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Issue:	Ameren Missouri's 2016-2018 Energy Efficiency Plan
Witness:	Tim Woolf
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Sponsoring Party:	Sierra Club
Case No.:	EO-2015-0055
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a	)	
Ameren Missouri's 2nd Filing to Implement	)	**File No. EO-2015-0055**
Regulatory Changes in Furtherance of Energy	)	
Efficiency as Allowed by MEEIA	)	

Surrebuttal Testimony of
Tim Woolf

On Behalf of
Sierra Club

On the Topic of
Ameren Missouri's 2016-2018 Energy Efficiency Plan

April 27, 2015

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1. INTRODUCTION

Q. Please state your name, title and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Sierra Club.

Q. Have you previously testified in this docket?

A. Yes. I submitted rebuttal testimony on behalf of Sierra Club on March 20, 2015. My resume is attached to my rebuttal testimony as Schedule TW-1.

Q. What is the purpose of your surrebuttal testimony?

A. I'd like to begin first by noting that most of the parties that filed rebuttal testimony generally agree that Ameren's proposed Plan includes savings levels that are too low, does not represent progress towards achieving all cost-effective energy efficiency savings, and should not be approved as filed. Parties' rebuttal testimony in this case provides strong evidence that Ameren's proposal vastly underestimates achievable potential and is insufficient. That is why I recommend that the Commission approve Ameren's Plan only on the condition that Ameren modifies the Plan to achieve greater efficiency savings during the 2016-2018 period, to reach the levels provided in the MEEIA energy savings guidelines. (Woolf Rebuttal at p. 8, ll. 12-15).

Despite this consensus on Ameren's low savings, I do have concerns about one aspect of the rebuttal testimony of Commission Staff witness John Rogers, which suggests that demand side programs must pass a rate impact screen. The purpose of my surrebuttal testimony is to respond to Mr. Rogers' rebuttal testimony on this topic.

2. SUMMARY OF TESTIMONY

Q. Please summarize your surrebuttal testimony.

A. My surrebuttal testimony makes the following key points:

- Mr. Rogers' testimony implies that efficiency programs must pass a rate impact screen in order to be approved by the Commission. This is based on the premise that the right way to assess benefits to customers who do not participate in energy efficiency programs is through a rate impact screen.
- A rate impact screen does not account for some efficiency benefits that accrue to all customers, such as risk benefits.
- Requiring efficiency programs to pass a rate impact screen is inconsistent with the cost effectiveness tests used under MEEIA.
- Requiring efficiency programs to pass a rate impact screen would harm customers, because it would likely preclude significant reductions in electricity costs in order to potentially prevent very small rate impacts.
- Requiring efficiency programs to pass a rate impact screen is an overly simplistic and unduly stringent standard that is inconsistent with the treatment of equity issues raised by supply-side resources.

3. STAFF'S TESTIMONY ON RATE IMPACTS

Q. How does Mr. Rogers address rate impacts in his rebuttal testimony?

A. Mr. Rogers addresses rate impacts in the context of interpreting MEEIA's and its implementing regulations' requirements concerning cost recovery. Specifically, as Mr. Rogers states in his testimony, MEEIA provides that a utility can recover demand-side program costs only if the programs are approved by the Commission, result in savings, and are "beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers." (Rogers Rebuttal at p. 18, ll. 17-19; p. 19, ll. 2-4, quoting Mo. Ann. Stat. § 393.1075(4) and 4 Mo. Code Regs. Ann. 240-20.093(2)(C)). Staff interprets this last clause to mean that energy efficiency programs must benefit each customer in each class, including those who do not directly participate in any program. (Rogers Rebuttal at p. 19, ll. 10-13).

Mr. Rogers then concludes that demand-side programs are beneficial to customers who do not participate directly in any program "only [] if the impact of the Plan causes rates – at some point in time – to be lower than the rates that would have occurred if there were no DSM programs and no DSIM." (*Id.* at ll. 14-16). Mr. Rogers presents an annual rate impact analysis, comparing the program costs, performance mechanism and lost revenues to Ameren's avoided costs, and concludes that Ameren's programs provide no benefits to non-participants, and therefore cannot be approved.

Q. What is your understanding of how Mr. Rogers' conclusion relates to screening efficiency programs?

A. Mr. Rogers' testimony on this issue implies that efficiency programs must pass a rate impact screen.

Q. Do you believe that proposed programs should have to pass a rate impact screen?

A. I do not. First, I do not believe that a rate impact screen is the right way to measure the benefits of demand side programs to non-participating customers. Such a view disregards the system-wide benefits that efficiency programs provide to all customers. Second, screening efficiency programs based on a rate impact analysis is inconsistent with MEEIA and the cost-effectiveness screens it provides. Finally, requiring a rate impact measure screen would harm consumers by taking millions of dollars of benefits off of the table.

This is not to say that the Commission should ignore the impact of energy efficiency on rates. Concerns about rate impacts should be balanced against the benefits of reducing electricity costs. Further, concerns about rate impacts on non-participants should be addressed through program design and implementation practices that will increase efficiency program participation, not through denying customers efficiency programs. I address each of these points below.

4. EFFICIENCY BENEFITS ALL CUSTOMERS

Q. Do you believe that the right way to assess benefits to customers who do not participate in energy efficiency programs is through a rate impact screen?

A. No. While it is generally true that customers participating in energy efficiency programs experience more benefits from efficiency programs than do non-participants (because participants will experience bill reductions), this does not mean that non-participants experience no benefits at all. However, non-participant benefits are not necessarily captured by a limited rate impact screen.

Q. How do non-participants benefit from DSM programs?

A. Some of the benefits of energy efficiency programs accrue to the entire electricity system and are generally shared by both program participants and non-participants. One such benefit is reduced risk. Energy efficiency is widely recognized as a relatively low-risk resource to implement.[1] In addition, efficiency can help reduce the risk related to other resources. For example:

- Energy efficiency reduces the rate of growth in energy and peak demand, which provides utilities with relatively more time to meet new energy and capacity needs as they arise. Increased time provides utilities with more flexibility and more options—sometimes referred to as increased optionality—for meeting new energy and peak demands.

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1 Ron Binz et al., Practicing Risk-Aware Electricity Regulation: 2014 Update: A Ceres Report, at pp. 3-4, 14, 17. (Nov. 2014). Attached as Schedule TW-4.

- Energy efficiency can defer or avoid the need for new power plants, which themselves have risks associated with siting, construction costs, and construction schedules.
- Energy efficiency reduces the consumption of fossil fuels, thereby mitigating the risks associated with volatile fossil fuel prices.
- Energy efficiency can defer or avoid the need for new transmission lines, which have risks associated with siting, construction costs, and construction schedules.
- Energy efficiency can mitigate risks associated with complying with future federal greenhouse gas requirements, such as the EPA's proposed Clean Power Plan (CPP).
- Energy efficiency can defer or avoid the need for costly power plant retrofits to comply with other environmental regulations.

It is important to note that these risk mitigation benefits are not typically captured in utility energy efficiency cost-effectiveness analyses, nor are they typically captured in rate impact analyses.

Q. Are there other ways that energy efficiency can provide benefits to all customers?

A. Yes. Whenever a utility makes a large capital investment, such as in a new power plant or a major plant retrofit, rates increase for all customers. In some cases, the rates can increase by such large percentages that it is referred to as "rate shock." Energy efficiency can help mitigate these rate impacts whenever it defers, avoids, or reduces the size of a new power plant. This benefit is not captured in the total resource cost test (TRC), the utility cost test (UCT), or a simple rate impact screen.

Q. According to Ameren's 2014 IRP, the Company may not need to construct a new power plant for many years. If this is the case, do energy efficiency programs provide any customer benefits?

A. Yes. First, I should point out that I have not reviewed the analysis of supply-side resources in the Company's 2014 IRP in much detail, because my review focused on the demand-side resources. There may be opportunities to defer or avoid more supply-side investments than what is indicated in the 2014 IRP.

Nonetheless, if it is the case that Ameren does not need new generating capacity for many years, energy efficiency can still provide an important benefit for all customers by helping to defer, avoid, or reduce the size of a new power plant when it is needed. To fully appreciate this point, it is critical to recognize that energy efficiency resources take many years to develop, especially to develop the amount of capacity savings to defer or avoid a new power plant. In order for energy efficiency to have a significant impact on the need for a new power plant several years from now, it is necessary to implement all cost-effective energy efficiency programs until then.

Conversely, if the Company does not implement all cost-effective energy efficiency every year between now and then, then it becomes much more difficult for efficiency programs to have a meaningful impact on the need for a new power plant if and when the need does arise. If the Company implements only a small amount of energy efficiency over the next few years, as it proposes in the 2016-2018 Plan, there may not be sufficient time to develop of the level of efficiency savings needed to potentially defer or eliminate the need for that plant.

Energy efficiency resources cannot simply be turned on and off like a faucet of water, based on short-term expectations. Efficiency programs are most effective when they are provided with consistent funding and resources over many years in order to provide stability regarding (a) the utility management and staff dedicated to efficiency planning and implementation; (b) the infrastructure of contractors and trade allies in the state and region needed to implement programs; and (c) the customer engagement needed to adopt efficiency measures in their homes and businesses.

Q. What is the impact of the efficiency benefits you discuss on Mr. Rogers' suggestion that the sole measure of non-participant benefits is a rate impact screen?

A. Respectfully, I believe that these benefits undermine the premise of this position. While I appreciate the value in examining rate impacts along with bill impacts and participation rates, as I discuss below, I believe that requiring programs to pass a rate impact screen is an overly simplistic approach that does not recognize some important benefits that efficiency programs provide to all customers.

5. REQUIRING EFFICIENCY PROGRAMS TO PASS A RATE IMPACT SCREEN IS INCONSISTENT WITH THE COST EFFECTIVENESS TESTS USED UNDER MEEIA

Q. You mentioned earlier that you believe that requiring programs to pass a rate impact screen is inconsistent with MEEIA. Please explain.

A. A rate impact screen ignores the fact that MEEIA aims to encourage utilities to implement demand side programs with a "goal of achieving all cost-effective demand-side savings" and the meaning of cost-effective. (Mo. Ann. Stat. § 393.1075(4); 4 CSR 240-20.094(2), (3)(A)(1)).

Q. How do MEEIA and its implementing regulations address cost-effectiveness in energy efficiency programs?

A. The MEEIA statute and regulations provide that the TRC is "a preferred cost-effectiveness test." (Mo. Ann. Stat. § 393.1075.4; *see also* 4 CSR 240-20.094(3)(A) and 4 CSR 240-20.094(3)(C)). As described in my rebuttal testimony, the MEEIA statute and regulation also allow that the Utility Cost test be used when considering efficiency program cost-effectiveness. (Woolf Rebuttal Testimony at 46-52).

Q. How does requiring programs to pass a rate impact screen relate to the use of the TRC and the UCT tests for assessing cost effectiveness?

A. I believe that eliminating efficiency programs based on a rate impact screen would be inconsistent with the use of the TRC and UCT cost-effectiveness tests. Energy efficiency programs can result in increased rates—even those programs that are found to be cost-effective under the TRC or the UCT. A rate impact screen is much more difficult for efficiency programs to pass than the TRC or UCT. In effect, a rate impact screen is so stringent that it would render the other tests essentially meaningless for the purpose of screening programs.

Q. Are there other important implications of requiring programs to pass a rate impact screen?

A. Yes. A rate impact screen implies a fundamentally different goal than the TRC or the UCT. A rate impact screen implies a goal of minimizing rates, while the other two tests imply a goal of minimizing costs. For some efficiency programs, these two goals can be in conflict.

Q. What is the best way to address any tension between rates and costs?

In general, the public interest is best served by striking the appropriate balance between the two goals of maintaining low costs and low rates. If either goal is given too much of a priority, then the other goal can be jeopardized, and customers can be worse off.

Applying a rate impact screen to energy efficiency programs would not result in a good balance between these two goals. It would provide too much emphasis on minimizing electricity rates, would forgo millions of dollars in electricity cost savings, would lead to higher average customer bills, and would therefore not best serve customers' interest or the public interest in general. I elaborate on these points in the following sections.

