PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection

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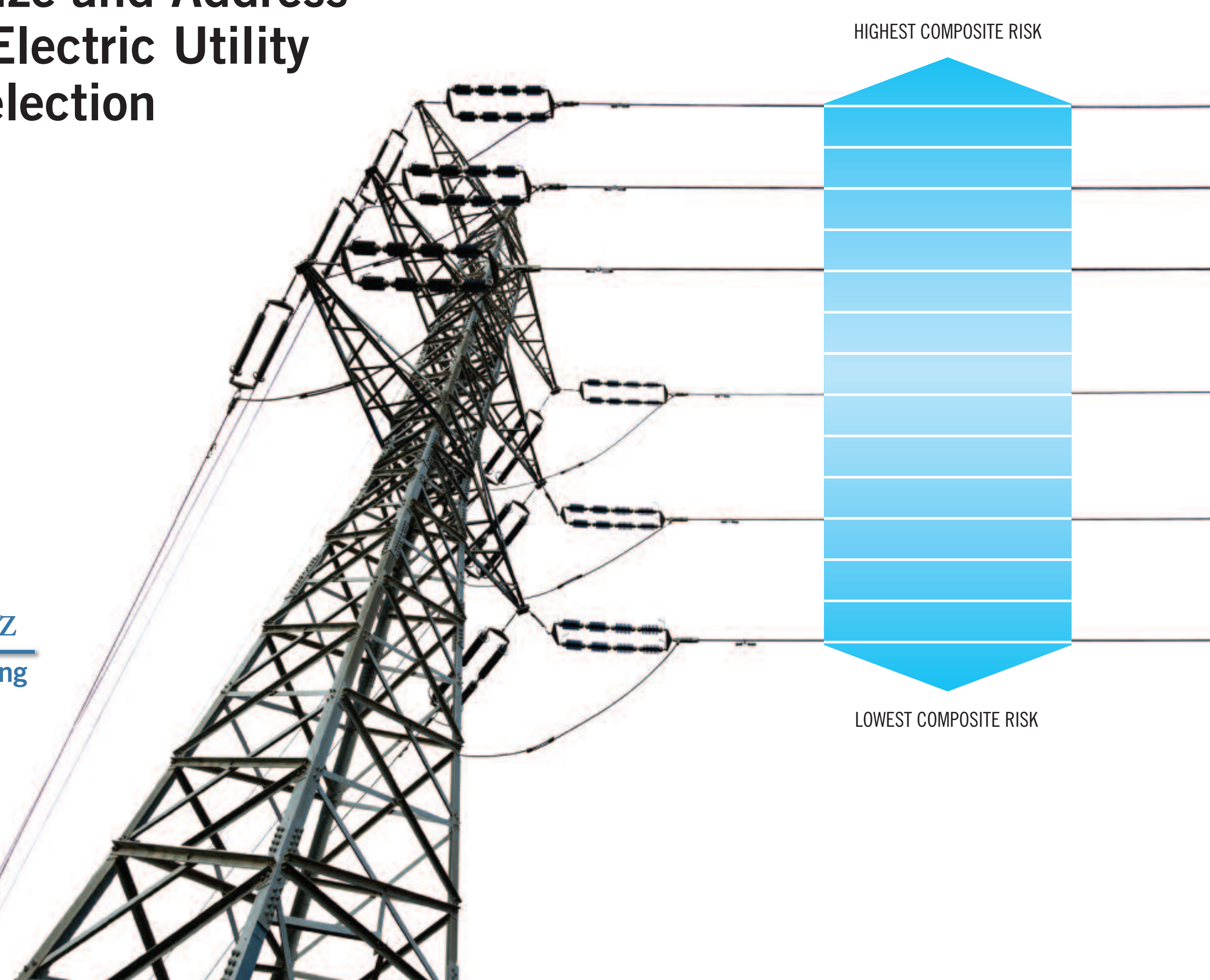

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Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

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ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to **state regulatory utility commissioners**, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous **secondary audiences**, including **utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders** with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado's "New Energy Economy." He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

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Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres' Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society's 21st century energy needs. In addition to developing Ceres' intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres' climate change initiatives and organizational development.

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FOREWORD

Today's electric industry faces a stunning investment cycle. Across the country, the infrastructure is aging, with very old parts of the power plant fleet and electric and gas delivery systems needing to be replaced. The regulatory environment is shifting dramatically as rules tighten on air pollution from fossil-burning power plants. Fossil fuel price outlooks have shifted. New options for energy efficiency, renewable energy, distributed generation, and smart grid and consumer technologies are pressing everyone to think differently about energy and the companies that provide it. Customers expect reliable electricity and count on good decisions of others to provide it.

The critical nature of this moment and the choices ahead are the subject of this report. It speaks to key decision-makers, such as: state regulators who have a critical role in determining utility capital investment decisions; utility executives managing their businesses in this era of uncertainty; investors who provide the key capital for utilities; and others involved in regulatory proceedings and with a stake in their outcomes.

The report lays out a suite of game-changing recommendations for handling the tremendous investment challenge facing the industry. As much as $100 billion will be invested each year for the next 20 years, roughly double recent levels. A large portion of those investments will be made by non-utility companies operating in competitive markets. But another large share will be made by utilities—with their (and their key investors') decisions being greatly affected by state regulatory policies and practices.

This is no time for backward-looking decision making. It is vital—for electricity consumers and utilities' own economic viability—that their investment decisions reflect the needs of tomorrow's cleaner and smarter 21st century infrastructure and avoid investing in yesterday's technologies. The authors provide useful advice to state regulators on how they can play a more proactive role in helping frame how electric utilities face these investment challenges.

A key report conclusion in this regard: sensible, safe investment strategies, based on the report's detailed cost and risk analysis of a wide range of generation resources, should include:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on renewable energy resources such as onshore wind and distributed and utility-scale solar;
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.

At its heart, this report is a call for "risk-aware regulation." With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises. And utilities' use of robust planning tools needs to be sharpened to incorporate risk identification, analysis, and management.

This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy efficiency makes sense regardless of how and when carbon controls come into play. Placing too many bets on the conventional basket of generation technologies is the highest-risk route, in the authors' analysis.

We're in a new world now, with many opportunities as well as risks. More than ever, the true risks and costs of utility investments should be made explicit and carefully considered as decisions on multi-billion-dollar commitments are made.

As the industry evolves, so too must its regulatory frameworks. The authors point out why and offer guidance about how. This is news regulators and the industry can use.

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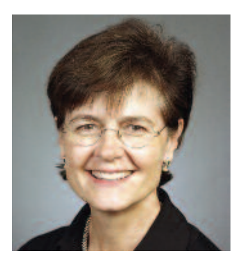


EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]

Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. **Figure ES-1** summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19, 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency) that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]

Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" **(Figure ES-2, p. 8)**.[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking"*; and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequences is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically-integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see 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 costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

RELATIVE COST RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)

- Solar Thermal
- Solar—Distributed*
- Large Solar PV*
- Coal IGCC-CCS
- Solar Thermal w/ incentives
- Coal IGCC
- Nuclear*
- Coal IGCC-CCS w/ incentives
- Coal IGCC w/ incentives
- Large Solar PV w/ incentives*
- Pulverized Coal
- Nuclear w/ incentives*
- Biomass
- Geothermal
- Biomass w/ incentives
- Natural Gas CC-CCS
- Geothermal w/ incentives
- Onshore Wind*
- Natural Gas CC
- Onshore Wind w/ incentives*
- Biomass Co-firing
- Efficiency

LOWEST LEVELIZED COST OF ELECTRICITY (2010)

Figure ES-3

RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST COMPOSITE RISK

- Nuclear
- Pulverized Coal
- Coal IGCC-CCS
- Nuclear w/ incentives
- Coal IGCC
- Coal IGCC-CCS w/ incentives
- Natural Gas CC-CCS
- Biomass
- Coal IGCC w/ incentives
- Natural Gas CC
- Biomass w/ incentives
- Geothermal
- Biomass Co-firing
- Geothermal w/ incentives
- Solar Thermal
- Solar Thermal w/ incentives
- Large Solar PV
- Large Solar PV w/ incentives
- Onshore Wind
- Solar—Distributed
- Onshore Wind w/ incentives
- Efficiency

LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

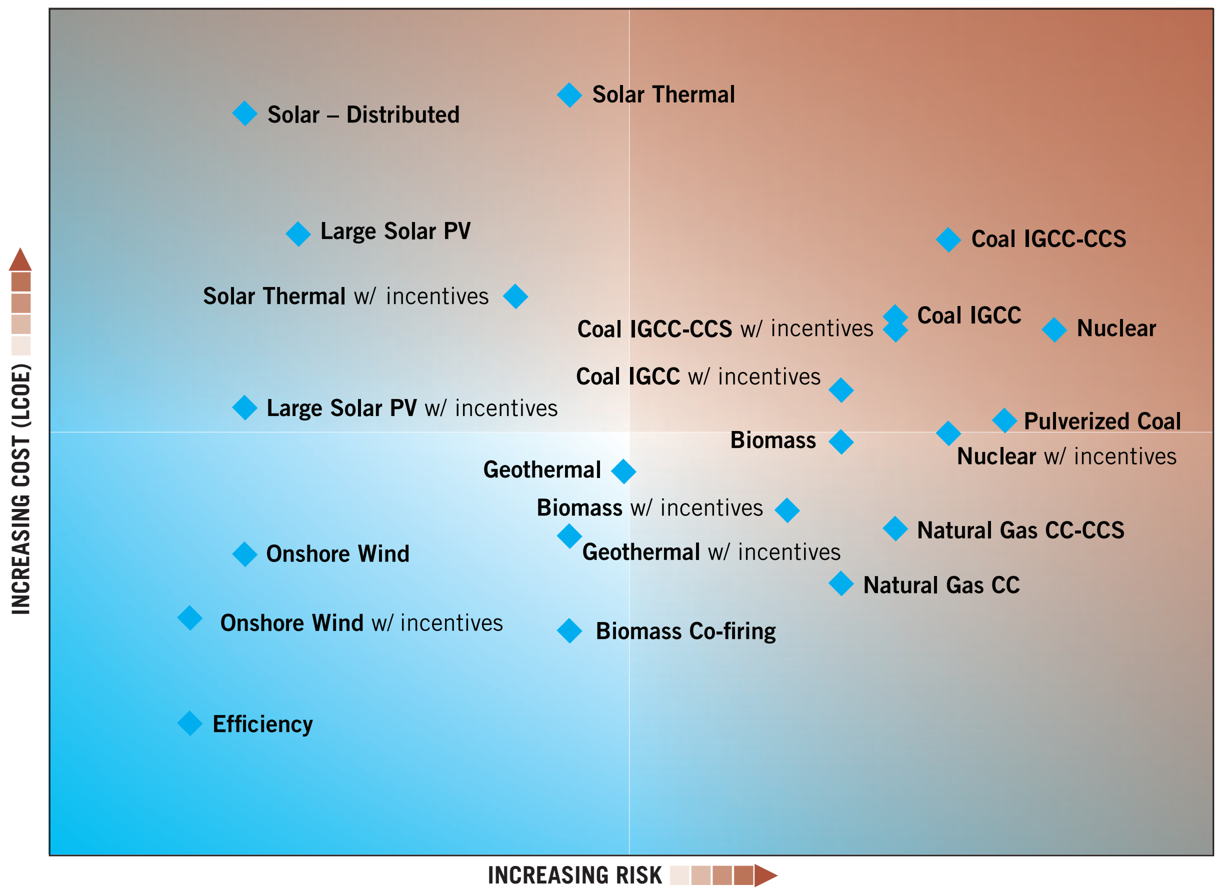
- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile **(Figure ES-3)**.

