rates and other incentives.... More rigorous analysis is needed....

2. *“Remedy misalignments between economic incentives to customers and the cost and value to the system provided by distributed resources.*

Existing rates and incentives fail to provide accurate economic signals to align distributed generation investment with system costs and benefits over the long term. Retail net energy metering, combined with tiered volumetric rates does not provide a sustainable long-term business model for electric utilities, nor does it provide accurate price signals for customers. 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.... These solutions could require fundamental changes in existing non-time differentiated tiered rate structures.... Given the right price signals, distributed generators can adapt over the long term to provide new sources of value to the utility system....

3. *“Adapt utility business models to create and sustain value in a future characterized by higher levels of efficiency and increased deployment of distributed resources.*

Utilities have important and valuable roles as enablers and integrators in the deployment and operation of distributed resources. However, proliferation of distributed energy resources poses challenges to existing utility business models and regulatory structures, whose basic tenets were designed under a production and delivery model dominated by centralized generation and one-way distribution.... Utilities must develop new ways of pricing the network services they provide and of promoting value creation through distributed resource development. However, they expressed differing views about how California’s regulated utilities might best adapt to a future with increasing shares of distributed generation resources. Two approaches were discussed:

- a. *“Incentive regulation approach: An “incentive regulation” approach that would allow the utility a more expansive role in managing and, potentially, investing in distributed resources as a tool for reducing costs.*
- b. *Network utility approach: A ‘network utility’ approach under which the utility would provide highly differentiated price signals to incent customers to provide the highest value energy supply, load management, or ancillary services to the utility system.”*

Small, F., and L. Frantzis. 2010. *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*. Boston: Ceres. <https://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1>.

In the Executive Summary of this report from Ceres, the authors outline three fundamental challenges utilities face in deploying clean energy resources on a large scale:

1. A lack of sufficient regulatory support
2. A business model based on electricity sales, which would be eroded by energy efficiency and distributed clean energy resources
3. A limited electricity delivery infrastructure, which may limit the amount of clean energy resources that can be integrated without compromising reliability or increasing cost excessively

Faced with these challenges, five key elements necessary to yield successful, financially solvent U.S. utilities in the 21st century are identified:

1. Successful utilities will effectively manage carbon emissions in the face of tightening federal air-quality regulation. Utilities will need to account for carbon emission costs in resource planning and align those costs and risks with likely carbon-reduction scenarios.
2. Pursue all cost-effective energy efficiency
3. Integrate cost-effective renewable energy resources into the generation mix, including distributed generation
4. Incorporate smart-grid technologies for consumer and environmental benefit. This will include technologies such as smart metering, distribution automation, and synchrophasor monitoring.
5. Effective utilities in the 21st century will need to conduct “robust and transparent” resource planning that takes into account the risks, probabilities, benefits, impacts, and applications of multiple energy resources under various scenarios.

The authors state that in order to ensure the successful evolution of electric utilities, mandatory regulatory policies will be needed to encourage and incentivize innovation. State governments and utility regulatory commissions will need to align clean energy goals across government agencies and make a deliberate commitment to the adoption of clean energy resources. Renewable portfolio standards, as well as energy efficiency resource standards, will be necessary to incentivize compliance, provide clear market signals for utilities, and reward those parties that deliver results. Additionally, revenue decoupling is essential to remove “utilities’ inherent disincentive to implement large-scale energy efficiency.” Lastly, Small and Frantzis iterate the major role net metering will play in facilitating consumer investment in onsite renewable energy generation, as well as the need for incentive rate making for utilities to provide premium returns on investments in clean energy technologies.

DOE (U.S. Department of Energy). 2003. *“Grid 2030”: A National Vision for Electricity’s Second 100 Years*. Washington, DC: U.S. Department of Energy.
<http://energy.gov/oe/downloads/grid-2030-national-vision-electricity-s-second-100-years>.

Adapted from the executive summary:

“Major Findings

- “America’s electric system, ‘the supreme engineering achievement of the 20th century,’ is aging, inefficient, and congested, and incapable of meeting the future energy needs of the information economy without operational changes and substantial capital investment over the next several decades.
- Unprecedented levels of risk and uncertainty about future conditions in the electric industry have raised concerns about the ability of the system to meet future needs. Thousands of megawatts of planned electric capacity additions have been cancelled. Capital investment in new electric transmission and distribution facilities is at an all-time low.
- The regulatory framework governing electric power markets – both at the federal and state levels – is also under stress. Efforts to loosen regulations and unleash competition have generally fallen short of producing their expected results.
- There are several promising technologies on the horizon that could help modernize and expand the nation’s electric delivery system, relieve transmission congestion, and address other problems in system planning and operations. These include advanced conductors made from new composite materials and high-temperature superconducting materials, advanced electric storage systems such as flow batteries or flywheels, distributed intelligence and smart controls, power electronics devices for AC-DC conversion and other purposes, and distributed energy resources including on-site generation and demand management.
- The revolution in information technologies that has transformed other network industries in America (such as telecommunications) has yet to transform the electric power business. The proliferation of microprocessors has led to needs for greater levels of reliability and power quality. While the transformation process has begun, technological limitations and market barriers hinder further development.
- It is becoming increasingly difficult to site new conventional overhead transmission lines, particularly in urban and suburban areas experiencing the greatest load growth. Resolving this siting dilemma, by a) deploying power electronic solutions that allow more power flow through existing transmission assets and b) developing low-impact grid solutions that are respectful of land-use concerns, is crucial to meeting the nation’s electricity needs.

“Conclusions

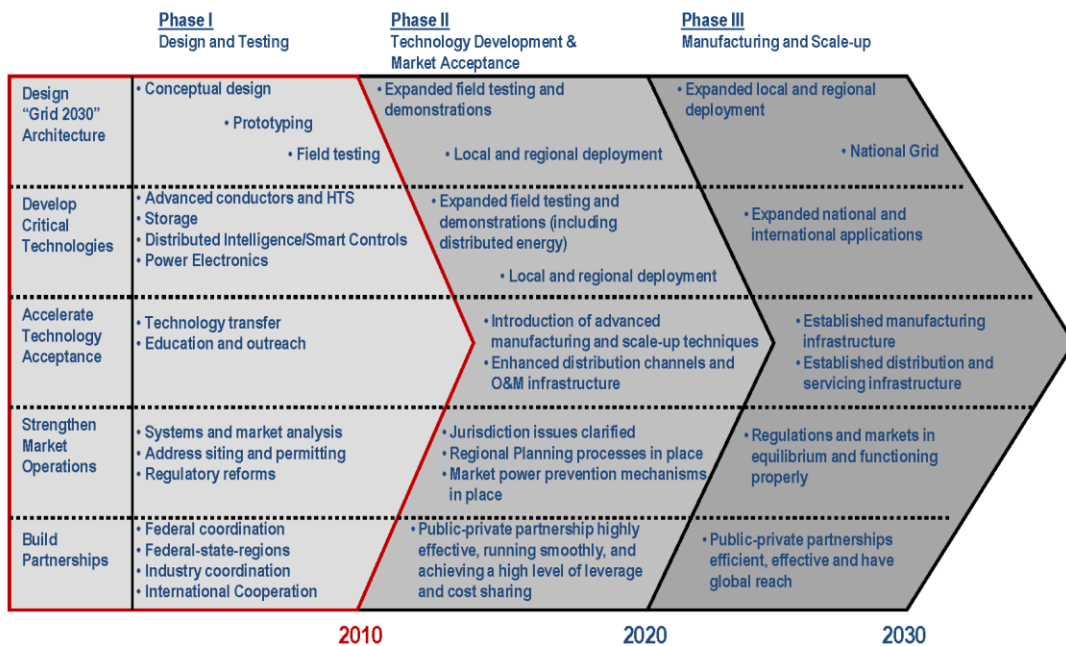
- “The technology readiness of critical electric systems needs to be accelerated, particularly for high-temperature superconducting cables and transformers, lower-cost electricity storage devices, standardized architectures and techniques for distributed intelligence and smart power systems, and cleaner power generation systems, including nuclear, clean coal, renewable, and distributed energy devices such as combined heat and power.
- A breakthrough is needed to eliminate the political log jam and reduce the risks and uncertainties caused by today’s regulatory framework. This includes clarifying

intergovernmental jurisdiction, establishing ‘rules of the road’ for workable competitive markets wherever they can be established, ensuring mechanisms for universal service and public purpose programs, and supporting a stable business climate that encourages long-term investment.

- The industry will be investing billions of dollars over the next several decades to replace electric power equipment. The economic life of this new equipment will last 40 years or more, so this turnover of the nation’s capital stock of electric power assets needs to include the latest technologies to ensure clean, efficient, reliable, secure, and affordable electricity for generations to come. An expanded research, development, and deployment effort is paramount.
- A logical next step is the collaborative development of a *National Electric Delivery Technologies Roadmap*.”

The roadmap was subsequently prepared and is summarized in the following slide).

Grid 2030 Roadmap (2003)



Adapted from US DOE Office of Electric Transmission and Distribution, "National Electric Delivery Technologies Roadmap: Transforming the Grid to Revolutionize Electric Power in North America", January 2004 (available at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/ER_2-9-4.pdf).

TRANSMISSION, DISTRIBUTION, AND INFRASTRUCTURE

EPRI (Electric Power Research Institute). 2014. *The Integrated Grid. Realizing the Full Value of Central and Distributed Energy Resources*. Palo Alto, CA: Electric Power Research Institute. <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733>.

From the executive summary with permission:

“The electric power system has evolved through large, central power plants interconnected via grids of transmission lines and distribution networks that feed power to customers. The system is beginning to change – rapidly in some areas – with the rise of distributed energy resources (DER) such as small natural gas–fueled generators, combined heat and power plants, electricity storage, and solar photovoltaics (PV) on rooftops and in larger arrays connected to the distribution system. In many settings DER already have an impact on the operation of the electric power grid. Through a combination of technological improvements, policy incentives, and consumer choices in technology and service, the role of DER is likely to become more important in the future.

“The successful integration of DER depends on the existing electric power grid. That grid, especially its distribution systems, was not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from central power stations. To realize fully the value of distributed resources and to serve all consumers at established standards of quality and reliability, the need has arisen to integrate DER in the planning and operation of the electricity grid and to expand its scope to include DER operation – what EPRI is calling *the integrated grid*.

“The grid is expected to change in different, perhaps fundamental ways, requiring careful assessment of the costs and opportunities of different technological and policy pathways. It also requires attention to the reality that the value of the grid may accrue to new stakeholders, including DER suppliers and customers.

“This paper is the first phase in a larger EPRI project aimed at charting the transformation to the integrated grid. Also under consideration will be new business practices based on technologies, systems, and the potential for customers to become more active participants in the power system. Such information can support prudent, cost-effective investment in grid modernization and the integration of DER to enable energy efficiency, more responsive demand, and the management of variable generation such as wind and solar.

“Along with reinforcing and modernizing the grid, it will be essential to update interconnection rules and wholesale market and retail rate structures so that they adequately value both capacity and energy. Secure communications systems will be needed to connect DER and system operators. As distributed resources penetrate the power system more fully, a failure to plan for these needs could lead to higher costs and lower reliability.

“Analysis of the integrated grid...should not favor any particular energy technology, power system configuration, or power market structure. Instead, it should make it possible for

stakeholders to identify optimal architectures and the most promising configurations—recognizing that the best solutions vary with local circumstances, goals, and interconnections.

“Because local circumstances differ, this paper illustrates how the issues that are central to the integrated grid are playing out in different power systems. For example, Germany’s experience illustrates consequences for price, power quality, and reliability when the drive to achieve a high penetration of distributed wind and PV results in outcomes that were not fully anticipated. As a result, German policymakers and utilities now are changing interconnection rules, grid expansion plans, DER connectivity requirements, wind and PV incentives, and operations to integrate distributed resources.

“In the United States, Hawaii has experienced a rapid deployment of distributed PV technology that is challenging the power system’s reliability. In these and other jurisdictions, policymakers are considering how best to recover the costs of an integrated grid from all consumers that benefit from its value.

“Action Plan

“The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial character of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. “Interconnection Rules and Communications Technologies and Standards
 - *Interconnection rules* that preserve voltage support and grid management
 - *Situational awareness* in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
 - Robust *information and communication technologies*, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cybersecurity
 - *A standard language and a common information model* to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems
2. Assessment and Deployment of Advanced Distribution and Reliability Technologies
 - *Smart inverters* that enable DER to provide voltage and frequency support and to communicate with energy management systems
 - *Distribution management systems and ubiquitous sensors* through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time
 - *Distributed energy storage and demand response*, integrated with the energy management system
3. Strategies for Integrating DER with Grid Planning and Operation
 - *Distribution planning and operational processes* that incorporate DER
 - *Frameworks for data exchange and coordination* among DER owners, distribution system operators (DSOs), and organizations responsible for transmission planning and operations

- Flexibility to *redefine roles and responsibilities* of DSOs and independent system operators

4. Enabling Policy and Regulation

- *Capacity-related costs* must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
- *Power market rules* that ensure long-term adequacy of both energy and capacity
- *Policy and regulatory framework* to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
- *New market frameworks* using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs”

CSIRO, Australia. 2013. *Change and Choice: The Future Grid Forum's Analysis of Australia's Potential Electricity Pathways to 2050*. <http://www.csiro.au/Organisation-Structure/Flagships/Energy-Flagship/Future-Grid-Forum-brochure.aspx>.