6. A RATE IMPACT SCREEN WOULD HARM CONSUMERS

Q. How would a requiring efficiency programs to pass a rate impact screen impact customers?

A. A strict application of such a screening standard could easily result in the rejection of significant reductions in utility system costs to avoid what may be very small impacts on customers' rates. In this case, the Company has estimated that its energy efficiency programs could reduce electricity costs and average bills by as much as $135 million in present value terms (Ameren's 2016-2018 Energy Efficiency Plan, Table 2.6 at p. 20). If the Company were to achieve the MEEIA energy savings guidelines, then the electricity cost and bill savings would be even greater.

Yet the rate impacts from these savings are likely to be very small. As Mr. Rogers finds in his rebuttal testimony, the long-term average rate impacts of the Realistically Achievable Potential and the Maximum Achievable Potential portfolios in the 2014 IRP are likely to be 0.03 percent and 0.36 percent, respectively. (Rogers Rebuttal at 29). To forgo the opportunity to reduce electricity costs by $135 million in order to avoid this magnitude of rate impacts is not, in my view, in customers' best interest.

Q. Are there other examples of how a rate impact screen could result in outcomes that are not in customers' best interest?

A. Yes. As described in my rebuttal testimony, energy efficiency resources are widely regarded as one of the lowest-cost options for complying with the EPA's proposed CPP for reducing greenhouse gases. (Woolf Rebuttal Testimony at p. 38). If a rate impact screen is applied to energy efficiency programs, then utilities will be very limited in how much of this low-cost option can be used for complying with the CPP. Consequently, utilities will have to turn to higher-cost options to reduce CO_2 emissions, such as redispatch of natural gas, improved operating efficiencies at coal plants, or renewable resources. The Company has even suggested that it might construct new nuclear units to help meet the requirements of the proposed CPP.[2] It would clearly not be in customers'

[2] Ameren's 2014 IRP, Chapter 1 at 15.

interest to prevent the use of the lowest-cost carbon abatement option in order to achieve a theoretical, ideal standard of no rate increases, when this practice would require relying upon more expensive options whose higher costs would have to be collected from all customers.

7. RATE IMPACTS AND EQUITY CONCERNS

Q. Are you suggesting that the impact of efficiency on rates should be disregarded?

A. Not at all. As explained below, rate impacts raise equity considerations that should be addressed.

Q. Please explain the impacts that energy efficiency programs can have on electricity rates and bills?

A. Cost-effective energy efficiency programs will reduce electricity costs and therefore reduce average electric bills. In some cases, cost-effective efficiency programs will also result in increased rates. Therefore, customers who participate in efficiency programs will experience higher rates but lower electricity bills, while customers who do not participate in efficiency programs will experience higher rates. Consequently, concerns about rate impacts are essentially concerns about customer equity: equity between efficiency program participants and non-participants.

Q. How should the Commission address customer equity issues raised by energy efficiency programs?

A. First, it is important to put the customer equity issues in context. Then, it is important to develop some meaningful information to help analyze the equity issues. I discuss methods of developing meaningful information in Section 8.

Q. Please describe what you mean by putting the equity issues in context.

A. In the regulated electricity industry it is very difficult to eliminate all customer inequities. While it is important to minimize and mitigate customer inequity wherever possible, it is also important to recognize that customer inequity occurs in many ways with regard to both supply-side and demand-side resources. For example:

- When a utility installs a new power plant to meet increasing electricity demands due to new customers or an increase in the use-per-customer, all customers pay for the new power plant. However, existing customers whose electricity demands have not increased in recent years do not benefit from that new power plant.
- When a utility installs a new transmission line for economic or reliability reasons, all customers typically pay for the new transmission line. However, many customers may not experience the reliability or economic benefits of the new line because they are not located in the affected areas.
- When a utility installs new distribution systems to serve a newly developed residential neighborhood or a new industrial park, all customers typically pay for the new distribution systems. However, many customers do not experience the benefits of the new systems because they are not located in the affected areas.
- The cost of electricity is much greater during times of peak demand, but most customer rates do not reflect this difference in cost. Consequently, there is

typically some inequity between customers who use a lot of power during times of peak demand and those who do not.

- Residential customers have an energy charge and a customer charge. Consequently, there is typically some inequity between low-use and high-use customers.

Q. Why is it so important to recognize that supply-side resources result in customer inequities?

A. It is important to recognize these inequities in order to put equity concerns associated with energy efficiency in perspective. With supply-side resources in general, it is very difficult to achieve a standard of ensuring absolutely no inequity among customers. It is not possible to build power plants, transmission lines, or distribution systems without some customers benefitting more than others. In this context, regulators and utilities have an obligation to balance the goal of minimizing customer inequities with the other goals of providing safe, reliable, efficient, low-cost electricity services.

The same concept should apply for demand-side resources. In order to significantly reduce electricity system costs through energy efficiency programs, it is not possible or reasonable to achieve a standard of ensuring that there will be absolutely no inequity among customers. A rate impact test for screening efficiency programs would require energy efficiency to meet this overly burdensome and inappropriate standard. Instead, regulators and utilities have the same obligation that they have for supply-side resources: to balance the goal of minimizing customer inequities with the other goals of providing safe, reliable, efficient, low-cost electricity services.

Note that MEEIA states that "it shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure" (Mo. Ann. Stat. § 393.1075(3)). This concept should be applied to the consideration of customer equity issues, as well as the consideration of other cost-effectiveness and planning issues.

8. ASSESSMENT OF RATE, BILL, AND PARTICIPATION IMPACTS

Q. How should regulators and utilities strike the right balance between reduced costs and increased rates?

A. In order to strike the right balance, it is important to first develop the information needed to fully understand both the reduced costs and the customer equity impacts.

Q. What information is needed to demonstrate the extent to which energy efficiency can reduce electricity costs and bills?

A. The cost-effectiveness results based on the UCT provide the best indication of the extent to which energy efficiency can reduce electricity costs and bills. As described in my rebuttal testimony, the UCT includes only those costs and benefits that affect a utility's revenue requirements. (Woolf Rebuttal Testimony at p. 49, ll. 15-16). Consequently, the UCT provides the best indication of the extent to which efficiency programs can reduce costs and customer bills on average. (*Id*. at p. 49, ll. 117-19). For the Company's proposed 2016-2018 Plan, the results of the UCT indicate that the portfolio of programs is expected to reduce electricity system costs, revenue requirements, and average customer bills by $135 million in net present value terms. Furthermore, every ratepayer dollar spent on energy efficiency will result in 2.1 dollars in savings for ratepayers. (2016-2018 Plan, Table 2.5 at p. 20).

Q. What information is needed to understand the equity implications of energy efficiency programs?

A. In order to fully understand the equity implications of energy efficiency programs, it is necessary to consider three types of impacts: rate impacts, bill impacts, and DSM program participation rates. Rate impacts, properly estimated, indicate the extent to which rates might increase due to energy efficiency. Bill impacts indicate the extent to which average customer bills might be reduced due to energy efficiency. Participation rates indicate the extent to which customers will experience bill reductions or bill increases. Taken together, these three measures indicate the extent to which customers as a whole will be affected by energy efficiency.

Q. How should rate impacts be estimated?

A. Rate impact estimates should account for all factors that impact rates, either positively or negatively. This would include all avoided costs that might exert downward pressure on rates (e.g., generation, transmission, and distribution), including the avoided costs of complying with environmental regulations. Rate impacts should be estimated over the long term, to capture the full period of time over which the efficiency savings will occur. Rate impacts should also be put into terms that place them in a meaningful context; for example, in terms of cents per kilowatt-hour or percent of total rates.

Q. How should bill impacts be estimated?

A. The bill impacts should build upon the estimates of rate impacts described above. The rate impacts apply to every customer within the rate class analyzed. Bill impacts, on the other hand, will vary among customers depending upon whether they participate in the DSM programs, and depending upon which DSM program they participate in. Therefore, bill impacts should be estimated separately for each of the types of DSM programs. As with rate impacts, they should be estimated over the long term, and they should be put into terms that place them in a meaningful context; for example, in terms of dollars per month or percent of total bills.

Q. How should program participation rates be estimated?

A. Program participation rates should be estimated by dividing the program participants by the total population of eligible customers to get a rate in percentage terms. This should be done for each year, and for each program. Participation rates should be compiled across several years to indicate the extent to which customers are participating in the programs over time. To the extent possible, participation in multiple programs and across multiple years should be captured. The long-term program participation rates can be compared with the long-term bill impacts and the long-term rate impacts to get a sense of the extent to which customers are benefiting from the DSM programs.

Q. How should all this information be used?

A. This information should be used by regulators and utilities to strike an appropriate balance between reduced costs and increased rates. This information should be used to answer several key questions:

- How much will the efficiency programs reduce electricity system costs and average customer bills?
- How much will the efficiency programs increase customer rates, on average over the long term?
- What portion of customers is expected to participate in efficiency programs over the long term, and thereby experience a net reduction in bills?
- What additional benefits, beyond rate and bill impacts, are the efficiency programs expected to provide? (This issue is addressed in Section 7.)

Answers to these questions will help regulators and utilities to understand the full impact of efficiency programs, and to balance the tradeoffs between reduced costs and customer equity concerns.

Q. Would a rate impact screening test allow for this type of analysis?

A. No. A rate impact screen for efficiency programs is an overly simplistic way of looking at just one aspect of a multi-faceted equity issue. It creates a standard that ignores the cost and bill reductions from energy efficiency, and thus does not allow for a balancing of rate impacts and cost impacts.

Furthermore, a simplistic rate impact test ignores and precludes the use of other options available for mitigating equity concerns created by energy efficiency.

9. OPTIONS FOR MITIGATING EQUITY CONCERNS

Q. What options are available to address equity concerns raised by energy efficiency?

A. Instead of simply eliminating efficiency programs by using a rate impact screening test, utilities can design their programs to mitigate equity concerns. There are many such program design options, including:

- Programs can promote a wide variety of types of efficiency measures that offer cost-effective savings, in order to increase the likelihood of customers being able to participate.
- Programs can provide all customer types with an opportunity to participate, including hard-to-reach customers such as low-income customers and small businesses.
- Programs can use delivery mechanisms, such as upstream buydown programs, that reduce the cost and increase the participation of efficiency programs.
- Programs can focus on market transformation activities, which should eventually benefit a wider range of customers, including program non-participants.
- Programs can utilize third-party financing options to offset the need for ratepayer funding.
- Programs can utilize on-bill financing options to increase the contribution to costs made by participating customers.
- Program marketing techniques can be used to actively identify, target, and pursue customers that have not participated in efficiency programs to date.

- Program budgets can be increased in order to allow for greater participation across customers.

Programs that incorporate these design concepts can help to mitigate equity concerns by reducing the amount of funding required from ratepayers, and increasing the number of customers who participate in efficiency programs and experience bill reductions.

Q. Would a rate impact screening test allow for some of these options to be used to mitigate equity concerns?

A. Not necessarily. A rate impact screen is too blunt and simplistic to allow for some of these options. In fact, such a test might preclude some of these options from being used to address equity concerns. For example, an efficiency program designed to serve small business customers might not pass a rate impact screening test because it is sometimes more costly to reach these customers. In this case, an entire class of customers would have limited options to benefit from utility-run efficiency programs. Such an outcome would work against the goal of customer equity, and would not allow for mitigating equity concerns through some of the program design options described above.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	))))	File No. EO-2015-0055

AFFIDAVIT OF TIM WOOLF

COMMONWEALTH OF MASSACHUSETTS)
) ss
COUNTY OF MIDDLESEX)

I, Tim Woolf, of lawful age and being duly sworn, state and affirm the following: that the foregoing prepared testimony in question and answer format constitutes my Surrebuttal Testimony in the above-captioned proceeding; that the answers set forth therein were given by me and that I have knowledge of the matters set forth in such answers; and that the answers contained therein are true and correct to the best of my information, knowledge and belief.