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph **(Figure ES-4)**.[12]

While this report focuses on new generation resources, the approach to “risk-aware regulation” described herein works equally well for the “retire or retrofit” decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to “risk-aware regulation” described herein works equally well for the “retire or retrofit” decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

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 IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

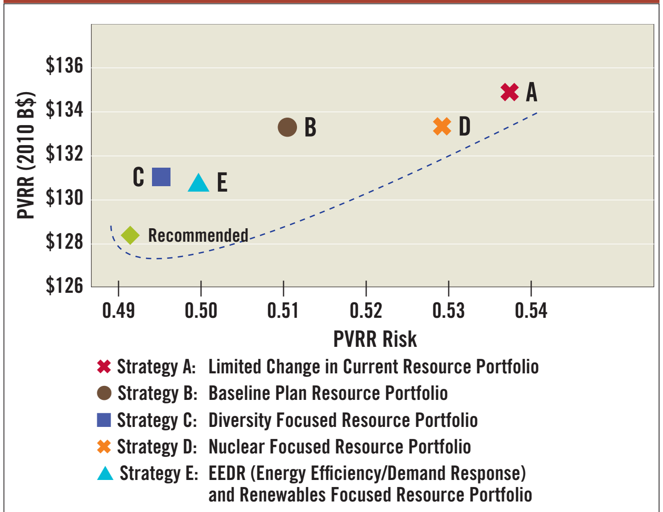
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. **Figure ES-5** shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

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

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

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

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

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

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

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

- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors.** Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.

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

1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

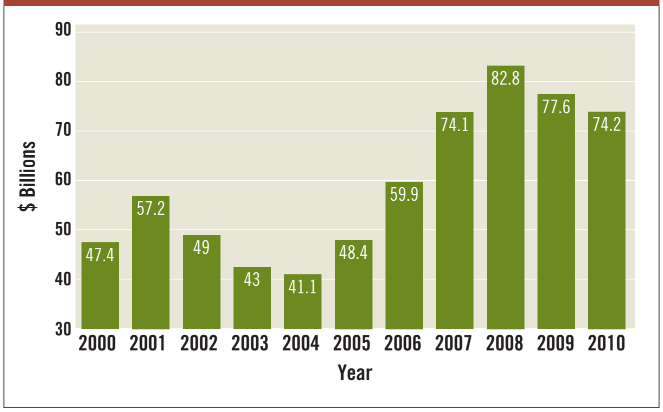
THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1

CAPITAL EXPENDITURES BY U.S. INVESTOR-OWNED UTILITIES, 2000-2010



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

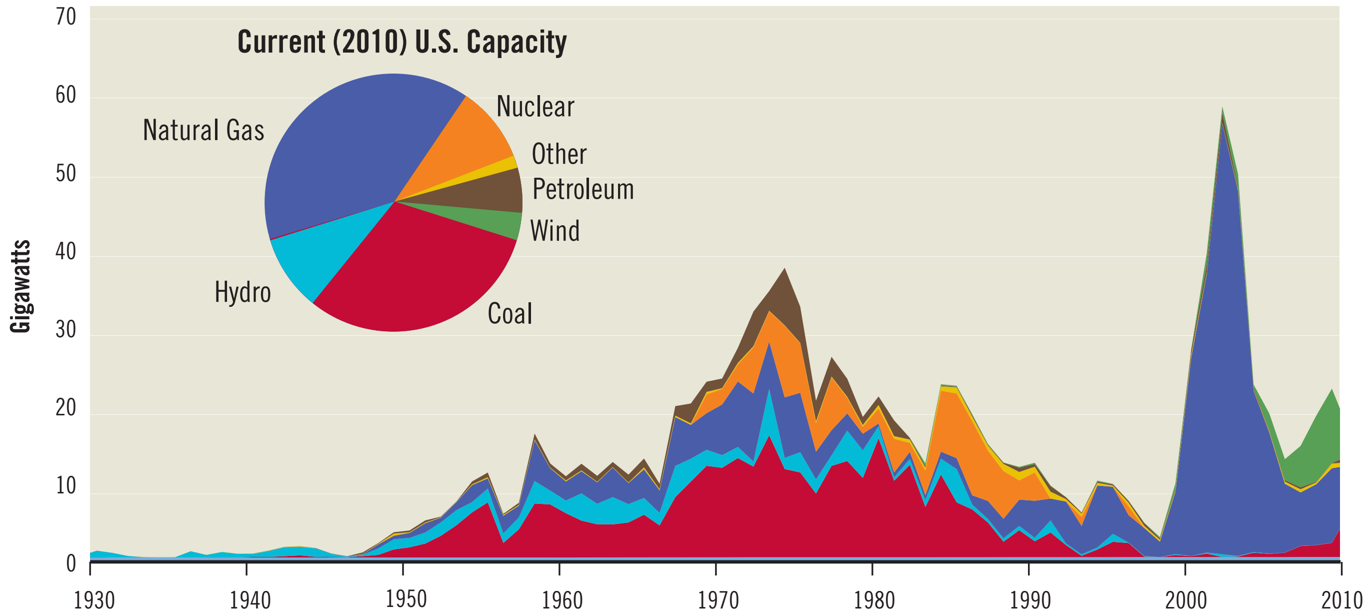
18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

Figure 2

U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR AND FUEL TYPE



In 2008, the Brattle Group projected that the collected U.S. electric utility industry—IOUs, munis, and co-ops—would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between $1.5 trillion and $2.0 trillion.[21] Assuming that the U.S. implements a policy limiting greenhouse gas emissions, the collected utility industry may be expected to invest at roughly the same elevated annual rate as in the 2006-2010 period *each year for 20 years.*

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital.

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital. This growth is considerably faster than the country has seen in many decades.

To understand the seriousness of the investment challenge facing the industry, consider the age of the existing generation fleet. About 70 percent of U.S. electric generating capacity is at least 30 years old (**Figure 2**).[22] Much of this older capacity is coal-based generation subject to significant pressure from the Clean Air Act (CAA) because of its emissions of traditional pollutants such as nitrous oxides, sulfur dioxides, mercury and particulates. Moreover, following a landmark Supreme Court ruling, the U.S. Environmental Protection Agency (EPA) is beginning to regulate as pollutants carbon dioxide and other greenhouse gas emissions from power plants.[23] These regulations will put even more pressure on coal plants, which produce the most greenhouse gas emissions of any electric generating technology. The nuclear capacity of the U.S., approximately 100,000 megawatts, was built mainly in the 1970s and 80s, with original licenses of 40 years. While the lives of many nuclear plants are being extended with additional investment, some of these plants will face retirement within the next two decades.

21 Chupka et al., *Transforming America's Power Industry*, vi. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. The range in Brattle's investment estimate is due to its varying assumptions about U.S. climate policy enactment.

22 U.S. Energy Information Administration, "Today in Energy: Age of electric power generators varies widely," June 16, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

23 U.S. Supreme Court, *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007), http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

Figure 3

PROJECTED GENERATION CAPEX BY REGION

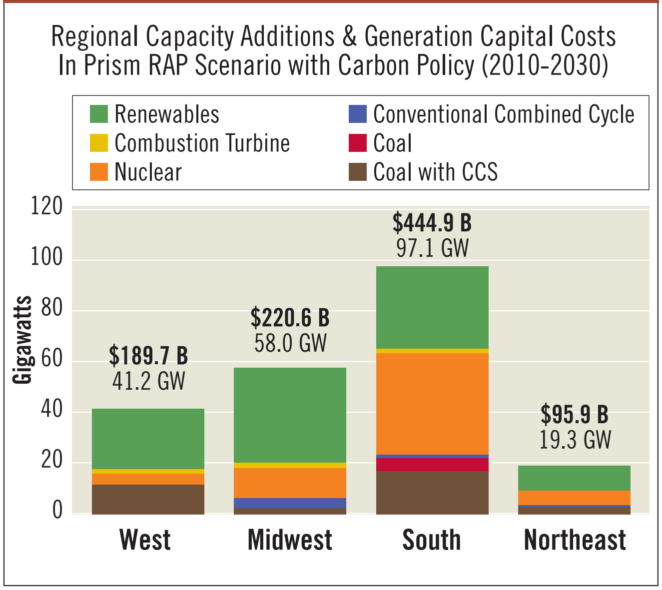


Figure 4

PROJECTED CAPACITY ADDITIONS BY STATE & AS A PERCENTAGE OF 2010 GENERATING CAPACITY

State	Predicted Capacity Additions (MW), 2010-2030[25]	Predicted Additions as a Percentage of 2010 Generating Capacity[26]
Texas	23,400	22%
Florida	12,200	21%
Illinois	11,000	25%
Ohio	8,500	26%
Pennsylvania	6,300	14%
New York	5,400	14%
Colorado	2,500	18%

Figure 3 shows the Brattle Group's investment projections for new generating capacity for different U.S. regions,[24] while **Figure 4** predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators and utilities pursued maximum levels of energy efficiency.

DRIVERS OF UTILITY INVESTMENT

Technological change, market pressures and policy imperatives are driving these historic levels of utility investment. As we will see, these same forces are interacting to create unprecedented uncertainty, risk and complexity for utilities and regulators.

Here are eight factors driving the large investment requirements:

1. **THE NEED TO REPLACE AGING GENERATING UNITS.** As mentioned earlier, the average U.S. generating plant is more than 30 years old. Many plants, including base load coal and nuclear plants, are reaching the end of their lives, necessitating either life-extending investments or replacement.

2. **ENVIRONMENTAL REQUIREMENTS.** Today's Clean Air Act (CAA) traces its lineage to a series of federal laws dating back to 1955. Until recent years, the CAA has enjoyed broad bipartisan support as it steadily tightened controls on emissions from U.S. electric power plants. These actions were taken to achieve science-based health improvements for people and the human habitat. While the current set of EPA rules enforcing the CAA has elicited political resistance, it is unlikely that the five-decade long movement in the United States to reduce acid rain, smog, ground ozone, particulates and mercury, among other toxic pollutants, will be derailed. Owners of many fossil-fueled plants will be forced to decide whether to make significant capital investments to clean up emissions and manage available water, or shutter the plants. Since the capacity is needed to serve consumers' demand for power (or "load"), these clean air and clean water policies will stimulate the need for new construction.