CSIRO is Australia's national science agency. Australia has experienced large electric-rate increases in recent years, with household electricity prices increasing from about 15 cents (Australian) per kilowatt-hour in 2007 to over 25 cents in 2012. The largest contributing factor is large investments in the electricity distribution system to replace and refurbish it and improve its reliability. Many are now questioning whether reliability standards have been set too high. Electricity use and peak demand have begun to decline in most states, and deployment of solar panels has become widespread. Many states as well as the federal government are interested in substantially reducing emissions of greenhouse gases. The Smart Grid Forum convened 120 representatives from all sectors of the electricity industry, as well as from the government and the community, and developed four scenarios for the future. The scenarios are premised on sustained low demand for centrally supplied electricity, the need for significant greenhouse gas abatement, the likely advent of low-cost electricity storage, and increased consumer choice enabled by new business and pricing models and increased consumer engagement. The four scenarios are:

1. Set and forget: Widespread use of automated load management, with consumers choosing their settings
2. Rise of the prosumer (producer-consumer): Widespread adoption of onsite generation, which is projected to be supplying nearly half of consumption by 2050, but most consumers remain on the grid
3. Leaving the grid: Many consumers disconnect from the grid in 2030 and beyond, driven by high grid prices, increased availability of storage options, and the desire to be independent
4. Renewables thrive: Centralized renewables ramp up and by 2050, centralized and onsite renewables generate 86% of consumption

In all the scenarios, electricity prices go up, but roughly in line with income. However, scenarios 1 and 3 result in slightly lower bills in 2050 as a percentage of income than was the case in 2013, scenario 4 results in a modest increase, and scenario 2 yields a more significant increase (from 2.5% to 2.9% of income). Energy efficiency is part of all four scenarios, with annual improvements in the residential and commercial sectors of 0.3% per year in scenarios 1 and 2, and 0.7% per year in scenarios 3 and 4. Industrial efficiency was not included. The forum discussed many possible reactions to these scenarios and recommended four actions:

1. Implementing a long-term program to increase consumer awareness of electricity pricing and demand management
2. Reviewing Australia's electricity consumer social safety net (since electricity prices will continue to increase)
3. Developing bipartisan agreement on Australia's long-term greenhouse gas emissions reduction target and implementation, so that the electricity industry can respond to the challenge in the most efficient way
4. Identifying any changes that might be required in market and regulatory frameworks.

Jimison, J. W., and B. White. 2013. "Transmission Policy: Planning for and Investing in Wires." *Electricity Journal* 26 (8): 109–124.
<http://www.sciencedirect.com/science/article/pii/S1040619013001899>.

Adapted from the introduction with permission:

"The cost of moving power from here to there remains the smallest part of the typical consumer electric bill – about 11% on average – compared with two-thirds of the bill for generation and a quarter for distribution. Importantly, needed investments in transmission can frequently be more than paid for by savings in energy costs the new capacity makes possible.

"High-voltage transmission lines make the grid more efficient and reliable by alleviating congestion, promoting bulk-power competition, reducing generation costs, and allowing grid operators to balance supply and demand over larger regions. And these considerations will be ever more important in a high-renewable energy scenario.

"The primary barriers to building new high-voltage lines and optimizing the grid are not so much technical or economic but rather bureaucratic. Inefficient *institutions* and insufficient *policies* are the key factors preventing the United States from accessing its rich resources of clean energy, and spreading that wealth throughout the economy. Currently, the main obstacles include:

- Disputes over how to allocate or share costs for new lines among rate payers in different subregions of the electric grid
- Concerns over whether the costs of new high-voltage transmission lines will outweigh benefits for rate payers, and whether the cost of new lines will unfairly be allocated to customers who will not benefit from them
- Concerns related to the impact of siting the lines, including environmental and cultural impacts, and compensation to landowners, as well as inconsistent and uncoordinated state policies on transmission line siting
- Failure to accord proper weight to the clean nature of renewable energy in much of the country

"Throughout the United States, [a variety of] recent developments have favored the rapid growth of new transmission investments that are easing the transition to a higher renewable energy scenario:

- Renewable energy sources such as solar and wind are rapidly falling in price
- Recent federal actions...and the growth in the number of independent system operators mean more competition and less risk in the market for new transmission, stimulating new investments
- More industry actors are recognizing the multiple benefits of planning and sharing transmission over larger regions, reducing the number of separate balancing areas where utilities are required to balance internal generation with internal demand at all times

“Transmission planners must also account for the rapid growth of demand-side resources, such as demand-response, energy efficiency, distributed generation, storage, and smart-grid technologies that have reduced the required new transmission capacity from the massive amounts that would be necessary if such demand-side resources were not available. Transmission planners must evaluate how these resources may affect the need for specific transmission investments, their timing, and the capacity of the grid to reliably and cost-effectively achieve high levels of renewable integration. While demand-side resources are unlikely to substitute for transmission investments needed to access remote high-quality renewable resources, serve high-voltage loads, maintain regional power quality, or expand balancing areas, they are likely to mitigate variability and reduce the need for balancing generation. Moreover, a planning process that fully considers demand-side resources will build confidence in and broaden support for any new transmission investments [that] are identified....

“Investment in high-voltage transmission has increased in every region of the country over the past decade, most rapidly in regions with linked planning and cost allocation processes operating across large geographic regions (such as Midcontinent Independent System Operator and Southwest Power Pool).

“Several wildcards could have important impacts on transmission planning and build-out in the coming years:

- “Dramatic cost reductions in offshore wind, distributed generation, or bulk electricity storage
- Development of cost-effective DC circuit breakers
- Broad adoption of new technologies that allow the transmission system to be operated more efficiently, such as synchrophasors and dynamic line rating
- Accelerated use of cost-effective and efficient grid operational practices, such as intrahour transmission scheduling, improved wind and solar forecasting, dynamic transfers of variability between balancing areas, real-time path ratings, and improved reserve sharing
- Dismantling state and local barriers to a more integrated, competitive, and cost-effective transmission system”

Based on their review of the many issues affecting transmission, the authors make several policy recommendations:

1. Assess and communicate the benefits of transmission expansion
2. Prioritize interregional lines that link balancing areas
3. Harmonize grid operations and increase competition in electricity markets
4. Slash the timeline for planning, building, and siting transmission
5. Make the most of the lines once they are built

Massachusetts Department of Public Utilities. 2013. “DPU Order 12-76A Re Modernization of the Electric Grid.” <https://sites.google.com/site/massdgic/home/interconnection/grid-modernization>.

This document is a draft decision written in response to a report authored by a stakeholder Electric Grid Modernization Working Group. In the draft decision, the Massachusetts Department of Public Utilities (DPU) provides a straw proposal on grid modernization for comment. The proposal has two main components: (1) a requirement for electric distribution companies to prepare and file with the DPU ten-year grid modernization plans (GMPs) that describe the companies’ investment and operational strategies for achieving grid modernization and (2) a decision to address a number of grid modernization topics in separate proceedings, including (a) time varying rates; (b) cybersecurity, privacy, and access to meter data; and (c) electric vehicles.

In the draft decision, the DPU “finds that evaluating and investing in technologies that further grid modernization should be an integral component of electric distribution companies’ ongoing and routine investment and operational plans,” but “recognize[s] that, initially, it will involve some changes to their traditional planning and practices.” The DPU also notes that “to advance grid modernization we must address certain existing barriers, consider potential benefits and costs to customers and the distribution companies, and balance the interests of competitive suppliers, clean energy companies, and technology innovators” and “conclude[s] that we must take a comprehensive approach to addressing the various, interrelated aspects of modernizing the electric grid.”

The Working Group produced a taxonomy with four broad objectives for grid modernization: (1) reduce the effect of outages; (2) optimize demand, including reducing system and customer costs; (3) integrate distributed resources; and (4) improve workforce and asset management. The DPU says that each GMP must lay out a strategy for measureable progress on all four of these objectives.

Furthermore, according to the Working Group report, advanced metering functionality can provide: (1) the collection of customers’ interval data, in near real-time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage and restoration notification; (3) two-way communication between customers and the electric distribution company; (4) with a customer’s permission, communication with and control of appliances; (5) large-scale conservation voltage reduction programs; (6) remote connection and disconnection of a customer’s electric service (while maintaining the department’s consumer protections); and (7) measurement of customers’ power quality and voltage. The DPU directs that GMPs include a proposal for implementing advanced metering functionality that will achieve these seven functions, labeling this a “comprehensive advanced metering plan.”

The Working Group report included a variety of possible regulatory changes regarding grid modernization investments, including use of a future test year for moving toward performance-based regulation. In the DPU straw proposal, they reject a future test year (the future is too uncertain) and also reject special cost-recovery procedures for all grid modernization investments, but they do “find that it may be appropriate to make a targeted approach to cost recovery available for investments associated with advanced metering functionality, but only

until such time as the costs are incorporated into companies' base distribution rates." The DPU agrees that performance metrics for grid modernization can be useful and says it will set such metrics overall and by company. It states: "For now, the purpose of the metrics will be to record and report relevant information, without a decision as to whether in the future it is appropriate to connect such metrics to financial penalties and rewards."

The Working Group report can be found at:

<http://www.mass.gov/eea/docs/dpu/electric/grid-mod/ma-grid-mod-working-group-report-07-02-2013.pdf>.

Moreland Commission on Utility Storm Preparation and Response, New York State. 2013. *Final Report*. <http://www.governor.ny.gov/assets/documents/MACfinalreportjune22.pdf>.

This is a report about a variety of issues related to utilities in New York State and their response to Super Storm Sandy. Two of their recommendations are relevant to our research. First, they note that there is confusion between energy efficiency programs operated by utilities and state agencies and recommend that clearer lines be drawn, such as having the utilities concentrate on serving end-use customers and the state agency concentrate on upstream market transformation initiatives. Second, they recommend improving infrastructure to improve resiliency, but subject to a cost constraint. They note that New York already has high electric rates and suggest several possible funding mechanisms that would not require rate increases. They recommend that utilities prepare plans that prioritize and maximize the effectiveness of capital expenditures within whatever budget is ultimately determined to be available.

MIT (Massachusetts Institute of Technology). 2011. *The Future of the Electric Grid*. Cambridge, MA: Massachusetts Institute of Technology.
http://mitei.mit.edu/system/files/Electric_Grid_Full_Report.pdf.

“One of the most important emerging challenges facing the grid is the need to incorporate more renewable generation in response to policy initiatives at both state and federal levels. Much of this capacity will rely on either solar or wind power and will accordingly produce output that is variable over time and imperfectly predictable, making it harder for system operators to match generation and load at every instant. Utilizing the best resource locations will require many renewable generators to be located far from existing load centers and will thus necessitate expansion of the transmission system, often via unusually long transmission lines. Current planning processes, cost-allocation procedures, and siting regimes will need to be changed to facilitate this expansion. In addition, increased penetration of renewable distributed generation will pose challenges for the design and operation of distribution systems, and may raise costs for many consumers.

“Increased penetration of electric vehicles and other ongoing changes in electricity demand will, if measures are not taken, increase the ratio of peak to average demand and thus further reduce capacity utilization and raise rates. Changes in retail pricing policies, enabled by new metering technology, could help to mitigate this problem. Increased penetration of distributed generation will pose challenges for the design and operation of distribution systems. New regulatory approaches may be required to encourage the adoption of innovative network technologies.

“Opportunities for improving the functioning and reliability of the grid arise from technological developments in sensing, communications, control, and power electronics. These technologies can enhance efficiency and reliability, increase capacity utilization, enable more rapid response to remediate contingencies, and increase flexibility in controlling power flows on transmission lines. If properly deployed and accompanied by appropriate policies, they can deal effectively with some of the challenges described above. They can facilitate the integration of large volumes of renewable and distributed generation, provide greater visibility of the instantaneous state of the grid, and make possible the engagement of demand as a resource.

“All these new technologies involve increased data communication, and thus they raise important issues of standardization, cybersecurity, and privacy.

“Decision makers in government and industry have taken important actions in recent years to guide the evolution of the U.S. electric power system to address the challenges and opportunities noted above. Yet the diversity of ownership and regulatory structures within the U.S. grid complicates policymaking, and a number of institutional, regulatory, and technical impediments remain that require action.”