Tim Woolf

Tim Woolf

SUBSCRIBED AND SWORN before me this 27th day of April 2015.

Notary Public

My Commission Expires:

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

PRACTICING RISK-AWARE ELECTRICITY REGULATION:

2014 Update

A Ceres Report

November 2014

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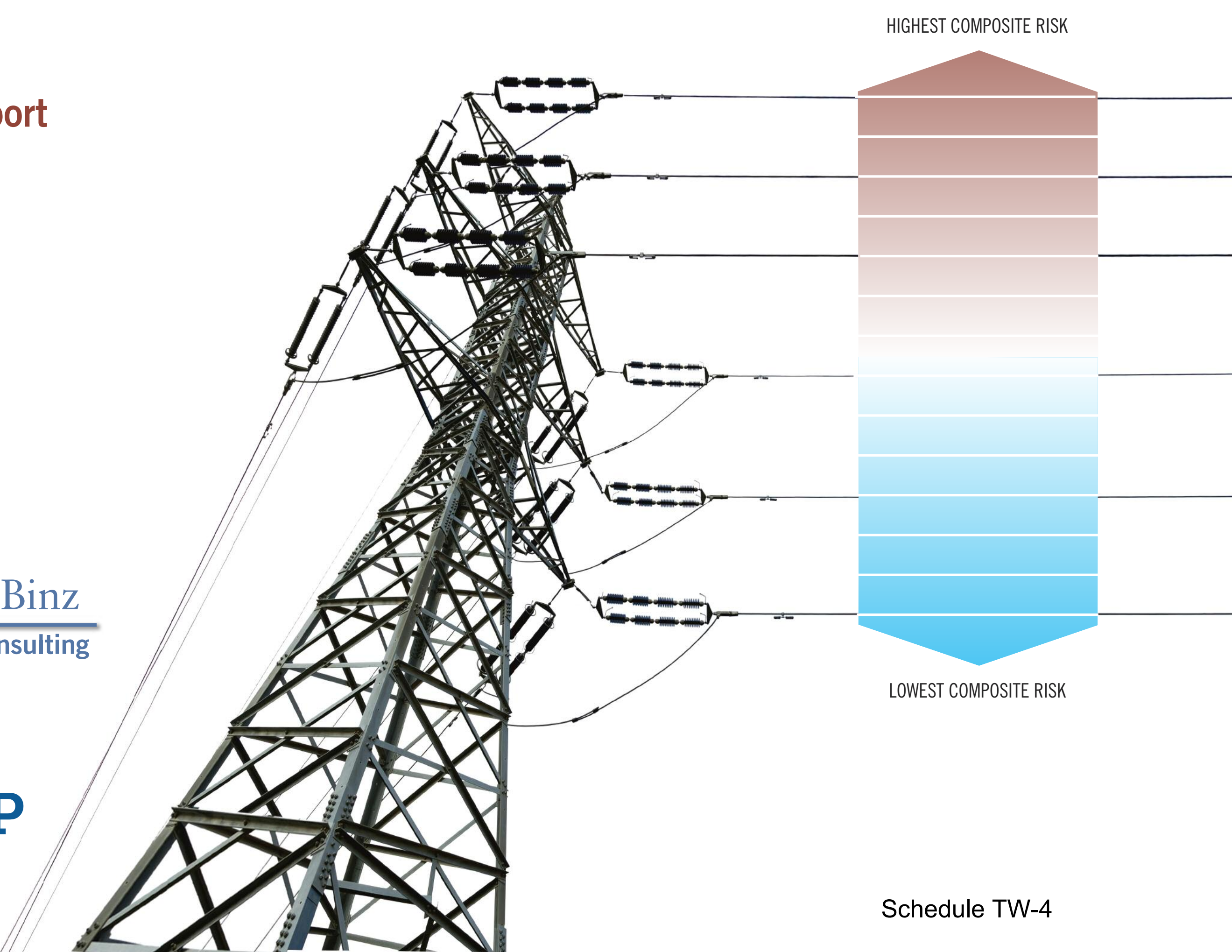

Ronald J. Binz
Public Policy Consulting

RAP

Schedule TW-4

ABOUT CERES

Ceres is a nonprofit organization mobilizing business and investor leadership on climate change, water scarcity and other sustainability challenges. Ceres directs the Investor Network on Climate Risk, a network of over 110 institutional investors with collective assets totaling more than $12 trillion. For more information, visit www.ceres.org or follow Ceres on Twitter: @CeresNews

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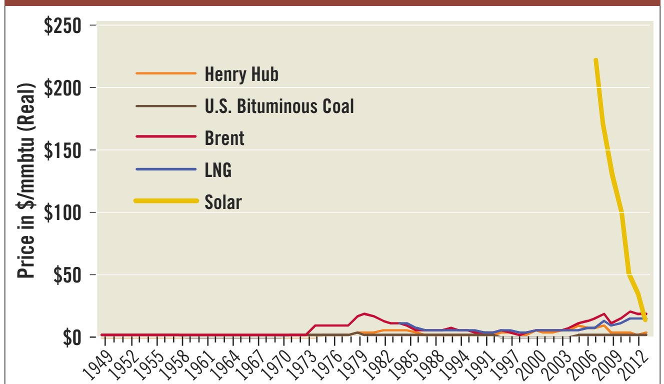
EXECUTIVE SUMMARY

In April 2012, Ceres published ***Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know***.[1] That paper examines wide-ranging challenges facing the U.S. electric utility industry—such as aging power plant fleets, evolving energy technologies and environmental regulatory pressures. It also includes recommended steps that utility regulators can take to minimize risks and costs for utilities, customers, shareholders and society as future investments are being considered. Two years later, this ***2014 Update*** looks at key trends that continue to reshape the U.S. electricity industry, analyzes changing costs and risk profiles of energy resources (especially renewable energy), and offers further insights and recommendations for smart, "risk-aware" decision-making by utility regulators.

This report, authored by utility industry and finance experts, concludes that almost without exception the riskiest investments for utilities—the ones that could cause the most financial harm for utilities, ratepayers and investors—are large base load fossil fuel and nuclear plants. In contrast, energy efficiency, distributed energy and renewable energy (whose costs, in some cases, have come down dramatically since 2012) are seen as more attractive investments that have lower risks and costs. Among the paper's findings:

Figure ES-1

COST TRENDS: SOLAR & FOSSIL FUELS



Source: EIA, CIA, World Bank, Bernstein analysis

I. KEY DEVELOPMENTS IN THE U.S. ELECTRICITY SECTOR SINCE 2012

1. **The EPA has begun regulating carbon dioxide emissions from electricity generation as a pollutant.** Assuming the EPA's regulations for new and existing power plants survive judicial review, utilities will place a much higher emphasis on low-carbon or no-carbon resources.
2. **Hurricane Sandy and an armed attack on the power grid near San Jose, CA highlighted the need for greater grid resilience and security.** These events in 2012 and 2013 make clear that the landscape for "risk-aware" regulators extends far beyond considering risks in energy supply portfolios to include safeguarding the entire electric grid.
3. **Renewable energy technology costs have fallen sharply, closing the cost gap between renewable resources and traditional fossil fuel resources.** Solar photovoltaic (PV) energy costs, in particular, have declined precipitously in recent years (Figure ES-1).[2] Wind and solar costs are expected to continue to fall through at least 2020, a characteristic not shared by other generation technologies.
4. **Potential "disruptive challenges" to utilities are now more evident than ever.** Cheaper renewable energy options and projections for anemic electricity demand growth are just two of the trends that are intensifying pressure on electric utilities and catalyzing an industry-wide conversation about the changing role of utilities in the 21st century. Put simply, utility business models are shifting from a simple "cost of service" approach to one that expands utility service offerings and capabilities in light of carbon reduction, grid resilience and customer engagement imperatives. This transformation is already happening to a degree and in a timeframe that seemed unthinkable just a few years ago.
5. **Cheap natural gas and increasing renewables penetration are changing the topology of the electricity grid, accentuating the need for more flexible energy resources.** In some areas, high penetration of solar and wind resources may soon replace the afternoon demand *peak* with an afternoon demand *trough*, challenging system grid operators to adopt new grid management techniques, increase demand response and boost energy storage.[3] Kauai, Hawaii expects to wrestle with this phenomenon as early as 2015, five years sooner than California (Figure ES-2).
6. **The pace of innovation in utility regulation is accelerating.** Massachusetts, New York and Hawaii, most notably, have instituted proceedings to pursue the market and regulatory structures needed to build a cleaner, smarter, more decentralized 21st century electric grid.

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1 Ron Binz, Richard Sedano, Denise Furey and Dan Mullen, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (Boston, MA: Ceres, 2012), http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view.

2 Bernstein Research, "Bernstein Energy & Power Blast: Equal & Opposite… If Solar Wins, Who Loses?," April 4, 2014.

3 For solutions to challenges associated with the "duck curve," see Jim Lazar, *Teaching the Duck to Fly* (Montpelier, VT: The Regulatory Assistance Project, 2014), http://www.raponline.org/document/download/id/6977.

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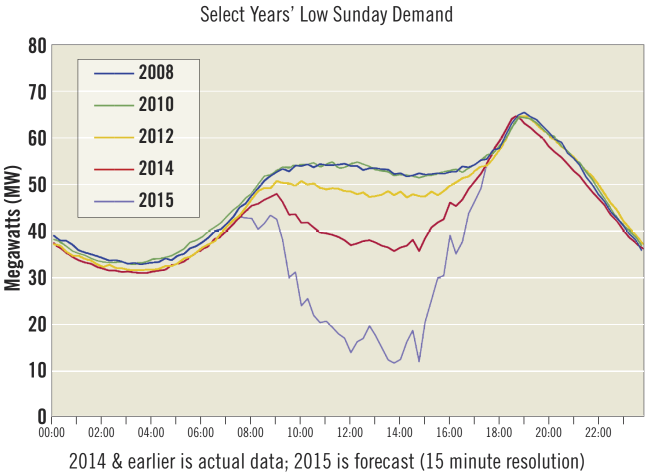
Figure ES-2

KAUAI'S "DUCK CURVE"



2014 & earlier is actual data; 2015 is forecast (15 minute resolution)