24 Chupka et al., *Transforming America's Power Industry,* x. Brattle's Prism RAP Scenario "assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's [Electric Power Research Institute] Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP [realistically achievable potential] EE/DR programs" (ibid., vi). Brattle used EPRI's original Prism analysis, published in September 2007; that document and subsequent updates are available online at http://my.epri.com/portal/server.pt?open=512&objID=216&&PageID=229721&mode=2.

25 State capacity addition predictions are based on Brattle's regional projections and assume that new capital expenditures will be made in proportion to existing investment levels.

26 State generating capacity data: U.S. Energy Information Administration, "State Electricity Profiles," January 30, 2012, http://www.eia.gov/electricity/state/. Percentage is rounded to the nearest whole number.

3 **NEW TRANSMISSION LINES AND UPGRADES.** Utility investment in transmission facilities slowed significantly from 1975 to 1998.[27] In recent years, especially after the creation of deregulated generation markets in about half of the U.S., it has become clear that the transmission deficit will have to be filled. Adding to the need for more transmission investment is the construction of wind, solar and geothermal generation resources, far from customers in areas with little or no existing generation or transmission. Regional transmission planning groups have formed across the country to coordinate the expected push for new transmission capacity.

4 **NETWORK MODERNIZATION/SMART GRID.** The internet is coming to the electric power industry. From synchrophasors on the transmission system (which enable system-wide data measurement in real time), to automated substations; from smart meters, smart appliances, to new customer web-based energy management, investments to "smarten" the grid are fundamentally changing the way electricity is delivered and used. While much of today's activity results from "push" by utilities and regulators, many observers think a "pull" will evolve as consumers engage more fully in managing their own energy use. Additionally, "hardening" the grid against disasters and to enhance national security will drive further investment in distribution infrastructure.

5 **HIGHER PRICES FOR CONSTRUCTION MATERIALS.** Concrete and steel are now priced in a world market. The demand from developing nations is pushing up the cost of materials needed to build power plants and transmission and distribution facilities.

6 **DEMAND GROWTH.** Overall U.S. demand for electric power has slowed with the recent economic recession and is projected to grow minimally in the intermediate term (though some areas, like the U.S. Southwest and Southeast, still project moderate growth). Further, the expected shift toward electric vehicles has the potential to reshape utility load curves, expanding the amount of energy needed in off-peak hours.

7 **DEPLOYING NEW TECHNOLOGIES AND SUPPORTING R&D.** To meet future environmental requirements, especially steep reductions of greenhouse gas emissions by 2050, utilities will need to develop and deploy new technologies at many points in the grid. Either directly or indirectly, utilities will be involved in funding for R&D on carbon capture and storage, new renewable and efficiency technologies, and electric storage.

8 **NATURAL GAS PRICE OUTLOOK.** Natural gas prices have fallen sharply as estimates of U.S. natural gas reserves jumped with the development of drilling technologies that can economically recover gas from shale formations. Longer-term price estimates have also dropped, inducing many utilities to consider replacing aging coal units with new gas-fired units. But in January 2012, the U.S. Energy Information Administration (EIA) sharply revised downward its estimates of U.S. shale gas reserves by more than 40 percent and its estimates of shale gas from the Marcellus region by two-thirds.[28] Reduced long-term supplies and a significant commitment to natural gas for new electric generation could obviously lead to upward pressure on natural gas prices.

FINANCIAL IMPLICATIONS

The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade (**Figure 5, p. 18**).[29] The industry's financial position today is materially weaker than it was during the last major "build cycle" that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of "A" or higher; today the average credit rating has fallen to "BBB."

While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions.

This erosion of credit quality is mainly the result of intentional decisions by regulators and utility managements, who determined that maintaining an "A" or "AA" balance sheet wasn't worth the additional cost.[30] And while there isn't reason to believe that most utilities' capital markets access will become significantly constrained in the near future, the fact remains that more than a quarter of companies in the sector are now one notch above non-investment grade status (also called "Non-IG," "high yield" or "junk"), and nearly half of the companies in the sector are rated only two or three notches above this threshold.[31] While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions. Dropping below

27 Edison Electric Institute, *EEI Survey of Transmission Investment* (Washington DC: Edison Electric Institute, 2005), 3, http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Survey_Web.pdf.

28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf.

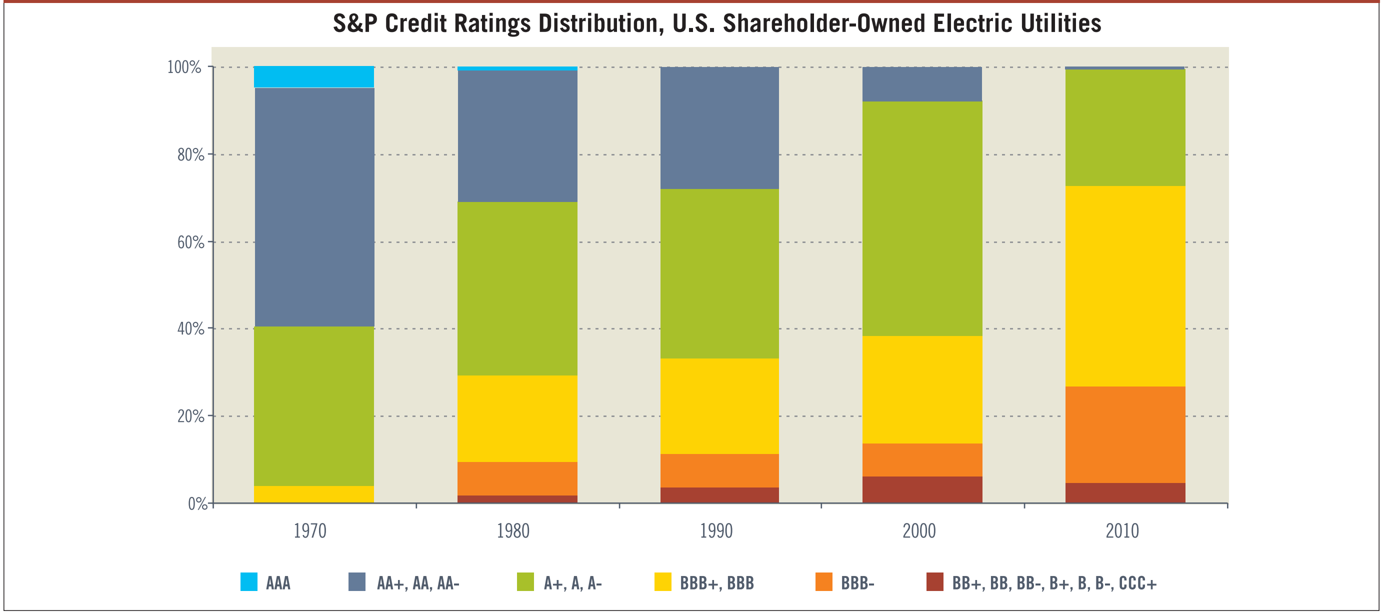
29 Source: Standard & Poor's Ratings Service.

30 The difference in the interest rate on an "A" rated utility and BBB is on average over time rarely more than 100 basis points. By contrast, equity financing typically costs a utility at least 200 basis points more than debt financing.

31 Companies in the sector include IOUs, utility holding companies and non-regulated affiliates.

Figure 5

U.S. ELECTRIC IOUs CREDIT RATINGS HISTORY, 1970 – 2010



investment grade (or "IG") triggers a marked rise in interest rates for debt issuers and a marked drop in demand from institutional investors, who are largely prohibited from investing in junk bonds under the investment criteria set by their boards.

According to a Standard & Poor's analyst, utilities' capital expenditure programs will invariably cause them to become increasingly cash flow negative, pressuring company balance sheets, financial metrics and credit ratings: "In other words, utilities will be entering the capital markets for substantial amounts of both debt and equity to support their infrastructure investments as operating cash flows will not come close to satisfying these infrastructure needs."[32] Specific utilities that S&P has identified as particularly challenged are companies—such as Ameren, Dominion, FirstEnergy, and PPL—that have both regulated and merchant generation businesses and must rely on market pricing to recover environmental capital expenditures for their merchant fleets.[33]

Appendix 1 of this report presents an overview of utility finance.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery.

CUSTOMER IMPACTS

The surge in IOU capital investment will translate directly into higher electric rates paid by consumers. Increased capital investment means higher annual depreciation expenses as firms seek to recover their investment. Greater levels of investment mean higher revenue requirements calculated to yield a return on the investment. And since electric sales may not grow much or at all during the coming two decades, it is likely that unit prices for electricity will rise sharply.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery. The rating agency Moody's Investors Service has noted that "consumer tolerance to rising rates is a primary concern"[34] and has identified political and regulatory risks as key longer-term challenges facing the sector.[35]

Further, Moody's anticipates an "inflection point" where consumers revolt as electricity bills consume a greater share of disposable income (**Figure 6, p. 19**),[36] pressuring legislators and regulators to withhold from utilities the recovery of even prudently incurred expenses.

32 Cortright, "Testimony."

33 Standard & Poor's, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor's, 2012).

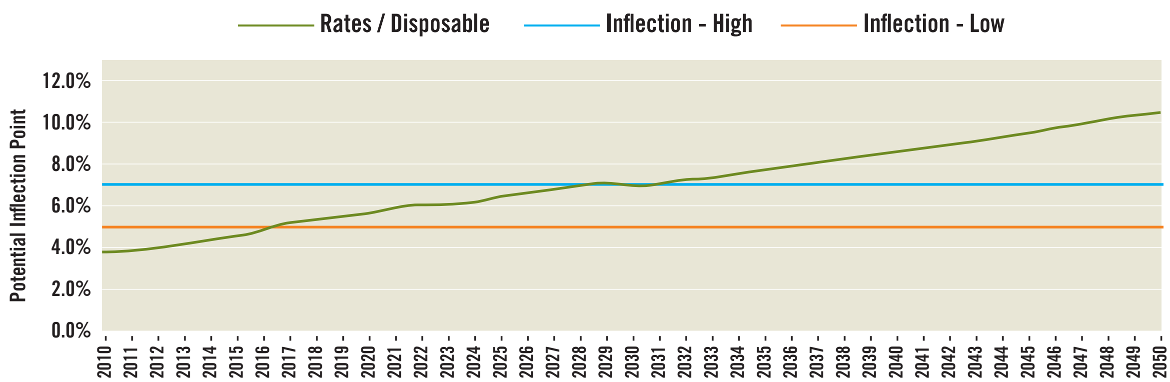
34 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2011).