Main recommendations:

- “To facilitate the integration of remote renewables, the Federal Energy Regulatory Commission should be granted enhanced authority to site major transmission facilities that cross state lines.

- To cope more effectively with increasing cybersecurity threats, a single federal agency should be given responsibility for cybersecurity preparedness, response, and recovery across the entire electric power sector, including both bulk power and distribution systems.
- To improve the grid's efficiency and lower rates, utilities with advanced metering technology should begin a transition to pricing regimes in which customers pay rates that reflect the time-varying costs of supplying power.
- To improve utilities' and their customers' incentives related to distributed generation and energy conservation, utilities should recover fixed network costs through customer charges that do not vary with the volume of electricity consumption.
- To make effective use of new technologies, the electric power industry should fund increased research and development in several key areas, including computational tools for bulk power system operation, methods for wide-area transmission planning, procedures for response to and recovery from cyberattacks, and models of consumer response to real-time pricing.
- To improve decision making in an increasingly complex and dynamic environment, more detailed data should be compiled and shared, including information on the bulk power system, comprehensive results from smart-grid demonstration projects, and standardized metrics of utility cost and performance."

REGULATION AND COMPETITION

GE Digital Energy and Analysis Group. 2013. *Results-Based Regulation*.
<http://www.gedigitalenergy.com/regulation/>.

Adapted from the executive summary with permission:

“Creating a Modernized Grid Requires Modern Regulation

Today’s electric distribution companies face a fundamental dilemma as they plan for the future design and operation of their networks. Increasingly, these utilities are expected to improve their resilience during severe weather events, replace aging infrastructure, integrate greater quantities of distributed and variable renewable generation, and secure their systems against cyber and physical attacks. Yet these expectations arise at a time of slow-growing, flat, or declining sales – a trend that impedes a utility’s ability to recover its fixed costs and discourages much-needed capital investment.

“This dilemma is rooted in the fact that the rates of most electric distribution utilities continue to be set under a model focused on reviewing utility costs. Utilities face a regulatory lag between when they make an investment and can recover their costs in rates, which can negatively impact cash flow. During a period of rising costs but slowly growing sales, this lag can impair a utility’s earnings and compel it to defer discretionary investments that could benefit customers. Moreover, cost-of-service regulation can slow the pace of innovation and may offer little incentive for utilities to improve operational efficiency or service quality beyond the minimum levels set by regulators.

“Some regulators have experimented with alternative models – including capital trackers or multiyear revenue caps – to provide either greater support for new investments or stronger incentives for utilities to reduce costs. However, such alternatives may not effectively integrate incentives for efficiency, innovation, and service quality. A new regulatory model may be needed to create a 21st-century power grid and enable utilities to deliver greater value to customers.

“An Emerging Regulatory Model: Results-Based Regulation

As regulators look for a means to meet industry challenges without discarding the traditional objectives of regulation, a results-based model offers an attractive alternative. Results-based regulation is designed to support investments that deliver long-term value to customers, reward utilities for exceptional performance, and remain affordable by encouraging operational efficiencies and sharing the cost savings with customers.

“One example of such an approach is the United Kingdom’s newly adopted RIIO model, or Revenue set to deliver strong Incentives, Innovation, and Output.” Under the RIIO model, utility revenues are determined by regulatory review of forward-looking utility business plans. A multiyear revenue cap is set that provides an incentive for utilities to reduce their costs, as well as an earnings-sharing mechanism that enables customer to benefit from utility cost savings. Utility rewards are determined by clearly defined metrics based on performance with incentives for delivering value to customers. Additionally, funding is set aside to inspire innovation.

Linville, C., J. Shenot, and J. Lazar. 2013. *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition*. Montpelier, VT: Regulatory Assistance Project. www.raonline.org/document/download/id/6898.

In the authors' view, the rise of distributed generation (DG) technologies as cost-effective resources that offer genuine value to the grid has fundamentally altered the evolution of the electricity system. The report states that the increased implementation of these resources has created a transactive energy economy involving third-party aggregators and intermediary service providers in which the exchange of services will be at least a two-way transaction.

"Given the central role of customer side of the meter resources, regulators need to be proactive in ensuring that they are fairly compensated." The main focus of this report is on how these structures of compensation can be designed in an equitable way that fairly distributes the costs, and benefits, among utilities, customers who employ DG resources, and nonparticipating utility customers.

The authors offer 12 policy recommendations that may yield more accurate resource compensation structures while simultaneously nurturing the development of alternative energy resources.

1. Recognize that value is a two-way street. DG resources offer value to the electricity system and vice versa. Utilities, customers, and third-party participants should all be fairly compensated for the services they provide each other with consideration of the full range of benefits and costs associated.
2. DG should be compensated at levels that reflect all components of relevant value over the long term. This means including avoided generation, distribution, and transmission, avoided line losses, and avoided price and supply risks from other forms of generation.
3. Select and implement a consistent valuation methodology with objective oversight of any potential inequities.
4. Remember that cross-subsidies may flow to or from DG owners. Regulators should remain objective and allow for the possibility that the value provided to all customers by DG may be greater than the costs incurred to support the presence of DG tariffs. Conversely, regulators should be open to the possibility that nonparticipating customers may be getting less value from DG than they are paying to support those tariffs.
5. Do not extrapolate for anomalous situations. Policy and tariff solutions should be tailored to the characteristics of the state or region they serve.
6. Infant-industry subsidies are a long-standing tradition that has been used to spur innovation and prop up promising new industries for centuries.
7. Remember that interconnection rules and other terms of service matter. DG should have fair and open access to the grid at nondiscriminatory terms and rates, and regulators should ensure such access through administered rules and incentive programs.
8. Tariffs should be no more complicated than necessary. They should be simple, understandable to the consumer, acceptable to the public, feasible to apply, and free from controversy over interpretation.

9. Support innovative business models and delivery mechanisms for DG.
10. Keep the discussion of incentives separate from rate design. Rate design should be about fair compensation for the value of services provided and fair allocation of the costs to reliably operate the system. Incentives should be added in a transparent manner that does not distort the assessment of fair compensation.
11. Keep any discussion of addressing the throughput incentive separate.
12. Consider mechanisms for benefiting “have not” consumers. Since low-income customers contribute to the revenue pool that supports incentive payments, it is fair for them to benefit from at least a pro rata portion of their contribution toward these payments.

NRDC (Natural Resources Defense Council). 2013. "SMUD Rate Design Refinement Proposal." <http://switchboard.nrdc.org/blogs/rcavanagh/2013/09/11/SMUD%20Rate%20Design%20Refinement%20Proposal%20-%202013-08-13.pdf>.

In this proposal, the NRDC offers suggestions on how the Sacramento Municipal Utility District (SMUD) may alter its rate structure in order to adjust to the changing electricity marketplace while simultaneously upholding its key principles of "cost recovery, economic efficiency, customer equity, rate simplicity, and minimal cost (including environmental cost) to customers." The authors assert that the alterations contained in the proposal will allow SMUD's electricity rate structure to better reflect the cost of energy used, reduce peak energy consumption, and encourage energy efficiency.

The proposal offers three revenue-neutral measures.

1. Reduce the system infrastructure fixed charge ("fixed charge") from the previously proposed \$20 per month to no more than \$10.
 - This \$10 fixed charge would reflect the actual costs of distribution and would not change based on consumption.
2. Convert the resulting fixed charge into a minimum bill requirement.
 - From a customer's perspective, implementing a \$10 minimum bill requirement will incentivize energy efficiency and consumption reductions, while still maintaining fixed cost recovery for electric utilities.
3. Institute a variable demand charge that recovers an average of at least \$10 per month from customers.
 - Long-run variable costs should be recouped using a more equitable variable demand charge rather than a flat rate. This variable charge would change based on a customer's demand. This charge could be based on a variety of options.
 - i. Maximum demand charge: Variable demand charge based on the customer's highest level of demand throughout a month. This charge format would incentivize off-peak charging of electric vehicles and reduced electricity consumption in general.
 - ii. Average maximum demand charge: Variable demand charge based on an average of several meter readings
 - iii. Restrictions to on-peak hours: SMUD could restrict the designation of either a maximum demand charge or an average demand charge to demand that coincides with peak hours. This would align the charge more closely with stress on the grid.
 - iv. Capping the variable demand charge: A maximum cap on monthly demand charges

Additionally, the NRDC suggests similar measures for commercial customers within SMUD's service territory, as well as further analysis of the potential effects of electric vehicles on the policies they recommend.

Binz, R., R. Sedano, D. Furey, and D. Mullen. 2012. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*. Boston: Ceres.

<https://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view>.

From the conclusion of the executive summary and incorporating some additional points from the rest of the executive summary, with permission:

“The U.S. electric utility industry has entered what may be the most uncertain, complex, and risky period in its history. Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies, and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency, and accountability among regulators, policymakers, utilities, and a wide range of stakeholders.

“These challenges call for new utility business models and new regulatory paradigms. Both regulators and utilities need to evolve beyond historical practice. Today’s electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

“Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, rate making, and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies, and shaking off ‘we’ve always done it that way’ thinking.

“Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process. One of the most important duties of a 21st-century electricity regulator is to understand, examine, and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

“Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories (construction cost risk, fuel and operating cost risk, new regulation risk, carbon price risk, water constraint risk, capital shock risk, and planning risk) reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large-baseload fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources. Three observations about risk should be stressed: (1) risk cannot be eliminated, but it can be managed and minimized; (2) it is unlikely that consumers will bear the full cost of poor utility resource investment decisions; and (3) ignoring risk is not a viable strategy.

“Regulators practicing ‘risk-aware regulation’ must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.

“More than ever, ratepayer funding is a precious resource. Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in their resource investment decisions and could pose a threat to utility earnings.

“Risk shifting is not risk minimization. Some regulatory practices that are commonly perceived to reduce risk (for example, construction work-in-progress financing, or CWIP) merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk – for consumers in the short term, and for utilities and shareholders in the longer term.

“Investors are more vulnerable than in the past. During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than 6% of utilities’ overall capital investment, costing shareholders roughly \$19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers.

“Investors should closely monitor utilities’ large capital expenditure decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.

“Cost recovery mechanisms currently viewed positively by the investment community, including the rating agencies, could pose longer-term threats to utilities and investors. Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility’s regulatory and business environments in the long run.

“Some successful strategies for managing risk are already evident. Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply- and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk-management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, ‘betting the farm’ on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

“Regulators have important tools at their disposal. Careful planning is the regulator’s primary tool for risk mitigation. This is true for regulators in both vertically integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios, and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.”

IEA (International Energy Agency). 2007. *Climate Policy Uncertainty and Investment Risk*. Paris: International Energy Agency.

http://www.iea.org/publications/freepublications/publication/Climate_Policy_Uncertainty.pdf

The primary focus of this report is on the effect climate change policy will have on the risk associated with investment. “The response of business to policy risk is important for the effectiveness of both climate and energy policy. This analysis suggests that in some cases business decisions [power sector investment] will be different under conditions of policy uncertainty, and that therefore policies may need to be designed differently or made more stringent than expected.”

The approach taken to quantify uncertainty in this analysis is characterized as putting climate policy uncertainty on an equal footing with other forms of investment risks faced by power companies. Policy uncertainty creates an uncertain outcome in the cash flow of a project, one that is directly correlated in magnitude to the scope of the climate change policy being considered. All climate change policies in the analysis are characterized in terms of a carbon price. Two elements of carbon price uncertainty are modeled, a jump in price to reflect future policy decisions, as well as an annual fluctuation to reflect price volatility. A risk premium is attached to fuel price uncertainty and carbon price uncertainty. The premium amount is directly related to the amount of time left in the remaining life of a policy before a new policy is adopted. The shorter this life span, the higher the premium.

The analysis presents several key messages.

1. It is unlikely in most markets that climate policy uncertainty will pose a serious threat to overall generation capacity levels. Climate policy set over long timescales will divert risk more toward fuel prices. In the short term, climate policy uncertainty will have a larger effect on investment risk. However, as a credible market for climate solutions and pollution mitigation investment is created, this risk will gradually decrease.
2. Modeling results indicate that climate policy risks may be brought down to modest levels compared to other risks if policy is set over a sufficiently long timescale in the future. The ideal time shift of a policy into the future to lessen risk to manageable levels is five to ten years.
3. Climate policy risks will be important for investments for which climate policy is a dominant economic driver, such as carbon capture and storage. The greater the level of policy uncertainty, the less effective climate change policies will be at incentivizing investment in low-emitting technologies.
4. The closer in time a company is to a change in policy, the greater the policy risk will be, and the greater the impact on investment decisions. It is therefore possible that there could be a period with very little new investment in the lead-up to the start of a new policy if key parameters such as tax rates or emissions caps are not announced well in advance.
5. Risk premiums could be reduced if price constraints could be established that limited future price variability, for either a tax or a trading scheme. These constraints

- would have to be credible over a long period, with a very low probability that prices would move outside of these constraints.
6. Companies will generally be confident in committing capital to projects, even in an uncertain environment, as long as they can establish a competitive advantage over other players in the market. This requires policymakers to establish clear rules and apply them consistently.