Source: Kaua'i Island Utility Cooperative

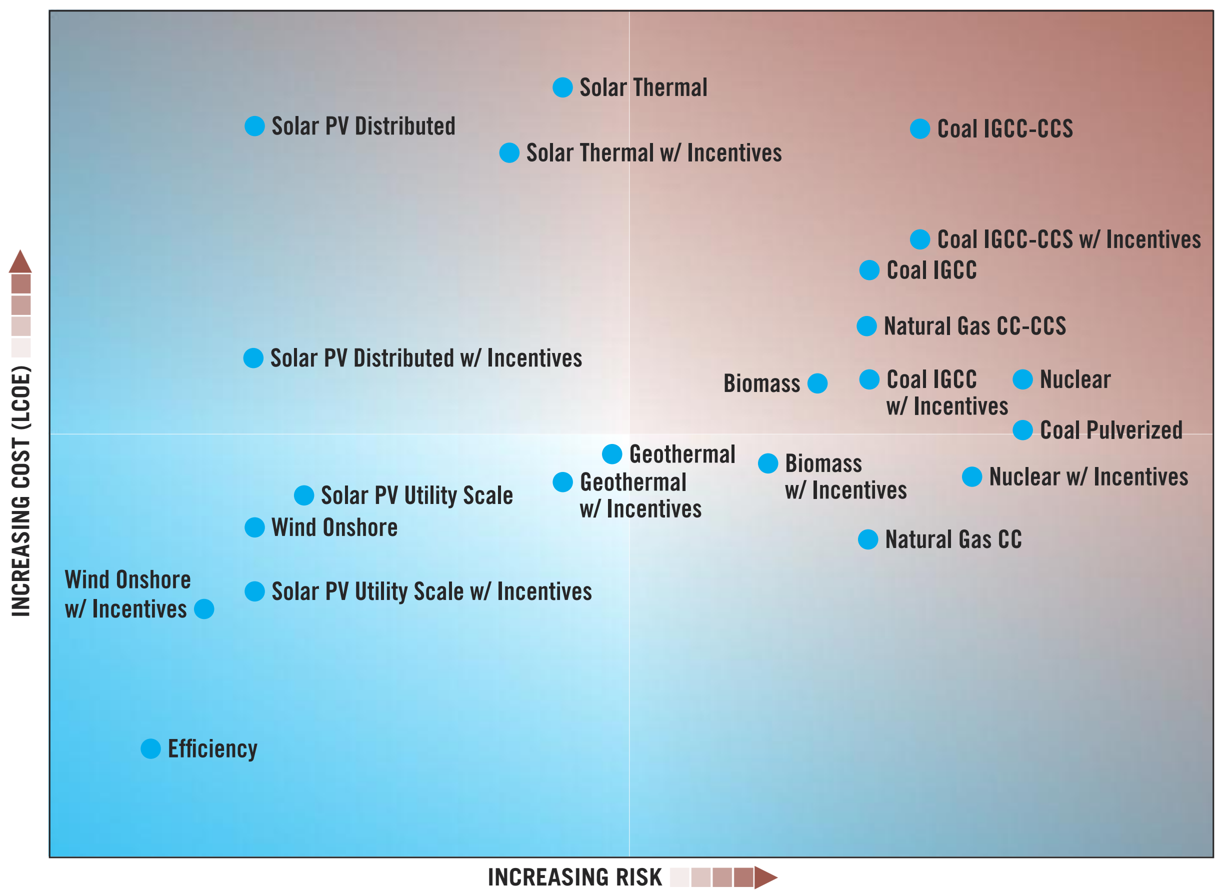
II. UPDATED COST AND RISK RANKINGS OF NEW GENERATION RESOURCES

This report computes levelized energy costs (LCOE) for various generation resources using analysis from four authoritative sources: Bloomberg New Energy Finance, Citi, Lazard and the U.S. Energy Information Administration (EIA).[4] The report ranks the resources by LCOE, with and without subsidies, as we did in the 2012 report. Utility-scale solar photovoltaic power shows the biggest decline in relative cost among all resources, while the estimated LCOE for fossil-powered plants with carbon capture and storage (both coal and gas) moved those resources higher in the cost ranking.

We also revisited the risk profiles for each resource, making only a few adjustments. Figure ES-3 shows our *2014 Update* analysis of the relative cost and relative risk of utility generation resources. As in 2012, fossil fuel resources are grouped on the right side of the chart (higher risk), and renewables on the left (lower risk). Utility scale PV joined wind generation and energy efficiency as the energy resources with the lowest risk and lowest cost.

Figure ES-3

2014 UPDATE **RANKING: RELATIVE COST VS. RELATIVE RISK OF NEW GENERATION RESOURCES**



4 LCOE is the price at which electricity must be generated from a specific source to break even over the lifetime of the project (including a profit). LCOE factors in all costs: capital, finance, fuel, O&M, profit, etc.

III. CONCLUSIONS & RECOMMENDATIONS

This *2014 Update* reaffirms the conclusions and recommendations from our 2012 report, which emphasized the need for intelligent risk management practices by utility regulators in overseeing utility investment. In light of recent developments, particularly advances in renewable energy and increasing pressures on utility business models and regulatory paradigms, this *2014 Update* offers the following observations and insights for regulators as they consider the relative merits of proposed utility investments:

- **There is a clear and durable imperative for clean energy in the U.S.,** driven by advancing technology, federal air quality rules and the lower cost and risk profile of renewable and demand-side energy resources.
- **Costs for some renewable energy technologies, particularly solar PV and wind, are likely to continue to fall at least until 2020.** This will narrow—and perhaps erase—any cost gap between renewable and traditional fossil fuel and nuclear resources. It will also increase pressure to modernize many aspects of the power sector and will lower the costs of achieving carbon pollution reductions.
- **Distributed energy resources (DER)—including distributed generation, demand response and energy storage—will play an increasingly important role in the 21st century electricity system.** While DER's precise share of energy supply will emerge over time, three points are clear today: i) DER penetration levels will continue to increase, accelerated by falling renewable costs and EPA rules to reduce carbon emissions; ii) DER reshapes the topology and requirements of the grid; and iii) effective DER integration requires focused, "risk-aware" electricity regulation.
- **New analytical methods and modeling tools are needed to plan investment in a modern, 21st century electricity system with significant DER.** As states grapple with increasing amounts of DER, a sophisticated approach to Integrated *Distribution* Planning must emerge. Such planning must model a much more complicated system; anticipate and absorb new technologies; and solve for a range of high-priority outcomes (e.g., carbon reduction, grid resilience, forward-compatibility, customer empowerment and affordability).
- **Electricity regulation must continue to evolve.** Some states have begun to explore regulatory models that move beyond simple "cost of service" and align utility compensation with broader customer interests and societal goals. This trend will continue in the state "laboratories" as a set of new regulatory models will evolve.
- **Collaboration and transparency are essential.** Near-term priorities in this area include: i) coordination between state utility and air quality regulators to arrive at a least cost/least risk compliance strategy for EPA rules; ii) enhanced transparency and governance at Independent System Operators (ISOs) and Regional Transmission Operators (RTOs); iii) robust, transparent and inclusive processes for both Integrated Resource Planning and Integrated Distribution Planning.

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INTRODUCTION

In April 2012, Ceres published a report called ***Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know***. That report discussed wide-ranging challenges in the electric utility industry—such as aging power plant fleets, evolving technologies and regulations for climate change—and the changing nature of risks that these challenges present for utilities, customers and shareholders. We analyzed the costs and risks involved in meeting America's power needs through a variety of strategies, from constructing large centralized power plants to reducing demand through energy efficiency and deploying distributed generation and renewable energy sources.

We illustrated our points by analyzing these various supply options, comparing them not only on the basis of levelized cost, but also based on our estimate of the risk associated with each resource. Our report was aimed primarily at state utility regulators, who will oversee some $2 trillion of utility capital investments in the next 20 years to replace aging power plants, implement new technologies and meet new regulatory requirements, including carbon-reducing regulations.

Two and a half years after our original analysis, we think it is important to review the cost and risk landscape in light of significant changes in the relative costs of certain resources, mounting concerns about global climate change and the slow but steady evolution of utility regulation. For that reason, we are updating and supplementing our 2012 report with new data and additional recommendations for regulators.

This update is presented in three sections:

1. **Key Developments in the U.S. Electricity Sector Since 2012**
2. **Updated Cost and Risk Rankings of New Generation Resources**
3. **Conclusions & Recommendations**

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1 KEY DEVELOPMENTS IN THE U.S. ELECTRICITY SECTOR SINCE 2012

We begin by identifying six major developments in the U.S. electric power sector since 2012.

1 The EPA has begun to implement the judicial mandate of *Massachusetts vs. EPA*, a decision that requires the agency to regulate carbon dioxide emissions from electricity generation as a pollutant.

In April 2007, the U.S. Supreme Court ruled that the U.S. Environmental Protection Agency (EPA) must begin to regulate the emissions of greenhouse gases. In September 2013, the EPA proposed a new source performance standard (NSPS) for emissions of carbon dioxide for *new* affected fossil fuel-fired electric generating units under section 111(b) of the Clean Air Act. In rough terms, EPA's 111(b) rule requires that the carbon dioxide emissions of new fossil-fueled units do not exceed 1100 lbs./MMBTU, about the same emissions level as efficient gas-fueled combined cycle generators.

In June 2013, the President ordered the EPA to begin preparing a rule to regulate greenhouse gas emissions from *existing* generation resources. In June 2014, the EPA announced proposed new rules for existing fossil power plants under section 111(d) of the Clean Air Act. The proposed rule, called the Clean Power Plan, is complex, but comes down to a simple mandate: each state is responsible for reducing the intensity of carbon dioxide emissions from power plants by a formula-driven percentage that varies from state to state. Overall, the Clean Power Plan aims to reduce carbon pollution from the U.S. power sector 30 percent below 2005 levels by 2030.

It's Not Just the EPA: Why and How States are Reducing Carbon Emissions in the Power Sector

The United States Congress has been unable to produce political agreement for federal action on climate change. This occurs despite multiple polls showing that Americans, including likely voters, strongly support federal action, even while acknowledging that action on climate change might raise energy costs. Polling by the *Wall Street Journal* in mid-2014 demonstrated majority support for the EPA's Clean Power Plan.[5]

Several states moved to reduce carbon in generation portfolios prior to the EPA's proposed carbon rules. Historically, state action has usually taken the form of mandates or incentives for renewable energy sources and for energy efficiency. But cheap natural gas has allowed several states with vertically integrated markets to proceed formally to reduce carbon emissions by reducing the fraction of coal generation in the portfolios of regulated companies. Significantly, in Nevada and Colorado, state legislation was passed to accelerate the retirement of coal plants before their previous planned closing dates.[6]

In states with wholesale competition, other forces are driving the change to cleaner energy mixes. The low price of natural gas and the falling cost of wind generation have lowered the market price of electricity in PJM, ERCOT and MISO, placing substantial pressure on coal and nuclear generation. Going forward, we can expect utility-scale solar production to add further downward pressure to wholesale electricity prices. Thus, the EPA's proposed Clean Power Plan will probably follow the parade of many coal plant closures, not lead it.

5 Amy Harder, "Obama Carbon Rule Backed by Most Americans – WSJ/NBC Poll," *The Wall Street Journal*, June 18, 2014, http://blogs.wsj.com/washwire/2014/06/18/obama-carbon-rule-backed-by-most-americans-wsjnbc-poll/.

6 Chris Clarke, "Nevada Votes to Close Coal Plant," KCET.org, June 4, 2013, http://www.kcet.org/news/rewire/coal/nevada-votes-to-close-coal-plant.html.

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As proposed, EPA's Clean Power Plan gives each state significant flexibility in how to meet its emissions reduction target. The proposed rule does not apply to individual power plants, but instead to the state as a whole. The EPA does not specify what measures a state must take, but makes clear that it will consider plans that feature more energy efficiency, more renewable energy, low-carbon power sources and improved utilization of existing facilities. Finally, the EPA's plan allows states to combine efforts, whether regionally connected or not. Such an arrangement would permit states to employ carbon pricing mechanisms, reducing the cost of compliance to the states in such a pact.

Assuming the EPA's regulations survive judicial review, utilities will place a much higher emphasis on low-carbon or no-carbon resources.

The Clean Power Plan will have a significant and predictable impact on utilities' evaluation and acquisition of energy resources. Assuming the EPA's regulations survive judicial review, utilities will place a much higher emphasis on low-carbon or no-carbon resources. Further, the Clean Power Plan is likely to give a big boost to energy efficiency, since every analysis shows that energy efficiency is the least-cost compliance option.

2 Two incidents of unprecedented destruction—Hurricane Sandy and an armed attack on the grid in California—highlighted the need for greater grid resilience and security.

Instances of extreme weather and grid sabotage have brought the vulnerability of the aging U.S. power grid into stark focus. In October 2012, Hurricane Sandy, a "once-in-a-generation" storm on the U.S. East Coast, cut power to more than 10 million homes and businesses in 17 states, in some cases for weeks. In the end, a national response was required to get the grid back up and running. A few months before Sandy, severe wind and thunderstorms known as a *derecho* devastated power systems in the Midwest and Mid-Atlantic, causing blackouts for five million electric customers from Illinois to New Jersey.

The two storms killed more than 200 people, and Sandy alone caused $50 billion in U.S. property damage. Sandy occurred only seven years after another "once-in-a-generation" storm, Hurricane Katrina on the Gulf Coast.

