The 21st Century Electric Utility

Positioning for a Low-Carbon Future

July 2010

Ceres
A Ceres Report

Authored by
NAVIGANT CONSULTING

Ceres commissioned this report from Navigant Consulting.

Ceres is a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges such as global climate change. Ceres directs the Investor Network on Climate Risk, a group of more than 90 institutional investors and financial firms from the U.S. and Europe managing approximately $10 trillion in assets.

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Preface *by Mindy S. Lubber*

Most experts who follow the U.S. electric power sector agree that the industry stands at a crossroads. This Ceres report reaffirms that perspective; as report author Navigant Consulting concludes, "changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."

Once extremely stable and predictable, today's electric power sector faces an array of challenges and opportunities amid a fast-shifting landscape. New approaches to serving customers by using less energy, cleaner energy and emerging technologies are taking hold at the same time that business-as-usual approaches have become more expensive, complicated and risky. Complying with scientists' urgent calls to dramatically reduce greenhouse gas (GHG) emissions also has enormous implications for the power sector, the largest source of U.S. and global emissions. Responding to these trends requires nothing short of a fundamental rethinking of how we produce, transmit and use electricity.

Investors are paying close attention to how electric utilities are responding to this shifting landscape. The Investor Network on Climate Risk (INCR), a Ceres-organized group of more than 90 institutional investors managing about $10 trillion in assets, has engaged with electric utilities since 2003 on their strategies to mitigate climate risks and prepare for emerging carbon-reducing regulations. A recent INCR report found that asset managers view the utility sector as being uniquely exposed to climate risks. Earlier this year, after numerous requests from investors, the U.S. Securities and Exchange Commission issued formal guidance requiring utilities and other publicly-traded companies to disclose "material" climate-related risks in their financial filings, including impacts from carbon-reducing policies.

But investors and analysts are increasingly aware that the discussion about the 21st century electric utility extends far beyond carbon. Energy efficiency – serving customers by helping to reduce electricity demand – is likely utilities' most important energy resource in the 21st century, as this report points out; but utilizing this resource requires a new business model that doesn't rely on electricity sales to drive profits. And given the investment required to modernize and decarbonize our electricity system – an amount estimated well into the trillions – utility "best practices" such as transparent planning and proactive stakeholder engagement are now essential business activities for mitigating political risks and facilitating cost recovery of proposed investments.

This report identifies five key elements of a 21st century electric utility business model and makes specific recommendations to utilities as they transition to a low-carbon future. It is by no means the final word on this complex and constantly evolving subject. Rather it is a starting point for utilities, policymakers, regulators, investors, analysts, and advocates to consider the utility decisions and behaviors best suited to helping us realize the energy future we all want – a future that, as the report says, "minimizes cost, risk and environmental impact, and maximizes opportunity, options and societal benefit."

Mindy S. Lubber is president of Ceres and director of the Investor Network on Climate Risk.

Foreword *by Tom King*

Today's electric utilities face unprecedented challenges. On top of our traditional goals of safety, efficiency and reliability, the modern utility must address global environmental issues such as climate change, national security issues surrounding our dependence on foreign energy, and a growing desire by customers to have greater control over their energy use decisions to lower costs and decrease their environmental footprint.

Meeting our customers' demands to turn these challenges into opportunities requires transformation of the traditional electric utility business model. Delivering safe and reliable electricity will always form the bedrock of what we do, but the modern utility must expand its vision and adapt to changing circumstances in order for our employees to provide energy sustainably for our customers, communities and shareholders.

This begins with addressing climate change, the seminal issue that impacts our global environment and economy today. As public utilities, we should make our business decisions and set our financial targets with climate change issues and carbon reduction goals at the forefront. This ranges from factoring the price of carbon into major capital investment decisions to elevating key sustainability issues such as climate change to the governance level. At National Grid, one way we are trying to embody that approach is by linking executive compensation to performance on specific goals in meeting greenhouse gas reduction targets.

Fortunately, as Ceres details in this *21st Century Electric Utility* report, many of the actions that we must take to address climate change will benefit our customers and communities in a variety of ways. Energy efficiency is a prime example. Energy efficiency can cost as little as 3 cents per kilowatt hour saved, while electricity costs 6 to 12 cents per kilowatt hour. Thus, energy efficiency measures reduce emissions, avoid unnecessary energy supply investments, lower customer bills and create jobs for electricians, plumbers, laborers, and engineers. Despite these obvious advantages, we have historically grossly underinvested in energy efficiency as an industry. Altering this course by investing in all cost-effective energy efficiency measures is the most effective way to both reduce greenhouse gas emissions and lower customer bills.

Expanding and diversifying our investments in wind, solar and other forms of renewable and low-emission electricity is also critical. This includes not only large scale renewable energy projects, but facilitating local, distributed energy solutions – from solar homes to fuel cells. In conjunction with Smart Grid technologies that optimize energy delivery and use, these alternative, innovative uses of energy will enhance our energy security by reducing our dependence on foreign energy, make our electricity supply more diverse and reliable and create sustainable "green" jobs.

To be sure, electric utilities cannot achieve these goals on their own – it requires the support of our customers and other stakeholders and supportive policies such as federal climate change legislation, revenue decoupling and renewable energy and energy efficiency portfolio standards. However, it is incumbent on us to lead the transformation of our industry, and Ceres' *21st Century Electric Utility* report provides an indispensable blueprint for making the transition a success.

Tom King is president of National Grid U.S.

Executive Summary

The successful 21st century electric utility company will be very different from the utility of the 20th century. To remain competitive, today's utility must respond to the risks and opportunities from climate change, carbon costs, volatile fuel prices, emerging clean technologies, expanding energy efficiency programs, increasing customer expectations and competing third party energy providers. Responding to these challenges will require new core competencies and revised business models for U.S. utilities.

The Shifting Landscape of the 21st Century Electric Power Sector

The business landscape for electric utilities is shifting quickly. In turn, the traditional operating paradigm of building large generation facilities to sell ever-increasing amounts of electricity is changing. Key drivers include:

- The imperative to reduce greenhouse gas (GHG) emissions upwards of 80 percent by 2050 (Figure ES-1);
- Significant climate/clean energy policy momentum in a majority of U.S. states, with likely near-term federal action that will further increase costs and complicate development of fossil-fuel based electricity generation;
- Continued declines in production costs for renewable energy technologies;
- Growing support and uptake of regulatory policies to allow utilities to utilize large-scale energy efficiency as the lowest-cost energy resource;
- Implementation of Smart Grid technologies that offer utilities and their customers the information and tools to better manage electricity usage;
- Growing interest and activity in the development of plug-in electric vehicles (PEVs); and
- Increasing recognition of domestic natural gas as a resource that is less carbon intensive than other fossil fuels for large scale electricity generation, complementary to renewable energy resources, and domestically abundant.

While each of these drivers will materially influence the electric power sector in the coming years, one of the greatest effects will be felt from climate change concerns and the pursuit of steep reductions in greenhouse gas emissions. This is because the electric power sector is the largest single source of U.S. and global carbon dioxide emissions, responsible for approximately 40 percent of total emissions. When carbon dioxide emissions are factored in, the economics of producing electricity with large, centralized fossil-fueled generation will change considerably.

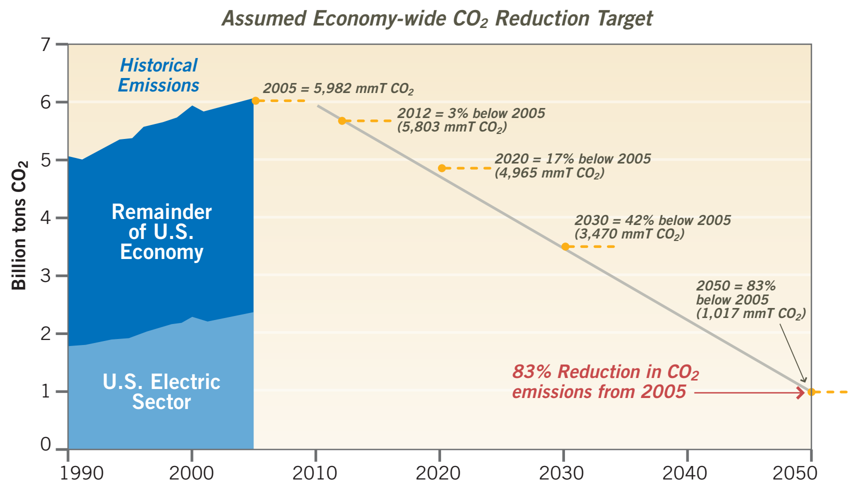

Figure ES-1: *Illustration of 80 percent CO_2 reduction by 2050*
Source: Electric Power Research Institute

Clean energy resources available today will play a critical role in achieving CO_2 reduction targets. Energy efficiency and some renewable energy resources can reduce GHG emissions cost-effectively, while maintaining electric system reliability and reducing system-wide risk. However, deploying these clean energy resources at a large scale presents fundamental challenges:

- First, most utilities lack sufficient regulatory support;
- Second, the traditional utility business model is based on electricity sales which would be eroded by energy efficiency and distributed clean energy resources; and
- Third, the capabilities of the existing electricity delivery infrastructure may limit the amount of clean energy resources that can be integrated without compromising reliability or increasing cost excessively.

A utility that deals effectively with these trends, and receives sufficient support from regulators and legislators, will be better positioned to succeed in the 21st century. All else equal, such a utility is also more likely to attract lower cost capital, enabling it to earn stronger returns for investors. On the other hand, a utility that fails to effectively manage risk, including higher carbon exposure, may suffer greater financial impacts if climate legislation takes hold and fossil generation costs rise.

Factor	20th Century	21st Century
Business Model	Simple, based on steadily increasing electricity sales typically from an expanding asset base of centralized generation and traditional[1] delivery infrastructure	Complex, integrated energy services serving diverse and evolving customer needs with an information-enabled infrastructure
Electricity Demand	Increasing	Flattening with potential decline, exception being the deployment of new electric vehicles[2]
Capacity Cost	Average cost of new capacity stable or declining	Average cost of new capacity increasing[3]
Cost of Carbon	None	Moderate and increasing
Utility Objectives	Reliability, Customer Service, Affordability (low rates), Returns to Shareholders[4]	Reliability, Environmental Quality, Service Quality, Affordability (low bills), Returns to Shareholders
Role of the Customer	Passive	More active, equipped with the technology and incentives to manage energy consumption and generate energy

Table ES-1: *Differences between the Utility Business in the 20th and 21st Centuries*

1. Although new technologies have been introduced, long equipment lifecycles, standardization and utilities' aversion to risk have tended to limit the implementation of innovative transmission and distribution system technology.
2. New energy services such as powering electric vehicles may increase demand, but the net impact is currently unclear.
3. The cost of new capacity will be partially offset as low carbon generating resources become commercially mature.
4. Investor owned utilities, in addition to managing costs, have the goal of earning market-based returns for shareholders, while publicly owned utilities have the goal of minimizing cost for members.

Key Elements of a 21st Century Utility Business Model

In addition to maintaining highly efficient business operations and effectively managing capital, successful U.S. utilities in the 21st century will need to do several things well:

1. Manage carbon across the enterprise. With national climate and energy legislation under consideration and a patchwork of state and regional carbon-reducing policies already in place, it is expected that all utilities will have to deal with expected carbon controls in the future, and probably within their system planning horizons. Utilities should account for carbon emission costs in resource planning, and align those costs and risks with likely carbon-reduction scenarios. Failing to effectively mitigate carbon risk will lead to higher shareholder and lender risks, as well as unreasonably burdening ratepayers with higher costs. Investors and utility commissions will be scrutinizing electricity supply portfolios more closely to evaluate impacts associated with new climate regulations.

2. Pursue all cost-effective energy efficiency. Energy efficiency is among the least expensive energy resources for utilities (Figure ES-2), and one of the most cost-effective ways to reduce GHG emissions. As policymakers, regulators and utilities grapple with the challenge of achieving steep emissions cuts, energy efficiency is likely to emerge as the single most important energy resource for the 21st century power sector. Studies show that energy efficiency lowers consumer energy bills, and implementing it becomes less expensive as utilities use it more widely. Because energy efficiency reduces electricity sales, it has not been fully adopted by most utilities due to their rate structure being directly tied to consumption. However, supportive regulations and ratemaking mechanisms are making it more attractive for utilities to pursue cost-effective energy efficiency.

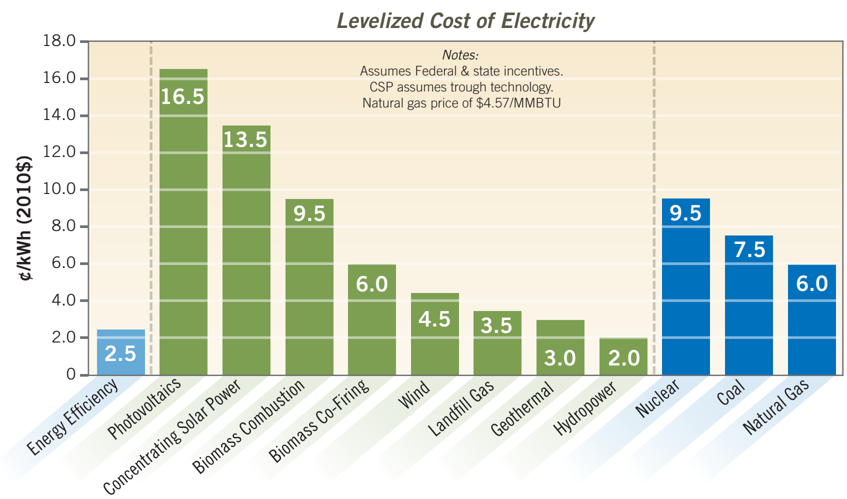

Figure ES-2: *Cost of EE as Compared to Other Resources*
Source: Navigant Consulting, Inc.

3. Integrate cost-effective renewable energy resources into the generation mix. The U.S. is one of the strongest and most attractive renewable energy markets in the world. With continued downward movement in production costs and prices, and upward pressures sustaining or increasing fossil-generated power costs, simple operating economics are becoming an increasingly powerful driver for renewables growth. The U.S. has seen substantial and promising growth in large-scale wind and concentrating solar power (CSP) installations in recent years. However, achieving Renewable Portfolio Standard (RPS) targets using only large-scale renewable energy resources will be challenging due to the need for new transmission development which emcompasses siting, permitting, environmental and cost constraints. For these reasons, a growing number of states and utilities are pursuing expanded investment in distributed energy resources (DER) such as solar photovoltaics (PV) (Figure ES-3). Recent analysis by Navigant Consulting indicates that in some parts of the U.S. PV has the potential to achieve grid parity by 2015, or sooner depending on pricing and incentive levels.

4. Incorporate Smart Grid technologies for consumer and environmental benefit. Smart Grid technologies, including smart metering, distribution automation and synchrophasor monitoring are entering the mainstream, with most U.S. utilities involved in full-scale system implementations or pilot programs. An effective Smart Grid will help reduce both peak electricity demand and overall energy consumption. It will integrate increasing amounts of renewable energy and improve grid efficiency. It will also help utilities gain operational efficiencies and manage infrastructure and operating costs. Utilities should ensure that they implement the Smart Grid in a manner that maximizes consumer and clean energy benefits, including energy efficiency and demand management, and integration of renewable and distributed energy.