Joskow, P. 2003. *The Difficult Transition to Competitive Electricity Markets in the U.S.* Center for Energy and Environmental Policy Research. Cambridge, MA: MIT Center for Energy and Environmental Policy Research.

<http://dspace.mit.edu/bitstream/handle/1721.1/45001/2003-008.pdf>.

“This paper provides a comprehensive discussion of the causes and consequences of state and federal initiatives to introduce wholesale and retail competition into the U.S. electricity sector between 1995 and the present.”

The author states that electricity system restructuring was first attempted in England and Wales in 1990. U.S. programs did not go into operation until 1998. Stateside, the development of restructuring was facilitated in large part by the Energy Policy Act of 1992, which removed large barriers to the development of nonregulated nonutility generating facilities and expanded Federal Energy Regulatory Commission (FERC) authority to order utilities to provide transmission service to support wholesale power transactions.

Initial political debates at the state level for restructuring and deregulating utilities began in California and New England, and tended to focus on three main topics: retail price reductions, stranded cost recovery, and the creation of opportunities for incumbents and hungry new entrants. However, intellectual debates on these same issues tended to focus on public interest goals and implementation strategies. As utility deregulation developed, the overriding reform goal became to create new governance arrangements for the electricity sector that would provide long-term benefits to consumers. These benefits would accrue by relying on competitive wholesale markets for power to provide better incentives for controlling capital and operating costs of new existing generating capacity, to encourage innovation in power supply technologies, and to shift the risks of technology choice, construction cost, and operating mistakes to suppliers and away from consumers.

“The early state restructuring and competition programs included the unbundling of the retail supply of generation services from the supply of distribution and transmission service and giving retail customers...the opportunity to choose their power supplier from among competing retail suppliers. These programs also included various utility restructuring requirements designed to separate (functionally or structurally) competitive services (for example, generation, retail supply) from monopoly services (such as distribution and transmission) that would continue to be subject to (better) regulation, as well as various transition arrangements involving stranded cost recovery, generation assets sales, and regulated retail supply services.

“These transition arrangements typically involved a mandatory reduction of regulated retail prices charged to all consumers (or at least residential consumers) and some type of default service arrangement to supply retail customers with a regulated backstop retail power supply option until they migrated to competitive retail suppliers during what was expected to be a short transition period.”

Many policymakers and their advisers underestimated the nature and magnitude of the technical and institutional challenges associated with successfully introducing competitive wholesale and retail markets, and the uncertainties associated with responding to challenges.

Many challenges arose during restructuring due to the innate physical and economic attributes related to electricity system hierarchies (nonstorability, supply and demand must be cleared continuously at every point on the network, spot electricity price volatility, multiple opportunities for suppliers to act unilaterally, vast demand variations depending on time and place, and so on).

According to the author, the development of functioning competitive wholesale and retail electricity markets has encountered more problems and proceeded less quickly than anticipated when restructuring first began in the late 1990s.

The author goes on to list some successes of restructuring, as well as some disappointments experienced thus far.

Successes:

- Substantial investments to new generating capacity have been completed by merchant generating companies
- A shifting of construction costs, operating performance, and market risks to suppliers rather than consumers has occurred
- There has been substantial growth in the fraction of electricity supplied through competitive wholesale market transactions (physical and financial) as a restructuring of incumbent vertically integrated utilities, the entry of new generating capacity built by merchant generating companies, and the development of public and private wholesale power trading institutions
- Order 888 and FERC initiatives have substantially increased access to transmission networks, facilitating wholesale market development
- Retail consumers in many states have benefited from restructuring (lower prices), although direct benefits of competition have been biased toward large customers

Disappointments:

- Boom in merchant generating investment and growth in wholesale market has busted, putting merchant generating and trading companies in financial trouble. These companies will now be operating in an environment where access to investment capital is more restricted and stability will be a requirement to garner investment.
- Wholesale market liquidity has fallen dramatically
- In California, market design imperfections, market power problems, and poor policy responses has caused an increase in retail prices, as well as financial problems for retail and wholesale suppliers
- The performance of retail competition programs has been disappointing almost everywhere, especially for residential and small commercial customers
- Various issues concerning transmission infrastructure plague markets. These include stagnant investment in transmission capacity; inefficient non-price rationing mechanisms to manage congestion; poorly defined property rights; too many system operators; and conflicts of interest concerning transmission capacity owners. The

independent system operator and regional transmission organization institutional arrangements were created by FERC to manage these transmission issues.

The author notes that at the time of publication the states in the Northeast, Texas, and a few Midwestern states had gone the farthest down the restructuring path and were committed to these reforms. California still remains in shock from the 2000 and 2001 electricity crisis, thus making the future of restructuring murky. Most other states to this point had taken a wait-and-see approach or rejected restructuring altogether. The author characterizes the market of these regulated states as offering relatively low retail rates for electricity, solid system reliability, and little consumer pressure for change. In restructuring, states inevitably turn over a large amount of regulatory control to federal jurisdiction. In order to convince new states to take this initiative, it must first be demonstrated that restructuring can run smoothly to bring long-term benefits to consumers.

Kushler, M., and P. Witte. 2001. *Can We Just “Rely on the Market” to Provide Energy Efficiency? An Examination of the Role of Private Market Actors in an Era of Electric Utility Restructuring*. Washington, DC: American Council for an Energy-Efficient Economy.
<http://www.aceee.org/research-report/u011>.

From the executive summary with permission:

“With the movement toward restructuring the electric industry, some have argued that energy efficiency would be better accomplished by relying on market forces than by continuing government and regulatory requirements for energy efficiency programs. In response, others have argued that market barriers to energy efficiency are significant with or without restructuring, and that energy efficiency programs should be continued. Underlying this debate is a key public policy question: To what extent can private market forces be relied upon to achieve energy efficiency in the absence of long-standing utility and government efforts? The purpose of this study was to gather data to help address that question.

“This study focused on three key groups of private sector market actors expected to be involved in the provision of energy efficiency services in a restructured electricity market: energy efficiency service companies; electricity commodity providers; and distribution utilities. Furthermore, in order to review market activities that have emerged to their maximum extent, the study specifically focused on nine states that were early implementers of electric restructuring – Arizona, California, Connecticut, Illinois, Massachusetts, Michigan, New York, Pennsylvania, and Rhode Island. Data collection methodologies included website content analysis, document review, and nearly 100 detailed telephone interviews (with representatives of each of those three key market actor groups plus a number of expert observers of the energy efficiency service industry).

“Briefly stated, the key conclusions of this study are as follows.

“First, while the energy services company (ESCO) industry performs a very valuable role in delivering energy efficiency in the United States, there are at least two important reasons why this industry could not be expected to step in and replace the role of government/regulatory policies and programs in providing energy efficiency.

- “There are major gaps in the market segments reached by this industry. In particular, ESCOs generally have demonstrated little or no ability (or interest) in serving the residential or small commercial customer markets. To a lesser extent, ESCOs have also had some difficulty reaching the industrial customer market.
- “Even in the market sectors where ESCOs perform the best (institutional and larger commercial markets), the ESCO industry is in fact intricately involved with, and supported by, existing government/regulatory policies and funding programs for energy efficiency. Indeed, these policies and programs in substantial part helped create the ESCO industry and continue to play a major role in sustaining its work today.

“Second, for a variety of reasons, the retail electricity commodity supplier industry has not demonstrated itself to be an effective vehicle for achieving energy efficiency improvements.

Significant challenges include a high failure rate among supplier firms, a mixed interest in energy efficiency among suppliers, a lack of commodity suppliers actually marketing tangible energy efficiency measures, and a lack of customer interest in obtaining energy efficiency from commodity suppliers (due to perceived conflict of interest and other reasons). Regardless of the specific causes, the vision of a robust supplier industry bundling the electricity commodity and energy efficiency to provide customers with lowest-cost energy solutions has simply not materialized.

“Third, absent legislative or regulatory requirements (for example, system benefit charge-funded programs, shareholder incentives for effective utility energy efficiency programs, and so on), there is strong evidence that in a restructured electric industry, utility companies will not choose to provide substantive energy efficiency programs. Rather, if they provide anything at all, they are much more likely to provide minimal information-type programs, largely as a customer service and customer relations mechanism.

“In summary, this study has found little evidence to support the premise that relying on private market actors to provide energy efficiency would be a superior approach and that government/regulatory policies and funding for energy efficiency can be phased out or eliminated. Indeed, after focusing on nine states that were early adopters of electric restructuring and gathering data from the three private market actors most prominently mentioned as entities that would pick up the ball and deliver energy efficiency in a restructured marketplace, this study supports conclusions contrary to that premise. Those private market actors each face significant limitations in their interest and ability to deliver energy efficiency and have thus far demonstrated no realistic capability to replace government/regulatory policies and programs to provide energy efficiency.”

ENERGY EFFICIENCY

Frankel, D., and H. Tai. 2013. "Giving U.S. Energy Efficiency a Jolt." Insights and Publications, McKinsey and Company.

http://www.mckinsey.com/insights/energy_resources_materials/giving_us_energy_efficiency_a_jolt.

Utilities and energy retailers can scale up energy efficiency efforts and increase cost-effective savings through consumer attitudinal segmentation. Promising initiatives include leveraging social media, developing streamlined surveys, running energy efficiency campaigns, and assembling a consumer data set. Appliance vendors can cut through consumer confusion about energy efficiency benefits and differentiate the best-performing appliances, perhaps by refining current labeling systems such as ENERGY STAR®.

An increasing number of well-funded, sophisticated players are entering the market for energy efficiency technology products. Utilities are currently well positioned to offer energy efficiency information and services, but consumers are open to other providers. Energy retailers, technology companies, and home-improvement and construction-material retailers are increasingly competing with utilities in this space. As the market matures and competition heats up, utilities and technology vendors can get a leg up through segmentation based on consumer feelings and attitudes.

Parker, S., and F. Huessy. 2013. *What's a Utility to Do? Next-Generation Energy Services and a New Partnership to Serve Customers*. Burlington, VT: Vermont Energy Investment Corporation. <http://www.veic.org/documents/default-source/resources/white-papers/whats-a-utility-to-do-parker-huessy.pdf>.

The first four paragraphs are from the report summary at the website link. Portions of the two other paragraphs draw from a VEIC article about the report. Both are quoted with permission.

“The next generation of energy production and use will require a dramatic improvement in the energy industry’s capacity to provide ongoing, independent, and trusted support to customers.

“This improvement will mean that customers can invest in energy under a new energy utility structure that offers fully coordinated services dedicated to meeting their energy needs. This will require interdependent functions between utilities and other entities providing customer-engaged energy services. These interdependent functions can harness the immense potential for meeting our energy needs in a way that maximizes benefits to the customer, our energy systems, and society.

“There is an explosion of opportunity for new types of utility service to customers. If thoughtfully deployed as a comprehensive system, these services can fully engage utility customers, redefine the utility system, and realize the societal benefits of new strategies and technologies. This is a new utility model, to be sure.

“The greatest challenge will be to identify new roles, responsibilities, and investment strategies that are consciously designed to maximize customer and societal benefits through the new business models, rather than simply pursuing new revenue streams for traditional utilities.

“Doing this right will require deliberate, imaginative work on the part of all stakeholders.”

As these conversations unfold, the omnipresent – yet often disregarded – elephant in the room is energy efficiency, which in recent years has emerged as a powerful force for customer engagement and empowerment. Arguably, the most effective efficiency implementation strategies emerged from jurisdictions such as Vermont and Oregon, where a *deliberate choice* was made to institutionalize and invest in new energy efficiency models. Now that we are confronting institutional models again, it is clear that there is an exciting role for the evolved distribution utility to play. But if we start by asking "How will the utility survive?" rather than "What energy future do we really need?" we will come up with answers that are at best incomplete, and at worst deeply flawed.

Although most energy efficiency efforts are currently delivered by distribution utilities, energy efficiency and other customer-focused services are not inherently utility functions: They can be effectively delivered in a new way, specifically with a separately chartered and regulated sustainable energy utility (SEU) that is focused on consumers and on facilitating the markets. An SEU would work closely with a refocused energy investment utility (EIU).