Another troubling incident occurred in April 2013 near San Jose, CA. Attackers used high-powered rifles to destroy 17 transformers at PG&E's Metcalf transmission substation in an apparent attempt to disable the grid and paralyze Silicon Valley. PG&E managed to avoid a blackout but incurred more than $15 million in damages that required nearly a month to repair. *The Wall Street Journal* later reported that coordinated attacks on only nine substations across the country could take down the entire U.S. power grid "for weeks, if not months."[7]

These unrelated but seminal events show that the purview for "risk-aware" regulators extends far beyond considering of risks in energy supply portfolios to include safeguarding the entire electric grid. The task for regulators and utilities is to build a modern, 21st century grid that is secure, resilient and adaptable in the widest range of possible scenarios (including, plainly, extreme weather and physical and even cyber-attacks). Full consideration of this task exceeds the bounds of this report, but it's worth noting that a central "risk-aware" concept, diversification, remains relevant since smaller-scale distributed resources and the introduction of self-healing "microgrids"—grid-connected but "island-able" assemblies of supply and demand—relieve stress and mitigate risks for a centralized electricity system.[8]

3 Renewable energy technology costs have fallen sharply, closing the cost gap between low-carbon resources and traditional fossil fuel resources.

The energy technology that's experienced by far the greatest cost reductions in recent years is solar photovoltaic (PV). In September 2014, financial advisory Lazard reported that the levelized cost of energy (LCOE) of PV technologies had fallen by nearly 20 percent in the past year, and nearly 80 percent in the last five years.[9] Bernstein Research depicted solar PV's dramatic descent down the cost curve with a graphic in an April 2014 report, shown on the next page in Figure 1.[10]

7 Rebecca Smith, "U.S. Risks National Blackout From Small-Scale Attack," *The Wall Street Journal*, March 12, 2014, http://online.wsj.com/news/articles/SB10001424052702304020104579433670284061220.

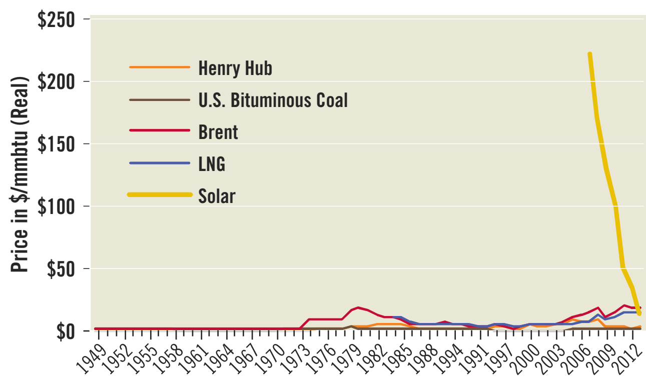
8 The U.S. Department of Energy defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and that connects and disconnects from such grid to enable it to operate in both grid-connected or 'island' mode." See http://energy.gov/sites/prod/files/EAC%20Presentation%20-%20OE%20Microgrid%20R%26D%20Initiative%202011%20-%20Smith.pdf.

9 "Lazard Releases New Levelized Cost of Energy Analysis," Lazard press release, September 18, 2014, http://www.marketwatch.com/story/lazard-releases-new-levelized-cost-of-energy-analysis-2014-09-18.

10 Bernstein Research, "Bernstein Energy & Power Blast: Equal & Opposite… If Solar Wins, Who Loses?," April 4, 2014.

Figure 1

COST TRENDS: SOLAR & FOSSIL FUELS



Source: EIA, CIA, World Bank, Bernstein analysis

Prices for wind generation have also fallen sharply in the past two years. Reported prices for wind power in Texas and Colorado have been less than 3 cents per kilowatt-hour (kWh).[11] In its recent Integrated Resource Plan in Colorado, Xcel Energy projects significant fuel cost savings as wind energy supplants natural gas generation on its system, even with natural gas prices at historical lows.[12]

Anecdotally, *current* costs for solar and wind appear to be at the bottom of the range of analyst estimates of *future* costs. Each day seems to bring new headlines about the falling cost of wind and solar power:

- The City of Austin, Texas recently signed a 25-year contract with Current Energy for 150 megawatts (MW) of solar PV at a price of 5 cents per kWh.[13] This bid relies on the existing federal investment tax credit for solar generation, but no additional support. In March 2014, Austin signed an 18-year contract for 300 MW of wind power at a price of 2.6 to 3.6 cents per kWh.[14]
- Just last month, Georgia Power announced the acquisition of 515 MW of solar PV at an average price of 6.5 cents per kWh.[15]
- In March 2014, Xcel Energy contracted to purchase 170 MW of solar PV, with 120 MW to be installed near an existing coal plant in Pueblo, Colorado.[16] The price for the solar PV ranges from 5.8 to 6.3 cents per kWh.

Wind and solar costs are expected to continue to fall through at least 2020, a characteristic not shared by other generation technologies

Finally, wind and solar costs are expected to continue to fall through at least 2020, a characteristic not shared by other generation technologies. The Department of Energy's SunShot Initiative aims to lower the installed cost of utility-scale solar to $1.00 per installed watt, down from today's level of about $2.00 per watt. The National Renewable Energy Laboratory (NREL) predicts an additional 20-30 percent reduction in the costs of wind energy by 2030.[17]

4 Potential "disruptive challenges" are gaining attention from utilities, analysts and policy makers, bringing opportunities along with the challenges.

Pressures on electric utilities, and on the traditional utility business model, have grown more acute. Strong renewable energy growth, low natural gas prices and near-zero electricity demand growth have suppressed prices in U.S. wholesale power markets, cut into power producers' revenues and forced unanticipated closures of some suddenly-unprofitable coal and nuclear plants. At the same time, advances in alternative energy technologies are increasing opportunities for customers to provide their own energy services. All these events are accelerating an industry-wide exploration of the changing role of the electric utility in the 21st century and how the utility will deliver value and earn reasonable profit.

Arguably the most disruptive factor is the plummeting cost of distributed solar PV. As rooftop solar continues to get cheaper and approach "grid parity"—the point at which solar panels provide power as cheaply as the grid—solar becomes a viable option for a larger share of utility customers. Clearly, this could threaten utility revenues and change the relationship among customers, utilities and the grid. In a recent analysis, Deutsche Bank predicts solar PV will reach grid parity in 47 U.S. states as soon as 2016, assuming today's 30 percent solar investment

11 See, for example, this AWEA report on wind prices, especially in the interior U.S. through 2012: http://www.awea.org/Resources/Content.aspx?ItemNumber=5547.

12 Public Service Company of Colorado, *2013 All Source Solicitation 120 Day Report: 2011 Electric Resource Plan*, September 9, 2013, http://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/Redacted_Version_120DayReport_REVISED_FINAL.pdf.

13 Nora Ankrum, "AE's Solar Deal: 'Game Changer,'" *The Austin Chronicle*, July 4, 2014, http://www.austinchronicle.com/news/2014-07-04/aes-solar-deal-game-changer/.

14 Wayne Barber, "Austin, Texas Approves Wind Power Agreement to Achieve Utility's Renewables Goal Four Years Early," *GenerationHub*, March 3, 2014, http://www.renewableenergyworld.com/rea/news/article/2014/03/austin-texas-approves-wind-power-agreement-to-achieve-renewables-goal-four-years-early.

15 Stephen Lacey, "Georgia is the Latest State to Procure Dirt-Cheap Solar Power," *GreenTech Media*, October 15, 2014, http://www.greentechmedia.com/articles/read/how-cheaply-can-georgia-power-buy-solar-for-6.5-cents.

16 Dennis Darrow, "Colorado's Largest Solar Power Facility Coming to Pueblo," *The Pueblo Chieftain*, March 4, 2014, http://www.chieftain.com/news/pueblo/2346770-120/solar-energy-pueblo-project.

17 Eric Lantz, et al., "IEA Wind Task 26: The Past and Future Cost of Wind Energy," National Renewable Energy Laboratory, April 2012, https://www.ieawind.org/index_page_postings/WP2_task26.pdf.

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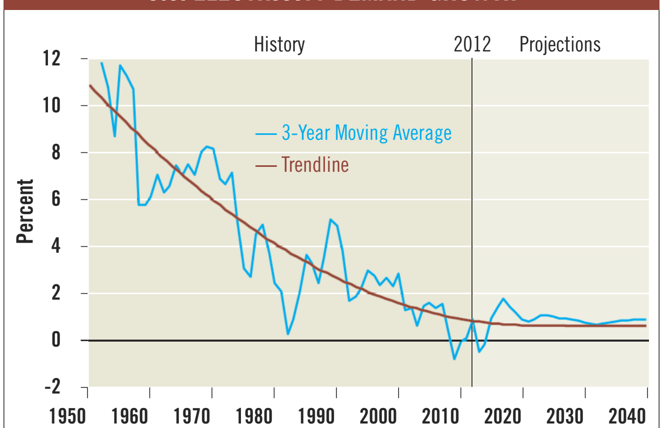
tax credit (ITC) is extended.[18] (If the ITC drops to 10 percent beyond 2016, Deutsche Bank still predicts grid parity in 36 states, up from about 10 states in 2014.)

Similarly, Morgan Stanley projects the "total addressable market" for U.S. distributed solar PV, in a base case scenario, will grow to 241 gigawatts (GW) over the next five years (compared to an installed base, in spring 2014, of only 6.2 GW).[19] In an aggressive scenario, Morgan Stanley expects the total addressable PV market in the U.S. could reach as high as 415 GW—roughly equivalent to the electric generating capacity of 800 mid-sized coal-fired power plants.

Another challenging trend is that growth in demand for electric power, traditionally a key driver of utility profits, has declined steadily since the 1970s and remained very modest despite the economy's recovery from the Great Recession. Figure 2, from the U.S. Energy Information Administration (EIA) shows that year-on-year growth in electricity demand is approaching one percent in the U.S.[20] Some regions, especially the Northeast and West Coast, are projecting flat to negative growth. Importantly, EIA does not project that year-on-year demand growth will return to the levels of the early 2000s, even assuming a full economic recovery.

Figure 2

U.S. ELECTRICITY DEMAND GROWTH



Source: EIA

It is now clear that the transformation of the U.S. electricity industry, already underway, could occur to a degree and in a timeframe that seemed unthinkable just a few years ago. This possibility has not gone unnoticed by utilities or Wall Street analysts. The Edison Electric Institute (EEI), in a widely cited 2013 report, warned specifically of the threat that distributed solar PV could pose to utility revenues. EEI has proposed solutions, including revising net metering policies and increasing customer fixed charges, that seem aimed at maintaining the *status quo* and may prove unpopular with consumers and regulators.[21] In May 2014, Barclays issued a controversial across-the-board downgrade of U.S. investor-owned electric utility bonds to "underweight" from "market weight," due primarily to the threat that solar PV plus energy storage could represent to utility earnings.[22]

While extreme solar-plus-storage scenarios could certainly wreak havoc for utilities, Rocky Mountain Institute has pointed out that customers won't necessarily defect from the grid just because they can, and that widespread grid defection could bring suboptimal outcomes for customers as well as utilities.[23] Of course, the flip side of these challenges will be opportunities for utilities who successfully adapt their business models. As we will see, regulators are testing new regulatory approaches that could help utilities make the needed changes.

5 Cheap natural gas and increasing renewables penetration are changing the U.S. generation fleet, the fortunes of power producers in wholesale markets, and the topology of the electricity grid, accentuating the need for more flexible energy resources.

To see how low-marginal-cost resources like wind and solar lower the cost of energy in an organized wholesale market, consider the hypothetical dispatch curve in Figure 3. This figure, produced by EIA, illustrates the supply curve for power for a typical summer day.[24] Note that the price of power differs depending on the load at a given hour. In this hypothetical case, the price of power is approximately $40 per megawatt-hour (MWh) in the early morning with the price set by the marginal unit—likely a combined-cycle gas plant or a coal plant. The price during the afternoon peak is approximately $100 per MWh, set by a simple-cycle gas plant. Note the relatively small amount of renewables (about 3 GW) at the far left side of the curve.

18 Deutsche Bank Markets Research, "Vivint Solar: Initiating Coverage with a Buy," October 26, 2014.

19 Giles Parkinson, "Morgan Stanley: Tipping point nears for going off-grid," *RenewEconomy*, March 24, 2014, http://reneweconomy.com.au/2014/say-investors-wake-solar-pro-sumers-24413.