RPS Policies	Solar carve-outs/compliance
Revenue Opportunity	Opportunity to rate-base solar assets and leverage existing corporate functions
Federal ITC	Utilities can now use the 30% ITC through 2016
Added Resource	Quick way to deploy RE, avoiding challenges related to transmission, interconnection, permitting
3rd Party Threat	3rd party solar service providers could lead to utility revenue erosion
Brand Halo	Some utilities see solar as a way to create a brand halo
Potential FASB Changes	Financial Accounting Standards Board may reclassify Power Purchase Agreements (PPAs) as debt

Figure ES-3: *Key Drivers of Utility Ownership of PV*
Source: Navigant Consulting, Inc.

5. Conduct robust and transparent resource planning. Utilities should employ open and transparent planning processes that consider the risks, probabilities, benefits, impacts and applications of multiple energy resources under various scenarios. Planning processes should include a full commitment by utilities to implement cost-effective energy efficiency and renewable energy. Resource planning should involve greater stakeholder involvement on a wider regional level and consider the full spectrum of energy efficiency and distributed energy resources. Clear policy frameworks allow all parties to better understand the goals and regulatory objectives that will influence or constrain the planning process. Finally, utilities should update planning processes to reflect current and future costs for CO_2, energy efficiency, distributed energy resources, equipment and permitting.

Financial Implications

Building a clean energy supply and a Smart Grid infrastructure will require utilities to capitalize hundreds of billions of dollars in rate base. Given that average retail electricity rates have increased an average of 50 percent across all sectors over the past 10 years,[5] increasing them even more will be challenging. It is expected that regulators will be more comfortable approving large-scale investments and their associated rate adjustments when the associated risks have been clearly accounted for and managed. Protracted approval processes associated with investments that are perceived by regulators to be unclear or questionable present a significant financial risk to utilities. Some financial analysts are predicting that key credit metrics for utilities

5. U.S. Energy Information Administration

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will be negatively impacted in the long term due to cost recovery risks from downward rate pressure.

Key Regulatory Policies for the 21st Century Electric Power Sector

Mandatory regulatory policies will be needed to enable utilities to deploy the approaches and technologies described in this report. These policies, which typically fall within the purview of state governments and utility regulatory commissions, include:

- **Clean energy policies** that set an overall direction aligning clean energy goals across government agencies (including utility regulators); promote the development and compatibility of complementary policies; and demonstrate a commitment to clean energy resources;
- **Enforceable Renewable Portfolio Standards** that incentivize compliance, provide clear market signals for utilities, and reward those parties that deliver results;
- **Revenue decoupling** to remove utilities' inherent disincentive to implement large-scale energy efficiency;
- **Effective net metering for distributed generation** to facilitate consumer investment in on-site renewable energy generation; and
- **Incentive ratemaking for utilities** to provide premium returns on the "right" utility investments.

Additionally, it is likely that the federal government will set policies that put a price on carbon and increase energy independence, renewable energy and energy efficiency.

Conclusion

Utilities, whether investor owned or consumer owned, are public entities that build and operate the electricity infrastructure that powers our nation and economy. They have an obligation to serve customers in a way that minimizes financial and environmental risk. The ideas discussed in this paper are based on two lynchpin principles that utilities should:

- Minimize cost, risk, and environmental impact; and
- Maximize opportunity, options, and societal benefit.

Utilities need to deploy capital in ways that provide affordable and secure electricity, while meeting the nation's climate objectives. Pursuing approaches that are overly capital-intensive puts upward pressure on electricity rates and increases the risk of unfavorable recovery of cost. This, in turn, could lower a utility's credit rating and increase its cost of capital. Utilities that pursue diversified strategies utilizing cost-effective energy efficiency and distributed energy resources are likely to reduce capital investment risk.

The most successful utilities will likely be those that pursue this agenda aggressively, transparently, and across all aspects of the business. The inherent risk management benefits of this approach are apt to be recognized by the financial institutions that rate and lend to electric utilities. The ongoing support of credit rating agencies and financial institutions is crucial to maintaining the momentum of capital into the ongoing transformation from a simple, regimented, centralized commodity seller to a complex, diversified, innovative service provider.

Key Report Recommendations for U.S. Utilities

Manage Carbon Across the Enterprise

- Make an overall corporate commitment to minimizing carbon emissions as a central guiding policy;
- Perform rigorous scenario analysis that assumes a range of carbon costs;
- Incorporate carbon prices into business and energy resource plans;
- Complete an internal inventory of greenhouse gas (GHG) emissions using widely accepted standards;
- Set a meaningful GHG reduction target that will help prepare the company for future regulation; and
- Disclose relevant data and plans thoroughly to stakeholders.

Pursue All Cost-Effective Energy Efficiency

- Recognize the value of energy efficiency;
- Actively seek out lessons learned and best practices from other jurisdictions;
- Advocate for appropriate policies that support aggressive energy efficiency;
- Develop goals that aim for at least 1% annual electricity savings, consistent with results achieved by leading utility programs;
- Fully include energy efficiency in electric system resource planning; and
- Follow rigorous and transparent monitoring and verification (M&V) protocols.

Integrate Cost-Effective Renewable Energy

- Actively pursue development of a range of renewable energy projects to meet and/or exceed state renewable targets;
- Consider owning PV assets to gain experience in their implementation given the potential near-term grid parity and possible threat of third party providers serving utility customers solar power;
- Evaluate business models being used by private competitors and other utility companies to own distributed energy resources and other renewable assets; and
- Create new risk hedging and grid management mechanisms to deal with variance in customer load response and intermittent renewable energy resources.

Incorporate Smart Grid Technologies for Consumer and Environmental Benefit

- Simplify the interconnection and integration of distributed renewable energy resources;
- Leverage the operational efficiencies provided by Smart Grid technology to reduce operational costs;
- Prioritize Smart Grid investments that seek to maximize benefits from energy efficiency, energy delivery, and clean energy technologies;

Key Report Recommendations for U.S. Utilities

- Provide customers with information and energy management technologies that are aligned with effective pricing programs; and
- Build out the Smart Grid by pursuing a long-term capital improvement program premised on delivering enhanced value to consumers.

Conduct Robust and Transparent Resource Planning

- Utilize transparent analysis and decision frameworks;
- Fairly evaluate energy efficiency and renewable energy in robust scenario analyses;
- Facilitate input from key stakeholders; and
- Educate the public and policy makers about complex energy issues

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I. Introduction: *The Shifting Landscape of the 21st Century Power Sector*

Powerful trends are transforming the U.S. utility sector, including climate change, energy security, and energy price volatility concerns; increasing deployment of alternative resources like energy efficiency and renewable energy; and shifts in natural gas and other fossil fuel industries. Utilities that respond most effectively to these key trends – and whose regulators and legislators support them in doing so – will be best positioned to succeed in the 21st century. Below are highlights of key drivers facing the industry.

Climate Change: A Major Challenge

Climate change is one of the biggest and most complex challenges the world faces today – and utilities are commonly identified as key players in how to respond.

The most recent assessment from the Intergovernmental Panel on Climate Change (IPCC), a worldwide body of hundreds of climate scientists from more than 130 countries, concludes that warming is "unequivocal" and that observed increases in temperatures are "very likely" due to rising greenhouse gas concentrations from human activity. While there is uncertainty on how much warming we can expect, there is strong scientific consensus of the urgency for reducing heat-trapping emissions 50 to 80 percent by 2050.

The electric power sector produces 40 percent of U.S. carbon dioxide (CO_2) emissions, making it a top target of carbon-reducing policies. State and regional governments are already limiting greenhouse gas emissions from electric generation plants. Sector companies operating in multiple states face management challenges and associated costs from these varying regulatory environments. Eighteen states have taken initial steps towards greenhouse gas (GHG) trading systems, including the Western Climate Initiative, California's Global Warming Solutions Act, Florida's State Action Team on Energy and Climate, and the Regional Greenhouse Gas Initiative in the northeast. Some states have taken action to limit CO_2 emissions from electric generation by prohibiting utilities from building new coal-fired generation without carbon sequestration, or from signing long-term supply contracts from such generation. Some state laws also require new generation plants to offset some other their projected CO_2 emissions.

In the U.S., national climate legislation to reduce CO_2 emissions from utilities and other sources is widely seen as inevitable, although such legislation may not pass in 2010. In June 2009, the House of Representatives passed the American Clean Energy and Security Act, landmark legislation to cap GHG emissions across all sectors of the economy. As this report went to press, several alternative bills to limit carbon emissions across the economy or specifically in the electric power sector were under consideration in the Senate.

Energy Security: A Growing National Priority

In this country there is strong interest in achieving greater energy independence and increasing the security of our energy infrastructure. This is leading to growing support for the transition of America's transportation fleet away from oil toward other energy sources, including electricity. The vigorous development of plug-in electric vehicles (PEVs) would require increased flexibility and robustness of the electricity infrastructure. Enhancing the reliability and resilience of the electricity grid to withstand major equipment outages, weather effects, and potential terrorist attacks is also gaining attention.

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Customer Involvement: Leveraging Technology to Better Manage Energy Use

The energy industry, like most others, will continue to experience an evolution in customer expectations, from information on demand to high degrees of control and engagement to the ability to create collaborative and personalized interaction channels with energy service providers. Experts increasingly mention customer involvement and the conversion of end-use load into an energy resource as one of the most transformative changes the industry will undergo. The capability and complexity of loads, including smart appliances, energy management systems, plug-in electric vehicles, and distributed energy resources, are creating the opportunity to engage customers as active energy partners rather than passive ratepayers. The expectation is that new energy products will emerge, including service bundles, customized service levels, and retail energy exchanges.

Grid Technology: Creating Greater Intelligence

Over the 20th century, many of the core technologies used in the power sector for the production and delivery of electricity remained relatively unchanged. Even now, much of the power equipment in service would be recognizable to the utility engineers from the early 1900s. However, over time utilities have applied technology strategically to increase reliability and reduce cost. In recent years, advancements in information technology, communications and electronics have been applied to electric power systems. Increases in capability and reductions in cost for this technology mean that utilities are deploying it at greater scale, which will enable fundamental changes in the way the grid is configured and operated.

Electricity Demand: Multiple Factors Pushing it Down

In the late 1990s and early 2000s, energy use per capital in the U.S. leveled off and began to decline slightly.[5] The recent economic recession resulted in a sharp reduction in energy use, and it is not clear how quickly demand will return to pre-recession levels. The increasing attention and activity around energy efficiency means that electricity demand could continue to drop over the long term.

Defining the U.S. Electric Utility Industry

In recent years, the idea of an "electric utility" has become more diverse and complex. Policy changes at the federal and state levels have reshaped the electric power sector and the structure of the organizations that generate, deliver and sell electricity to end users. For the purposes of this report, utilities include organizations that deliver electricity to customers and charge those customers for that service. These utilities may obtain electricity from their own generators, from other parties, or both, but it is not necessary that they own and operate generation.

Different types of utilities are regulated differently. **Investor owned utilities** are for-profit companies regulated by state utility commissions. **Municipal utilities** are regulated by municipal governments in their various forms. **Cooperatives** are regulated by boards or committees elected by their members, subject to Rural Utility Service standards. (Co-ops may also be regulated by state commissions in certain aspects of their operations.) The structure and regulation of different utilities affect the business models and incentives that, in turn, affect the way each utility approaches clean energy. This report focuses primarily on investor owned utilities, although much of the content should be relevant for municipal utilities and cooperatives.

5. U.S. Energy Information Administration, "Annual Energy Outlook 2010"

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Renewable Energy: Gaining Share in the Supply Mix

Renewable energy is benefiting from advancements on multiple fronts. State policies are mandating it, technology advancements are increasing its performance, and manufacturing scale and process improvements are driving down cost. While renewable energy is still a relatively small portion of the overall energy resource mix, it has been a significant part of new capacity additions in the U.S. in the last few years. This trend is expected to continue.

Natural Gas: An Increasingly Important Strategic Resource

Energy security concerns and technology development are driving momentum for increased reliance on domestic natural gas reserves. Recent technological breakthroughs in extracting natural gas from shale and other "tight" formations have led to a startling reassessment of the nation's natural gas supplies, previously thought to be dwindling. Some experts now predict that the U.S. has over 100 years of proven and potential natural gas supply at current levels of demand. Natural gas is positioned to play a growing role as a complement to variable renewable energy resources. In addition, natural gas can help optimize overall energy efficiency by integrating thermal and electric technologies and end-uses.

Coal: Facing an Array of Challenges

The majority of the nation's coal-fired power plants are at least 30 years old, with many approaching retirement age. Forthcoming regulations from the U.S. Environmental Protection Agency (EPA) to reduce power plant emissions of nitrogen oxides, sulfur dioxide, mercury and other air toxics are expected to materially increase and accelerate coal plant retirements; Bernstein Research concludes that such EPA regulations would likely result in the retirement of roughly a quarter of U.S. coal-fired generation by 2015.[6] In 2008, the U.S. Geological Survey's investigation of the nation's largest and most profitable coalfield found that its economically recoverable coal reserves could amount to only 6 percent of previous estimates, raising questions about the long-term price and availability of coal in other areas of the U.S.[7] More than 120 proposals for new coal-fired power plants have been canceled over the last decade due to concerns about environmental and financial risks, while another 50 face continued legal opposition.[8]

Nuclear Power and Carbon Capture and Storage: Significant Uncertainties Remain

Carbon capture and storage (CCS) and nuclear power are important technological options to decrease carbon emissions, but face considerable financing and implementation challenges. In a February 2010 report, Moody's concluded that "companies that pursue new nuclear generation will take on a significantly higher business and operating risk profile, based on the risks associated with long-term approval, construction and execution processes needed

6. Bernstein Research, "U.S. Utilities: A Visit to Washington Finds Utility Lobbyists & Environmentalists Agreeing on the Grim Outlook for Coal," 9 March 2010.

7. U.S. Geological Survey, "Assessment of Coal Geology, Resources, and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming," December 2008.

8. Lester Brown, "Coal-Fired Power on the Way Out?," 24 Feb 2010. http://ipsnews.net/news.asp?idnews=50449.

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for such projects." While it is likely that some new nuclear plants will begin construction and a small number of CCS pilots will be undertaken in the near term, it will be at least a decade before utilities will be able to confidently pursue development of these resources on a large scale.

Individually, each of these trends creates a degree of uncertainty for electric utilities and the power sector. Combined, they signal a major shift in the landscape of the 21st century power sector. The following report discusses what electric utilities can do to be successful in this new environment.

II. Five Key Elements of a 21st Century Utility Business Model

1 Manage Carbon Across the Enterprise

The discussion surrounding climate change legislation has matured to the point where federal action designed to limit greenhouse gas (GHG) emissions is likely in the near term. Numerous state and regional policies have already emerged. Most utilities are now thinking about climate change, and commitments to clean energy and environmental stewardship are increasingly common. In addition to reliable, affordable electricity, many utilities have added "clean" to their long-term strategic objectives.