While it is a possibility that SEU and EIU functions may be combined, this would create several challenges. Combining SEU and EIU functions may limit the SEU’s ability to explore innovative

sources of public benefit, an essential aspect of its function. The SEU function should not be a way for the incumbent utility to gain market advantage in other energy sectors, beyond the base service it provides, nor should the focus be put on sales volume. Though it is not clear how an SEU function could be a truly independent function of an incumbent utility, there may be actual value to the EIU of being complemented by an independent SEU. This relationship could increase trust between the EIU and its customers, as well as allow the EIU to evolve to provide services in new ways to customers.

Neme, C., and R. Sedano. 2012. *U.S. Experience with Efficiency as a Transmission and Distribution System Resource*. Montpelier, VT: Regulatory Assistance Project.
www.raponline.org/document/download/id/4765.

This report focuses on the potential to defer upgrades in electricity system transmission and distribution through the employment of energy efficiency measures and technologies. Investments in transmission and distribution currently are projected to account for 60% of forecast investments for the electricity sector over the next two decades. A significant portion of these investments will likely be due to load growth, growth that may be averted through efficiency.

As the report states, efficiency programs can defer transmission and distribution investments either passively or actively. Passive deferrals are those that occur as a result of efficiency programs that were not undertaken primarily for the purpose of deferring transmission and distribution (e.g., systemwide efficiency programs). Active deferrals are those that result from efficiency programs that are geographically targeted for the express purpose of deferring the need for upgrades to specific elements of the transmission and distribution infrastructure. A variety of reasons have contributed to limited employment of these active methods.

- Lack of financial incentives when compared to investments in “poles and wires”
- The nature of energy efficiency benefit evaluation requires a holistic, systemwide approach many utilities have not yet adopted
- The highly technical nature of transmission and distribution planning creates a bias toward technical solutions
- System engineers have little experience/interaction with efficiency program managers
- The perceived risk of demand-side approaches, both regulatory and financial
- Transmission solution costs are socialized regionally, efficiency program costs are not
- Due to the diffuse nature of transmission planning, it is difficult for new approaches to gain traction

The report then goes on to examine ten case studies in which active deferral of transmission and distribution investment was pursued.

- Pacific Gas and Electric’s Delta Project (California, early 1990s) – The project was initiated to avoid construction of a new substation. Several efficiency programs were launched in the service area, with 10% of homes implementing major measures. The new substation was deferred for two years.
- Portland General Electric’s Downtown Portland Pilot (Oregon, early 1990s) – The utility aggressively marketed existing systemwide efficiency programs to individual buildings where transformer upgrades may have been necessary. Additionally, the utility contracted with energy supply companies to reduce the consumption for 10- to 15-block areas. The results were mixed.
- Bonneville Power Administration’s Puget Sound Area Electric Reliability Plan (Washington, early 1990s) – Addressed reliability concerns by adding voltage

- support to the existing transmission system, coupled with intensive energy efficiency deployment. Transmission upgrades were deferred for over a decade.
- Green Mountain Power’s Mad River Valley Project (Vermont, mid to late 1990s) – A large customer’s planned expansion would have added megawatts of new load to the system, requiring upgrades that the customer would be required to pay the majority of. Negotiations led to an agreement between the utility and the customer that would keep load at previous levels through the use of efficiency.
 - Consolidated Edison (New York City, early 2000s to present) – This ongoing program seeks to defer distribution system upgrades through a competitive resource bidding process. To date, only efficiency has been selected. Contracts include upfront security and downstream liquidated damage provisions to ensure reliability. The program has been successful in deferring upgrades to over one-third of the distribution networks.
 - Efficiency Vermont Geo-Targeted Demand-Side Management (2007 to present) – This involved implementing performance goals that were more aggressive in areas identified for deferring transmission and distribution investments. Peak demand savings in the targeted areas were three to five times more than statewide savings. Since starting, no system upgrades have been necessary in the targeted areas.
 - NV Energy (Nevada, late 2000s) – An efficiency initiative designed to defer the need to either run an expensive generating station more frequently or construct a new transmission line and substation has seen success, with no upgrades having been necessary to date, nor has the expensive unit been run more frequently.
 - Central Maine Power (currently under development) – After approving plans for construction of significant transmission upgrades, the utility identified two regions where nontransmission alternatives may defer the need for upgrades. Although still being hashed out, an initial report on alternatives describes efficiency resources as “highly competitive.”
 - National Grid (Rhode Island, currently under development) – State law requires system reliability plans to be submitted every three years. The plans must consider non-wires alternatives such as efficiency when determining the need for new transmission and distribution investments.
 - Bonneville Power Authority (Washington, Oregon, and Idaho, currently under consideration) – The utility developed a formal process by which transmission alternatives would be assessed. Currently, it is assessing non-wires solutions, including energy efficiency, in three geographic areas.

Additionally, the authors make several policy recommendations to maximize the potential for efficiency in the deferral of transmission and distribution upgrades.

- Require least-cost transmission and distribution planning
- Require consideration of integrated solutions with various resource combinations
- Institutionalize a long-term planning horizon (at least ten years)
- Level the playing field in payment for wires and non-wires alternatives by providing incentives for least-cost solutions
- Collect more data on the impacts of energy efficiency
- Start with pilot projects to lower risk
- Leverage smart-grid investments as data collection tools

DOE SEE Action (U.S. Department of Energy, State and Local Energy Efficiency Action Network). 2011. *Impacts of Energy Efficiency Programs on Customer Satisfaction*. Technical Brief. Washington, DC: U.S. Department of Energy, State and Local Energy Efficiency Action Network.
http://www1.eere.energy.gov/seeaction/pdfs/ratepayer_efficiency_customersatisfaction.pdf.

This paper compiles data from utility customer satisfaction surveys alongside two case studies to promote utility adoption of energy efficiency programs and services. The paper draws on survey data compiled by J.D. Power and Associates in 2011 that measured customer satisfaction with gas utility companies. The survey found that 32% of business customers overall were familiar with their gas utility's energy efficiency programs, but those who were familiar were significantly more satisfied with gas prices than those who were not. A similar correlation can be gleaned from a similar 2010 J.D. Power study of residential gas and electric utility customers. The results of these studies suggest that customer satisfaction levels are directly correlated with knowledge of, and exposure to, utility-run efficiency programs, regardless of whether or not the customer participates.

Two case studies support the findings from these J.D. Power studies. MidAmerican Energy Company found that customers who were aware of energy efficiency programs ranked the company higher on overall corporate citizenship. MidAmerican analysts also consulted data from Market Strategies International (MSI), which found similar results. According to MSI, factors that primarily influence customer satisfaction include reliability, customer service reputation, and rates/prices. Awareness of energy efficiency programs was also a significant driver of satisfaction.

When it was faced with low customer satisfaction levels, DTE Energy began implementing targeted energy efficiency programs in 2008. Through the implementation of these programs, DTE Energy found that targeted customers were more likely to view their electric and gas rates as reasonable, with customer satisfaction rising by 11% with some groups.

In terms of causality, the article references the concept of a "reservoir of goodwill" that is built from the perceived benevolence a utility garners through efficiency programs. Benefits for utilities with increased customer satisfaction include customers who are generally less likely to contest mild rate increases, as well as decreased skepticism during regulatory proceedings.

In conclusion, the authors note that more research on this correlation may be necessary, and they make six recommendations.

1. Utilities may want to expand their energy efficiency programs to improve customer satisfaction
2. Utilities (and, where appropriate, regulators) could reap benefits by making more of an effort to increase customer awareness of energy efficiency programs that already exist and communicate the results achieved by those programs
3. Utilities that operate in a performance-based regulatory environment may be especially motivated to expand and promote their efficiency programs

4. Consumer advocates should add “customer satisfaction” to the list of reasons why well-designed energy efficiency programs are an appropriate use of ratepayer dollars
5. Consumer advocates and utility regulators should take note of the evidence that customer satisfaction improves with awareness of a utility’s efficiency programs, even among customers who do not actually participate in the programs.
6. All stakeholders involved in program design and actual implementation should consider that elements that are not executed properly (for example, timely payments of incentives, adequate funding) have the potential to negatively affect customer satisfaction.

EEI (Edison Electric Institute). 2007. *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*. Washington, DC: Edison Electric Institute.
http://www.eei.org/issuesandpolicy/stateregulation/Documents/Making_Business_Energy_Efficiency.pdf.

Adapted from the executive summary with permission:

“Today, energy efficiency is at the forefront of energy policy. Concern about global climate change and the environment, combined with rate pressures from the need to build expensive baseload generation plants and to recover fluctuating fuel prices, has brought the issue of energy efficiency front and center with utility executives, regulators, and public-policy advocates. Energy efficiency is again in the public limelight, and utilities are increasingly being called upon to adapt their business models to incorporate the provision of cost-effective energy efficiency....

“Consideration of the energy service value chain suggests that a utility could choose to occupy several different value chain positions, meaning several different strategic architectures appear to be possible. While a number of families of business models might be possible, we have chosen to focus on three to represent the range of possibilities available to utilities.

“*Conventional Regulatory Incentives Family* – This family uses regulatory mechanisms that historically have been adopted to promote energy efficiency investment by utilities. Each business model has a specific mechanism to address the throughput issue, a specific mechanism to recover the energy efficiency program costs, and a positive shareholder incentive to encourage utility promotion of energy efficiency. This family encompasses two specific business models:”

- Shared savings business model: The utility earns a share of the net benefits from its efficiency efforts
- Capitalization business model: The utility can earn a rate of return on its efficiency investments

“*Performance Model Family* – Through a long-lived performance-based regulation (PBR) plan, the utility shares savings arising from implementation of energy efficiency. PBR mechanisms – tailored to energy efficiency issues – could include multiyear versions of the conventional regulatory incentives....

“*Energy Services Model Family* – The utility (or an affiliate) directly sells services to customers on a fee-for-service model, which allows utility shareholders to profit from the provision of energy supply company-type services. This family encompasses three specific business models.”

- Customer infrastructure business model: The utility contracts with a customer for delivery of specified energy services, such as heating or cooling
- Fee-for-service business model: The utility sells efficiency services to customers
- Green power business model: A variation on fee-for-service in which utility offers green power to consumers who are willing to pay the full incremental cost of green power or offsets

“All six business models are potentially applicable to all major utility types (vertically integrated, wires only, and nonregulated) *except* that the conventional regulatory incentives and performance models are *not* applicable to nonregulated entities.

“Most likely, the approach that a utility will adopt will be some mixture of the above strategies. Potential strategic architectures encompass both regulated and nonregulated characteristics and elements. Moreover, potential strategic architectures will reflect not only a company’s strategic choices, but also – critically – the regulatory constraints within which the company must operate. Thus, available or appropriate strategic architectures will vary not only with the type of market participant (for example, integrated versus not, largely regulated versus not), but also by jurisdiction and market.

“These models represent a range of options for utilities and regulators to consider in thinking about energy efficiency. They also represent a continuum in sustainability. The conventional regulatory incentives group models are the least likely to be sustainable, as they rely upon the continuity of regulatory favor for their sustainability. These models are most likely to be adopted with aggressive implementation of large-scale energy efficiency programs; as a result, they likely have the largest rate impacts on nonparticipants. Experience with these mechanisms suggests that they *do* change utilities’ interest in promoting energy efficiency, but they also often lead to the creation of regulatory assets, customer and consumer advocate pressure to end or substantially reduce the energy efficiency programs, and ultimate reduction of the energy efficiency business.

“The performance model family is more sustainable, as it is predicated on a long-lived agreement with the regulator and on providing greater flexibility to utility management. However, this family of models still relies upon the periodic review of regulators, and there is no assurance that energy efficiency will remain an important issue at the time of those reviews.

“The energy services model family is the most durable, as it looks directly to customers for its implementation. While this family may have regulatory risk, these issues generally can be averted by implementing the model through an affiliate.”

A few overarching conclusions:

- “The most durable and sustainable business models require significant change in either the regulatory framework or the utility’s orientation to service delivery. While the amount of change is not to be underestimated, circumstances indicate that these changes are more feasible today than previously.
- There are transition paths to the more durable models. They need not be implemented in a single leap, but rather through an orderly transition.
- Without significant change to the business models, energy efficiency will continue to follow a path of ‘hot today, not tomorrow.’

“Perhaps the central question is, Can a utility engage in energy efficiency lines of business and make money doing so? The results of this project clearly point to a simple answer: Yes. But doing so depends on a variety of regulatory and business circumstances.”

SOLAR ENERGY

Bird, L., J. McLaren, J. Heeter, C. Linvill, J. Shenot, R. Sedano, and J. Migden-Ostrander. 2013. *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar*. Golden, CO: National Renewable Energy Laboratory.
<http://www.nrel.gov/docs/fy14osti/60613.pdf>.