20 EIA, "Growth in electricity use slows, but use still increases by 29% from 2012 to 2040," http://www.eia.gov/forecasts/aeo/MT_electric.cfm. Accessed October 21, 2014.

21 Edison Electric Institute (EEI), "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," January 2013, http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf.

22 Michael Aneiro, "Barclays Downgrades Electric Utility Bonds, Sees Viable Solar Competition," *Barron's*, May 23, 2014, http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition/.

23 Jules Kortenhorst, Lena Hansen and James Mandel, Ph.D., "Why the Potential for Grid Defection Matters," *RMI Outlet*, March 11, 2014, http://blog.rmi.org/blog_2014_03_11_why_the_potential_for_grid_defection_matters.

24 EIA, "Electric generator dispatch depends on system demand and the relative cost of operation," August 17, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7590. Accessed October 21, 2014.

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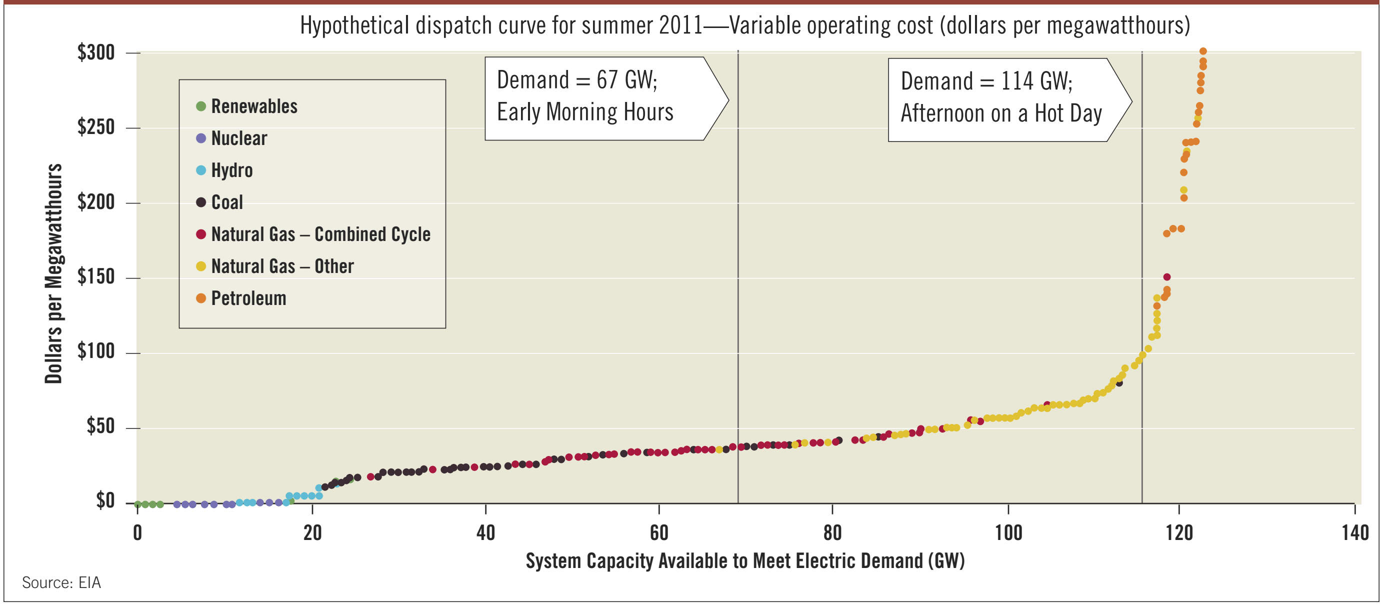
Figure 3

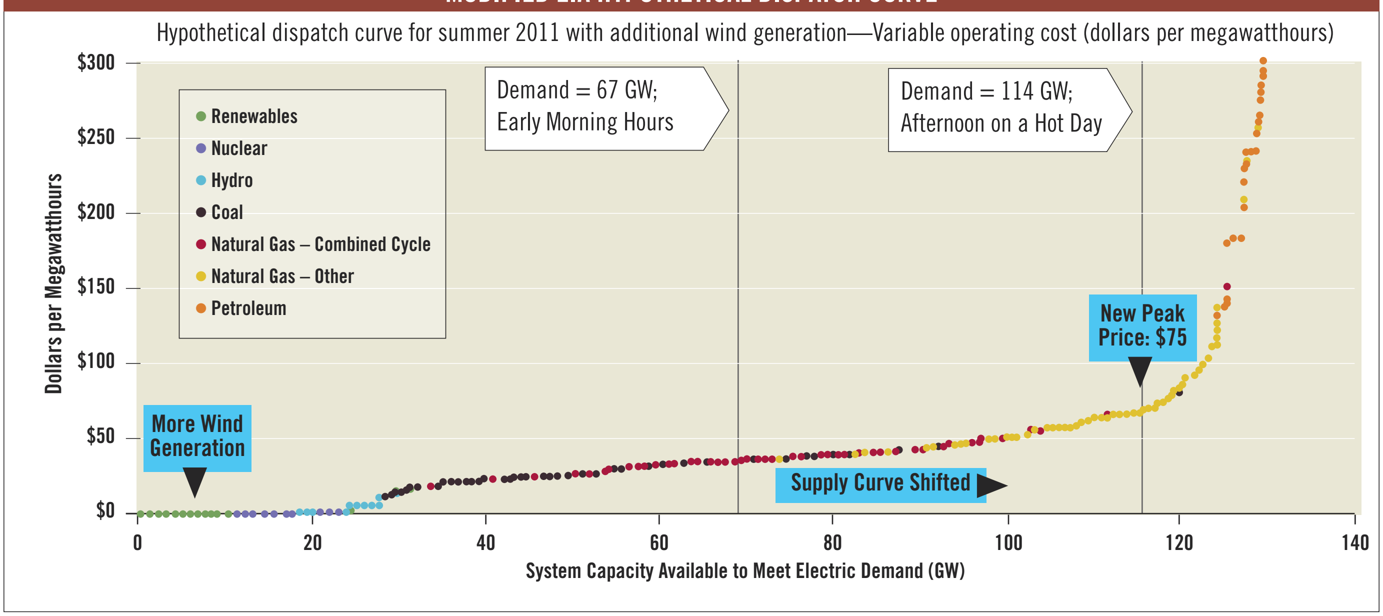
EIA HYPOTHETICAL DISPATCH CURVE



Source: EIA

Figure 4

MODIFIED EIA HYPOTHETICAL DISPATCH CURVE



Now notice what happens when this supply curve is modified by adding more wind generation (or other low-marginal-cost resource). In Figure 4, the amount of renewable resources is increased from 3 GW to 10 GW (from 2.6 percent to 8.8 percent of peak load).[25] The revised supply curve in Figure 4 is shifted to the right by the amount of assumed new wind power.

The market price in the early morning is not much changed because that portion of the supply curve is fairly flat. However, the market price during the afternoon peak is reduced—in this illustration, from about $100 per MWh to $75 per MWh—because the wind generation displaces higher-cost simple-cycle gas generation.

25 The EIA dispatch curve is hypothetical, and the percentages are approximate, gained from inspection of the chart. However, this example models accurately the shift in the supply curve observed in U.S. and overseas electric markets. The effect that entry of low-marginal-cost resources has on the market price is known as the "merit-order effect."

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The lower power price in the afternoon is welcome news for business and residential customers, but can create new winners and losers among owners of power plants. Because wind and solar power generation is variable and not dispatchable, the grid requires capacity of another type—flexible generation capacity—to stand ready to be dispatched when wind or solar production drops. This process tends to raise the valuation of demand response and flexible power plants (chiefly hydro and some natural gas plants) and decrease the valuation of plants with less flexibility, like base load coal and nuclear plants and some natural gas plants.

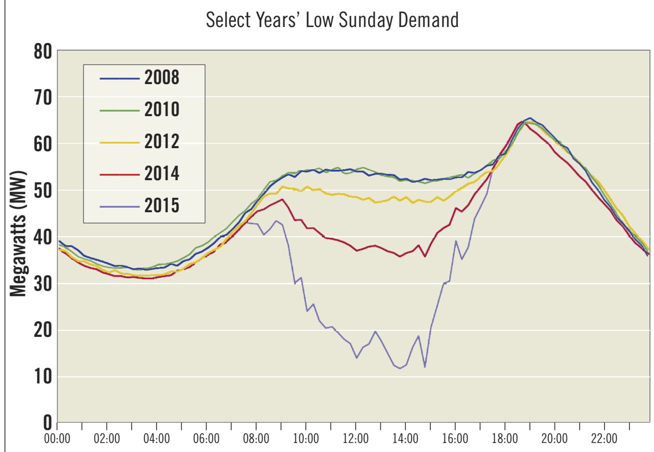
As examples, the Kewaunee nuclear plant in Wisconsin, owned by Dominion Resources, was closed in 2013, due chiefly to its inability to make money in the MISO market. Similarly, the Vermont Yankee nuclear plant, owned by Entergy, will close in 2014. Although the plant has weathered other controversies over the years, Entergy cited market conditions and poor economics of the plant in its decision to close Vermont Yankee.[26] Finally, the combination of lower wholesale prices and stricter environmental requirements have caused the closure of numerous Midwestern coal plants, including the 1100 MW Tanners Creek plant in Indiana, owned by American Electric Power.

The changing topology of the grid is seen nowhere better in the U.S. than in California and Hawaii. Readers may be familiar with the famous "duck curve" developed by the California Independent System Operator (CAISO).[27] It shows CAISO's projection that, on some days of the year beginning in 2020, the afternoon demand peak will be replaced with an afternoon demand *trough*. The switch from peak to trough is caused by the planned presence of large amounts of customer-owned and developer-owned wind and solar capacity. (The afternoon trough forms the "belly of the duck.") This new daily demand curve would present problems for owners of base load plants that may not be needed during the heat of the day, typically their most profitable period. At the trough, demand climbs steeply, challenging the system operator to adopt new grid management techniques, increase demand response and boost energy storage.[28]

While the California duck has gained the most notoriety, Hawaii has its own species, shown in Figure 5.[29] The predominance of customer-owned solar power has created a duck curve in Kauai as early as 2015, five years ahead of what's projected for California. The Kauai cooperative utility is planning for this event by seeking proposals for energy storage and flexible generation. While the duck emerges in Kauai only on certain days of the year, the message is clear: grid resources need

Figure 5

KAUAI'S "DUCK CURVE"



Source: Kaua'i Island Utility Cooperative

to be increasingly flexible as we add more variable generation resources to the grid.

In short, utilities can no longer be "your father's utility." All these changes demand new behavior by utilities and new methods for regulators.

6 The pace of innovation within utility regulation is accelerating.

State regulators in Massachusetts, New York and Hawaii are among the first to tackle the question of what the modern grid will look like and how utilities must be regulated in order to get there. The Massachusetts Department of Public Utilities is exploring key issues of grid modernization "to enhance the reliability of electricity service, reduce electricity costs, and empower customers to adopt new electricity technologies and better manage their use of electricity."[30] The New York Public Service Commission created the "Reforming the Energy Vision" (REV) proceeding to identify regulatory changes needed to "promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, [and] wider deployment of 'distributed' energy resources."[31] The Hawaii Public Utilities Commission is considering proposals for regulatory changes to accompany the modern grid: "The future distribution system must have the capability to act both as a delivery service and an aggregator of customer-sited distributed energy resources to benefit the customer and the grid."[32]

26 "Entergy to Close, Decommission Vermont Yankee," Entergy press release, August 27, 2013, http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2769. See also the explanation for nuclear plant closures given by the industry trade group Nuclear Matters: http://www.nuclearmatters.com/challenge/what-is-driving-nuclear-plant-closures.