National Grid's Approach to Carbon Management

National Grid presents a good example of how a utility can integrate carbon costs into its business operations. In 2008, National Grid set a long-term target to reduce its Scope 1 and Scope 2 GHG emissions by 80 percent by 2050. The company also discloses a shorter-term reduction target of 45 percent by 2020. The timeframes and magnitude of these goals are closely aligned with reduction goals from the scientific community.

The utility company's executives have been using a shadow price for carbon of $50 per ton in its business decisions and planning. Carbon budgets have been established by business lines, and incentive compensation for executives is linked to achieving carbon reductions.

Truly managing the financial risk associated with carbon will require more than acknowledgement that it is important. Utilities should account for carbon emission costs in their resource planning and properly and fully recognize the costs and risks associated with likely scenarios for carbon reduction.[9] Further, the likelihood that coal-fired power generation will become a more expensive and less integral part of baseload generation in the coming years should be a key consideration as utilities map next steps.

While some utilities are beginning to account for carbon risk in their planning, other utility executives and analysts believe that the uncertainty around pending legislation is so great that the value of planning and analysis is quite limited. Uncertainties aside, the lack of a robust and consistent response by utilities to carbon-related financial risks has raised concerns among some financial analysts; as Moody's observed in a February 2010 report, "The electric utility sector does not appear to be responding to the potential climate risks with any sense of urgency, and some companies may find themselves unprepared for legislative changes. We think preparations to strengthen the balance sheet should have begun years ago, and worry that the opportunity costs associated with inaction may yet prove substantial."[10]

The Legislative and Regulatory Context

A number of federal bills have been introduced that aim to reduce GHG emissions using cap-and-trade or cap-and-dividend approaches (Figure 1). The most prominent of these are the American Clean Energy and Security (ACES) Act of 2009 (H.R. 2454), which was passed in the House in June 2009, and the American Power Act "discussion draft," which was introduced by Senators Kerry and Lieberman into the Senate in May 2010. Although the details of the various bills differ, most have proposed similar reductions in GHG emissions, which are significant (83 percent reduction by 2050).

9. "Influence of Retail Market Structure on Financial Impacts of Multi-Pollutant Bills at the Company Level," Kevin Cooney, James Henderson and Robert Repetto, Electric Utilities Environmental Conference, Tucson, AZ, January 20, 2004.

10. Moody's Investors Service, "U.S. Electric Utilities See Some Clarity in Evolving Federal Energy Policies," February 2010.

II. Five Key Elements of a 21st Century Utility Business Model

States and regional entities are already limiting greenhouse gas emissions from electric power plants, creating a patchwork national market in the absence of federal legislation. Multi-state utilities already face management challenges and associated costs from these varying regulatory environments. Eighteen states have taken initial steps toward GHG trading systems, including the Western Climate Initiative, California's Global Warming Solutions Act, Florida's State Action Team on Energy and Climate, and the Regional Greenhouse Gas Initiative in the Northeast (Figure 2).[11] Several states, including California, Montana, Oregon and Washington, have passed laws that prohibit utilities from building or signing long-term contracts with new coal generation without carbon sequestration, and that require new plants to offset some of their projected CO_2 emissions.[12]

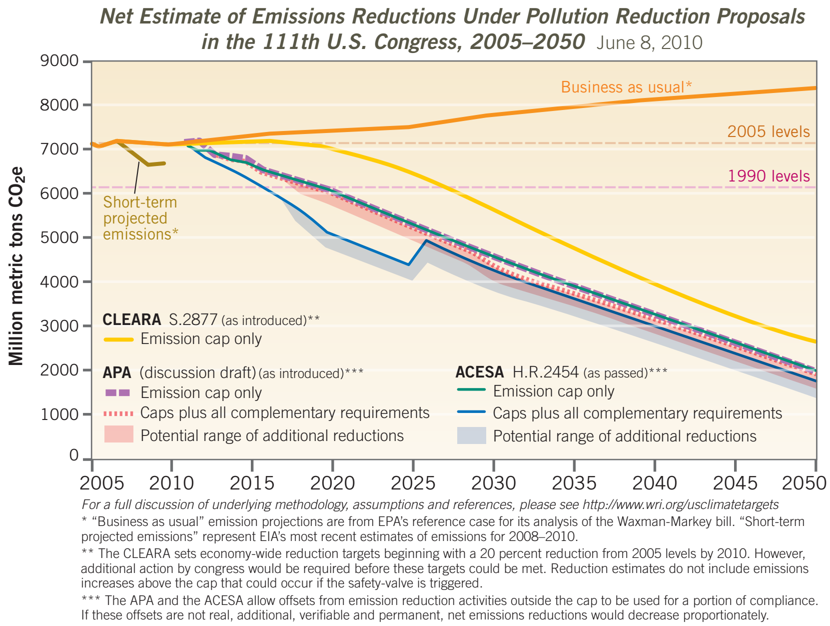


Figure 1: *CO_2e Emission Reductions Required by Waxman-Markey, Kerry-Boxer, Cantwell-Collins, and Kerry-Lieberman*
Source: World Resources Institute

With national climate and energy legislation in process and a patchwork of state and regional efforts advancing in the meantime, it is inevitable that all utilities will have to deal with such a system in the future, and probably within their timeframe of their planning horizons. However, the details of climate change proposals can take many forms, and until such details are fully in place, significant implementation uncertainties will remain. A utility will

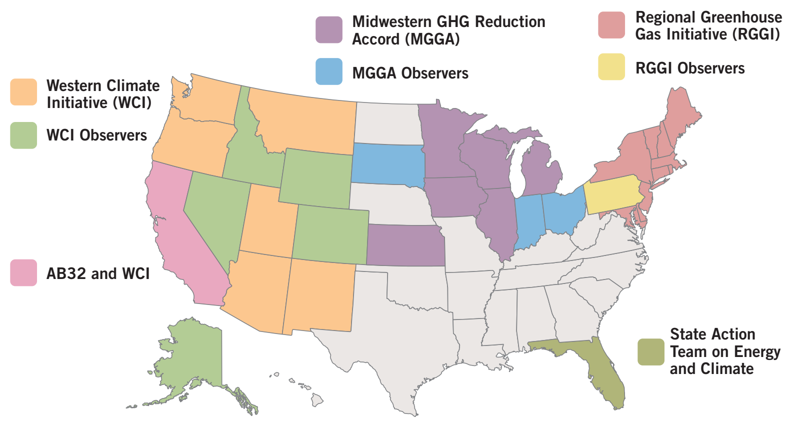


Figure 2: *State and Regional Programs Involving CO_2 Emissions Trading*
Source: Navigant Consulting, Inc.

11. "Uncovering the Full Renewable Energy Potential," renewable Energy World Conference & Expo, Navigant Consulting Pre-Conference Workshop, March 2009.

12. California Senate Bill 1368 prohibits the state's utilities from taking new ownership interest in, or signing new contracts of five years or longer for baseload generation with a CO_2 emission rate exceeding that of a combined-cycle natural gas unit. Washington Senate Bill 6001 includes similar restrictions. Montana House Bill 25 prohibits the state PUC from approving a utility application to lease/acquire an equity interest in a coal plan constructed post-2006, unless it has at least 50 percent capture and storage of CO_2, and requires use of cost-effective carbon offsets if leasing/acquiring an equity interest in a power plant fueled by natural or synthetic gas and constructed after 2006. Oregon HB 3283 requires that new baseload gas generation and new non-baseload generation mitigate projected CO_2 emissions in excess of a specified level. Washington HB 3141 is similar.

need to use rigorous risk management approaches to be best prepared for a range of scenarios. Elements within the proposed national cap-and-trade systems are outlined in Table 1.

Key Design Variables of Cap-and-Trade Systems That May Vary with Legislation	
Emissions Cap	• The level of the system cap • Timing of reduction of cap
Allowances	• How allowances will be allocated, and who they will be allocated to • Which types of utilities will be held responsible to the trading system, and how their requirements will differ • Amount of banking / borrowing allowed in trading system
Offsets	• Criteria for determining legitimate sources of carbon offsets • Amount of offsets, both domestic and international, allowed in the system
Interaction with Existing Systems	• Links to other trading systems, such as the European Union Greenhouse Gas Emission Trading System (EU ETS) • Interaction of a national cap-and-trade with existing state or regional systems.

Table 1: *Key Design Variables of Cap-and-Trade Systems (Varying with Legislation)*

As the costs, complexity, and effectiveness of a market-based system are debated, the Environmental Protection Agency (EPA) has also been proceeding with GHG regulation under the Clean Air Act (CAA). This authority is based on a 2007 Supreme Court ruling allowing EPA to use the Clean Air Act to regulate GHG emissions.[13] Utilities may be exposed to GHG regulatory risk stemming from the CAA.

Effective Carbon Management

While the details of eventual federal, state and regional clean energy regulations will influence their impact, utilities will increasingly need to manage carbon emissions with a focus on the financial liabilities associated with these emissions. For example, analysis by Standard & Poor's (S&P) suggests that companies with carbon intensive generation portfolios could face negative earnings impacts of between 10 and 20 percent.[14] Electric utilities should view this imperative alongside other issues facing the industry such as grid integration of variable generation, transmission constraints, uncertain demand growth and differing electricity market structures – all of which can influence generation and portfolio planning and resource choices. Moreover, uncertain fuel (and carbon) prices, uncertain responses from regulators who set rates, different cost trajectories for renewable energy technologies and localized siting/permitting bottlenecks for new projects can further complicate strategic decisions on precisely how to cost effectively lower carbon emissions.

Suboptimal decision-making processes on carbon mitigation can lead to higher risks for shareholders and lenders as well as unreasonably burdening ratepayers with higher costs. In a carbon-constrained economy, capital providers and utility commissions will increasingly

13. *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007)

14. Standard and Poor's, "How Cap-And-Trade Will Affect U.S. Power Markets and Merchant Generators Profitability," September, 2009.

examine generation and fuel portfolios to evaluate risk associated with potential new regulations. The complexity of this new regulatory situation is highlighted in Figure 3, although by no means does this graphic represent an exhaustive list of financial issues arising from carbon emissions.

The financial community is increasingly aware of the risk that carbon-emitting generation represents in the energy portfolios of utilities. However, it does not appear that a consistent means for valuing that risk has been developed. While regulatory uncertainty makes it challenging to definitively assess carbon risk, analysts and utilities should still be performing extensive scenario analysis to help guide decision-making. Existing frameworks, such as the Carbon Principles' Enhanced Environmental Due Diligence, could be useful for supporting such analysis.

It is essential that utilities account for the cost of carbon in their resource planning. Even though the details of legislation could significantly influence the ultimate carbon price, accounting for a range of potential carbon costs will lead to more prudent decision-making.

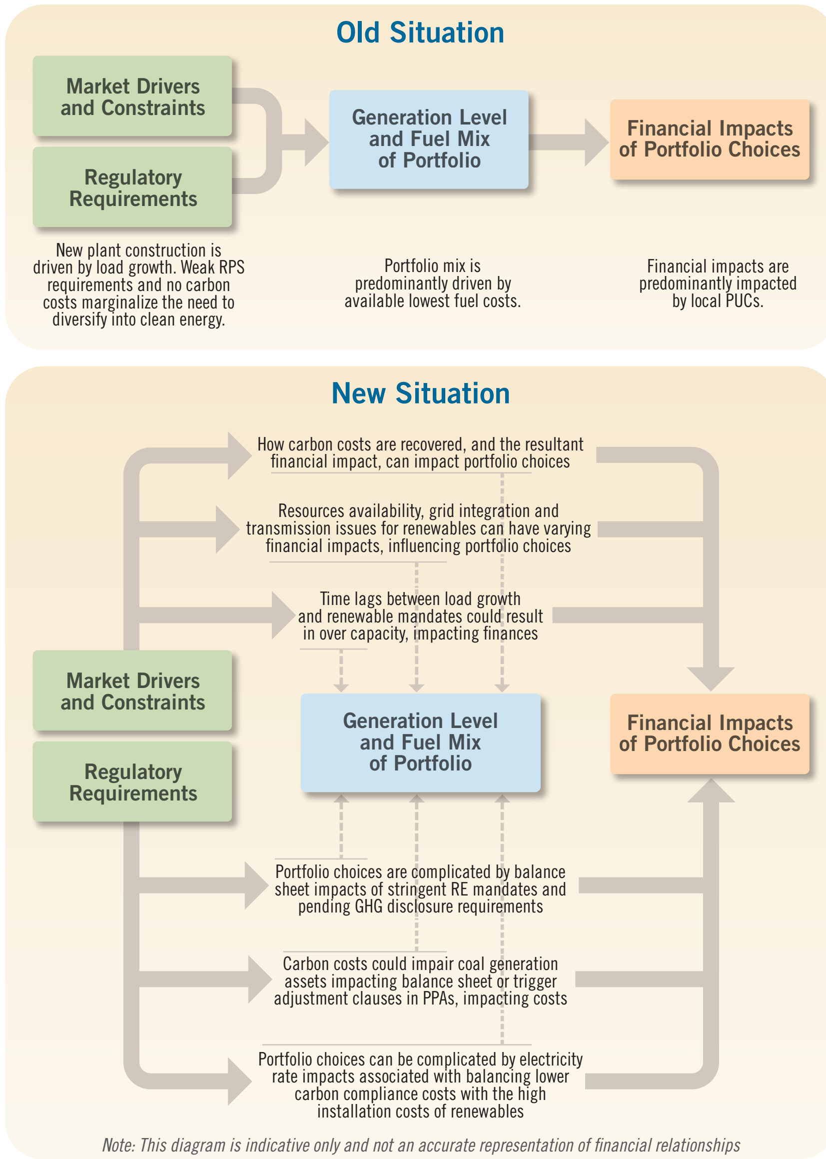


Figure 3: *Graphical Representation of Current and Future Relationships between Portfolio Drivers and Financial Impacts*
Source: Navigant Consulting, Inc.

The results of a Lawrence Berkeley National Laboratory study[15] of utility practices for quantifying carbon financial risks indicate that the best-equipped utilities will have planning scenarios that include:

- the most likely future regulatory outcomes;
- a wide range of possible carbon prices;

15. Managing Carbon Regulatory Risk in Utility Resource Planning: Current Practices in the Western United States, Galen Barbose, Ryan Wiser, Amol Phadke, and Charles Goldman, Ernest Orlando Lawrence Berkeley National Laboratory, March 2009.

- a diverse set of low-carbon portfolios capitalizing on energy efficiency and renewable resources;
- 10–20 year time horizons;
- potential indirect effects of carbon regulation;
- accounting for risks attributable to uncertainty in future technology costs; and
- the value of emissions avoided through EE and reduced carbon regulatory risk.

Long-Term Planning with Carbon Scenarios

The resource planning process at PacifiCorp, an Oregon-based utility, provides an example of robust planning that can curb carbon risk. The process includes a range of carbon prices, a long-term outlook, and potential indirect effects of carbon regulations in support of portfolio development. The company also accounted for EE in their candidate portfolios, incorporating their base case carbon prices into their assessment of EE cost effectiveness. The Oregon PUC required PacifiCorp to include carbon costs in their planning and helped to shape how the utility accounted for carbon in its planning process.