Adapted from the executive summary with permission:

“Consumer interest in and deployment of solar photovoltaics (PV) has accelerated in recent years. Increased adoption of distributed generation, particularly distributed solar PV, is expected to have impacts on utility–customer interactions, utility system cost recovery, and utility revenue streams. As a greater number of electricity customers choose to generate their own power, demand for utility system power declines. As a result, fixed system costs, such as the costs of transmission and distribution services, will be recovered over fewer kilowatt-hour (kWh) sales by the utility, and this could put upward pressure on electricity rates.

“Regulators are facing the challenge of defining and preparing for the potential rate and revenue impacts from expansion of distributed PV. Looking forward, it will be important to address potential financial impacts on utilities that are responsible for ensuring that the electricity infrastructure supports reliable electric service for customers. The regulatory context and rate structures governing utilities and owners of residential and commercial-scale distributed PV present both market opportunities and market barriers that will influence the path forward for the incorporation of higher penetrations of distributed PV....

“Costs and Benefits

Distributed PV benefits system owners, utilities, the power system, and society in a variety of ways, including through the provision of energy and capacity, transmission and distribution system deferrals, line loss savings, fuel cost hedging, and environmental and health benefits. The costs include those associated with equipment, operations and maintenance, program administration, interconnection, and integration of the distributed systems. The magnitude of the costs and benefits of distributed PV vary according to the level of penetration, the local grid characteristics, and the coincidence of the solar electric production with the peak demand in the region. Assessments of costs and benefits have varied widely, and in some cases there is a lack of consensus regarding appropriate methodologies for assessing them.

“Understanding the costs and benefits of distributed PV is essential to creating appropriate rate structures. The benefits and costs of distributed resources play into the consideration of ratepayer equity and rate design, especially at increased levels of adoption.

“Business Models

The expansion of distributed PV creates the potential for new business models to emerge. Growth in the PV industry has already given rise to new solar business models, such as solar leasing, often administered by third-party entities. Distributed PV has been viewed by some as a threat to utility business models that profit from increased kWh sales. A few utilities are exploring new business opportunities to increase their participation and role in the deployment of distributed solar. Potential models for utility participation include customer demand

aggregation, utility turnkey operations, utility-led community solar projects, partnership and investment in third-party leasing, value-added consulting services, and as a virtual power plant operator.

“The impact of distributed PV on utility revenues depends on the role the utility will play in distributed energy resource expansion. Key considerations for regulators include the regulatory changes necessary to enable new business models and the potential implications for competition, reliability, and market access. Regulators may need to consider the balance between the role of utilities and the dynamic benefits of a third-party service provider sector.

“Ratemaking Options

With expanding levels of distributed PV, new rate structures and regulatory policies may need to be considered. One issue will be to ensure that the utility collects sufficient revenue to cover its requirements and continue to safely and reliably provide vital services to all customers. Another key challenge will be to address equity across ratepayers and fairness for the utility and the distributed generator. Regulators will be challenged to design rates that compensate distributed PV customers for the net value they provide to the system while also requiring them to pay the full cost of the services they use. The solutions adopted will vary according to the state and locality and whether the utility is vertically integrated or operating in a state with a restructured electricity market.

“Options for addressing revenue issues related to expanded adoption of PV include a variety of traditional ratemaking elements such as fixed monthly customer charges, demand charges, standby rates, and time-based pricing. Other emerging options are two-way rates, such as value of solar tariffs, disaggregated rates, or the development of a separate customer class for PV customers. For rate designs that do not address issues associated with declining utility revenues, supplemental policies like decoupling or performance incentives can be applied to address the utility disincentive to support distributed solar or motivate utility participation. Regulators may seek to use a combination of tools to meet the needs of stakeholders.

“Questions for Framing the Regulatory Discussion

Regulators who face issues associated with the expanded adoption of distributed PV will need to address them within the context of their state. The rate of PV deployment varies today by location and will likely continue to vary based on solar insolation, electricity rates, policies, and the regulatory context of the particular state. Regardless of these differences, a common set of questions may be useful for exploring and equitably addressing issues related to higher penetrations of distributed PV. These include developing an understanding of expected future adoption rates, the ability to address any needed system upgrades, impacts on various stakeholders, the possibility of stranded assets, and lessons that may be gleaned from other jurisdictions.”

Horwitz, Y., and W. Graves. 2014. "Peering Over the 2017 Horizon for Solar, Part 1: Securitization." Greentech Solar, January 17.

<http://www.greentechmedia.com/articles/read/peering-over-the-2017-horizon-for-solar-part-1>.

Horwitz, Y., and W. Graves. 2014. "Peering Over the 2017 Horizon for Solar, Part 2: Beyond the ITC." Greentech Solar, January 21.

<http://www.greentechmedia.com/articles/read/peering-over-the-2017-horizon-for-solar-part-2>.

This is a two-part article on what may happen to the market for photovoltaics in 2017 after the 30% federal investment tax credit (ITC) sunsets on December 31, 2016. Discusses how interest rates for strong solar companies have come down and securitization is starting to happen, with the first deal now closed. Securitization involves issuing securities backed by contracts on thousands of individual systems, just as many home mortgages are now routinely wrapped into packages to issue mortgage-backed securities. Still, even with securitization, the authors predict that the effective cost of capital for developers with large uniform pools of solar assets with significant operational history will be 5–7%. This will help solar economics, but to be competitive without federal tax credits, the industry will need to continue to cut development, equipment, and customer acquisition costs.

The authors further argue that a 10% ITC may be possible in 2017 and will be a significant help. They conclude that "Depending on cost estimates and projections for the costs of capital, residential solar will become competitive with no state incentives in 15–20 states by 2017 with the 10% ITC, assuming a cost of capital of 6.5%. Similarly, commercial solar is likely to be competitive with no state incentives in 13–17 states in 2017 with the 10% ITC, assuming a cost of capital of 6.5%." These states will be states with the highest electricity rates, which, for residential, are now (in order): Hawaii, New York, Alaska, Rhode Island, Connecticut, Massachusetts, Vermont, California, New Hampshire, New Jersey, Michigan, Maine, Wisconsin, Maryland, and Pennsylvania.

Morgan Stanley. 2014. *Clean Tech, Utilities and Autos: Batteries + Distributed Gen. May Be a Negative for Utilities*. Morgan Stanley Research North America.

According to Morgan Stanley, some customers (especially in the West, Southwest, and Mid-Atlantic) may cut the cord to the power grid due to improvements in batteries and the cost and efficiency of distributed generation. Tesla Motors, for example, has plans for a gigantic battery factory.

Net metering rules and the 30% solar investment tax credit (ITC) are key determinants of the market for solar panels and batteries. Current net metering rules allow solar customers to avoid paying for utilities' investments in a reliable grid; Morgan Stanley expects that to change.

Morgan Stanley offers three scenarios for the U.S. residential and solar market:

Case	ITC	% of fixed grid charge payable	Market
Base	0%	50%	240 GW
Bull	10%	25%	415 GW
Bear	0%	100%	30 GW

Morgan Stanley concludes that higher fixed charges are likely to drive more customers to buy batteries and leave the grid. The rate headroom for batteries will rise in step with solar penetration. NRG Energy's use of a stirling engine powered by natural gas may be the most competitive off-grid strategy.

Sedano, R. 2014. "PV Proliferation: Rays of Opportunity." Montpelier, VT: Regulatory Assistance Project. <http://www.raonline.org/featured-work/pv-proliferation-rays-of-opportunity>.

In this short article posted on the Regulatory Assistance Project website, the author first describes the dramatic success of net metering as a driving force behind the evolution of the electric power sector. In the past ten years, the massive adoption of net metering policies by states has fostered a corresponding increase in the installation of both residential and commercial photovoltaic (PV) systems. These changes have inversely affected utility sales of electricity, driving down returns on investments. With enough participation, the author believes that PV implementation may have a profound effect on current utility regulatory systems, and may already be putting pressure on regulatory structures in some areas.

One potential policy response that intrigues the author is the reclassification of utility customers who implement onsite PV systems as customers who are taking "connection" service. These customers would "be distinct from a 'requirements' customer and would see a tariff reflecting the costs of service assigned to it."

Regardless of which regulatory changes are enacted to address the changing utility landscape, the author believes that politicizing the issue is unfavorable, and equity is essential going forward.

RMI (Rocky Mountain Institute). 2014. *The Economics of Grid Defection*. Old Snowmass, CO: Rocky Mountain Institute. http://www.rmi.org/electricity_grid_defection.

From the executive summary with permission:

“Distributed electricity generation, especially solar PV, is rapidly spreading and getting much cheaper. Distributed electricity storage is doing the same, thanks largely to mass production of batteries for electric vehicles. Solar power is already starting to erode some utilities’ sales and revenues. But what happens when solar and battery technologies are brought together? Together they can make the electric grid optional for many customers – without compromising reliability and increasingly at prices cheaper than utility retail electricity. Equipped with a solar-plus-battery system, customers can take or leave traditional utility service with what amounts to a utility in a box.

“This utility in a box represents a fundamentally different challenge for utilities. Whereas other technologies, including solar PV and other distributed resources without storage, net metering, and energy efficiency, still require some degree of grid dependence, solar-plus-batteries enables customers to cut the cord to their utility entirely.

“Notably, the point at which solar-plus-battery systems reach grid parity – already here in some areas and imminent in many others for millions of U.S. customers – is well within the 30-year planned economic life of central power plants and transmission infrastructure. Such parity and the customer defections it could trigger would strand those costly utility assets. Even before mass defection, a growing number of early adopters could trigger a spiral of falling sales and rising electricity prices that make defection via solar-plus-battery systems even more attractive and undermine utilities’ traditional business models.

“How soon could this happen?... Our analysis focuses on five representative U.S. geographies (New York, Kentucky, Texas, California, and Hawaii) and four possible scenarios” –base case, accelerated technology improvement, demand-side improvement, and combined improvement (technology + demand side). “Modeled scenarios [are compared] against a reasonable range of retail electricity price forecasts bound by U.S. Energy Information Administration (EIA) forecasts on the low side and a 3%-real increase per year on the high side.

“The analysis yields several important conclusions:

“1. Solar-plus-battery grid parity is here already or coming soon for a rapidly growing minority of utility customers, raising the prospect of widespread grid defection. For certain customers, including many customer segments in Hawaii, grid parity is here today. It will likely be here before 2030 and potentially as early as 2020 for tens of millions of commercial and residential customers in additional geographies, including New York and California. In general, grid parity arrives sooner for commercial than residential customers. Under more aggressive assumptions, such as accelerated technology improvements or investments in demand-side improvements, grid parity will arrive much sooner....

“2. Even before total grid defection becomes widely economic, utilities will see further kilowatt-hour revenue decay from solar-plus-battery systems. Our analysis is based on average load profiles; in

each geography there will be segments of the customer base for whom the economics improve much sooner. In addition, motivating factors such as customer desires for increased power reliability and low-carbon electricity generation are driving early adopters ahead of grid parity, including with smaller grid-dependent solar-plus-battery systems that can help reduce demand charges, provide backup power, and have other benefits. Still others will look at investments in solar-plus-battery systems as part of an integrated package that includes efficiency and load flexibility. This early state could accelerate the infamous utility death spiral – self-reinforcing upward rate pressures, making further self-generation or total defection economic faster.

“3. Because grid parity arrives within the 30-year economic life of typical utility power assets, it foretells the eventual demise of traditional utility business models. The old cost recovery model, based on kilowatt-hour sales, by which utilities recover costs and an allowed market return on distribution networks, central power plants, and/or transmission lines, will become obsolete. This is especially profound in certain regions of the country. In the Southwest, across all megawatt-hours sold by utilities, for example, our conservative base case shows solar-plus-battery systems undercutting utility retail electricity prices for the most expensive one-fifth of load served in the year 2024; under more aggressive assumptions, off-grid systems prove cheaper than all utility-sold electricity in the region just a decade out from today....

“Though many utilities rightly see the impending arrival of solar-plus-battery grid parity as a threat, they could also see such systems as an opportunity to add value to the grid and their business models. The important next question is how utilities might adjust their existing business models or adopt new business models – either within existing regulatory frameworks or under an evolved regulatory landscape – to tap into and maximize new sources of value that build the best electricity system of the future at lowest cost to serve customers and society.”

Mendelsohn, M. 2013. "Where Is All the Utility Investment? Are Utilities Missing an Opportunity to Finance Solar and Storage?" Renewable Energy Project Finance, National Renewable Energy Laboratory. <https://financere.nrel.gov/finance/content/where-all-utility-investment-are-utilities-missing-opportunity-finance-solar-and-storage>.

This article begins by examining the rapid development of both photovoltaic (PV) and energy storage technologies in recent years. PV deployment has experienced exponential growth and ever-decreasing prices, with similar trends expected for energy storage. In order to provoke investment in these burgeoning areas, renewable energy companies will need some level of project standardization in order to reduce risk for investors, an effort that has been facilitated by the work of the National Renewable Energy Laboratory.