27 California ISO, "Fast Facts: What the duck curve tells us about managing a green grid," http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

28 For solutions to challenges associated with the "duck curve," see Jim Lazar, *Teaching the Duck to Fly* (Montpelier, VT: The Regulatory Assistance Project, 2014), http://www.raponline.org/document/download/id/6977.

29 Kaua'i Island Utility Cooperative (KIUC), "Request for Proposal (RFP): Energy Storage / Dispatchable Renewable Energy," March 3, 2014, http://kauai.coopwebbuilder.com/sites/kauai.coopwebbuilder.com/files/2014-03-energystoragerfp.pdf.

30 Massachusetts Department of Public Utilities, "Vote And Order Opening Investigation", DPU 12-76, October 2, 2012.

31 See http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument.

32 Hawaii Public Service Commission, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," April 2014, http://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf.

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There will undoubtedly be a spectrum of approaches to the new-style regulation of the distribution grid, distinguished by the structure of the retail market. The New York PSC is building REV in the context of a competitive electric retail market. While the underlying grid itself will remain regulated, market structures and market prices will determine the cost of energy services bought and sold using that grid. The REV vision will eventually require many of the same market elements as the wholesale electric market: prices that vary with time and place, determined by the supply and customer (and grid) demands and, likely, an analogue of firm transmission rights.

Utility regulators have also begun exploring risk-aware approaches to utility resource selection, as we urged in our 2012 report. The National Association of Regulatory Utility Commissioners (NARUC) has hosted several workshops for regulators under the heading of "Risk Training and Risk-Aware Regulation for Public Utility Commissioners," usually in partnership with Duke University's Nicholas Institute for Environmental Policy Solutions.[33] In February 2014, NARUC convened a National Energy Risk Lab to assist commissioners, commission staff and other participants in "making decisions about the energy sector while dealing with changing regulations, market conditions, and technologies" and "to explore the implications, implementation challenges and opportunities of different Section 111(d) compliance options, and the role for coordinating within and across States."[34]

Risk-Aware Regulation for the Distribution Grid

Three developments—the falling cost of distributed energy resources (DER), attention to grid resilience, and smart grid technologies—have created a new focus among policy makers on the distribution grid. The formerly sleepy business of running and maintaining an electric distribution grid has moved to front and center in the policy arena. Experts now discuss the potential for significant penetration of DER and the need for distribution grid with a fundamentally different purpose and architecture.

As long as delivery of electricity requires a distribution grid, the cost of building and operating the grid will likely remain regulated. Recall that, in telephony, regulators were reluctant to eliminate regulation of the legacy wire line telephone network until new delivery platforms arose (wireless and cable).

What are the features of risk-aware regulation of the distribution electric grid? Much like generation and transmission in vertically integrated states, the task of regulating the distribution grid will require a new type of planning—Integrated Distribution Planning.

To achieve the goals of least cost, least risk and maximum customer benefit, regulators must require utilities to synchronize their implementation of advanced grid technologies with the growing DER market. Utilities perform this planning function today, but not usually in the public arena and not closely coordinated with other actors providing services on an upgraded distribution grid.This planning exercise is now loaded with new responsibilities for the grid operator. Further, if the utility also has a stake as a competitor with DER services, it is essential that an independent authority such as the state regulator oversees the planning.

Once again, consider the telecom sector following the passage of federal legislation in 1996. Incumbent carriers were required to unbundle their grid (the public switched network) and provide access to new players with new products, often competing with the grid owners. Regulators ensured that new competitors got access to the network on the same terms as the incumbents. Regulation of all players moved significantly away from the traditional cost-of–service model.

Risk Aware regulation of the distribution grid will include these practices for regulators:

- Creating an open, transparent public planning process for the distribution grid;
- Ensuring access to all providers of distributed energy resources on equal terms;
- Engaging customers and recognizing their expanded role as a dynamic resource in the 21st century electricity system;
- Evolving the regulation of the traditional utilities.

33 See http://www.naruc.org/Grants/default.cfm?page=8.

34 See http://www.naruc.org/energyrisk/index.cfm.

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2 UPDATED COST & RISK RANKINGS OF NEW GENERATION RESOURCES

In our 2012 report, we discussed the relative cost of many electric generation resources, and compared that cost to the risk associated with employing each resource in a portfolio of generation assets. We relied on a 2011 report by the Union of Concerned Scientists (UCS) that compiled levelized cost of electricity (LCOE) data from several sources.[35]

The UCS report has not yet been refreshed with current costs. For this update, we rely on LCOE estimates found in recent reports by four authoritative companies and agencies: Bloomberg New Energy Finance, Citi, Lazard, and the U.S. Energy Information Administration (EIA).[36] In brief, we compiled LCOE estimates from these four sources into a single set of ranges for each resource. Based on that compilation, we rank the resources by their LCOE midpoints, both with and without subsidies. This is very similar to the approach we took in the original report.

2014 Updated Cost Ranking: Data Sources

- Bloomberg New Energy Finance, *Sustainable Energy in America Factbook 2014* (February 2014)
- Citi, *Evolving Economics of Power and Alternative Energy* (March 2014)
- Lazard, *Lazard's Levelized Cost of Energy Analysis—Version 8.0* (September 2014)
- U.S. Energy Information Administration, *Annual Energy Outlook 2014* (April 2014)

COST RANKING OF RESOURCES

The overall ranking in this update of resources by cost is similar to the ranking we presented in 2012. Certain renewable resources (wind and large scale solar with incentives) appear among the least cost resources; other renewables (solar thermal) are the most expensive. As before, fossil and nuclear generation are distributed throughout the ranks, differing mainly in whether the fossil resources are designed to capture carbon dioxide, and whether nuclear power receives a federal subsidy. Notably, energy efficiency maintains its spot as the least cost option for meeting new system demands. In 2012 and in this update, energy efficiency is far and away the lowest cost resource.

35 Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE is the price at which electricity must be generated from a specific source to break even over the lifetime of the project (including a profit). LCOE factors in all costs: capital, finance, fuel, O&M, profit, etc.

36 Bloomberg Finance L.P. and the Business Council for Sustainable Energy, "Sustainable Energy in America: 2014 Factbook," February 2014, http://www.bcse.org/factbook/pdfs/2014%20Sustainable%20Energy%20in%20America%20Factbook.pdf; Citi Research, "Evolving Economics of Power and Alternative Energy," March 23, 2014, https://ir.citi.com/xTCfhm65e3stqHLMoq9vFFtw38r5adyTiKwFYxYA2Z37EuFvOGL63A%3d%3d; Lazard, "Lazard's Levelized Cost of Energy Analysis – Version 8.0," September 2014, http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf; EIA "Annual Energy Outlook 2014," April 2014, http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

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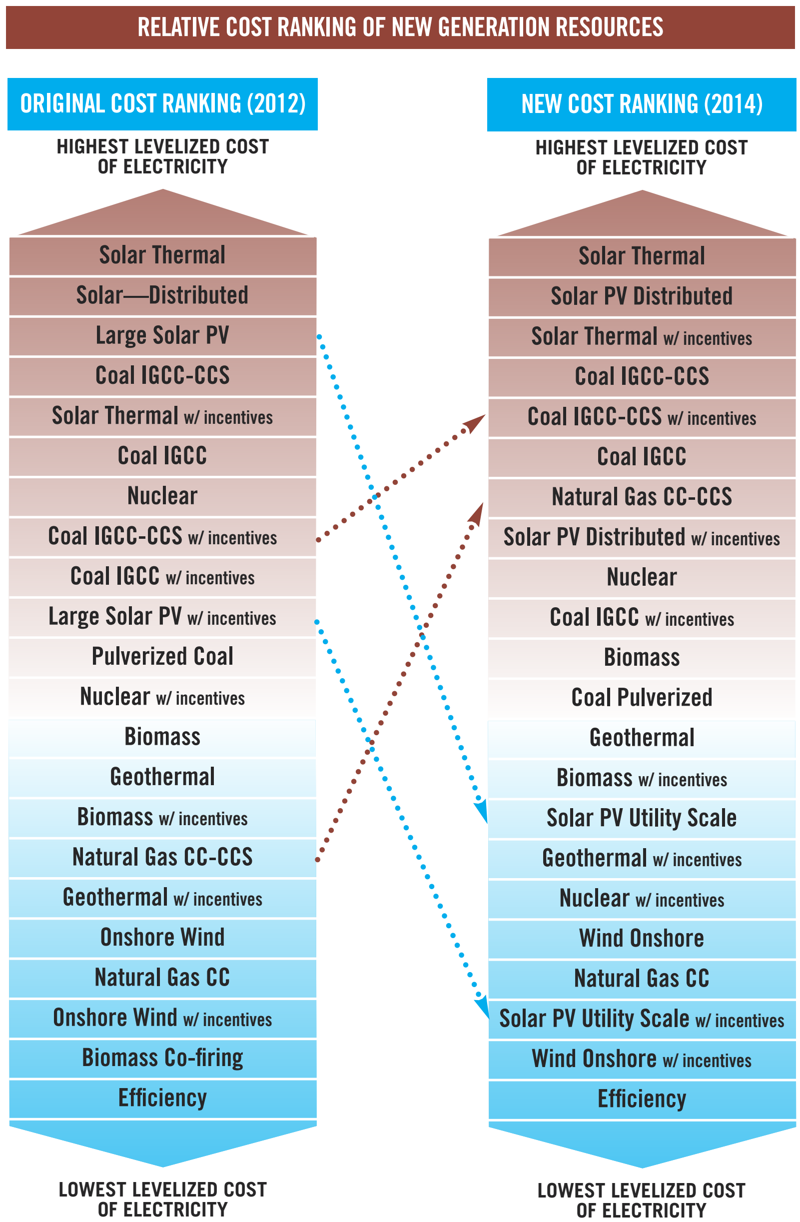
Figure 6



Utility-scale solar photovoltaic power (with or without incentives) showed the biggest decline in relative cost among all resources in the current ranking, compared to the ranking in 2012. As suggested earlier, actual on-the-ground prices for utility-scale photovoltaic power are even lower in some cases than the low end of the ranges estimated by the analysis we used. The sharp decline in solar costs appears to result from a number of factors, including much lower solar panel prices due, in part, to the growth of the German solar market. Analysts have observed that the German *Energiewende* program has stimulated global production of solar panels, chiefly in China, bringing down the worldwide price of panels.

In the other direction, the estimated LCOE for fossil-powered plants with carbon capture and storage (both coal and gas) moved those resources higher in the ranking.

The right hand column of Figure 6 shows the updated ranking of the studied resources with respect to their levelized costs. It also illustrates the moves made by solar PV and fossil plants with carbon capture and storage, two of the largest movers in our updated report.

Keep in mind that the estimates used in this ranking are sensitive to many assumptions, and that two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

It also bears repeating that the LCOE ranking tells only part of the story. The main point of our 2012 report is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

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RISK RANKING OF RESOURCES

Our 2012 report emphasized that utilities and their regulators must consider the risk of new resources in addition to their cost. We do not think there is a canonical assessment of risk; there will inevitably be some differences of opinion. The 2012 report invited readers to perform their own qualitative risk analysis and offered an example based on our assessment of relative risk of new resources. Mainly, we stressed the need for regulators to undertake this analysis, incorporating their own risk assessments, instead of ignoring risk or focusing narrowly on short-term cost.

For this update, we reviewed our risk analysis and revised it slightly since the original assessment. Table 1 shows this revised risk assessment with changes noted in six entries, compared to our previous report. The entries with arrows indicate a move of one step up or down in risk estimate.