PacifiCorp identified a broad range of candidate portfolios, some of which included planning horizons out to 2026. Many portfolios included a resource mix that exceeded Oregon's current renewable portfolio standard (RPS) targets. Potential indirect effects of carbon regulations included the impacts on electricity market prices, natural gas prices, air pollutant permit prices, and regional generation expansion. Product cost models were developed to create electricity price forecasts for each scenario.

Finally, PacifiCorp used a capacity expansion model to determine how resources performed across carbon scenarios, helping them to more transparently and accurately incorporate carbon into the portfolio selection process. A threshold analysis was used to determine a carbon price point at which a candidate portfolio would become the preferable least-cost option. This approach allows the utility to consider the probability of carbon prices reaching a point with major implications for the composition of the least-cost portfolio.

Utilities should measure their carbon footprint in detail to fully understand their exposure. Existing reporting standards – such as EPA's GHG Reporting program, the Global Framework for Climate Risk Disclosure, the Carbon Disclosure Project, and the Greenhouse Gas Protocol[16] – can help utilities achieve this goal within an accepted framework.

Along with a rigorous accounting for carbon cost, setting a target for GHG reductions is important. Once a target is established, utility managers can develop long-term action plans across various business units that will contribute to achieving the reduction. Building carbon reductions into business operations frameworks will also help foster innovation around practices for achieving targets. Many utility companies, including American Electric Power, Entergy, Duke Energy, Exelon, National Grid, Consolidated Edison, Xcel Energy, PSEG, NiSource, and Pinnacle West, have already set absolute or intensity targets. Many of these companies cite multiple benefits of setting GHG reduction targets, including improved operational efficiencies, preparedness for emerging regulations and enhanced standing with key stakeholders.

It is critical that utilities capably manage carbon across their enterprise, and properly account for carbon exposure in their business planning. Given the challenges related to regulatory and financial uncertainties, utilities can begin to account for carbon exposure by

16. The Greenhouse Gas Protocol (GHG Protocol) is an international accounting tool for government and business leaders to understand, quantify, and manage greenhouse gas emissions. The GHG Protocol is a decade-long partnership between the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). www.ghgprotocol.org.

establishing a shadow carbon price for planning purposes. Furthermore, utilities should develop and analyze scenarios to explore the impacts of variations in carbon regulation and market conditions to inform decisions throughout the enterprise, not just around generation or supply procurement. This will allow the utility to include "carbon externalities" as it conducts its future planning, as well as develop ways to reduce its carbon exposure. Finally, utilities should develop carbon-related risk management competencies and fully incorporate these into the company's enterprise risk management (ERM) approach.

In summary, to effectively manage carbon, utilities should:

- Make an overall corporate commitment to minimize carbon emissions as a central guiding policy;
- Perform rigorous scenario analysis that assumes a range of carbon costs;
- Incorporate carbon prices into business and energy resource plans;
- Complete an internal inventory of GHGs using widely accepted standards;
- Set a meaningful GHG reduction target that will help prepare the company for future regulation; and
- Disclose relevant data and plans thoroughly to stakeholders.

Exelon's 2020 Low Carbon Roadmap

After far surpassing its initial goal of reducing GHG emissions by 8 percent from 2001 to 2008 (and actually achieving a 38 percent reduction), Exelon committed to a new 2020 goal. The Illinois-based utility now aims to reduce, offset or displace more than 15 million metric tons of greenhouse gas emissions per year by 2020, roughly the same amount that the power company emitted in 2001.

Exelon's three-pronged strategy for achieving comprehensive GHG reductions:

1. Reduce or offset its carbon footprint by greening operations
2. Help customers and communities reduce their emissions
3. Offer more low-carbon electricity in the marketplace

The strategy is predicated on a comprehensive economic analysis of the GHG abatement options available to the company.

2 Pursue All Cost-Effective Energy Efficiency

Energy Efficiency (EE) is a critical mechanism for reducing energy consumption, maintaining system reliability and reducing GHG emissions. In addition, energy efficiency is often the cheapest source of energy for utilities. The Institute of Electric Efficiency (IEE), created by the Edison Electric Institute in 2008, calls EE the "first fuel" for the industry. IEE states that EE is a cost-effective way to reduce carbon emissions and moderate electricity demand growth.[17] A recent report backed by the U.S. Department of Energy (DOE) and U.S. Environmental Protection Agency (EPA) indicates that EE should be a key component of any national climate policy because it is a low-cost way to reduce GHG emissions, and consequently helps minimize the overall economic impact of climate action.[18]

17. "Impact of Energy Efficiency and Demand Response on Electricity Demand, Perspectives on a Realistic United States Electric Power Generation Portfolio: 2010 to 2050," Lisa Wood, Executive Director, Institute for Electric Efficiency, October 26, 2009.

18. "Energy Efficiency as a Low-Cost Resource for Achieving Carbon Emissions Reductions," National Action Plan on Energy Efficiency, September 2009.

Energy efficiency portfolios typically save electricity at a cost of about 3 cents per kWh, which is roughly two to three times less expensive than many supply-side resources (Figure 4).

In addition to its advantage as the lowest-cost energy resource, energy efficiency provides numerous benefits to utilities and customers. The National Action Plan on Energy Efficiency (NAPEE) – a consensus-based initiative involving dozens of power sector, regulatory, consumer and industry representatives launched in 2006 by DOE and EPA – points out the following energy efficiency benefits:

- Lower energy bills, greater customer control, and greater customer satisfaction
- Modular and quick to deploy
- Environmental benefits from reduced fuel consumption (including reduced air pollution, GHG emissions, water consumption, and environmental damage from fossil fuel extraction)
- Economic development
- Energy security

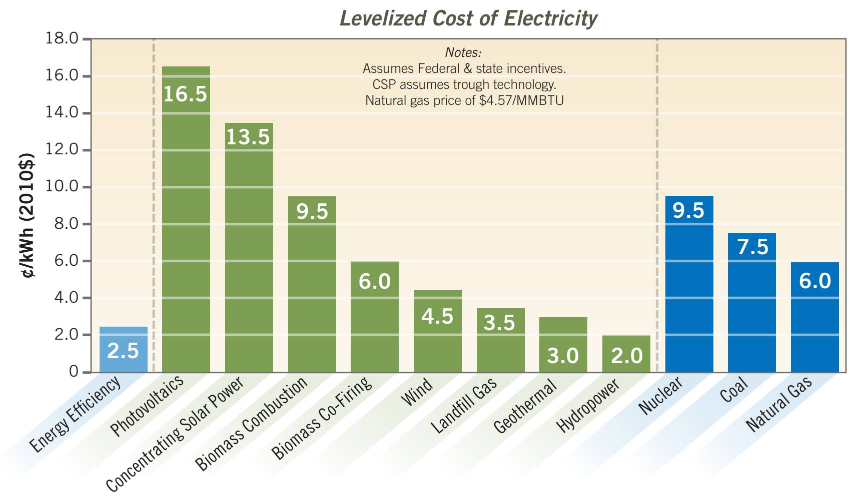


Figure 4: *Cost of EE as Compared to Other Resources*
Source: Navigant Consulting, Inc. 2010

Some states have been implementing successful EE measures for years. The State Energy Efficiency Scorecard produced by the American Council for an Energy Efficient Economy (ACEEE) ranks states in six categories related to energy efficiency. Table 2 shows the top 10 states as ranked according to ACEEE's six categories, along with their associated electricity savings. As shown in the table, leading states have been able to achieve EE savings of 1 percent or more of electricity sales per year.

Top Ten States Based On ACEEE's State Energy Efficiency Scorecard	
2009 Rank (2008 savings*)	2008 Rank (2007 savings*)
1. California (1.3%)	1. California (1.3%)
2. Massachusetts (0.86%)	2. Oregon (0.90%)
3. Connecticut (1.1%)	3. Connecticut (1.1%)
4. Oregon (0.90%)	4. Vermont (1.8%)
5. New York (0.36%)	5. New York (0.36%)
6. Vermont (1.8%)	6. Washington (0.74%)
7. Washington (0.74%)	7. Massachusetts (0.86%) & Minnesota (0.68%) (tie)
8. Minnesota (0.68%)	9. Wisconsin (0.66%)
9. Rhode Island (0.81%)	10. New Jersey (0.30%)
10. Maine (0.91%)	

Table 2: *Top States in Energy Efficiency Based On ACEEE Scorecard*
**Savings as a percent of electricity sales. Source: ACEEE*

While leading states have tended to be located on the coasts (as Table 2 indicates), EE is gaining traction across the country. Less experienced states are now taking ambitious steps toward implementing large-scale EE programs. Ohio and Indiana, for example, adopted identical energy savings targets in 2009 ramping up to 2 percent of annual electricity sales by 2019, ranking among the most aggressive targets in the nation.

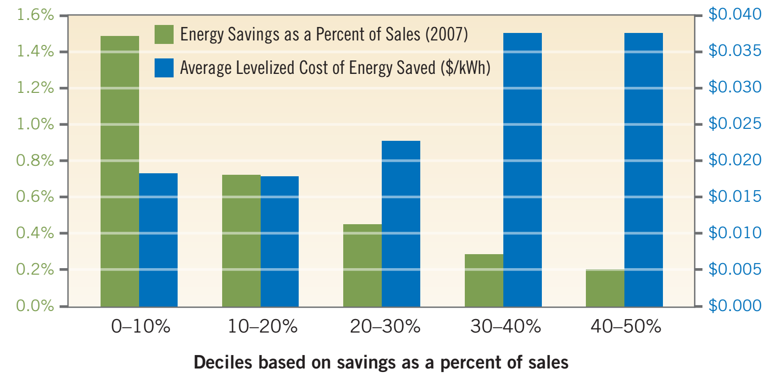


Figure 5: *Cost of Energy Saved and Savings as a Percent of the Utility's Sales*
Source: EIA, Navigant Consulting analysis

But even states with long track records on EE continue to make significant strides. For example, Massachusetts finalized plans in January 2010 to make EE its "first fuel," with the state's Department of Public Utilities calling on electric and gas utilities to invest $2.2 billion aimed at saving customers $6 billion in energy costs. The plan establishes electricity savings targets for utilities that reach up to 2.4 percent of annual sales by 2012, amounting to 2,600 GWh of cumulative electricity savings by that time. By 2020, the plan calls for 30 percent of the state's electricity demand to be met by EE.

Analysis by Navigant Consulting indicates that the utility EE programs that achieve the highest levels of energy savings also deliver EE at the lowest cost, suggesting that energy efficiency becomes less expensive as utilities use it more widely (Figure 5). After ranking utility EE programs in deciles based on 2007 electricity savings, Navigant Consulting looked the top five deciles and compared how much energy was saved with how much it cost utilities to save it. The top decile of utilities saved energy equal to 1.4 percent of their sales at an average utility[19] levelized cost of less than 2 cents per kWh saved.

Because EE is the lowest-cost energy resource, successful energy efficiency programs lower customer electricity bills. The Northwest Power and Conservation Council, whose ambitious EE programs save 35,000 GWh annually and in 2008 delivered consumer savings of

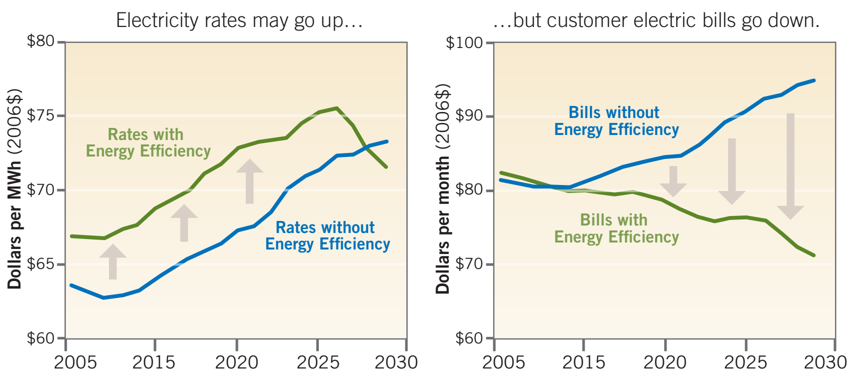


Figure 6: *Energy Efficiency Increases Rates, but Decreases Bills*
Source: Tom Eckman, Northwest Power and Conservation Council, BPA Utility Energy Efficiency Summit, March 17, 2010, and Navigant Consulting analysis.

19. Utility cost of energy saved includes the utility program management and administration costs and the incentives provided to customers. The incentives often cover only a portion of the total cost of the measure.

roughly $1.8 billion, has demonstrated that while the cost of energy efficiency programs may slightly increase electricity *rates*, the resultant reductions in energy consumption will decrease customer electricity *bills* (Figure 6).[20]

Furthermore, studies suggest that consumer savings increase as the magnitude of EE investment increases. Analysis conducted during the development of the Regional Greenhouse Gas Initiative (RGGI) in the Northeastern U.S. indicated that doubling EE spending in the region could yield average energy bill savings of 4.7 percent for industrial customers and 12.4 percent for residential customers by 2021 relative to the reference case.[21] Again, while per-kWh rates would increase slightly, the number of kWh used by customers would decrease as would their bills.

EE is certainly not a new concept. For decades, government and utilities have supported EE through appliance and lighting programs, weatherization, and customer education. Some utilities and states have gone further; for example, California places EE at the top of its "loading order" of energy resources.[22] As of January 2010, 22 states had legislated some sort of energy savings goals or Energy Efficiency Resource Standards (EERS), and four others have a pending EERS (Figure 7).[23]

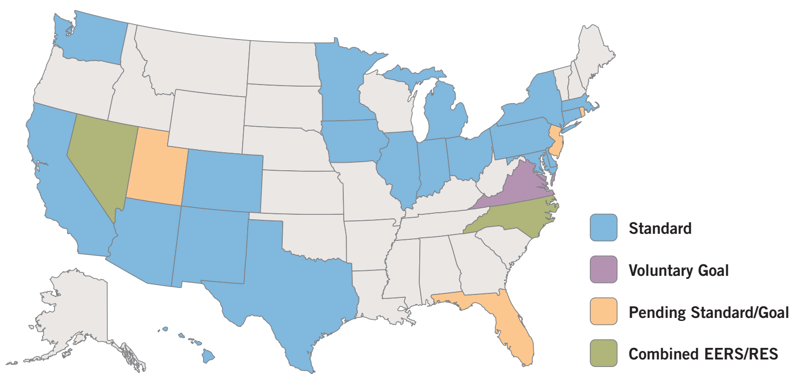


Figure 7: *States with Energy Efficiency Resource Standards (January 2010)*
Source: ACEEE

Like any energy resource, EE is not without challenges. Disparities among states in reporting program costs and energy savings makes it difficult to measure EE results achieved in comparable terms. Also, determining the baseline against which results will be measured can be difficult and varies among utilities and states. Program results are typically reported by estimating the amount of energy savings that various types of equipment will deliver, with state commissions increasingly requiring Monitoring and Verification (M&V) of savings.[24] Effective M&V is a critical factor in increasing the implementation of EE across the U.S.