35 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2010).

36 Moody's, *Special Comment: The 21st Century Electric Utility*, 12.

Figure 6

MOODY'S PROJECTED "INFLECTION POINT" OF CONSUMER INTOLERANCE FOR RISING ELECTRICITY BILLS



Source: Moody's

THE IMPORTANCE OF REGULATORS

With this background, the challenge becomes clear: how to ensure that the large level of capital invested by utilities over the next two decades is deployed wisely? How to give U.S. ratepayers, taxpayers and investors the assurance that $2 trillion will be spent in the best manner possible? There are two parts to the answer: *effective regulators* and the *right incentives for utilities*.

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.[37] It is essential that regulators understand the risks involved in resource selection, correct for the biases facing utility regulation and keep in mind the impact their decisions will have on consumers and society.

Are U.S. regulatory institutions prepared? Consumers, lawmakers and the financial markets are counting on it. The authors are confident that well-informed, focused state regulators are up to the task. But energy regulation in the coming decades will be quite different from much of its history. The 21st century regulator must be willing to look outside the boundaries established by regulatory tradition. Effective regulators must be informed, active, consistent, curious and often courageous.

This report focuses on techniques to address the risk associated with utility resource selection. It provides regulators with some tools needed to understand, identify and minimize the risks inherent in the industry's investment challenge. In short, we hope to help regulators become more "risk-aware."

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.

37 In 2012, the median number of years served by a state regulator was 3.7 years; see Janice A. Beecher, Ph.D., *IPU Research Note: Commissioner Demographics 2012* (East Lansing, MI: Michigan State University, 2012), http://ipu.msu.edu/research/pdfs/IPU-Commissioner-Demographics-2012.pdf.

2. CHALLENGES

TO EFFECTIVE REGULATION

THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

$$\text{Risk} = \sum_i \textit{Event}_i \times (\textit{Probability of Event}_i)$$

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, filling a role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT	
Cost-related	***Time-related***
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in **Figure 7**. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.

Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For **utility management**, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For **customers**, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- **Investors** focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- **Employees** are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- **Society generally** has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial, reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting

a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

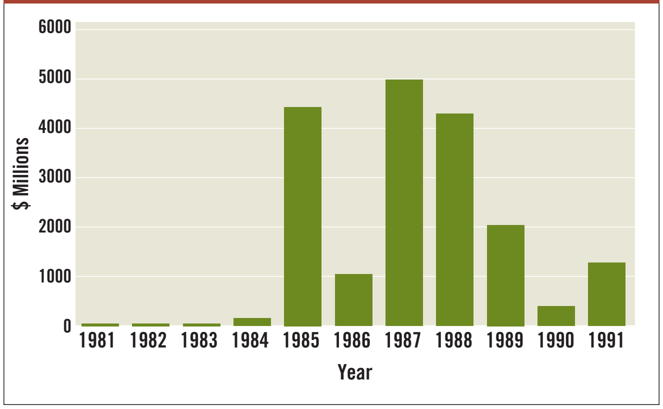
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (**Figure 8**).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider **Figure 9**. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]

A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.

45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.

46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.

47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CPUC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.

All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

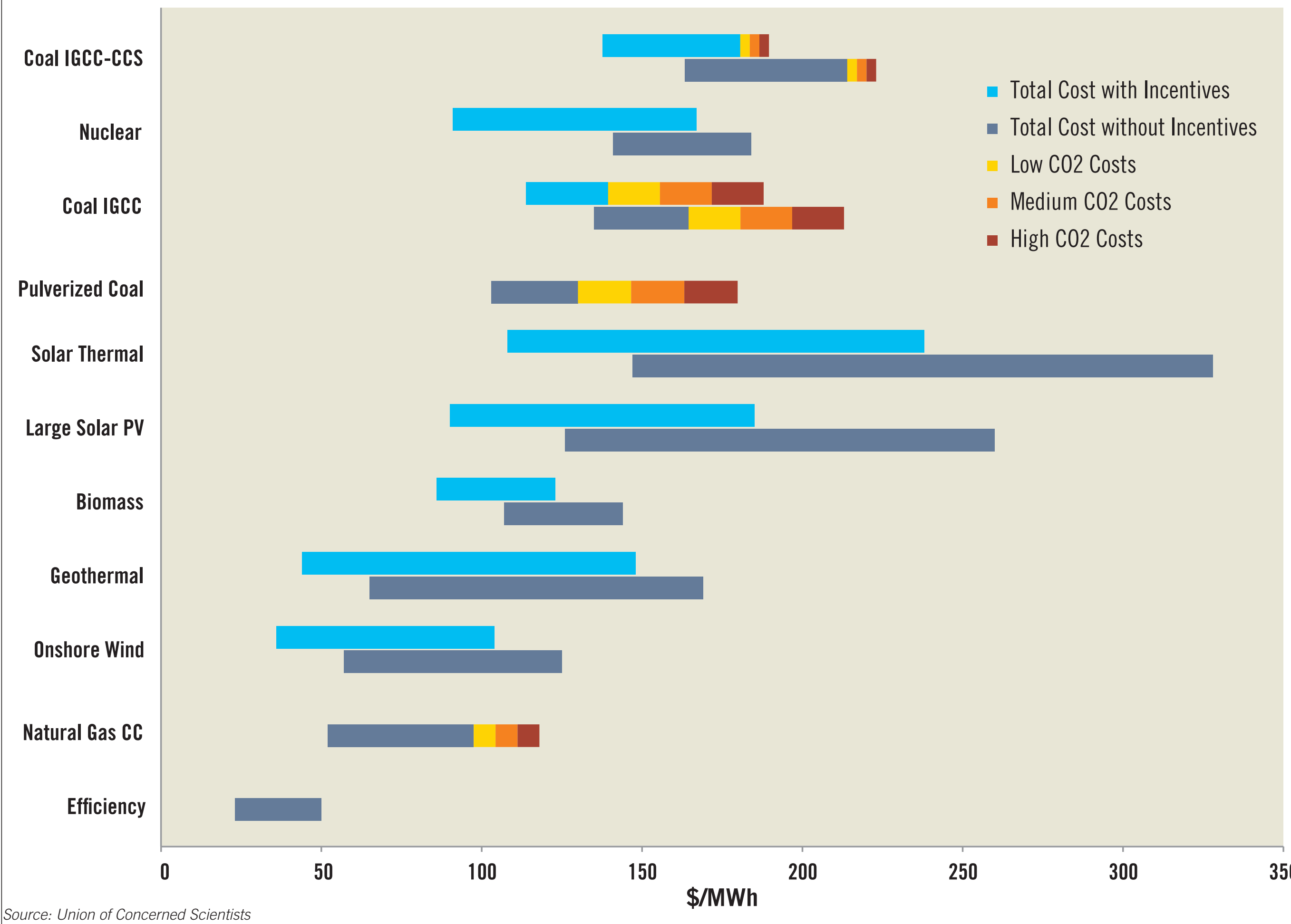
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (**Figure 10**).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (**Figure 11**).

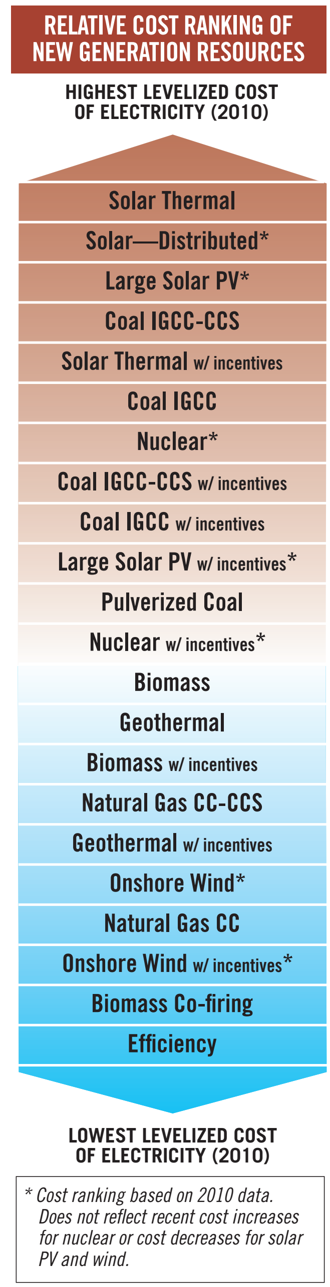
For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. 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.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

Figure 11



The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star,* October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]

Intermittency should not be confused with the concept of risk… For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the *availability factor* of a resource; the *capacity factor* of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

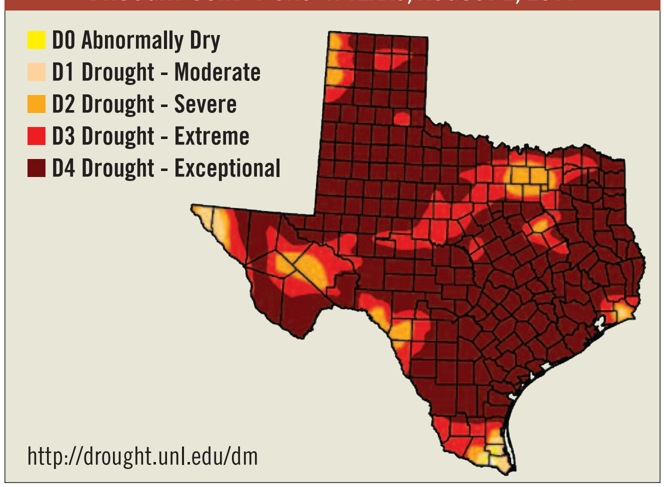
WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. **Figure 12** depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12

DROUGHT CONDITIONS IN TEXAS, AUGUST 2, 2011



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.