In the face of declining prices and rising rates, utilities are met with a unique opportunity to diversify their portfolios through investments in renewable energy projects. According to the author, utilities are uniquely positioned for three reasons:

1. Access to low-cost capital
2. A need for capital investment to ensure shareholder returns
3. The potential for increased grid resiliency from investments

According to the author, "The sheer volume of funds required and the regulated monopoly status provided to utilities enables them to raise capital at extremely favorable rates.... And yet solar and other renewable energy investment is made primarily by nonutility entities at far higher costs." Although some investor-owned utilities invest in renewable energy, factors such as complex financial structures, concerns about the financial solvency of solar technologies, as well as concerns about self-selection being limited by regulatory bodies limit investment by these groups.

The author urges utilities to reconsider these investments in light of the fact that they provide a wide array of grid benefits while simultaneously providing low-emission energy resources. Additionally, utility investment in renewable resources allows market development while leaving room for third-party developers to participate.

The author then goes on to differentiate potential utility investments into three categories:

1. Short-term investment: Investment for a limited period (typically one year) until the completion of construction or the asset is sold into a secondary market
2. Medium-term investment: The utility provides equity for a period of five years. After this period, the remaining interest is sold off to third parties, or into secondary markets
3. Long-term investment: The utility invests and holds the asset for the expected life. Projects provide long-term rate-based and shareholder returns. The utility and customer split the savings, with the utility receiving ancillary benefits in the form of carbon offsets and improved grid resiliency.

Moody's Corporation. 2013. "Announcement: Moody's: Rooftop Solar, Distributed Generation, Not Expected to Pose Threat to U.S. Utilities." Moody's Corporation Investors Service Global Credit Research. Nov. 2013. https://www.moody.com/research/Moodys-Rooftop-solar-distibuted-generation-not-expected-to-pose-threat--PR_286326?WT.mc_id.

The findings of a study conducted by Moody's Investors Service suggest that distributed generation resources are unlikely to have a major effect on the credit of U.S. regulated utilities. Due to the limited financial effects distributed generation has had thus far, coupled with the likelihood of regulatory intervention, Moody's believes that these resources should cause little worry for utility shareholders.

More specifically, the report points to a lack of suitable roof space as well as high installation costs as major deterrents to widespread photovoltaic (PV) adoption. The study also found that cost shifting has been minimal, and even in states with the highest rates of PV market penetration (Hawaii, California), rates have increased less than 1%.

Parkinson, G. 2013. "How to Avoid Energy Death Spiral – and Build More Solar." RenewEconomy.com, August 28. <http://reneweconomy.com.au/2013/avoid-energy-death-spiral-build-solar-98127>.

In this article posted on the Australian renewable energy news website RenewEconomy.com, the author begins by outlining an emerging idea in the Australian photovoltaic industry: a distributed energy market.

This market is presented as a means for utilities to mitigate the effects of declining energy sales in a rapidly diversifying market. It would "allow the 'prosumer' – households and businesses with rooftop solar and maybe battery storage – to buy and sell electricity from organizations other than their retailers. It also opens up the opportunity for network operators to enter the domestic market."

In order to realign markets to benefit customers and network operators, Australian regulators imagine a system with more equal competition between the supply- and demand-side options. This equal treatment would play into the planning process and minimize the need for large utility network infrastructure projects.

Additionally, the author suggests restructuring rates to decouple profits from sales will be necessary, as well as a host of other measures executed by regulatory agencies, including information and training, minimum energy performance standards, house energy rating schemes, and feed-in tariffs and white certificate schemes.

DISTRIBUTED GENERATION MORE BROADLY

Owens, B. 2014. *The Rise of Distributed Power*. General Electric. <http://info.ge-energy.com/DistributedPowerSubmitDownloadRequest.html>.

From the executive summary with permission:

A grand transformation is underway. A wave of decentralization is sweeping across the globe and changing the way we live, work, and play. The organization of resources and people is moving away from centralized systems toward integrated networks that include both distributed and centralized elements. The trend is pervasive across society and the global economy. Telecommunications, computing, retail, and entertainment have all moved toward decentralization. Today, we are at the beginning stages of decentralization in higher education, health care, and energy. The decentralization movement has the potential to enable unprecedented productivity gains and improve living standards for all.

“Electric power systems are riding the wave of decentralization through the deployment and use of distributed power technologies. Distributed power technologies, which have been around since Thomas Edison built the first power plant in 1882, are used more and more today to provide electrical and mechanical power at or near the point of use. When deployed, distributed power technologies create a decentralized power system within which distributed generators meet local power demand throughout the network.

“The portfolio of distributed power technologies includes diesel and gas reciprocating engines, gas turbines, fuel cells, solar panels, and small wind turbines. Although there is no standard definition, distributed power technologies are less than 100 megawatts (MW) in size – and typically less than 50 MW, which is the limit that distribution systems can accommodate at distribution voltages. They are highly flexible and suitable across a range of applications, including electric power, mechanical power, and propulsion. Distributed power technologies can stand alone, or they can work together within a network of integrated technologies to meet the needs of both large and small energy users.

“The rise of distributed power is being driven by the same forces that are propelling the broader decentralization movement: distributed power technologies are more widely available, smaller, more efficient, and less costly today than they were just a decade ago. But the rise of distributed power is also being driven by the ability of distributed power systems to overcome the constraints that typically inhibit the development of large capital projects and transmission and distribution lines. Because they are small, they have lower capital requirements and can be built and become operational faster and with less risk than large power plants. In addition, distributed power systems can be incrementally added to meet growing energy needs. Furthermore, some distributed power technologies are being propelled by the Age of Gas, an era of more widely available natural gas enabled by the growth of unconventional natural gas production, as well as the expansion of land and seaborne gas networks. Greater gas abundance creates opportunities for gas-fired distributed power systems. The emergence of virtual pipelines – a collection of technologies designed to move natural gas from the end of the pipeline to remote uses – has the potential to amplify the Age of Gas and make gas-fired distributed power technologies even more ubiquitous.

“Taken together, the net result is an increase in distributed power investment and capacity installations that is expected to continue over the next decade. In 2012, \$150 billion was invested in distributed power technologies, including gas turbines, reciprocating engines, and solar photovoltaics in electric, power, mechanical drive, and propulsion applications globally. Approximately 142 gigawatts (GW) of distributed power capacity was ordered and installed. During the same year, GE estimates that 218 GW of central power capacity was ordered. This means that distributed power capacity additions accounted for about 39% of total global capacity additions.

“By 2020, distributed power will play an even larger role. GE estimates that annual distributed power capacity additions will grow from 142 GW in 2012 to 200 GW in 2020. That’s a 58 GW increase and represents an average annual growth rate of 4.4%. During this period, investment in distributed power technologies will rise from \$150 billion to \$206 billion. As a point of reference, during this same period, global electricity consumption will rise from 20.8 to 26.9 terawatt-hours. This represents an average annual growth rate of 3.3%. Thus, through the end of the decade, distributed power capacity additions will grow at a rate that is nearly 40% faster than global power demand.

“The proliferation of distributed power systems will benefit nations, industries, and people around the world because power use is critical to human and economic development. Research has shown that increasing electricity use is positively correlated with advances in income, education, and health. This is particularly true in developing countries such as China, India, and Brazil that have lower per capita income levels, and this is where the demand for distributed power is the greatest today.

“These trends tell us that the reemergence of distributed power is a transformative event that promises to positively impact the future. At GE, we are proud to play a role in realizing the potential of distributed power and humbled by the opportunity to help usher in a new energy landscape, just as we did in 1882 when Thomas Edison built the world’s first power plant. The latest transformation has just begun and the best is yet to come.”

Chittum, A., and K. Farley. 2013. *How Natural Gas Utilities Can Find Value in CHP*. Washington, DC: American Council for an Energy-Efficient Economy. <http://aceee.org/files/pdf/white-paper/chp-and-gas-utilities.pdf>.

As one of three reports in a series on combined heat and power (CHP), the main focus of this report is delineating the ways in which natural gas distribution utilities, or local distribution companies (LDCs), can inspire investment in and implementation of CHP technologies, particularly among small and medium-sized commercial customers. Many barriers create reluctance among individual facilities in implementing CHP, including a lack of information about possible benefits, as well as high upfront capital costs. However, the report states that LDCs are in a unique position to change this tide because they:

- “Can leverage their existing long-term relationships with would-be hosts of CHP systems, such as large commercial, institutional, and industrial customers
- Generally view CHP as economically beneficial within their existing business structure
- Are familiar and comfortable with making long-term capital expenditures
- Can enter into reliable long-term contracts with CHP system hosts in order to mitigate risk
- Can enjoy CHP’s efficiency benefits within state-level energy efficiency goals and targets
- Have better bond ratings and access to cheaper capital than most other industries”

The report conveys the many benefits CHP may have for both LDCs and customers, despite fewer opportunities for monetization. These benefits include, but are not limited to:

- Gas system benefits – CHP can reduce risk and increase cost-effectiveness of natural gas infrastructure projects. CHP also provides insurance in terms of continued demand for gas and may also lower costs for all customers.
- Customer attraction and retention – CHP reduces customer energy costs, thus increasing their competitiveness and the likelihood that they remain reliable customers
- System resiliency – Most CHP is powered through direct connections to underground gas infrastructure, increasing the likelihood that systems will be unaffected by significant weather events
- Assistance with environmental compliance – CHP, coupled with other emission-reducing measures, helps states to mitigate pollution and reach air quality goals, including in the case of forthcoming greenhouse gas regulations

The article points out five mechanisms, and provides corresponding case studies, that LDCs can pursue to encourage CHP.

1. Providing direct assistance and incentives – Philadelphia Gas Works (PGW) pays for customers’ initial CHP feasibility assessment. If the project moves forward, PGW pays the initial upfront costs. The customer then pays PGW back via on-bill financing.

2. Including CHP in larger natural gas efficiency programs – Arizona’s Southwest Gas offers a CHP incentive of \$400–500 per kilowatt as part of its energy efficiency program. Costs for this program are recovered elsewhere in the company’s portfolio.
3. Owning the CHP infrastructure themselves – A large natural gas subsidiary of an anonymous gas and electric holding company is currently exploring a model that would have the utility design and make the initial capital outlay to own CHP assets themselves. In this model the onsite customer would pay a flat monthly fee for the CHP system from operating budgets.
4. Encouraging the partnering of individual facilities and CHP developers – United Illuminating, of Connecticut, designed and tested a zero-capital program to pair third-party owners with customers interested in on-site CHP. The program would set up power purchase agreements between parties.
5. Offering special gas rates for CHP systems – Among the many examples given are LDCs in Connecticut that offer CHP-using customers rebates that are equal to the gas delivery charge. Also, California LDCs are required to charge CHP systems the same price for gas as they charge electric utilities.

In conclusion, the article offers several policy recommendations for state regulators to spur the development of CHP resources.

1. Allow flexibility in the construction of CHP programs, long-term financing assistance, and feasibility assessments
2. Decouple rates and encourage LDCs to reduce customer gas consumption through CHP. The increased gas consumption of new CHP systems will still yield an overall net energy and emission reduction benefit
3. For joint natural gas/electric utilities, allow the costs of utility-owned and customer-sited CHP assets to be recoverable in rates
4. Establish methods to account for location-specific benefits of CHP to the gas distribution system and provide guidance on integrating this information into cost-benefit analyses
5. Prioritize thermal energy planning within energy planning activities to ensure CHP and waste energy recovery opportunities are considered alongside other resources
6. Establish statewide energy efficiency goals and treat net CHP savings from all types of CHP and waste heat recovery as equivalent to other energy efficiency resources
7. Support utility rate structures that are based on performance in certain areas like reliability, environmental performance, and so on
8. Allow CHP to generate compliance credits under forthcoming greenhouse gas regulations
9. Pursue the quantification of CHP’s reliability benefits and more directly integrate these benefits into tests that consider the costs and benefits of energy efficiency resources

Chittum, A. 2013. *How Electric Utilities Can Find Value in CHP*. Washington, DC: American Council for an Energy-Efficient Economy. <http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf>.

As one of three reports in a series on combined heat and power (CHP), the main focus of this report is delineating the ways in which electric utilities can inspire investment in and implementation of CHP technologies, particularly among small and medium-sized commercial customers. Electric utilities are uniquely positioned to make these investments due to their familiarity with long-term capital expenditures, as well as their access to better bond ratings and cheaper capital than other third-party investors. These relatively low-risk investments present a unique benefit to utilities in the form of improved grid reliability, creditable emissions reductions, and a potentially reliable rate of return. However, electric utilities are not significantly incentivized to invest in CHP at present time. What follows is a list of potential benefits CHP can provide in the context of electric utilities.