20. Tom Eckman, Northwest Power and Conservation Council.

21. "Energy Efficiency's Role in Limiting RGGI Leakage," Bill Prindle, ACEEE, June 15, 2006. www.rggi.org/docs/prindle.ppt

22. Preferred resources in California's loading order are energy efficiency, demand response, renewables, distributed generation and clean and efficient fossil fuel generation.

23. American Council for an Energy-Efficient Economy, March 2009. http://www.aceee.org/energy/state/policies/4pgStateEERSsummary.pdf

24. While different states have different M&V protocol requirements, the industry trend is to require use of standard protocols developed and used in many states and regions. Procedures for monitoring and evaluating the MW/MWh impacts of EE programs generally build on the requirement of the International Performance Measurement and Verification Protocol (IPMVP).

II. Five Key Elements of a 21st Century Utility Business Model

The benefits of EE are clear, including lower electricity cost to consumers, less consumption of CO_2 emitting fuel for generation, and less need for physical delivery infrastructure. The problem, however, is that the traditional utility business model involves supporting tremendous fixed capital costs with revenues collected by selling kWh to customers. Even small reductions in sales can disproportionately harm utility earnings; analysis commissioned by the Minnesota Public Utilities Commission illustrates that a one percent decline in sales can reduce earnings by about 10 percent for distribution-only utilities and 7 percent for vertically-integrated utilities.[25] Therefore, while utilities have offered EE programs for a long time, most have been doing so from a conflicted position.

Some utilities have indicated that, with the right policy mechanisms in place, implementing EE is a financially safe proposition. **Revenue decoupling** (or simply "decoupling"), discussed in more detail later in this report, is one such mechanism. Decoupling ensures that a utility recovers exactly its commission-approved rate of return regardless of sales fluctuations, thereby severing the link between sales and profits. This allows the utility to pursue large-scale EE programs without threatening profitability, and to support the suite of public policies (including building codes and appliance standards) required to realize energy efficiency at scale. California's decoupling program is a key reason why the state's per capita power consumption has remained flat since the mid-1970s while the rest of the U.S. has seen a doubling in energy use.

By itself, decoupling does not provide utilities with adequate financial incentive to aggressively pursue EE. Approaches to financial incentives vary, but once a policy is in place to protect the utility from declining sales it is generally recognized as best practice to reward utilities for performance towards an energy savings target, with the richest incentives being reserved for exemplary performance.[26]

Key Features of an EE Program

The EE model being pursued by Idaho Power Company has produced promising results at a low cost. The program combines three important features: funding, decoupling, and performance incentives. Through its program, the utility reduced total sales by 0.5 percent at a cost of 1.8 cents per kWh in utility expenditures.

Key features of the program include:

- A rider for EE of 1.5 percent of base revenue, producing about $8.5 million annually;
- A Fixed Cost Adjustment to offset revenue reductions due to lost sales; and
- A "Performance-Based DSM Incentive" to reward the company for exceeding program goals, and penalize it for failing to meeting those goals.

The Fixed Cost Adjustment and Performance-Based Incentive were instituted together at the beginning of 2007 as part of a decoupling pilot program involving the Residential Service and Small General Service (commercial) customer classes. The program has been monitored closely by the Commission staff and other parties.

All of Idaho's major utilities use riders to fund EE, ensuring that program money is available to make EE investments. This program takes the next step by providing the decoupling mechanism that removes the financial disincentive to investing in EE. Finally, the program provides the utility an opportunity to be rewarded for performance.

25. Regulatory Assistance Project, "Revenue Decoupling: Standards and Criteria," Report to the Minnesota Public Utilities Commission, 30 June 2008.

26. National Action Plan on Energy Efficiency, "Aligning Utility Incentives with Investment in Energy Efficiency," November 2007.

There are three key elements for incentivizing energy efficiency for investor owned utilities (Figure 8):

- Program cost recovery;
- Lost margin recovery; and
- Performance incentives.

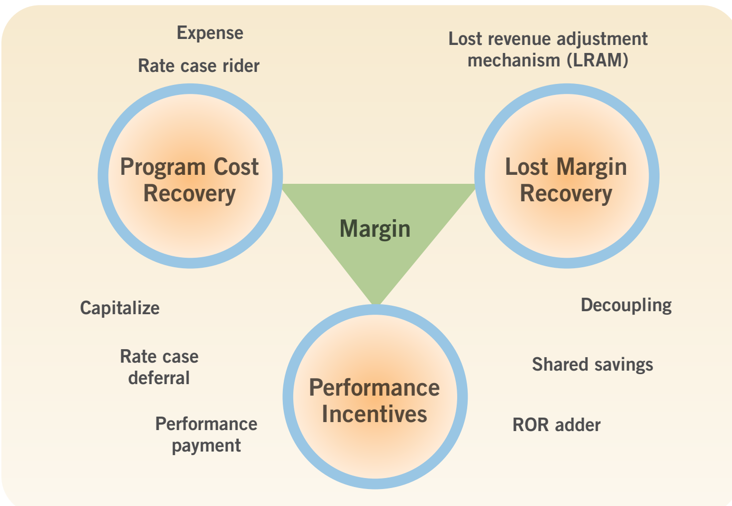


Figure 8: *Elements for Incentivizing EE for Investor Owned Utilities*
Source: National Action Plan for Energy Efficiency, November 2007

These elements can be achieved by utilizing a number of mechanisms including:

- Tariff riders for energy efficiency expenses;
- Capitalizing or rate basing energy efficiency investments;
- Lost revenue adjustment mechanism (LRAM);
- Decoupling;
- Shared savings;
- Performance payments; and
- Rate of return adders.

It is also important that customers receive proper education about energy efficiency programs and their benefits. This helps the utility achieve greater market penetration with its energy efficiency programs, and helps customers understand potential cost savings as well as the relevancy of energy efficiency to distributed generation investment decisions.

In summary, to pursue all cost-effective energy efficiency, utilities should:

- Recognize the value of energy efficiency;
- Actively seek out lessons learned and best practices from other jurisdictions;
- Advocate for appropriate policies that support aggressive energy efficiency;
- Develop goals that aim for at least 1% annual electricity savings, consistent with results achieved by leading utility programs;
- Fully include energy efficiency in electric system resource planning; and
- Follow rigorous and transparent M&V protocols.

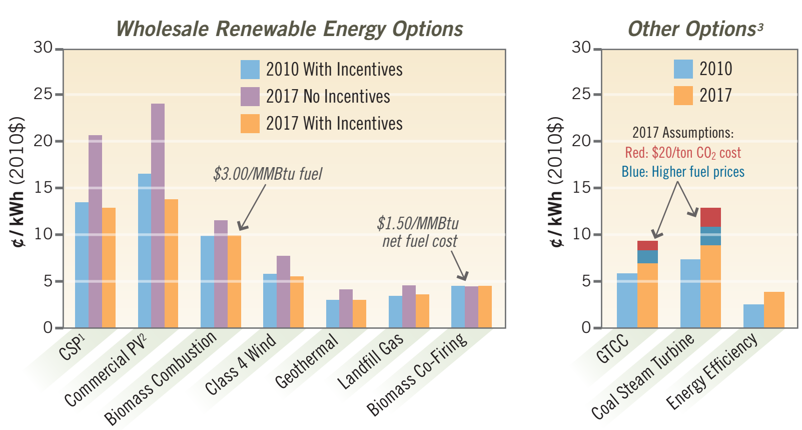
3 Integrate Cost-Effective Renewable Energy Resources into the Generation Mix

A confluence of factors has made the U.S. one of the strongest and most attractive renewable energy (RE) markets in the world – an important trend given the need to reduce the power sector's carbon footprint. Figure 9 illustrates the drivers that are stimulating the U.S. renewable energy market.

Figure 9: *Renewable Energy Market Drivers in the U.S.*
Source: Navigant Consulting, Inc.

Improvement in the economics of renewable energy relative to the market price of electricity will continue to result in significant additions of renewable energy to many generation portfolios. Technologies such as wind power are currently price-competitive with natural gas-fired power in locations with strong wind resources (Wind Power Class[27] 4 or better). In 2009, wind generation represented 39% of all new generating capacity installed, regardless of type.[28] Other renewable energy technologies such as landfill gas, solar thermal, biomass and geothermal are also at or near competitive pricing levels (Figure 10). With continued downward movement in price expected across most renewable energy sectors and upward pressures sustaining or increasing fossil generated power costs, simple operating economics will become an increasingly powerful driver over the near term.

Another key driver behind the large-scale adoption of renewable energy has been public policy, including incentives and Renewable Portfolio Standards (RPS). As of February 2010, 29 states and Washington D.C. had RPSs, and six states had renewable portfolio goals (Figure 11). If met in their entirety,



(1) High insolation (2) High Insolation (e.g. Southern California) and 2010 PV installed system price of $4.15/Wpdc; Note: All cost estimates exclude additional revenue from renewable energy certificates. (3) GTCC = $.06/kWh and Coal Steam Turbine = $.075/kWh in year 2010 and GTCC = $.071–$.085/kWh and Coal = $.089–$.11/kWh in 2017 for $4.57 & $6/MMBTU (Gas), respectively and $1 and $3/MMBTU (Coal), respectively. A $20/ton CO_2 results in ~.0075 & $.02/kWh incremental cost for GTCC and Coal, respectively.

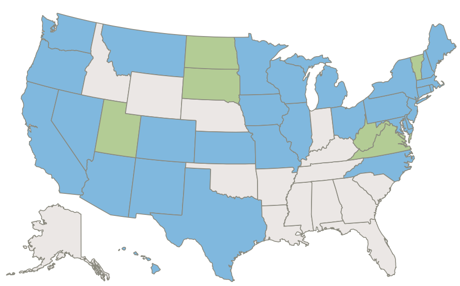
Figure 10: *Typical Levelized Cost of Electricity for Selected Wholesale RE Resources, Developer Financed*
Source: Navigant Consulting, Inc.

27. "Basic Principles of Wind Resource Evaluation," American Wind Energy Association, http://www.awea.org/faq/basicwr.html

28. AWEA U.S. Wind Industry Annual Market Report, Year Ending 2009.

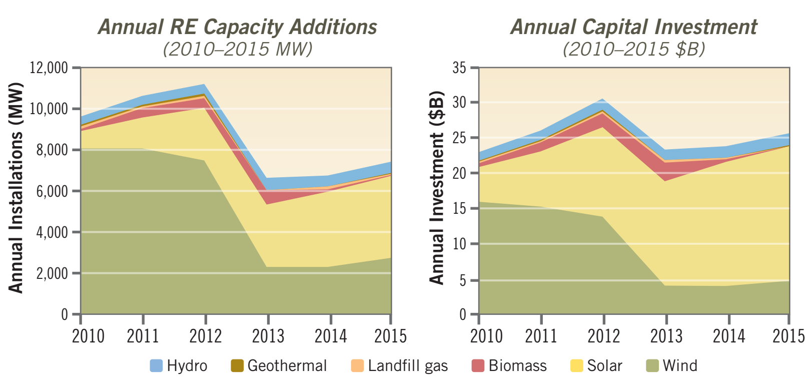
RPS Targets

AZ	15% by 2025	**ND**	10% by 2015 goal
CA	33% by 2020	**NH**	23.8% by 2025
CO	30% by 2020 (IOUs), 10% munis and co-ops	**NJ**	22.5% by 2021
CT	23% by 2020	**NM**	20% (IOUs), 10% (co-ops) by 2020
DC	20% by 2020	**NV**	25% by 2025
DE	20% by 2019	**NY**	24% by 2013
HI	40% by 2030	**OH**	25% by 2025
IA	105 MW (2% by 1999), add'l 1000 MW goal by 2011	**OR**	25% (large utilities), 5%–10% (small utilities) by 2025
IL	25% by 2025	**PA**	18% in 2020
KS	20% by 2020	**RI**	16% by 2020
MA[1]	15% by 2020 (+1%/year after for tier 1; 3.6% tier 2)	**SD**	10% by 2015 goal
MD	20% by 2022	**TX**	5,880 MW by 2015
ME[2]	10% additional by 2017 class 1	**UT**	20% by 2025 goal
MI	10% +1,100 MW by 2015	**VA**	15% of 2007 sales by 2025 goal
MN	25% by 2025, (Xcel 30% by 2020)	**VT**	Energy growth 2005–2012 goal met by RE; 20% RE & CHP by 2017
MO	15% by 2021	**WA**	15% by 2020
MT	15% by 2015	**WI**	10% by 2015
NC	12.5% of 2020 sales by 2021 (IOU), 10% of 2017 sales by 2018 (muni/co-op)	**WV**	25% by 2025 (RE & Alt E) goal



1. MA has enacted an additional Alternative Energy Portfolio Standard of 5% by 2020 and an added 0.25% of sales each following year. Eligible technologies include CHP, gasification with CO_2 capture, and flywheel energy storage among others.
2. ME has a goal of at least 3,000 MW of installed wind capacity by 2020.
3. Guam has enacted an RPS goal of 25% by 2035.

Figure 11: *Renewable Energy Market Drivers in the U.S.*
Source: January 2010, Database of State Incentives for Renewable Energy (DSIRE)



Forecasts assume 1) no renewal of existing federal tax credits after their current expiration dates and 2) no new federal stimulus program is created.

Figure 12: *Expected Future Growth of Renewable Energy in the U.S.*
Source: Navigant Consulting, Inc.

existing state targets would require 122.2 GW of renewable energy, or 330% of existing wind and solar capacity, by 2020. Furthermore, Congress is considering national renewable energy standards that would encourage development of renewable technologies in every state in the U.S.

The improving competitiveness of renewable energy generation has benefited from the challenges facing traditional forms of generation. In the last year, there is evidence that developing large coal and nuclear generation may have a negative impact on utility credit ratings. Recently, Moody's indicated that ratings pressure is increasing on utilities seeking to build nuclear plants, and characterized nuclear generation development as having "bet-the-farm risk."[29] More than 120 proposals for new coal-fired power plants have been withdrawn since 2000 due to concerns about environmental and financial risks, while another 50 face continued legal opposition.[30] Given these challenges, utilities can be expected to seek alternative strategies, including increased renewable energy access, to meet anticipated future demand.

Navigant Consulting expects significant growth in the U.S. for solar technologies and some other renewable energy technologies over the next few years (Figure 12). As this figure indicates, the expiration

29. "New Nuclear Generation: Ratings Pressure Increasing," Moody's Global Infrastructure Finance, June 2009

30. Lester Brown, "Coal-Fired Power on the Way Out?," 24 Feb 2010. http://ipsnews.net/news.asp?idnews=50449.

of the current federal Production Tax Credit (PTC) in 2013 would have a strong negative impact on the continued strong growth of wind power. If the PTC is extended again in 2013, wind growth is likely to continue to be strong beyond 2012.