In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M 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
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	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	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	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

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in **Figure 13** summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

Figure 14

RELATIVE COST RANKING AND RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar—Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Nuclear w/ incentives
Solar Thermal w/ incentives	Coal IGCC
Coal IGCC	Coal IGCC-CCS w/ incentives
Nuclear*	Natural Gas CC-CCS
Coal IGCC-CCS w/ incentives	Biomass
Coal IGCC w/ incentives	Coal IGCC w/ incentives
Large Solar PV w/ incentives*	Natural Gas CC
Pulverized Coal	Biomass w/ incentives
Nuclear w/ incentives*	Geothermal
Biomass	Biomass Co-firing
Geothermal	Geothermal w/ incentives
Biomass w/ incentives	Solar Thermal
Natural Gas CC-CCS	Solar Thermal w/ incentives
Geothermal w/ incentives	Large Solar PV
Onshore Wind*	Large Solar PV w/ incentives
Natural Gas CC	Onshore Wind
Onshore Wind w/ incentives*	Solar—Distributed
Biomass Co-firing	Onshore Wind w/ incentives
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

Figure 15

RELATIVE COST AND RISK RANKINGS OF NEW GENERATION RESOURCES WITHOUT INCENTIVES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar–Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Coal IGCC
Coal IGCC	Natural Gas CC-CCS
Nuclear*	Biomass
Pulverized Coal	Natural Gas CC
Biomass	Geothermal
Geothermal	Biomass Co-firing
Natural Gas CC-CCS	Solar Thermal
Onshore Wind*	Large Solar PV
Natural Gas CC	Onshore Wind
Biomass Co-firing	Solar–Distributed
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in **Figure 14**, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, **Figure 15** presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in **Figure 16**. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

Figure 16

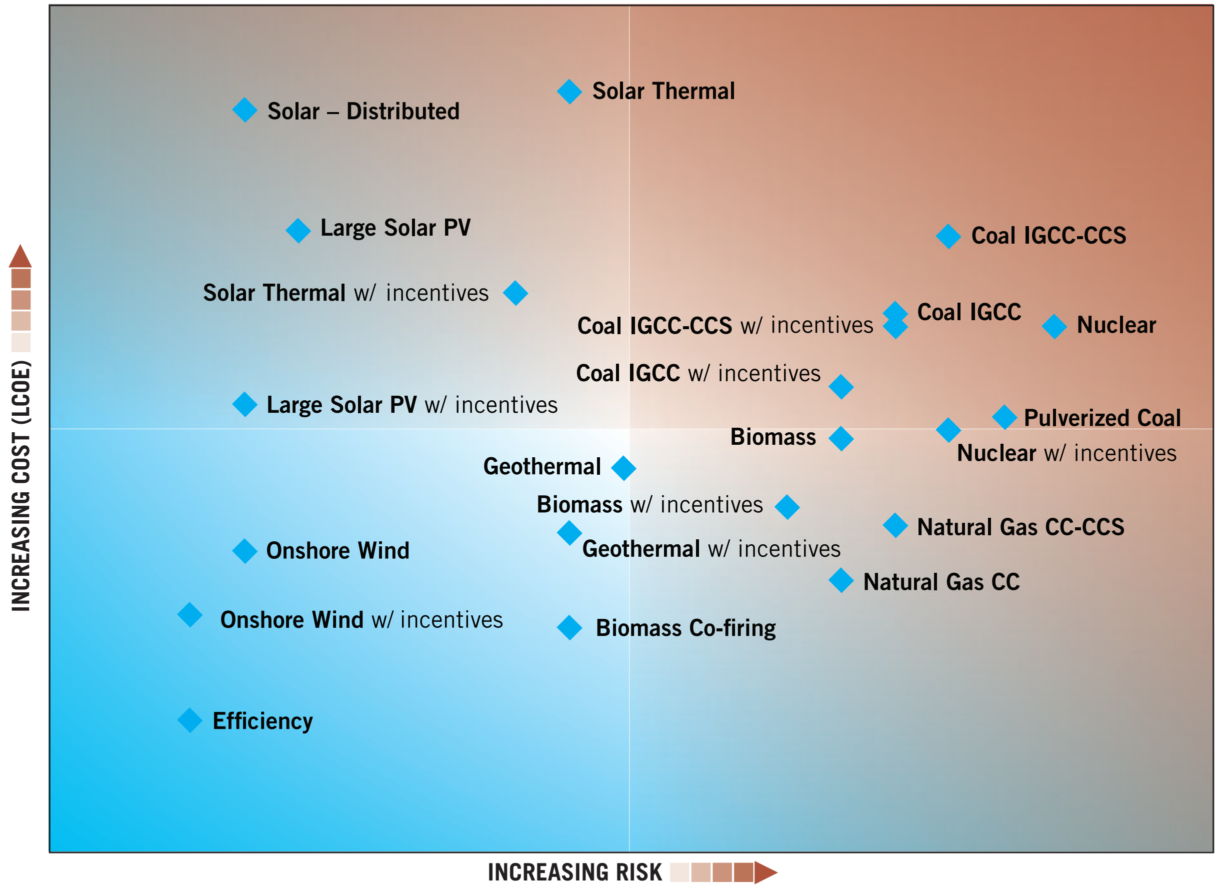
SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

Figure 17

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. **Figure 17** shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

4. PRACTICING RISK-AWARE REGULATION:

SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

UTILITY REGULATORS ARE FAMILIAR WITH A SCENE THAT PLAYS OUT IN THE HEARING ROOM: DIFFERENT INTERESTS—UTILITIES, INVESTORS, CUSTOMER GROUPS, ENVIRONMENTAL ADVOCATES AND OTHERS—COMPETE TO REDUCE COST AND RISK FOR THEIR SECTOR AT THE EXPENSE OF THE OTHERS. WHILE THE ADVERSARIAL PROCESS MAY MAKE THIS COMPETITION SEEM INEVITABLE, AN OVERLOOKED STRATEGY (THAT USUALLY LACKS AN ADVOCATE) IS TO REDUCE OVERALL RISK TO EVERYONE. MINIMIZING RISK IN THE WAYS DISCUSSED IN THIS SECTION WILL HELP ENSURE THAT ONLY THE UNAVOIDABLE BATTLES COME BEFORE REGULATORS AND THAT THE PUBLIC INTEREST IS SERVED FIRST.

Managing risk intelligently is arguably the main duty of regulators who oversee utility investment. But minimizing risk isn't simply achieving the least cost today. It is part of a strategy to *minimize overall long term costs*. And, as noted earlier, while minimizing risk is a worthy goal, eliminating risk is not an achievable goal. The regulatory process must provide balance for the interests of utilities, consumers and investors in the presence of risk.

One of the goals of "risk-aware" regulation is avoiding the kind of big, costly mistakes in utility resource acquisition that we've seen in the past. But there is another, more affirmative goal: ensuring that society's limited resources (and consumers' limited dollars) are spent wisely. By routinely examining and addressing risk in every major decision, regulators will produce lower cost outcomes in the long run, serving consumers and the public interest in a very fundamental way.

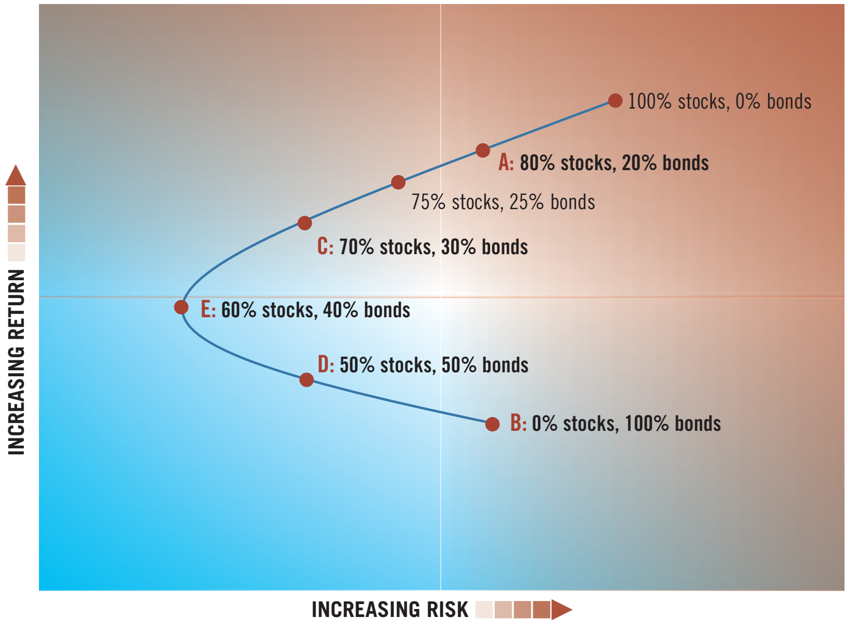
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Figure 18

RISK/RETURN RELATIONSHIPS AMONG DIFFERENT FINANCIAL PORTFOLIOS
(Illustrative)



We now discuss each of these strategies in more detail.

1. DIVERSIFYING UTILITY SUPPLY PORTFOLIOS

The concept of diversification plays an important role in finance theory. Diversification—investing in different asset classes with different risk profiles—is what allows a pension fund, for example, to reduce portfolio volatility and shield it from outsized swings in value.

Properly chosen elements in a diversified portfolio can increase return for the same level of risk, or, conversely, can reduce risk for a desired level of return. The simple illustration in **Figure 18** allows us to consider the relative risk and return for several portfolios consisting of stocks and bonds. Portfolio A (80% stocks, 20% bonds) provides a higher predicted return than Portfolio B (0% stocks, 100% bonds) even though both portfolios have the same degree of risk. Similarly, Portfolios C and D produce different returns at an identical level of risk that is lower than A and B. Portfolio E (60% stocks, 40% bonds) has the lowest risk, but at the cost of a lower return than Portfolios A and C. The curve in Figure 18 (and the corresponding surface in higher dimensions) is called an *efficient frontier*.

We could complicate the example—by looking at investments in cash, real estate, physical assets, commodities or credit default swaps, say, or by distinguishing between domestic and international stocks, or between bonds of various maturities—but the general lesson would be the same: diversification helps to lower the risk in a portfolio.

Portfolios of utility investments and resource mixes can be analyzed similarly. Instead of return and risk, the analysis would examine cost and risk. And instead of stocks, bonds, real estate and gold, the elements of a utility portfolio are different types of power plants, energy efficiency, purchased power agreements, and distributed generation, among many other potential elements. Each of these elements can be further distinguished by type of fuel, size of plant, length of contract, operating characteristics, degree of utility dispatch control, and so forth. Diversification in a utility portfolio means including various supply and demand-side resources that behave independently from each other in different future scenarios. Later we will consider these attributes in greater detail and discuss what constitutes a diversified utility portfolio.

For a real-world illustration of how diversifying resources lowers cost and risk in utility portfolios, consider the findings of the integrated resource plan recently completed by the Tennessee Valley Authority (TVA).[67] TVA evaluated five resource strategies that were ultimately refined into a single "recommended planning direction" that will guide TVA's resource investments. The resource strategies that TVA considered were:

- **Strategy A:** Limited Change in Current Resource Portfolio[68]
- **Strategy B:** Baseline Plan Resource Portfolio
- **Strategy C:** Diversity Focused Resource Portfolio
- **Strategy D:** Nuclear Focused Resource Portfolio
- **Strategy E:** EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

67 TVA, a corporation owned by the federal government, provides electricity to nine million people in seven southeastern U.S. states; see http://www.tva.com/abouttva/index.htm.

68 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent); see TVA, 73.