Table 1. Benefits of CHP to electric utilities

Benefit	Benefit magnitude	Opportunities to monetize	Examples
Low-cost generation	Major	Rate-based generation resource; energy efficiency resource standard	Alabama, Ohio
Cost-effectively meets transmission and distribution needs	Major	Reduced costs	Alabama, New York, Vermont
System resiliency	Major	Customer satisfaction; resiliency portfolio standard	New Jersey
Avoided marginal line losses	Major	Cost-benefit analyses	TK?
Power quality	Medium	Ancillary services markets, customer satisfaction	New Jersey
Fast and flexible development	Medium	Reduced costs	
Environmental compliance	Major	Clean Air Act regulations	Ohio
Fuel flexibility	Medium	Reduced costs	Louisiana
Customer retention	Minor	Sustain customer base	

The report goes on to outline three main ways electric utilities can enjoy these benefits; corresponding case studies are reviewed.

1. Rate-basing the asset – For utilities that own CHP themselves or enter into power purchase agreements for CHP-produced power, the costs of the CHP system are aggregated and embedded into the utility's rate base. Traditionally regulated

- utilities enjoy an economic benefit from a satisfactory rate of return to reach their revenue requirement. Both Southern Company and Austin Energy own CHP systems that are built into their rate bases, and both have power purchase agreements in place that allow excess CHP-produced power to be sold to the grid.
2. Utilizing CHP to meet efficiency goals – The efficiency benefits of CHP can be factored into overall system efficiency and emissions levels in order to meet state goals. In Massachusetts, specific portfolio standards for the implementation of all cost-effective CHP signal its priority among resource options.
 3. CHP as a for-profit business arm – Third-party owners can be engaged for electric utilities that cannot own generation directly. Connecticut-based United Illuminating is exploring a zero-capital program to aid third parties in adopting CHP on-site with power purchase agreements of five to ten years between the utility and system owner.

Due to current regulatory structures, CHP has been disincentivized in many states where electricity sales volume is directly attached to utility revenues. CHP benefits are not readily monetized and quantified, and therefore CHP's potential benefits go unrealized. The author offers a number of policies regulators can pursue in order to spur the adoption of CHP. These include:

- Clarifying how utility investment in customer-sited CHP is handled under current policy
- Allowing rate recovery for utility investment in CHP assets, similar to more traditional assets
- Establishing methods for and guidance on how to account for location-specific benefits of CHP
- Prioritizing thermal energy planning within wider energy planning efforts to offer CHP consideration similar to that given to other resources
- Establishing statewide energy efficiency goals that treat net CHP savings as equal to other resources
- Supporting performance-based rate structures
- Allowing CHP to be a compliance option for carbon reduction targets
- For markets that are no longer vertically integrated, clarifying the types of third-party subsidiaries who are allowed to own generation resources
- Treating CHP and other distribution resources as distribution assets in rate-base determinations
- Improving CHP reliability benefit quantification methods

Hannes, B., and M. Abbott. 2013. "Distributed Energy: Disrupting the Utility Business Model." Insights, Bain and Company. <http://www.bain.com/publications/articles/distributed-energy-disrupting-the-utility-business-model.aspx>.

This article describes distributed generation and how it is disrupting the traditional business model. The article suggests the following strategies that utilities can pursue to survive.

- Preserve and extend core capabilities. Manage the supply and demand balance of distributed energy systems through sophisticated control techniques. Manage large engineering projects. Optimize the use of operational assets.
- Expand existing capabilities. Take no-regret decisions to better position themselves to make the most of new opportunities. This particularly means improving customer loyalty and getting to know customers' needs and preferences better.
- Identify new businesses. One option is integrated contracting, where the utility offers services such as planning, installation, operations and maintenance, and load and demand management.
- Explore partnerships, joint ventures, and acquisitions. Use these to build up distributed energy capabilities and to tap into entrepreneurial activity in this area.

IEI (Institute for Electric Innovation). 2013. "Value of the Grid to DG Customers." Issue Brief. Washington, DC: Institute for Electric Innovation, Edison Foundation.
http://www.edisonfoundation.net/iei/Documents/IEE_ValueofGridtoDGCustomers_Sept2013.pdf.

In this short paper, IEI describes how a distributed generation (DG) customer (or a micro-grid) that is connected to the host utility's distribution system utilizes grid services on a continuous basis. There is a need for a methodology to determine what the DG customer should pay for these services, which include transmission, distribution, generation capacity, and the costs of ancillary and balancing services. IEI provides an example of how the cost of these services can, at times, account for 55% of the typical residential customer bill. Additionally, the paper notes that revenue decoupling promptly restores utility net revenues that would otherwise be lost due to declining electricity sales; however, DG impacts are much greater than the energy efficiency impacts typically covered by decoupling. The paper raises the concern that decoupling to address the costs of net metering would shift costs to non-DG customers.

In order to remedy these issues, IEI suggests three possible models.

1. "Redesign retail tariffs such that they are more cost-reflective (including adoption of one or more demand charges)
2. Charge the DG customer for its gross consumption under its current retail tariff and separately compensate the customer for its gross (that is, total on-site) generation
3. Impose transmission and distribution standby charges on DG customers."

SERVICES

Bentham, P. 2013. "Debate About the Future of Utilities Moves Deeper into the World of Regulation." Greentech Grid, October 17.
<http://www.greentechmedia.com/articles/read/debate-about-the-future-of-utilities-moves-deeper-into-the-world-of-regulat>.

This article summarizes a hearing and webinar on business model and regulatory issues. The author states that "both sessions underscored the need for greater flexibility in the relationship between regulators and utilities. The typically adversarial proceedings of a utility commission are not well suited to figuring out new approaches." The four utility leaders at the hearing uniformly expressed a desire for flexibility, simple regulation, and the opportunity to experiment – all of which could help leverage new business opportunities in the power sector.

"San Diego Gas and Electric chief executive officer Jessie Knight lamented the restrictions on his company. 'It can take two years for the [public utilities commission] to approve a new product,' he said, citing slow progress on building EV [electric vehicle] charging stations. 'Utilities need greater flexibility to be full-service energy companies, not just commodity providers.'" Likewise, Joseph Scalise of Bain noted that "distributed technologies are different. 'They are forcing the creation of a new market that the current regulatory system is not optimized for,' said Scalise.

"New technologies and services are causing a shift 'from a one-way customer mind-set to a two-way consumer mind-set,' said Greg Guthridge of Accenture. 'What consumers really want is control, which is different than choice.' Guthridge's research identified that about one-third of customers are interested and ready to buy new products and services today – and that number is growing. The rest he puts in the 'less is best' group, who want less cost, less choice, and less interaction with their power company.

"Ronald Litzinger, president of Southern California Edison, agreed. 'The distribution grid will need more functionality. We will need more of a network approach than a radial approach to facilitate distributed generation and EVs in two-way flows.'

"...Anne Smith, chair and chief executive officer of SoCal Gas, questioned the market readiness of new technologies. 'Many new technologies are not market-driven, but rather are policy-driven. Utilities are in a better position to implement policies than competitive companies,' she said."

But many were hedging their bets. "'Rather than predict the future, we are positioning ourselves to plan for the future,' said Chris Johns, president of Pacific Gas and Electric, 'regardless of what it looks like.'"

EPRI (Electric Power Research Institute). 2013. *The Program on Technology Innovation: Tracking the Demand for Electricity from Grid-Related Services – Preliminary Delphi Panel Results*. Palo Alto, CA: Electric Power Research Institute.

<http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=00000003002002285>

The Electric Power Research Institute (EPRI) asked 14 experts on electric demand issues to respond to a detailed survey.

Adapted from the executive summary with permission:

Thirteen variables were identified that are expected to have an impact on electricity demand from the grid over the next 20 years. These 13 factors are the economy; changes in housing stock; efficient end-use technology; efficiency investments; building codes and product efficiency standards; state energy efficiency portfolio standards; federal greenhouse gas legislation, or general concern about climate change; price and availability of natural gas; adoption of plug-in electric vehicles; new electric end uses; the price of electricity; the U.S. manufacturing base; and consumer-operated generation.

“Key points from [the] panel discussions are as follows:

- Annual Energy Outlook and other projections understate the increase in energy efficiency
 - Adoption of new technologies like solid-state lighting will be much more rapid than the last new technologies (e.g., compact fluorescent lightbulbs)
 - Enormous venture capital money is going into building controls
 - EPRI needs to add building commissioning and retro-commissioning as a category
 - EPRI needs to track third-party and wholesale market impacts
 - EPRI should assess changes in utility/regulatory policy resulting in customer access to low-cost capital
 - Further studies need to consider that new building codes may result in a 50% reduction in new building energy use
 - Changes in utility/regulatory policy resulting in customer access to low-cost capital could impact customer adoption of new technologies
 - The focus of the consumer electronics and information technology industry on efficiency and power management could result in fundamental changes in other appliance efficiency in the future. In the 1990s, this industry [spent an] enormous amount of research dollars in making processors faster and hard drives bigger. However, with mobility, the primary bottleneck they face today is no longer either of those two, but power management and efficiency of display and circuits.
 - The near-term prospect of built-in Wi-Fi connectivity for appliances and apps that will enable consumers to manage their energy usage without having to spend \$250 for a Nest thermostat
 - Appliance turnover with more efficient devices. For example, the near-term prospect of replacing the hundreds of millions of plasma screens with much more efficient technologies. By design, plasma has a shelf life of seven to eight years.
- On average, the adoption of local generation is insignificant except in a few regions. EPRI should include in their analysis:

- Impact of micro-grid establishment on military bases
- Dramatic reductions in photovoltaic (PV) costs
- Residential fuel cells
- Net metering and tariff changes can counter the impact of efficiency. Shifting volumetric costs to fixed costs decreases the economic incentives to reduce consumption. This needs to be considered.
- Panelists were mixed in their enthusiasm for the prospects for new uses of electricity. However, they acknowledged that there is a declining cost in electric energy services resulting from improvement in technology that could allow electric applications to continue to gain market share despite low gas prices.
- A minority of panelists felt that adoption of plug-in electric vehicles is a wild card in that they could see much greater market adoption than even the most aggressive forecasts now predict.
- The panel lacked consensus on the pace and scale of digitization of society and the impact of data storage and processing power requirements. A minority of the panelists felt that the electric utilities' enthusiasm related to increasing demand for electricity from this end lacked a fact-based analysis of the potential."

MANAGEMENT

Berst, J. 2014. "Avoiding the Death Spiral: Think 'Multipurpose' to Future-Proof Your Utility." Smart Grid Strategy, SmartGridNews.com, January 15.

http://www.smartgridnews.com/artman/publish/Business_Strategy/Avoiding-the-death-spiral-Think-multipurpose-to-future-proof-your-utility-6282.html/?fpm#.UubHFhAo6Uk.

In this brief article, the author emphasizes adaptability as the key characteristic that will allow electric utilities to persist within a rapidly evolving marketplace. As factors such as the rise of renewables, energy storage technologies, net metering, and micro-grids alter the face of electricity generation, utilities that embrace a multipurpose business model will position themselves for survival.

In this context, adaptability means employing "equipment and software that is flexible, versatile, and interoperable (while providing security and privacy to the end user)." This idea of a multipurpose utility can be applied to all levels of the electric power chain, from generation to end use, and necessarily entails increased data capabilities, smart metering, and improved communications infrastructure in order to increase utility flexibility and responsiveness.

However, the author does note several hurdles in the realization of this future, such as personnel training, vendor selection, and increasing regulatory literacy.

Scalise, J., and S. Zech. 2013. "Sustained Cost Reduction for Utilities." Insights, Bain and Company. <http://www.bain.com/publications/articles/sustained-cost-reduction-for-utilities.aspx>.

Given the squeeze between mandated investments and flat-line growth, cutting costs is no longer an option, but rather a requirement for survival. Four areas offer the greatest potential for cost reduction:

- Raising productivity at the front line. Improve field services and call centers. For example, optimize scheduling of field service (instead of making one stop and then returning to base) and improve communication between field crews, foremen, and planners so proper equipment is on board and problems can be solved in real time.
- Reducing external spending, such as through comprehensive and cross-company purchasing programs to give utilities more bargaining power and steeper volume discounts.
- Streamlining organizations. Restructure. Identify shadow functions, where remote sites have staff that replicate work done at the main office. Standardize common processes and eliminate custom, one-off initiatives. Streamline the managerial layer and overhead resources.
- Pruning the portfolio of assets. Manage the portfolio. Periodic reviews of costs and performance can reveal opportunities to rebalance operations or pare the organization. Examples include shifting more operations to low-cost fuels. Locking in long-term fuel supply controls when prices are low and integrating into upstream natural gas supplies. Consider selling portions of the territory with high costs, such as rural areas or areas with high regulatory costs.