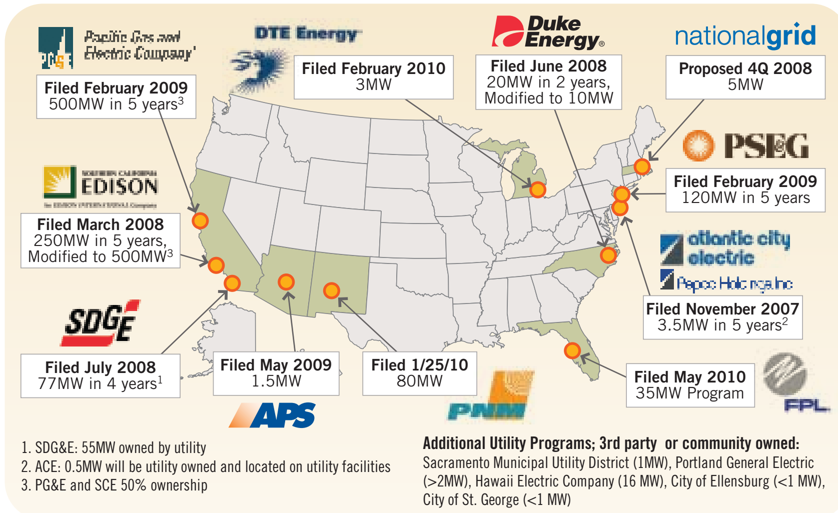


Figure 13: *Utility Programs for Distributed Solar – Examples of Filings for Rate Basing*
Source: Navigant Consulting, Inc.

Utility-scale wind plants are currently the leading source of renewable energy based on installed capacity. By the end of 2009, the wind industry had installed over 35,000 MW cumulatively in the U.S., approximately 10,000 MW of which – roughly 28 percent of the total – was installed in 2009 alone. Although some utilities and grid operators have had concerns about how large wind generation growth could impact grid operations, to date the increasing levels of wind generation have not posed any major grid performance issues.

Colorado's governor recently signed a law requiring investor-owned utilities to source 30 percent of their electricity from renewables by 2020. In California, lawmakers are considering legislation that will raise the state's RPS from 20 percent by 2010 to 33 percent by 2020. Achieving this target using large-scale renewables would require significant new transmission capacity, currently one of the major barriers to central renewable energy development throughout the U.S. The siting, permitting, and cost of new transmission infrastructure is likely to impede large-scale development of remotely-located renewable energy resources. To mitigate the risk involved with new transmission development, California is leading a number of states in examining the potential for distributed energy resources (DERs), especially solar PV.

RPS Policies	Solar carve-outs/compliance
Revenue Opportunity	Opportunity to rate-base solar assets and leverage existing corporate functions
Federal ITC	Utilities can now use the 30% ITC through 2016
Added Resource	Quick way to deploy RE, avoiding challenges related to transmission, interconnection, permitting
3rd Party Threat	3rd party solar service providers could lead to utility revenue erosion
Brand Halo	Some utilities see solar as a way to create a brand halo
Potential FASB Changes	Financial Accounting Standards Board may reclassify Power Purchase Agreements (PPAs) as debt

Figure 14: *Key Drivers of Utility Ownership of PV*
Source: Navigant Consulting, Inc.

A growing number of utilities are pursuing large-scale installations of distributed PV. While the configurations of these systems vary, a common characteristic is utility ownership and rate-basing of the capital investment (Figure 13).

Utilities are gaining interest in solar PV for a variety of reasons such as RPS compliance, grid

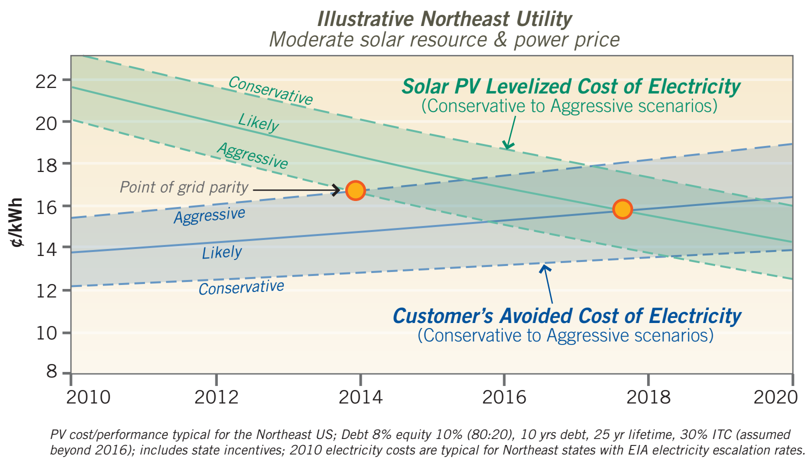


Figure 15: *Levelized Cost of Electricity (LCOE) vs. Avoided Cost of Electricity for a Typical Northeast Utility (Real terms)*
Source: Navigant Consulting, Inc.

Utility Ownership of PV

Earlier this year, Southern California Edison (SCE) received approval by the California Public Utilities Commission to build and own up to 250 MW of solar PV capacity and to execute contracts for up to 250 MW for generation from similar facilities owned and maintained by Independent Power Producers (IPP) through a competitive solicitation process. Motivation for the program includes:

- RPS compliance without additional transmission construction;
- Helps to reduce system load peaks; and
- Fills a gap in the California Solar Initiative program that targets applications less than 1 MW and an RPS that targets multi-MW systems.

Target locations for PV installation include large commercial, institutional, and industrial rooftops sufficient to support 1–2MW installations. Up to 10 percent of the systems will be ground mounted. SCE will own 50 percent of the installed PV, and 50 percent will be customer owned. Customer owned systems will be determined through a competitive bid with 20 year Power Purchase Agreements.

The program is limited to 500 MW of PV at cost cap of $963 million. IPP bids will be capped at $260/MWh. Funding for the program will come from SCE ratepayers, including 100 percent of reasonable startup costs. SCE can recover capital costs up to $3.85 per watt without review by the CPUC.

enhancement, public relations – and perhaps more importantly, protection of customer relationships and business (Figure 14). Many states, including California, Colorado, and New Mexico now allow third party providers to sell solar power directly to utility customers. As the cost of PV gets closer to grid parity,[31] these third party providers could win customers away with new on-site solar installations. Then, as retail access opens up, those same providers may offer energy services beyond solar, further eroding the utility's revenue. As shown in Figure 15, depending on the assumptions made for PV cost reductions and increases in conventional electricity prices, grid parity could occur around 2015, or sooner depending on pricing and incentive levels.

Although utilities are required to divest generation and operate as delivery-only companies in some states, value studies have shown that utility involvement in selecting distributed renewable energy location and managing the resource can significantly increase renewable power's contribution as a grid resource. Further supporting or accelerating this trend could increase the rate of renewable energy adoption, but ownership of generation by utilities must be addressed in the states that prohibit it.

Like energy efficiency, distributed energy resources are becoming more highly valued. New ratemaking and business model modifications, including decoupling and utility ownership of renewables, will be necessary to ensure

31. Grid parity is the point at which the cost of electricity produced by PV is equal to or cheaper than the price of electricity purchased from the utility.

effective utilization of both DER and EE.

For utilities, developing a robust risk analysis and planning process that takes into account EE and DER scenarios and technologies is essential. Given the progress that distributed energy technologies are making, and given the above-mentioned opportunity for third-parties in some states to cherry-pick the most attractive utility customers – those who have high electricity costs, strong credit, and the means to implement alternative energy solutions – some utilities are facing growing competitive pressures leading to accelerated customer exit and revenue erosion in a manner that breaks from past experience.

For some electricity customers – particularly retail and manufacturing firms where margins are critical – the ability to source competitively-priced peak PV power and fix that cost for up to 20 years presents a value proposition too strong to ignore. Utilities will need to meet or exceed the value proposition offered by third party firms in order to compete effectively in this space.

Energy Efficiency and Distributed Renewables for Capacity Deferral

Successfully implementing EE and DER programs requires customer involvement. In 2008, NSTAR, with funding from the Massachusetts Technology Collaborative (MTC), launched the Marshfield Energy Challenge to simultaneously implement EE, RE and demand response programs to limit demand on the local electricity distribution system. The program was designed to build community awareness and local commitment to implementing clean energy and EE.

The Marshfield Energy Challenge is a first-of-its-kind program designed to meet growing energy demand by combining targeted EE efforts with small renewable generation and demand response systems. The program involves energy audits, support for reduced-cost installation of solar panels, and the use of direct-load-control thermostats to help manage the peak demand for electricity on hot summer days. The long-term goal of the $4 million initiative is zero electrical load growth in the town.[33]

In parallel with NSTAR's Marshfield Energy Challenge, the MTC awarded funding to National Grid for a Summer Load Relief Program in Everett, East Longmeadow and Brockton, Massachusetts. This program is also expected to help defer distribution capacity upgrades with distributed energy resources and EE.

Utility companies that meet growing customer demand by offering PV products and services (as well as other distributed energy resources and energy efficiency offerings) have a significant business opportunity. They have tremendous potential to expand service offerings across an exciting and fast growing business sector, while protecting their existing relationships with some of the most attractive members of their customer base.

In summary, to expand renewable energy, utilities should:

- Actively pursue development of a range of renewable energy projects to meet and/or exceed state renewable targets;
- Consider owning PV assets to gain experience in their implementation given the potential near-term grid parity and possible threat of third party providers serving utility customers solar power;
- Evaluate business models being used by private competitors and other utility companies to own distributed energy resources and other renewable assets; and
- Create new risk hedging and grid management mechanisms to deal with variance in customer load response, and intermittent renewable energy resources.

32. NSTAR completes 600th energy audit in Marshfield. Mon Nov 24, 2008. http://www.wickedlocal.com/marshfield/homepage/x541355162/NSTAR-completes-600th-energy-audit-in-Marshfield

4 Incorporate Smart Grid Technologies for Consumer and Environmental Benefit

Smart Grid utilization is entering the mainstream, with most U.S. utilities involved in full-scale system implementations or pilot programs. As part of the American Recovery and Reinvestment Act of 2009, the U.S. Department of Energy catalyzed this activity by committing over $4 billion of stimulus funds for Smart Grid Investment Grants and Smart Grid Demonstrations. Over the next several years, the electric utility industry will deploy advanced sensors, communications infrastructure, and control systems that will enable changes in the way electricity is produced, delivered and used. Key components of the Smart Grid as it is currently being implemented include Advanced Metering Infrastructure (AMI), Distribution Automation (DA), synchrophasor measurement and grid visualization, and the integration of distributed energy resources (DERs), including renewable energy and energy storage.

PG&E and Demand Response

PG&E offers a range of demand response programs that provide financial incentives to customers to reduce energy consumption at times of peak demand. The programs help enhance reliability, reduce costs, and avoid the need to build new power plants.

PG&E's SmartAC™ program sends a signal to air conditioners during energy supply emergencies, instructing them to use less power. PG&E aims to enroll 400,000 residential customers by 2011, reducing peak load by 305 MW.

Additionally, the company's PeakChoice™ program provides incentives to implement specific energy savings measures at peak times and aims to reduce load by 36 MW.

Reducing Peak Demand and Energy Consumption

A recent informal poll of Smart Grid experts revealed that active involvement of customers and utilities' understanding of consumer electricity demand as a controllable energy resource are seen as the most transformative changes that the Smart Grid will enable. Enabling large-scale demand response by providing customers enhanced information about energy use – and giving them the means to control it – are key themes within the DOE's ARRA Smart Grid programs.

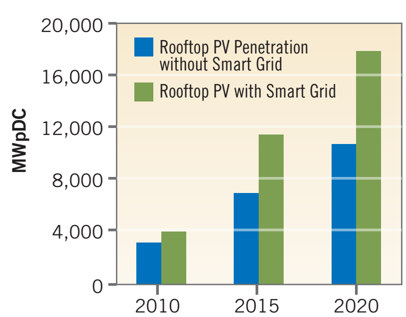
The Smart Grid Enables Higher Penetration of PV

Addressing technical challenges could result in:

- higher net metering caps
- better interconnection standards and processes
- more prevalent time of use tariffs options

These changes simplify interconnection of PV and improve its economics, increasing the projected installed capacity by over 60% by 2020.

Rooftop PV Installed Cumulative Capacity Total U.S. with Low PV System Pricing



Results based on Navigant Consulting PV Market Penetration Model and Low PV System Pricing. For the "Rooftop PV with Smart Grid" case Navigant Consulting assumes that because key technical barriers are addressed (voltage regulation, reverse power flow and power fluctuations/frequency regulation), that the some of the constraints on PV are relaxed and economics are improved.

Figure 16: *The Smart Grid Enables More PV on Distribution Feeders*
Source: Navigant Consulting, Inc.

Smart metering and AMI technology are only part of the solution. Utilities and regulators should develop effective pricing programs to ensure that customers are given the signals they need to make good decisions about their energy consumption. High customer participation rates in these programs are also important.

Importantly, effective technologies and pricing programs can have a significant positive impact on peak demand, allowing utilities and grid operators to reduce the amount of peaking and reserve capacity needed to maintain grid reliability.

Since peaking capacity is often less efficient than baseload generation, peak demand reductions could produce significant carbon reduction and financial benefits.

Integrating Renewable Energy

The Smart Grid should be instrumental in helping to integrate increasing amounts of renewable energy into the transmission and distribution system. A recent study by Navigant Consulting showed that by 2020, Smart Grid functionality could help increase the penetration of distributed PV by more than 60 percent over the reference case with a traditional grid (Figure 16).[33] The main regulatory changes modeled in the study were: increasing the amount of PV that could be net metered; standardized interconnection processes; and enhanced electricity tariffs to allow PV owners to receive time-based payments for system output. Each of these changes simplified the interconnection process and improved project economics to the point where the adoption of PV increased.

Increasing Energy and Operational Efficiency

The electric transmission and distribution system is also an indirect source of GHG emissions. The wires and equipment that make up this infrastructure cause electrical losses (wasted energy) as part of their normal operation. Utilities will be able to utilize Smart Grid technologies to optimize transmission and distribution to minimize these energy losses, thus improving grid efficiency.

Today, operating and maintaining the grid requires a high degree of direct human contact. Reading meters, throwing switches, and checking equipment all require utility personnel to physically drive around the system. The Smart Grid should eliminate much of this work, reducing vehicle miles traveled and associated fuel consumption and improving utility responsiveness and customer service.

Currently, ARRA Smart Grid programs are serving as a key driver in the deployment of Smart Grid technology and infrastructure. However, this funding support is a tiny fraction of the total investment required to modernize the grid and enable the functionality necessary to achieve the clean energy and customer benefits discussed above. Implementing a modern Smart Grid is expected to take 10 to 20 years of steady capital investment by utilities, a process that business cycles, regulation and customer adoption could hinder.

AEP's gridSMART℠ Program

In 2007 American Electric Power (AEP) launched gridSMART℠, a Smart Grid initiative designed to deliver a number of customer enablement and grid efficiency benefits. Begun as a pilot project in South Bend, Indiana with 10,000 smart meters, the gridSMART℠ is growing into a comprehensive demonstration program involving 110,000 customers in central Ohio.

The $150 million project is partially funded with $75 million from the DOE's Smart Grid Demonstration program. The demonstration will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart appliances and home energy management systems, a new cyber security center, PHEVs, and installation of utility-activated control technologies that will reduce demand and energy consumption without requiring customers to take action.