Figure 19

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK

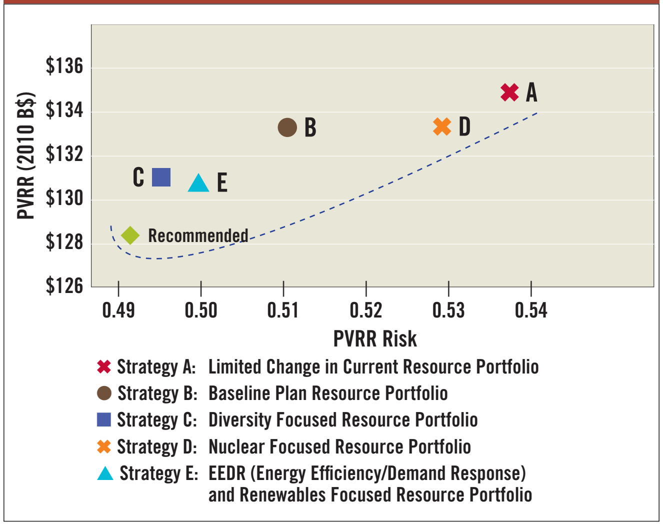


Figure 19 illustrates how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[69] The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy.[70] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio (mostly coal, natural gas and nuclear) or emphasized new nuclear plant construction.

The TVA analysis is very careful and deliberate. To the extent that other analyses reached conclusions thematically different from TVA's, we would question whether the costs and risks of all resources had been properly evaluated. We would also posit that resource investment strategies that differ directionally from TVA's "recommended planning direction" would likely expose customers (and, to some extent, investors) to undue risk. Finally, given the industry's familiarity with traditional resources—and the possibility that regulators and utilities may therefore underestimate the costs and risks of those resources—the TVA example illustrates how careful planning reveals the costs and risks of maintaining resource portfolios that rely heavily on large base load fossil and nuclear plants.

Robust planning processes like TVA's are therefore essential to making risk-aware resource choices. It is to these planning processes that we now turn.

2. UTILIZING ROBUST PLANNING PROCESSES

In the U.S., there are two basic utility market structures: areas where utilities own or control their own generating resources (the "vertically integrated" model), and areas where competitive processes establish wholesale prices (the "organized market" model).

In many vertically integrated markets and in some organized markets, regulators oversee the capital investments of utilities with a process called "integrated resource planning," or IRP. Begun in the 1980s, integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.

Elements of a Robust IRP Process

IRP oversight varies in sophistication, importance and outcomes across the states. Because a robust IRP process is critical to managing risk in a utility, we describe a model IRP process that is designed to produce utility portfolios that are lower risk and lower cost.[71]

These elements characterize a robust IRP process:

- The terms and significance of the IRP approval (including implications for cost recovery) are clearly stated at the outset, often in statute or in a regulatory commission's rules.
- The regulator reviews and approves the modeling inputs used by the utility (e.g., demand and energy forecasts, fuel cost projections, financial assumptions, discount rate, plant costs, fuel costs, energy policy changes, etc.).
- The regulator provides guidance to utility as to the policy goals of the IRP, perhaps shaping the set of portfolios examined.
- Utility analysis produces a set of resource portfolios and analysis of parameters such as future revenue requirement, risk, emissions profile, and sensitivities around input assumptions.
- In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties.
- Demand resources such as energy efficiency and demand response are accorded equal status with supply resources.
- The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP.
- The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime.
- Future challenges to prudence of utility actions are limited to the execution of the IRP, not to the selection of resources approved by the regulator.

69 TVA, 161.

70 In the end, TVA settled on a "recommended planning direction" that calls for demand reductions of 3,600 to 5,100 MW, energy efficiency savings of 11,400 to 14,400 GWh, and renewable generating capacity additions of 1,500 to 2,500 MW by 2020. At the same time, TVA plans to retire 2,400 to 4,700 MW of coal-fired capacity by 2017. See TVA, 156.

71 For an example of an IRP that uses sophisticated risk modeling tools, see PacifiCorp, *2011 Integrated Resource Plan* (Portland, OR: PacifiCorp, 2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

IRP: "Accepted" vs. "Approved" Plans

There are two varieties of IRP plans: "accepted plans" and "approved plans." Accepted plans are those where regulators examine the utility's process for developing its proposed plan. This can be a thorough review in which the Commission solicits the opinion of other parties as to whether the utility undertook a transparent, inclusive, and interactive process. If the regulator is convinced, the regulator "accepts" the utility's plan. This allows the utility to proceed but does not include any presumption about the Commission's future judgment concerning the prudence of actions taken under the plan.

With an "approved plan" the regulator undertakes a thorough review of the utility's preferred plan, possibly along with competing IRP plans submitted by other parties. Typically the scrutiny is more detailed and time-consuming in this version of IRP and the regulatory agency is immersed in the details of competing plans. At the end of the process, the regulator "approves" an IRP plan. This approval typically carries with it a presumption that actions taken by the utility consistent with the plan (including its approved amendments) are prudent. Over time, a Commission that approves an IRP plan will typically also examine proposed changes to the plan necessitated by changing circumstances.

In this report, we will focus on the "approved plan" process, although many of our findings apply equally to regulators that employ the "accepted plan" process.

A few of these elements deserve more elaboration.

Significance. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. From the regulator's point of view, the resource planning process must review a wide variety of portfolio choices whose robustness is tested and compared under different assumptions about the future. From the utilities' perspective, acceptance or approval of an IRP should convey that regulators support the plan's direction, even though specific elements may evolve as circumstances change. If a utility ignores the approved IRP or takes actions that are inconsistent with an IRP without adequate justification, such actions may receive extra scrutiny at the point where the utility seeks cost recovery.

Multiple scenarios. Many different scenarios will allow a utility to meet its future load obligations to customers. These scenarios will differ in cost, risk, generation characteristics, fuel mix, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, and so forth. While one scenario might apparently be lowest cost under baseline assumptions, it may not be very resilient under different input assumptions. Further, scenarios will differ in levels of risk and how that risk may be apportioned to different parties (e.g., consumers or shareholders). Regulators, with input from interested parties, should specify the types of scenarios that utilities should model and require utilities to perform sensitivity analyses, manipulating key variables.

Consistent, active regulation. An IRP proceeding can be a large, complex undertaking that occurs every two or three years, or even less frequently. It is critical that regulators become active early in the process and stay active throughout. The regulator's involvement should be consistent, even-handed and focused on the big-ticket items. Of course, details matter, but the process is most valuable when it ensures that the utility is headed in the right direction and that its planning avoids major errors. The regulator should then monitor a utility's performance and the utility should be able to trust the regulator's commitment to the path forward laid out in the IRP.

Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent decision. Second, effective stakeholder involvement can build support for the IRP that is ultimately approved, heading off collateral attacks and judicial appeals. An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources. Because an IRP decision is something of a political document in addition to being a working plan, regulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

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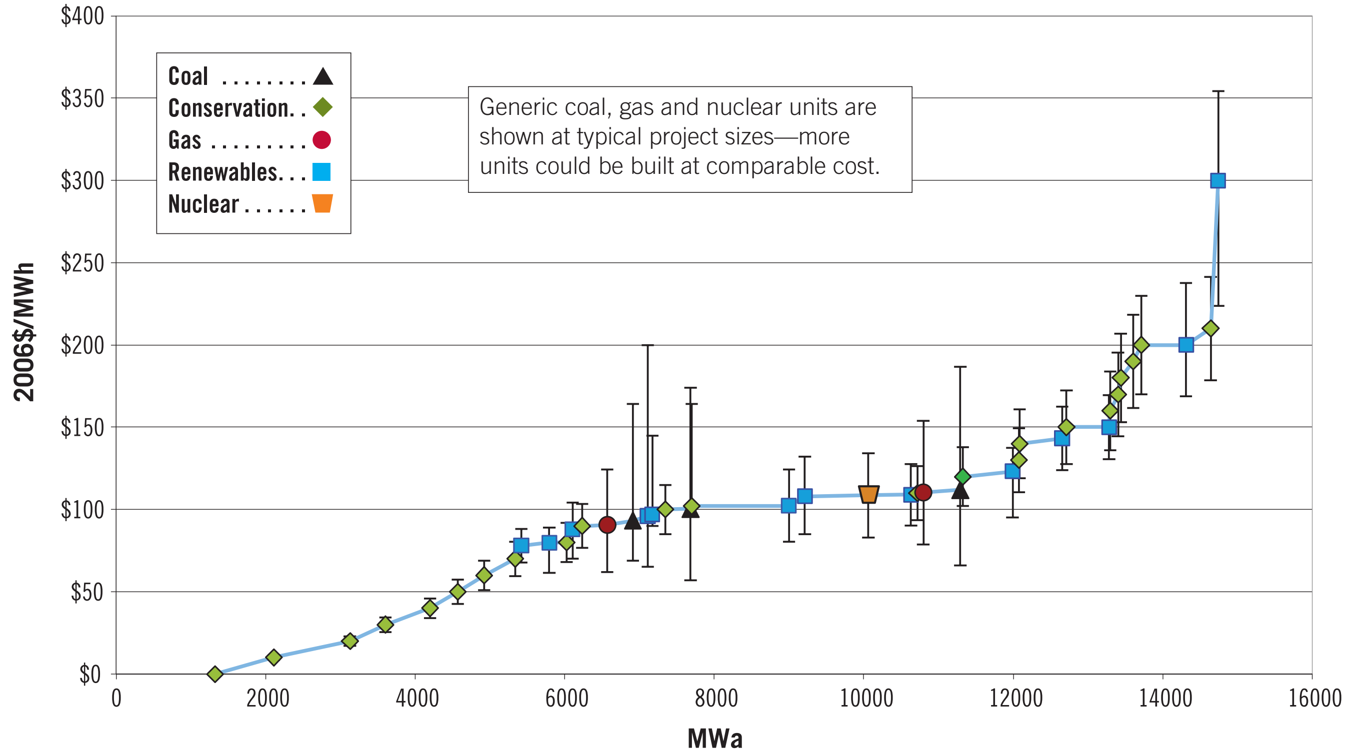
Transparency. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Certain data may be competitively sensitive and there is often pressure on the regulator to restrict unduly the access to such data. One possible solution to this challenge is to use an "independent evaluator" who works for the commission, is trusted by all parties and has access to all the data, including proprietary data. The independent evaluator can verify the modeling of the utility and assist the regulator in making an informed decision. The cost of an independent evaluator will be small in comparison to the benefits (or avoided mistakes) that the evaluator will enable. An independent evaluator will also add

Figure 20

PORTFOLIO ANALYSIS ON ONE PAGE
How Energy Efficiency Can Substitute for Generation Resources



credibility to the regulators' decision. In any event, the integrity of the IRP process will depend on regulators' ability to craft processes that are trusted to produce unbiased results.