Table 1

2014 UPDATE RISK ASSESSMENT OF NEW GENERATION RESOURCES

Resource	Initial Cost Risk	Fuel Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Medium ↑	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium ↑	High
Pulverized Coal	Medium	Medium	Very High ↑	Very High	High	Medium	Medium
Efficiency	Low	None	Low	None	None	None ↓	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Natural Gas CC	Medium	High	Medium	High ↑	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	High ↑
Solar PV Distributed	Low	None	Low	None	None	Low	Low
Solar PV Distributed w/ incentives	Low	None	Low	None	None	Low	Low
Solar PV Utility Scale	Low	None	Low	None	None	Medium	Low
Solar PV Utility Scale w/ incentives	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium
Wind Onshore	Low	None	Low	None	None	Low	Low
Wind Onshore w/ incentives	Low	None	Low	None	None	None	Low

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Figure 7

2014 UPDATE RANKING: RELATIVE RISK OF NEW GENERATION RESOURCES

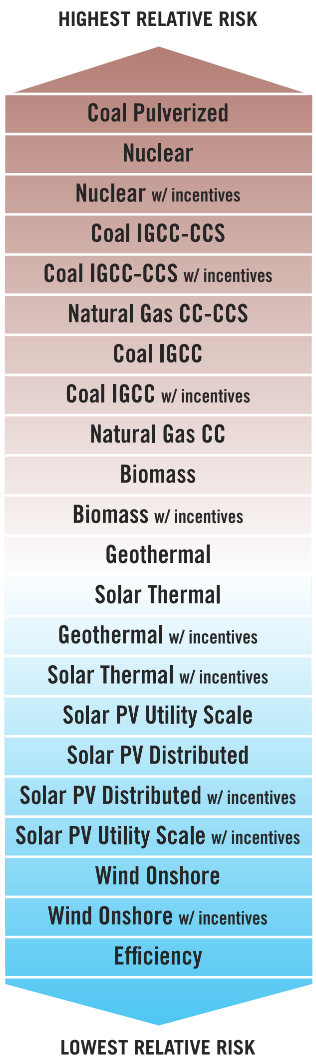
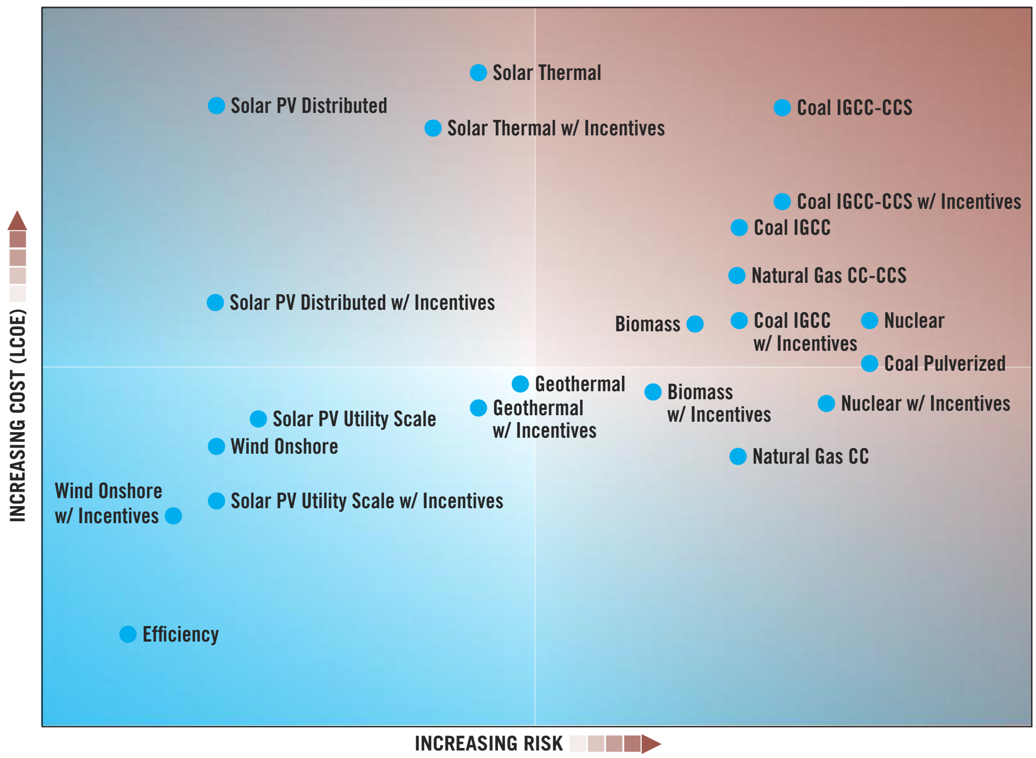


Figure 8

2014 UPDATE RANKING: RELATIVE COST VS. RELATIVE RISK OF NEW GENERATION RESOURCES



Based our risk assessment of these 22 resources, Figure 7 shows the 2014 Update ranking of the resources according to their relative risk.

We can now show the combined updated risk and cost rankings in this "x-y" plot, with relative cost on the vertical axis and relative risk on the horizontal axis (Figure 8). This plot shares many characteristics with the comparable chart in the prior version of the report, with fossil resources grouped on the right side of the plot area (higher risk) and renewables on the left (lower risk). Utility scale PV has joined wind generation and energy efficiency as resources with the lowest risk and lowest cost resources, in the lower left quadrant of the graph.

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Risk Aware Regulation in Organized Wholesale Markets

Compared to regulators in "vertically integrated" states, regulators have different responsibilities in markets where the price of generation and the selection of resources are determined in an auction market. In the U.S., there are seven regional organizations—independent system operators (ISOs) and regional transmission operators (RTOs)—that operate the transmission grid and administer auction markets. State regulators in those markets have a range of authority over the generation resources built in their state (from some to none) and all of the regulators have relationships with the ISO serving their state.

In our 2012 report, we emphasized tools that regulators could exercise to help lower the risk inherent in the selection and construction of generation resources. Commissioners in "market" states have much less to say about that process because the market—via pricing mechanisms for demand, energy and ancillary services—will indicate what type of resources are needed. That said, there remains much that the "risk-aware" regulator should do in this situation. We explore three topics:

- **Governance and transparency of ISOs and RTOs**

While auction markets can arguably provide better incentives for power plant owners than the regulators who preceded the marketplace, the actual results depend less on the theory than on the practice. An essential characteristic of a successful ISO/RTO is that its governance is active, representative of stakeholders and transparent in its decision-making.

State regulators should insist that ISO/RTO governance meets these expectations. Commissioners must be engaged with the ISO/RTO, participating wherever possible on advisory bodies or in forums where policy is decided. This includes participation in dockets at the Federal Energy Regulatory Commission (FERC) when ISO/RTO tariffs are considered.

- **Demand Response (DR) after the court reversal of FERC Order 745**

The D.C. Circuit Court of Appeals recently handed regulators in "market" states a new duty: regulate demand response, arguably the most under-utilized demand-side resource. The Court ruled that DR is a retail service, and not subject to FERC jurisdiction. (A large fraction of DR is unaffected by the ruling since the order applies only to states with wholesale markets.)

FERC Order 745 boosted demand response in wholesale markets. Now regulators in these states will step in for the market, setting compensation for demand response and ensuring that utilities make appropriate use of this valuable resource. ISOs have been using DR to meet peak demand and help integrate renewable energy; utilities in market states (like those in regulated states) can now use DR to avoid high peak energy costs, saving consumers money. Further, DR can help solve local reliability challenges in the distribution grid. As the dust settles on the court decision, "risk-aware" regulators in market states will rediscover DR as a tool to diversify and strengthen utilities' energy resources.

- **Need for diversified portfolios**

Our 2012 report identified diversification of generation resources as a key tool for limiting risk. In market states, regulators cannot, of course, influence the makeup of the generation portfolio directly. But regulators can help to create a strong DER market and support policies, such as Renewable Portfolio Standards, that deliver renewable power sources to the grid.

The concept of risk does not go away where an ISO/RTO is involved. While some risks are shifted from consumers to the plant owners, utility customers can be exposed to significant mid-term risk if the portfolio of the utility purchasing power in a market is unduly concentrated on a single fuel, such as natural gas or coal. A state-level RPS can address the diversification issue indirectly by causing more renewable generation to be built.

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3 CONCLUSIONS & RECOMMENDATIONS

- **There is a clear and durable imperative for clean energy in the U.S.** Even without a defined energy policy or an explicit climate policy, there is an unmistakable trend in the U.S. toward low-carbon energy resources, including renewable energy, energy efficiency and demand response. Drivers of this trend include advancing technology, international climate negotiations, federal air quality rules, consumer demand for clean energy and the lower cost and risk profile of renewable and demand-side energy resources. Significantly greater levels of variable generation resources appear to be feasible with intelligent management of the grid, employing flexible generation and a fleet of distributed energy resources (DER).
- **Costs for some renewable energy technologies, particularly solar PV and wind, are likely to continue to fall at least until 2020. This will narrow—and perhaps erase—any cost gap between renewable and traditional fossil and nuclear resources.** Other resources are not expected to experience such cost reductions. Continued advancements in cost-effective clean energy technologies will drive greater customer demand and renewables deployment and increase pressure to modernize many aspects of the power sector, including utility business models, regulation, grid management, and market rules. These changes will also lower the costs of achieving of carbon pollution reduction targets.
- **Distributed energy resources (DER) will play an increasingly important role in the 21st century electricity system, beginning in the near term.** DER includes resources such as distributed generation (e.g., rooftop solar and combined heat and power), demand response, distributed storage, energy efficiency and microgrids. DER's precise share of energy supply will emerge over time, and will depend on the relative

2012 Conclusions Revisited—And Reaffirmed

In the 2012 report, we observed that "managing risk intelligently is arguably the main duty of regulators who oversee utility investment. Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term." We concluded:

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history;**
- **These challenges call for new utility business models and new regulatory paradigms;**
- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process;**
- **More than ever, ratepayer funding is a precious resource;**
- **Risk shifting is not risk minimization;**
- **Investors are more vulnerable than in the past;**
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors;**
- **Some successful strategies for managing risk are already evident; and,**
- **Regulators have important tools at their disposal.**

These conclusions remain unchanged. If anything, the pressures on the utility business model and the regulatory paradigm have grown stronger in the past two and a half years.

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economics (value) of distributed resources, the pace of technological innovation and the speed with which society curtails carbon emissions. But three points are clear today: i) DER penetration levels will continue to increase, accelerated by falling renewable costs and EPA rules to reduce carbon emissions; ii) DER reshapes the topology and requirements of the grid; and iii) effective DER integration demands attentive, "risk-aware" electricity regulation, as regulators in Massachusetts, New York, Hawaii and other states are demonstrating.

- **Sophisticated analytical methods and modeling tools are needed to plan for and invest in a modern, 21st century electricity system with significant DER.** In regulated energy markets, robust integrated resource planning (IRP) has long been recognized as essential to selecting an energy portfolio with costs that remain affordable over time. As states grapple with increasing amounts of DER, a sophisticated approach to Integrated Distribution Planning must emerge so that society's resources are spent wisely. The complexities are daunting. The modern grid manager will need to model a much more complicated system that utilizes significant amounts of DER (both supply and demand resources) and other advanced technologies. Planning will also need to anticipate and absorb new technologies, and solve for a range of beneficial outcomes (e.g., carbon reduction, grid resilience, forward-compatibility, customer empowerment, affordability, etc.) These outcomes are all high priority, and none is assured without good planning.
- **Electricity regulation must continue to evolve.** In order for the utility business model to evolve, the way we regulate utilities must change. Some states have begun to explore regulatory models that move beyond simple "cost of service" and align utility compensation with customer interests and societal goals. This trend will continue in the state "laboratories" as a set of new regulatory models will evolve. In general, there will likely be a move away from traditional "cost-of-service" regulation toward "incentive-based" or "output-based" regulation.
- **Collaboration and transparency are essential to risk-aware electricity regulation.** The evolution of the electricity sector will create significantly expanded roles for many participants, including customers and non-utility service providers. Both will work alongside utilities to achieve large-scale implementation of clean energy resources and technologies in competitive markets as well as traditionally regulated markets. The evolution of electricity regulation and the task of implementing new federal air quality rules will also require collaboration among utility regulators and other state authorities. Near-term priorities in this area include: i) coordination between state utility and air quality regulators to arrive at a least cost/least risk compliance strategy for EPA rules; ii) enhanced transparency and governance at ISOs and RTOs; iii) robust, transparent and inclusive processes for both Integrated Resource Planning and Integrated Distribution Planning.

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