AEP is pursuing other gridSMART℠ projects in Oklahoma and Texas. The company has a goal of installing 5 million smart meters in its service areas by 2015.

33. "The Convergence of the Smart Grid with Photovoltaics: Identifying Value and Opportunities," Navigant Consulting, January 2009.

Utilities should ensure that they implement the Smart Grid in a manner that maximizes clean energy benefits, including energy efficiency and demand management, integration of renewable and distributed energy, and grid optimization. To do this, utilities must manage the technical risks of implementing a complex energy and information infrastructure over many years. They should also maintain high rates of customer participation in dynamic pricing and energy management programs.

In summary, when incorporating Smart Grid technologies, utilities should:

- Simplify the interconnection and integration of distributed renewable energy resources;
- Leverage the operational efficiencies provided by Smart Grid technology to reduce operational costs;
- Prioritize Smart Grid investments that seek to maximize benefits from energy efficiency, energy delivery and clean energy technologies;
- Provide customers with information and energy management technologies that are aligned with effective pricing programs; and
- Build out the Smart Grid by pursuing a long-term capital improvement program premised on delivering enhanced value to consumers.

5 Conduct Robust and Transparent Resource Planning

Energy planning has become extremely complex. Rate impacts, environmental impacts, water scarcity, siting and equipment and construction lead times are among of the many issues that utilities struggle with as they develop energy infrastructure plans and try to implement them. Dealing with these issues and the stakeholders that care about them can cause schedule delays and increase costs. Collectively these factors increase project risks and can undermine utility credit quality, particularly when the projects are very large and/or controversial.

Utilities should employ open and transparent planning processes that consider the risks, probabilities, benefits, impacts and applications of multiple energy resources under various scenarios. Planning processes should include a full commitment by utilities to implement all cost-effective energy efficiency and renewable energy. Resource planning should involve greater

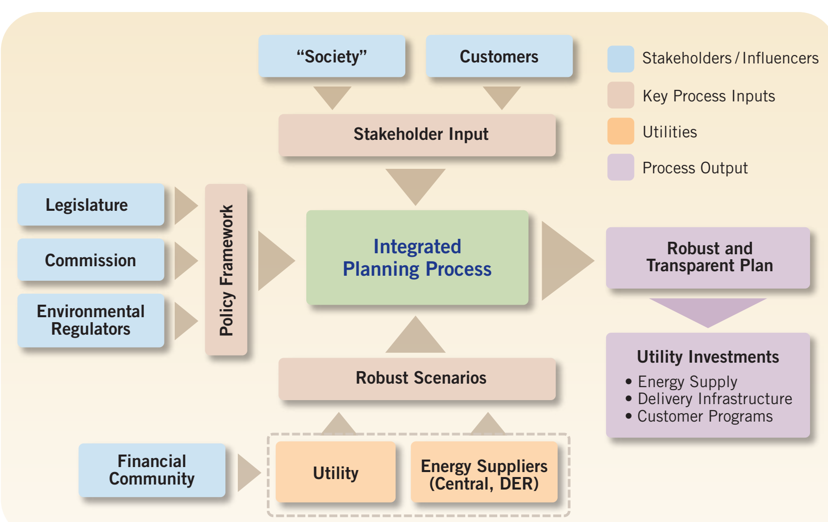


Figure 17: *Example Planning Process Framework*
Source: Navigant Consulting, Inc.

stakeholder involvement on a wider regional level and consider the full spectrum of EE and DER resources. Finally, utilities should update planning criteria and system design standards to reflect current and future costs for CO_2, EE, DER, equipment and permitting. Figure 17 presents an example planning process framework that could be used to ensure the development of robust and transparent resource and system plans.

This process ensures that the utility receives crucial input from the community at large. It enables the utility to reach out and educate customers, regulators, communities, and key influencers on issues that have significant impact on the utility's planning and operations. Clear policy frameworks allow all parties to better understand the goals and regulatory objectives that will influence or constrain the planning process. Finally, the development of robust planning scenarios, including assumptions about technology costs, carbon price, performance metrics, and risks, ensures that all parties have a better understanding of the tradeoffs and subtleties of different options.

In summary, utility planning processes should:

- Utilize transparent analysis and decision frameworks;
- Fairly evaluate EE and RE in robust scenario analyses;
- Facilitate input from key stakeholders; and
- Educate the public and policy makers about complex energy issues.

Engaging Stakeholders in the Planning Process

In January 2009, Arizona Public Service (APS) filed a Resource Plan Report with the Arizona Corporation Commission laying out the company's plan to meet 55 percent customer demand growth by 2025 with effectively no increase in carbon emissions. Arizona had not conducted a formal integrated resource planning process (IRP) since 1995, and APS filed its report voluntarily.

APS's Resource Plan Report emerged from a series of informal and frank conversations with environmental stakeholders – and, later, RE developers, merchant generators, large customers, Arizona's Energy Office and other utilities – on the subject of meeting Arizona's future energy needs. APS's goal was not only to obtain a wide spectrum of candid feedback, but also to inform stakeholders about real challenges the company faced. In total, APS conducted seven half-day stakeholder meetings – on topics such as climate change, RE, resource selection and load forecasting – and held additional meetings with community leaders and city councils throughout the state.

What began as an experiment is now viewed by APS as essential to its planning process going forward. APS found that focused outreach and collaboration with a small group of key stakeholders supplemented by broader outreach and communication effectively educated stakeholders (and the utility) about key issues and resources and built credibility and support for APS's future plans.

According to APS, proactive resource planning provides several important benefits to utilities:

- Positions the utility as a leader on a number of issues, including transmission, RE, and future mandatory planning;
- Educates stakeholders on the current and future issues facing the utility;
- Creates a clearer picture of what stakeholders want; and
- Helps build a relationship of trust between stakeholders and the utility.

III. Financial Implications

Utilities are grappling with several issues simultaneously, each of which will have major financial impacts. Accounting for the cost of carbon could significantly increase resource costs for some utilities that have large portions of carbon-heavy generation in their resource mixes. However, utilities are also faced with massive reinvestment in the existing delivery infrastructure at the same they are implementing the Smart Grid and its associated technologies. All of this will require a very large, diverse long- term investment program that will have significant effects on revenue requirements and rate bases.

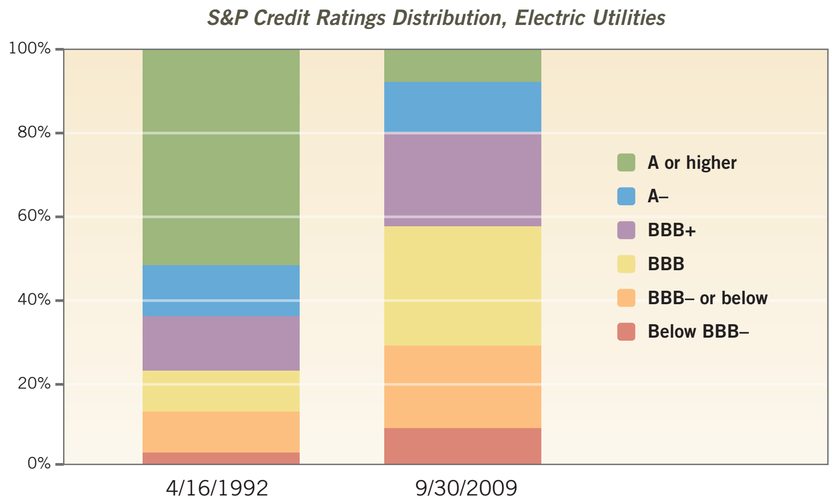


Figure 18: *Long-Term Decline in Credit Quality (S&P Credit Ratings, Electric Utilities)*
Sources: "Wall Street Turmoil: Impacts on Electric Utilities," Richard McMahon, Jr., Edison Electric Institute, NARUC Winter Committee Meetings, February 17, 2009; and "Q3 2009 Financial Update, Credit Ratings," Edison Electric Institute.

In the past, utilities were well known as low risk investments, with the majority having S&P credit ratings of A or higher. This meant that they were positioned to attract large amounts of capital at very attractive rates that allowed them to build large power plants and transmission lines while managing the cost to customers. Today, the average credit rating for the industry has slipped to BBB (Figure 18), increasing utilities' cost of debt and the overall cost of financing the transition to a cleaner power sector.

Over the last five years, annual capital expenditures by U.S. shareholder-owned utilities have almost doubled to over $84 billion per year (Figure 19). At this rate, these utilities could invest almost $1 trillion in capital over the next 10 years in generation, transmission and distribution assets. An outcome of this increase in capital spending (CapEx) has been a reduction in cash flow (cash from operations minus CapEx). As utilities continue to pursue large capital investment programs, they must be able to ensure that the investments are allowed into their rate base by state utility commissions to support revenue requirements. Otherwise, the utilities will incur financing costs

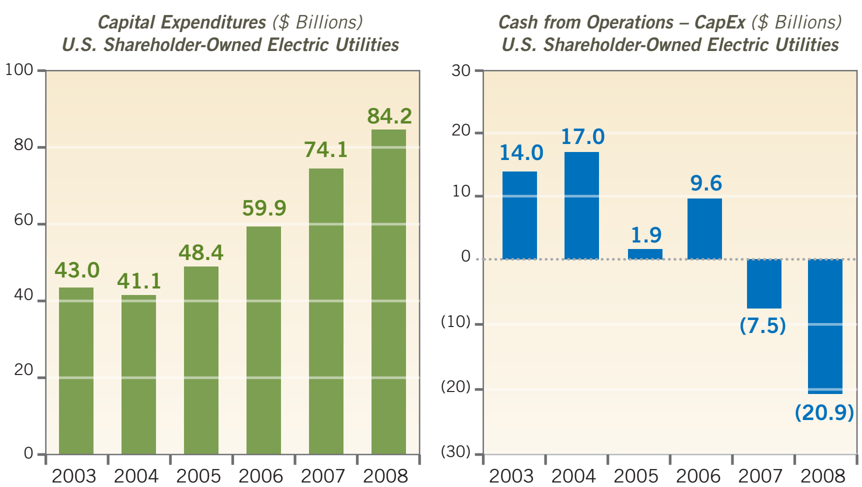


Figure 19: *CapEx and Impacts on Cash Flow*
Source: Edison Electric Institute

without offsetting revenues, which will increase overall costs and could negatively impact credit ratings.

A critical challenge with rate-basing billions of dollars of new CapEx is that regulators and customers are concerned about associated rate increases. Over the past 10 years average retail electricity rates have increased an average of 50 percent across all sectors (Figure 20). Increasing electricity rates even more to pay for clean energy and grid modernization will be challenging, particularly in today's down economy with high unemployment, and utility regulators will be concerned about rate impacts to customers.

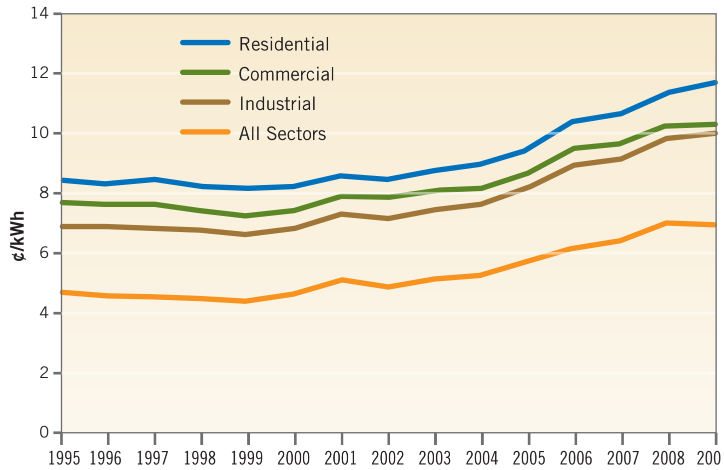


Figure 20: *Historical Average Retail Electricity Prices to Customers, 1995 to 2009*
Source: US Energy Information Administration

The regulatory approval process for large-scale investment decisions presents a significant risk to utilities in the long term. Pursuing approaches that are overly capital-intensive puts upward pressure on electricity rates and increases the risk of unfavorable recovery of cost. This, in turn, could lower a utility's credit rating and increase its cost of capital. Some financial analysts are predicting that key credit metrics for utilities will be negatively impacted in the long term due to cost recovery risks from downward rate pressure.[34] Utilities that pursue diversified strategies utilizing cost-effective energy efficiency and distributed energy resources are likely to reduce capital investment risk.

Along with a resistance to increasing rates, the economic recession has resulted in significant reductions in electricity demand across the country, particularly in the industrial sector. This reduction translated to dramatic decreases in retail sales revenue for utilities, and forced many utilities to make sizable cutbacks in capital budgets and operating expenses. All of this demonstrated the potential long-term impact of declines in electricity consumption under a scenario where utility revenues remain tied to kilowatt-hour sales.

Recent reductions of customer demand highlight the inherent conflict most utilities have with fully embracing energy efficiency. Similar effects would be felt from widespread adoption of customer owned or sited generation such as distributed PV, or any other resources that would tend to lower energy sales by utilities. These clean energy resources could end up having a significant negative impact on utility credit quality to the extent that they erode retail electricity sales. This effect will be compounded if utilities are also forced to enhance electricity delivery infrastructure and grid operations to manage high penetrations of distributed energy resources.

34. Moody's Investors Service, "Annual Outlook: U.S. Electric Utilities Face Challenges Beyond Near-Term," January 2010.

Rate decoupling mechanisms offer an important potential solution by allowing utilities to cover fixed costs regardless of energy sales. Some analysts believe that decoupling can be beneficial to utility credit quality,[35] which could lower the utility cost of capital, and reduce the upward pressure on electricity rates. Peter Darbee, President and CEO of PG&E, cited decoupling as part of the reason that the value of PG&E's stock dropped just 10 percent during the recent financial recession, as opposed to an industry average of closer to 50 percent.[36] PG&E still earned a reasonable return, even though its unit sales dropped.

20th Century	21st Century
Business Model	**Business Model**
• Simple, based on steadily increasing electricity sales typically from an expanding asset base of centralized generation and traditional delivery infrastructure	• Complex, integrated energy services serving diverse and evolving customer needs with an information-enabled infrastructure
Sources of Revenue	**Sources of Revenue**
• Power plant capital expenditures, primarily for coal, nuclear, natural gas plants • Transmission capital expenditures • Sales of generated and procured electricity • Modest energy efficiency programs in some states	• Power plant capital expenditures, primarily for natural gas and large scale renewables plants, upgrades to fleet, also some coal w/CCS and nuclear • Transmission capital expenditures • Recovery of fixed and variable costs for electricity delivery under a revenue decoupling approach • Aggressive energy efficiency programs in most states with financial incentives for performance • Effectively deployed Smart Grid technology and services, including smart meters, energy storage, vehicle charging, etc. • Utility-owned distributed renewables

Table 3: *An Emerging Business Model for Utilities*

Plug-in electric vehicles (PEVs) provide a new opportunity for utilities to capture a larger share of the energy market from oil companies if PEVs are deployed widely. As electric vehicles gain consumer acceptance, utilities will face both a burden and financial opportunity as consumers demand the necessary charging infrastructure and clean energy resources.