Competitive bidding. A successful IRP will lower risk in the design of a utility resource portfolio. After the planning process, utilities begin acquiring approved resources. Some states have found it beneficial to require the utility to undertake competitive bidding for all resources acquired by a utility pursuant to an IRP. If the utility will build the resource itself, the regulator may require the utility to join the bidding process or commit to a cap on the construction cost of the asset.[72]

Role of Energy Efficiency. A robust IRP process will fully consider the appropriate levels of energy efficiency, including demand response and load management, that a utility should undertake. Properly viewed and planned for, energy efficiency can be considered as equivalent to a generation resource. Regulators in some states list projected energy efficiency savings on the "loads and resources table" of the utility, adjacent to base load and peaking power plants. In Colorado, energy efficiency is accorded a "reserve margin" in the integrated resource plan, as is done with generation resources.[73]

Since its inception in 1980, the Northwest Power and Conservation Council, which develops and maintains a regional power plan for the Pacific Northwest, has stressed the role of energy efficiency in meeting customers' energy needs. **Figure 20** shows the Council's analysis, demonstrating the elements of a diversified energy portfolio and the role that energy efficiency (or "conservation") can play in substituting for generation resources at various levels of cost.[74]

Appendix 2 contains additional discussion of some of the modeling tools available to regulators.

3. EMPLOYING TRANSPARENT RATEMAKING PRACTICES

Economist Alfred Kahn famously observed that "all regulation is incentive regulation," meaning that any type of economic regulation provides a firm with incentives to make certain choices. Indeed, utility rate regulation's greatest effect may not be its ability to limit prices for consumers in the short run, but rather the incentives it creates for utilities in the longer run.

72 For a discussion of the use of competitive bidding in resource acquisition, see Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (Boston, MA: Analysis Group, 2008), http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Competitive_Procurement.pdf.

73 For Xcel Energy in Colorado, energy efficiency is listed on the "loads and resources" table as a resource. As such, it is logical that some fraction of the planned-for load reduction might not materialize. That portion is then assigned the standard resource reserve margin of approximately 15 percent. The planning reserve margin is added to the projected peak load, which must be covered by the combined supply-side and demand-side resources in the table.

74 Tom Eckman, "The 6th Power Plan… and You" (presentation at the Bonneville Power Administration Utility Energy Efficiency Summit, Portland, Ore., March 17, 2010), http://www.bpa.gov/Energy/N/utilities_sharing_ee/Energy_Smart_Awareness/pdf/0A_EESummit_Gen-Session_Public_Power.pdf.

There have been many debates through the years about the incentives that utility cost of service regulation provides. These range from the academic and formal (e.g., the aforementioned Averch-Johnson effect, which says that rate-regulated companies will have an inefficiently high ratio of capital to labor) to the common sense (e.g., price cap regulation can induce companies to reduce quality of service; the throughput incentive discourages electric utilities from pursuing energy efficiency, etc.).

While regulators may want to limit their role to being a substitute for the competition that is missing in certain parts of the electric industry, it is rarely possible to limit regulation's effects that way. The question is usually not how to eliminate stray incentives in decisions, but rather which ones to accept and address.

To contain risk and meet the daunting investment challenges facing the electric industry, regulators should take care to examine exactly what incentives are being conveyed by the details of the regulation they practice. We examine four components of cost of service regulation that affect a utility's perception of risk, and likely affect its preference for different resources.

Current Return on Construction Work in Progress. There is a long-standing debate about whether a utility commission should allow a utility to include in its rates investment in a plant during the years of its construction. Construction Work in Progress, or "CWIP," is universally favored by utility companies and by some regulators, but almost universally opposed by advocates for small and large consumers and by other regulators. CWIP is against the law in some states, mandated by law in others.

The main argument against CWIP is that it requires consumers to pay for a plant often years before it is "used and useful," so that there isn't a careful match between the customers who pay for a plant and those who benefit from it. Proponents of CWIP point out that permitting a current return on CWIP lessens the need for the utility to issue debt and equity, arguably saving customers money, and that CWIP eases in the rate increase, compared to the case where customers feel the full costs of an expensive plant when the plant enters service. Opponents counter by noting that customers typically have a higher discount rate than the utilities' return on rate base, so that delaying a rate hike is preferred by consumers, even if the utility borrows more money to finance the plant until it enters service.

Setting aside the near-religious debate about the equity of permitting CWIP in rate base, there is another relevant consideration. Because CWIP can help utilities secure financing and phase in rate increases, CWIP is often misunderstood as a tool for reducing risk. This is not true.

CWIP, Risk Shifting and Progress Energy's Levy Nuclear Plant

In late 2006, Progress Energy announced plans to build a new nuclear facility in Levy County, Florida, a few months after the state legislature approved construction work in progress (CWIP) customer financing. The site is about 90 miles north of Tampa, near the Gulf of Mexico. In 2009, Progress customers began paying for the Levy plant, which was expected to begin service in 2016 and be built at a cost of $4-6 billion. By the end of 2011, Progress customers had paid $545 million toward Levy's construction expenses.

The Levy plant is now projected to cost up to $22 billion, roughly four times initial estimates, and that number could keep climbing. (In March 2012, Progress Energy's market value as a company was almost $16 billion; the combined market value of Duke Energy and Progress Energy, which are seeking to merge and are pursuing construction of five nuclear facilities between them, is about $44 billion.) Levy's expected in-service date has pushed beyond 2021 and possibly as late as 2027—eighteen years after Progress customers began paying for the plant. Progress has estimated that by 2020, Levy-related expenses could add roughly $50 to the average residential customer's monthly bill.

The Levy plant's development appeared to take a step forward in December 2011 when the Nuclear Regulatory Commission approved its reactor design. But in February 2012, the Florida Public Service Commission approved a settlement agreement allowing Progress to suspend or cancel Levy's construction and recover $350 million from customers through 2017.

It is unclear whether Levy will ever be built. If the plant is canceled, Progress customers will have paid more than $1 billion in rates for no electricity generation, and Florida state law prohibits their recouping any portion of that investment. Such an outcome could help to deteriorate the political and regulatory climate in which Progress operates, which could ultimately impact credit ratings and shareholder value.

CWIP does nothing to actually reduce the risks associated with the projects it helps to finance. Construction cost overruns can and do still occur (see the text box about Progress Energy's Levy County nuclear power plant); O&M costs for the plant can still be unexpectedly high; anticipated customer load may not actually materialize; and so forth. What CWIP does is to reallocate part of the risk from utilities (and would-be bondholders) to customers. CWIP therefore provides utilities with both the incentive and the means to undertake a riskier investment than if CWIP were unavailable.

Regulators must be mindful of the implications of allowing a current return on CWIP, and should consider limiting its use to narrow circumstances and carefully drawn conditions of oversight. Regulators should also pay close attention to how thoroughly utility management has evaluated the risks associated with the projects for which it requests CWIP. Regardless of CWIP's other merits or faults, an important and too-often unacknowledged downside is that it can obscure a project's risk by shifting, not reducing, that risk.

Use of Rider Recovery Mechanisms. Another regulatory issue is the use by utilities of rate "riders" to collect investment or expenses. This practice speeds up cash flow for utilities, providing repayment of capital or expense outlays more rapidly than would traditional cost of service regulation. This allows utilities to begin collecting expenses and recovering capital without needing to capitalize carrying costs or file a rate case. Once again, regulators must consider whether these mechanisms could encourage a utility to undertake a project with higher risk, for the simple reason that cost recovery is assured even before the outlay is made.

Allowing a current return on CWIP, combined with revenue riders, is favored by many debt and equity analysts, who perceive these practices as generally beneficial to investors. And indeed, these mechanisms allow bondholders and stock owners to feel more assured of a return of their investment. And they might marginally reduce the utility's cost of debt and equity. But these mechanisms (which, again, transfer risk rather than actually reducing it) could create a "moral hazard" for utilities to undertake more risky investments. A utility might, for example, proceed with a costly construction project, enabled by CWIP financing, instead of pursuing market purchases of power or energy efficiency projects that would reduce or at least delay the need for the project. If negative financial consequences of such risky decisions extended beyond customers and reached investors, the resulting losses would be partially attributable the same risk-shifting mechanisms that analysts and investors originally perceived as beneficial.

Construction Cost Caps. Some regulatory agencies approve a utility's proposed infrastructure investments only after a cap is established for the amount of investment or expense that will be allowed in rates. Assuming the regulator sticks to the deal, this action will apportion the risk between consumers and investors. We wouldn't conclude that this actually reduces risk except in the sense that working under a cap might ensure that utility management stays focused on the project, avoiding lapses into mismanagement that would raise costs and likely strain relationships with regulators and stakeholders.

Rewarding Energy Efficiency. Another relevant regulatory practice concerns the treatment of demand-side resources like energy efficiency and demand response. It is well understood that the "throughput incentive" can work to keep a utility from giving proper consideration to energy efficiency; to the extent that a utility collects more than marginal costs in its unit price for electricity, selling more electricity builds the bottom line while selling less electricity hurts profitability. There are several adjustments regulation can make, from decoupling revenues from sales, to giving utilities expedited cost recovery and incentives for energy efficiency performance. Decoupling, which guarantees that a utility will recover its authorized fixed costs regardless of its sales volumes, is generally viewed by efficiency experts and advocates as a superior approach because it neutralizes the "throughput incentive" and enables utilities to dramatically scale up energy efficiency investment without threatening profitability. Ratings agencies view decoupling mechanisms as credit positive because they provide assurance of cost recovery, and Moody's recently observed "a marked reduction in a company's gross profit volatility in the years after implementing a decoupling type mechanism."[75] Whatever the chosen approach, the takeaway here is that without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.[76]

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4. USING FINANCIAL AND PHYSICAL HEDGES

Another method for limiting risk is the use of financial and physical hedges. These provide the utility an opportunity to lock in a price, thereby avoiding the risk of higher market prices later. Of course, this means the utility also foregoes the opportunity for a lower market price, while paying some premium to obtain this certainty.

Financial hedges are instruments such as puts, calls, and other options that a utility can purchase to limit its price exposure (e.g., for commodity fuels) to a certain profile. If the price of a commodity goes up, the call option pays off; if the price goes down, the put option pays off. Putting such a collar around risk is, of course, not free: the price of an option includes transaction costs plus a premium reflecting the instrument's value to the purchaser. Collectively these costs can be viewed as a type of insurance payment.

Another example of a financial hedge is a "temperature" hedge that can limit a utility's exposure to the natural gas price spikes that can accompany extreme weather conditions. A utility may contract with a counter-party so that, for an agreed price, the counter-party agrees to pay a utility if the number of heating-degree-days exceeds a certain level during a certain winter period. If the event never happens,

75 Moody's Investors Service, *Decoupling and 21st Century Rate Making* (New York: Moody's Investors Service, 2011), 4.

76 For a discussion of regulatory approaches to align utility incentives with energy efficiency investment, see Val Jensen, *Aligning Utility Incentives with Investment in Energy Efficiency*, ICF International (Washington, DC: National Action Plan for Energy Efficiency, 2007), http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Long-term Contracts for Natural Gas

In recent decades, utilities have mostly used financial instruments to hedge against volatile natural gas prices, and natural gas supply used for power generation has not been sold under long-term contracts. An exception is a recent long-term contract for natural gas purchased by Xcel Energy in Colorado. The gas will be used to fuel new combined cycle units that will replace coal generating units. The contract between Xcel Energy and Anadarko contained a formula for pricing that was independent of the market price of natural gas and runs for 10 years.