Finally, and perhaps most importantly, the uncertainty around the cost of reducing carbon emissions presents great risk to the power sector, particularly for those utilities that have carbon-heavy generation fleets or that purchase power in such markets. Some good news is that many currently measureable risks of CO_2 emissions are beginning to be incorporated into credit quality assessments by the financial community.[37] Frameworks to evaluate and address carbon risks in the financing of electric power projects have already been put in place and are gaining traction, such as the Enhanced Environmental Due Diligence Process of The Carbon

35. "When Electric Efficiency Means Lower Electric Bills, How Do Utilities Cope?," Standard & Poor's, March 2009.
36. "Google CEO fires at critics, defends its energy plan" (03/05/2009) Colin Sullivan, E&E reporter
37. "Emission Reductions Under Cap-and-Trade Proposals in the 111th Congress, 2005 – 2050." World Resources Institute. June 25, 2009. http://www.wri.org/publication/usclimatetargets

Principles, which is being used by Bank of America, Citi, Credit Suisse, JP Morgan Chase, Morgan Stanley and Wells Fargo.

Some analysts believe that while the economy as a whole will feel the effects of emissions reductions, the power sector will be required to reduce its carbon emissions to a greater extent.[38] Achieving reduction targets will go beyond pure fuel-switching from carbon-heavy to carbon-light or carbon-free resources. Integrating clean energy resources will require new technologies and operating practices to maintain grid reliability, and this also increases cost.

Fortunately, achieving a less carbon-intensive generation mix and smarter grid will create opportunities for utilities to generate revenue, as outlined in Table 3 above. Capital investments in transmission lines, smart metering and distribution automation will be added to utility rate bases. Performance incentives for EE and service quality should improve rates of return. And new applications such as electrification of transportation present growth opportunities.

Effective Risk Management Approaches

The changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history. Uncertainties in the industry which give rise to the need for more intense focus on risk assessment and risk mitigation planning include, but are not limited to:

- Inherent customer demand reduction aside from energy efficiency/DSM initiatives, placing upward pressure on rates for allocation of fixed costs;
- Cost impacts of renewable energy resources, inclusive of firming requirements needed to integrate resources into a power supply portfolio;
- Carbon compliance structure and cost uncertainties;
- Uncertainty of ability to extend the commercial life, or construct planned new coal-fired power plants due to financial market views of carbon reduction mandates/structures;
- Uncertainty related to limited water supplies for power plant cooling;
- Uncertainty of the effect on natural gas prices from increased demand from central generation and capacity firming for variable renewable resources;
- Challenges of timely completion of major new inter-state electric transmission to deliver renewable energy resources to load;
- Uncertainty of customer reaction to energy efficiency and DSM initiatives in the near-term and long-term customer continued behavior;
- The potential of demand-side resources not performing, requiring more expensive short-term replacement energy; and
- The extent of large load customer out-migration based on future comparative utility rates and resultant effect on demand and cost allocation.

38. Standard & Poor's, "The Potential Credit Impact Of Carbon Cap-And-Trade Legislation On U.S. Companies," Sept. 14, 2009.

In addition to the cost and customer load uncertainty examples noted above, directly related risks which need to be managed include:

- Debt rating agency interpretation of these uncertainties and risks and possible effects on cost of debt;
- For regulated utilities, the potential for disallowance of costs to the extent resultant rates are out of regional norms or levels of comfort;
- Regulatory treatment for the allocation of costs among customer classes as load characteristics change and cost-causation by customer class changes; and
- Retail customer reaction to rate effects.

Risk management actions that may need to be taken to address these risks could include:

- More robust analysis of possible resource mixes and associated customer reactions, along with more transparent sharing of resource-related assumptions and decisions, to inform regulators, governing boards, customer groups and financial markets; and
- Longer-term evaluation of resource mixes and associated ranges of revenue requirements to better enable identification and implementation of risk management measures.

IV. Key State Regulatory Policies for the 21st Century Power Sector

Key regulatory policies are required to support a sustainable 21st century power sector and to address the important issues discussed in this report. They include:

- Clean Energy Policies;
- Enforceable Renewable Portfolio Standards;
- Revenue Decoupling;
- Effective net Metering for Distributed Generation; and
- Incentive Ratemaking for Utilities.

These policies are most relevant at the state level, and typically fall within the purview of state governments and utility regulatory commissions. It is likely that the federal government will also set policies that put a price on carbon and increase energy independence, renewable energy and energy efficiency.

Clean Energy Policies

Achieving clean energy results requires strong leadership in government. Today, many states have a variety of policies that deal with certain aspects of energy, but many of these policies do not set an overall direction that aligns clean energy goals across their government agencies, including utility regulators. Such overarching policies are essential and serve as blueprints for how other policies should be designed, and also help to ensure that the mechanisms of these policies are compatible across the state.

To support a sustainable power sector, states need to make a full-fledged commitment to clean energy and the resources of which it is composed. In the near term these would include renewable energy, energy efficiency, distributed generation, natural gas fired generation[39] and the Smart Grid. Over the longer term, large-scale deployment renewable energy technologies can occur, as well as possible implementation of advanced nuclear and low-carbon coal technology. As lower-carbon resources are built, provisions for the retirement and repowering of the higher-polluting plants can be made.

California, like Massachusetts, has a state policy that places EE at the top of the priority list compared to other energy resources. California's principal energy agencies established its energy "loading order" in 2003 as energy efficiency, demand response, renewable energy and distributed generation. This loading order was established to develop and operate California's electricity system in the best long-term interest of the consumers, ratepayers and taxpayers. A key goal of the loading order is to decrease electricity demand, and then meet new generation needs, first with clean energy sources such as RE and distributed generation, and second with cleaner fossil fuel generation. This energy resource loading order continues to drive all energy policy decisions in California.

39. Natural gas fired generation is an attractive resource for significantly reducing CO_2 emissions in the near term, while at the same time being domestically available for the foreseeable future. 84 percent of the natural gas consumed in the US is produced domestically, with the remainder largely supplied from Canada. Domestic supplies have surged in recent years, with recent studies indicating that, even with a 50 percent increase in demand, natural gas would be available for 80 years. The location of natural gas supplies as an on-shore resource accessible by load centers is also attractive from an energy security perspective. For example, Marcellus shale gas in western Pennsylvania is close to load centers of PJM Interconnection.

IV. Key State Regulatory Policies for the 21st Century Power Sector

A clear, consistent, and coordinated energy policy is important because it sets the tone regarding the importance and commitment to clean energy. It clarifies priorities and serves as a roadmap for stakeholders in pursuing their detailed initiatives. It can help develop positive public attitudes toward clean energy and consequently help ensure the availability of resources necessary to pursue clean energy objectives. A clear state energy policy is also critical to provide utilities the regulatory and financial incentives to develop the five key elements of a 21st century utility business model described in this report. By establishing a firm and consistent regulatory framework, states can provide utilities with the necessary structure to manage their carbon emissions, ramp up investments in energy efficiency, renewable energy and distributed energy resources, work on maximizing the carbon and consumer benefits of the Smart Grid, and develop a robust and transparent resource planning process.

Enforceable Renewable Portfolio Standards

Another key regulatory policy in many states is a Renewable Portfolio Standard (RPS), discussed earlier and also known as Renewable Electricity Standard (RES). These regulations require electricity supply companies to produce a defined fraction of their electricity from RE sources, for which they receive renewable energy certificates (RECs). RE generators can then sell RECs (along with electricity) to utilities, who sell the electricity to consumers and use RECs to demonstrate compliance with the RPS standards. Supporters of RPS claim that since the RPS relies almost entirely on the private market for its implementation, it is an effective method to drive the growth of competition, efficiency and innovation among renewable energy generators, driving down costs and increasing adoption.

In practice, however, the presence of an RPS does not always lead to new RE installations. For example, sporadic implementation of the federal Production Tax Credit for wind power producers has led to sporadic investment and installations of wind projects, which has compromised efforts to achieve state RPS goals. Furthermore, an RPS alone is often not sufficient to stimulate the use of RE. Several states that have a RPS in place do not have enforcement mechanisms that incentivize compliance, and some of these states have little or no financial penalties for not meeting the RPS. In states like New Mexico and North Carolina, utilities are allowed to pass non-compliance costs onto ratepayers. Other states, such as New Jersey, have established appropriate non-compliance penalties that will drive new RE installations.

Creating a mandatory RPS would incentivize compliance and provide clear market signals for utilities. It would reinforce the notion that RE is a high priority and reward those parties that deliver results. It would build credibility for, and demonstrate commitment to, clean energy policy. The presence of an RPS with appropriate enforcement mechanisms in place would incentivize utilities to work toward developing some of the key characteristics of a leading 21st century utility.

Revenue Decoupling

Revenue decoupling is a key regulatory mechanism that breaks the link between a utility's profits and its electricity sales. It removes the inherent disincentive for utilities to encourage reductions in the amount of electricity used by customers. Importantly, decoupling ensures that utilities recover fixed costs during times when sales growth is declining, a trend that has been in play since the 1990s.

One important aspect of decoupling is the periodic adjustment in rates in order to precisely reconcile revenue collection with the utility's commission-approved revenue requirement. This usually focuses on the non-fuel or non-generation portion of the cost of service, and is usually applied across the board and does not affect rate design. Decoupling is often applied on a customer class basis, with a reassessment of the process within three to five years. Revenues in a sound decoupling plan will tend to track what frequent rate cases would have yielded. In the end, a utility's net revenue will not be affected by sales decreases or increases, thus allowing them to focus on other priorities, notably customers.

Many utilities – along with advocates, public utility commissioners and other experts – believe that decoupling is the key enabler that will allow utilities to embrace large-scale EE and DER. By April 2010, 20 states had either implemented electric decoupling, or had decoupling pending (Figure 21).

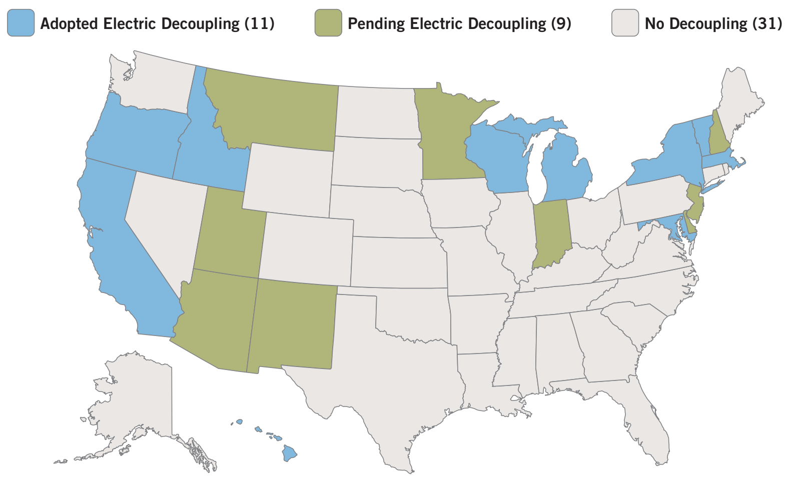


Figure 21: *Electric Decoupling in the U.S. – April 2010*
Source: Natural Resources Defense Council

Despite decoupling's advantages – including its elimination of the "throughput incentive," the financial incentive for (non-decoupled) utilities to sell ever-increasing amounts of power which conflicts with climate stabilization goals – not all parties currently favor decoupling. Some public advocates and customer groups oppose decoupling because they believe that it transfers risk to customers, changes rates without due consideration for all the underlying cost changes that may have occurred and reduces the incentive of utilities to operate efficiently and contain costs.

In simple form, decoupling guarantees utilities that if they promote energy efficiency, they will be compensated with appropriate rates that cover fixed costs and provide an adequate return on equity. But while decoupling eliminates a key barrier, it does not guarantee cost effective energy efficiency, nor does it provide sufficient financial incentives for utilities to embrace large-scale EE. Consequently, decoupling works best with well-designed performance based incentives. Management and performance incentives include performance based earnings, shared savings, and incentive rates-of-return. It is generally recognized as best practice to reward utilities for performance towards an energy savings target, with the richest incentives being reserved for exemplary performance.[40]

Given decoupling's positive attributes – especially its effectiveness in removing utilities' inherent conflict of interest – and given concerns about alternatives to decoupling, it is reasonable to expect that decoupling will continue to gain in popularity and become the regulatory method of choice for maintaining utilities' financial health while capturing EE as the key resource for the 21st century power sector. Utility targets and performance incentives, combined with the right rate model, will help ensure that utilities become drivers for EE and DER in a manner that won't harm the utility's credit ratings or other financial metrics.

Effective Net Metering for Distributed Generation

Net metering programs serve as an important incentive for consumer investment in renewable energy generation. Net metering enables customers to use their own generation sources (e.g., a rooftop solar PV panel) to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand. This offset means that customers receive retail prices for excess electricity they generate.

It is generally thought that net metering is a low-cost, easily administered method of encouraging customer investment in renewable energy technologies. It allows customers to "bank" the energy they generate using renewable sources for use at other times. This flexibility allows customers to maximize the revenue from their production. Utilities may also benefit from net metering because expanded customer production of electricity during peak periods improves the system load factor and can enable utilities to avoid expensive investment in peak generation resources.

Currently, net metering is offered in more than 35 states. However, the presence of net metering policy does not guarantee that net metering will drive growth in distributed generation (DG) technologies. Many states have weak net metering policies that do not actually encourage DG adoption. Examples include:

- Preventing customers from receiving credit for excess electricity
- Allowing utilities to charge excessive standby charges

The Interstate Renewable Energy Council (IREC) publishes an annual report documenting best and worst practices in net metering policies. According to IREC's rankings, leaders include Arizona, California, Colorado, Delaware, Florida, Maryland, New Jersey, Oregon, Pennsylvania and Utah. Leading net metering policies in Colorado, for example, supported the development of nearly 22 MW of solar PV capacity in 2008, an 88 percent increase over the previous year.[41]

40. National Action Plan on Energy Efficiency, "Aligning Utility Incentives with Investment in Energy Efficiency," November 2007.

41. Network for New Energy Choices, "Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Procedures," November 2009.

Incentive Ratemaking for Utilities

To achieve the conditions that will produce meaningful increases in clean energy resources and significant reductions in GHG emissions, utilities must be actively involved in the transformation. To ensure that this happens, utilities need to clearly understand the rules of the game, and receive strong signals from regulators on how to best deploy resources. A key component of successfully implementing a clean energy strategy is to reduce or eliminate the regulatory risk associated with these programs. Utility management will be hesitant to embrace what some might consider non-core activities if they feel they are putting shareholders at risk. A solution could be to create targeted incentives that give premium returns on the "right" investments. In such cases, policy makers:

- decide what the right investment choices are (e.g., generation with low carbon emissions, or energy efficiency);
- determine the value of the externality that is derived by selecting the right investment (e.g., the cost of a ton of CO_2); and
- build a portion of the value into the rate that the utility uses with its customers (e.g., 25 percent of the value of CO_2 avoided).

An important advantage to a targeted incentive is that it be crafted to reward specific choices, and is relatively simple to implement.