The long-term natural gas contract between Xcel Energy and Anadarko was made possible by a change in Colorado's regulatory law. For years, utilities and gas suppliers had expressed concern that a long-term contract, even if approved initially as prudent, might be subject to a reopened regulatory review if the price paid for gas under the contract was, at some future date, above the prevailing market price. Colorado regulators supported legislation making it clear in law that a finding of prudence at the outset of a contract would not be subject to future review if the contract price was later "out of the money." An exception to this protection would be misrepresentation by the contracting parties.

the utility forfeits the payment made for the hedge. If the event does happen, the utility might still need to purchase natural gas at an inflated price; even so, the hedge would pay off because it has reduced the company's total outlay. Simply stated, financial hedges can be used by a utility to preserve an expected value.

An illustration of a physical hedge would be when a utility purchases natural gas at a certain price and places it into storage. The cost of that commodity is now immune to future fluctuations in the market price. Of course, there is a cost to the utility for the storage, and the utility forgoes the possible advantage of a future lower price. But in this case the payment (storage cost) is justifiable because of the protection it affords against the risk of a price increase.

Long-term contracts can also serve to reduce risk. These instruments have been used for many years to hedge against price increases or supply interruptions for coal. Similarly, long-term contracts are used by utilities to lock in prices paid to independent power producers. Many power purchase agreements (PPAs) between distribution utilities and third party generators lock in the price of capacity, possibly with a mutually-agreed price escalator. But due to possible fuel price fluctuations (especially with natural gas), the fuel-based portion of the energy charge is not fixed in these contracts. So PPAs can shield utilities from some of the risks of owning the plants, but they do not hedge the most volatile portion of natural gas generation: the cost of fuel.

Regulated utilities and their regulators must come to an understanding about whether and how utilities will utilize these options to manage risk, since using them can foreclose an opportunity to enjoy lower prices.

5. HOLDING UTILITIES ACCOUNTABLE

From the market's perspective, one of the most important characteristics of a public utilities commission is its consistency. Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators. Indeed, this quality is often viewed to be as important as the absolute level of return on equity approved by a commission.

Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators.

Effective regulation—regulation that is consistent, predictable, forward-thinking and "risk-aware"—requires that regulators hold utilities accountable for their actions. Earlier, we stressed the value of regulators being actively involved in the utility resource planning process. But this tool works well only if regulators follow through—by requiring utilities to comply with the resource plan, to amend the resource plan if circumstances change, to live within an investment cap, to adhere to a construction schedule, and so forth. If the utility doesn't satisfy performance standards, regulatory action will be necessary.

This level of activity requires a significant commitment of resources by the regulatory agency. Utility resource acquisition plans typically span ten years or more, and a regulator must establish an oversight administrative structure that spans the terms of sitting commissioners in addition to clear expectations for the regulated companies and well-defined responsibilities for the regulatory staff.

6. OPERATING IN ACTIVE, "LEGISLATIVE" MODE

As every commissioner knows, public utility regulation requires regulators to exercise a combination of judicial and legislative duties. In "judicial mode," a regulator takes in evidence in formal settings, applies rules of evidence, and decides questions like the interpretation of a contract or the level of damages in a complaint case. In contrast, a regulator operating in "legislative mode" seeks to gather all information relevant to the inquiry at hand and to find solutions to future challenges. Judicial mode looks to the past, legislative mode

to the future. In his 1990 essay, former Ohio utilities regulator Ashley Brown put it this way:

> *Gathering and processing information is vastly different in judicial and legislative models. Legislating, when properly conducted, seeks the broadest data base possible. Information and opinions are received and/or sought, heard, and carefully analyzed. The process occurs at both formal (e.g., hearings) and informal (e.g., private conversation) levels. The goal is to provide the decision maker with as much information from as many perspectives as possible so that an informed decision can be made. Outside entities can enhance, but never be in a position to limit or preclude, the flow of information. The decision maker is free to be both a passive recipient of information and an active solicitor thereof. The latter is of particular importance in light of the fact that many of the interests affected by a decision are not likely to be present in the decision making forum.*[77]

Being a risk-aware regulator requires operating in legislative mode in regulatory proceedings, and especially in policy-making proceedings such as rulemakings. But the courts have also found that ratemaking is a proper legislative function of the states.[78] And since this state legislative authority is typically delegated by legislatures to state regulators, this means that, to some extent, regulators may exercise "legislative" initiative even in rate-setting cases.

In a recent set of essays, Scott Hempling, the former executive director of the National Regulatory Research Institute, contrasts regulatory and judicial functions and calls for active regulation to serve the public interest:

> *Courts and commissions do have commonalities. Both make decisions that bind parties. Both base decisions on evidentiary records created through adversarial truth-testing. Both exercise powers bounded by legislative line-drawing. But courts do not seek problems to solve; they wait for parties' complaints. In contrast, a commission's public interest mandate means it literally looks for trouble. Courts are confined to violations of law, but commissions are compelled to advance the public welfare.*[79]

Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.

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7. REFORM AND RE-INVENT RATEMAKING PRACTICES

It is increasingly clear that a set of forces is reshaping the electric utility business model. In addition to the substantial investment challenge discussed in this report, utilities are facing challenges from stricter environmental standards, growth in distributed generation, opportunities and challenges with the creation of a smarter grid, new load from electric vehicles, pressure to ramp up energy efficiency efforts—just to mention a few. As electric utilities change, regulators must be open to new ways of doing things, too.

77 Ashley Brown, "The Over-judicialization of Regulatory Decision Making," *Natural Resources and Environment* Vol. 5, No. 2 (Fall 1990), 15-16.

78 See, e.g., U.S. Supreme Court, *Munn vs. Illinois*, 94 U.S. 113 (1876), http://supreme.justia.com/cases/federal/us/94/113/case.html.

79 Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Silver Spring, MD: National Regulatory Research Institute, 2011), 22.

Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades. To deal with the digital revolution in telecommunications and the liberalization of those markets, regulators modernized their tools to include various types of incentive regulation, pricing flexibility, lessened regulation in some markets and a renewed emphasis on quality of service and customer education.

One area where electric utility regulators might profitably question existing practices is rate design. Costing and pricing decisions, especially for residential and small business customers, have remained virtually unchanged for decades. The experience in other industries (e.g., telecommunications, entertainment, music) shows that innovations in pricing are possible and acceptable to consumers. Existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

The risk-aware regulator must be willing to think "way outside the box" when it comes to the techniques and strategies of effective regulation. Earlier we observed that effective regulators must be informed, active, consistent, curious and often courageous. These qualities will be essential for a regulator to constructively question status quo regulatory practice in the 21st century.

THE BENEFITS OF "RISK-AWARE REGULATION"

We have stressed throughout this report that effective utility regulators must undertake a lot of hard work and evolve beyond traditional practice to succeed in a world of changing energy services, evolving utility companies and consumer and environmental needs. What can regulators and utilities reasonably expect from all this effort? What's the payback if regulators actively practice "risk-aware regulation"?

- **FIRST**, there will be benefits to consumers. A risk-aware regulator is much less likely to enter major regulatory decisions that turn out wrong and hurt consumers. The most costly regulatory lapses over the decades have been approval of large investments that cost too much, failed to operate properly, or weren't needed once they were built. It's too late for any regulator to fix the problem once the resulting cost jolts consumers.
- **SECOND**, there will be benefits to regulated utilities. Risk aware regulation will create a more stable, predictable business environment for utilities and eliminate most regulatory surprises. It will be easier for these companies to plan for the longer-term. If regulators use a well-designed planning process, examining all options and assessing risks, utilities and their stakeholders will have greater reliance on the long-term effect of a decision.
- **THIRD**, investors will gain as well. Steering utilities away from costly mistakes, holding the companies responsible for their commitments and, most importantly, maintaining a consistent approach across the decades will be "credit-positive," reducing threats to cost-recovery. Ratings agencies will take notice, lowering the cost of debt, benefitting all stakeholders.
- **FOURTH**, governmental regulation itself will benefit. Active, risk-aware regulators will involve a wide range of stakeholders in the regulatory process, building support for the regulators' decision. Consistent, transparent, active regulation will help other state officials—governors and legislators—develop a clearer vision of the options for the state's energy economy.
- **FINALLY**, our entire society will benefit as utilities and their regulators develop a cleaner, smarter, more resilient electricity system. Regulation that faithfully considers all risks, including the future environmental risks of various utility investments, will help society spend its limited resources most productively. In other words, risk-aware regulation can improve the economic outcome of these large investments.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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APPENDIX 1:

UNDERSTANDING UTILITY FINANCE

MOST INVESTOR-OWNED UTILITIES (IOUS) IN THE UNITED STATES ARE IN A CONSTRUCTION CYCLE OWING TO THE NEED TO COMPLY WITH MORE STRINGENT AND EVOLVING ENVIRONMENTAL POLICIES AND TO IMPROVE AGING INFRASTRUCTURE. NEW INFRASTRUCTURE PROJECTS INCLUDE SMART GRID, NEW GENERATION AND TRANSMISSION. THE IOUS, THEREFORE, WILL BE LOOKING TO THE CAPITAL MARKETS TO HELP FINANCE THEIR RATHER LARGE CAPITAL EXPENDITURE PROGRAMS.

DEBT FINANCING

While the IOUs will be issuing some additional equity, a higher percentage of the new investment will be financed with debt. In general, utilities tend to be more leveraged than comparably-rated companies in other sectors (see the Rating Agencies section below). The electric utility sector's debt is primarily publicly issued bonds, including both first mortgage bonds (FMB) and senior unsecured bonds. While the utilities also issue preferred stock and hybrid debt securities, these instruments tend to represent a small portion of a company's capital structure. Non-recourse project finance is rare for utilities, but it is commonly used by unregulated affiliates.

Most regulated IOUs in the U.S. are owned by holding companies whose assets are primarily their equity interests in their respective subsidiaries. These operating company subsidiaries are typically wholly owned by the parent, so that all publicly-held stock is issued by the parent. Because most of these holding companies are quite large, the market for a holding company's stock is usually highly liquid.

In contrast to equity, bonds are issued by both the utility holding company and individual operating subsidiaries. Typically, holding and operating company bonds are non-recourse to affiliates. This means that each bond issuer within the corporate family will have its own credit profile that affects the price of the respective bonds. To illustrate this point, compare two American Electric Power subsidiaries, Ohio Power and Indiana Michigan. The companies have different regulators, generation mix, customer bases and, consequently, different senior unsecured Moody's bond ratings of Baa1 and Baa2, respectively. For this reason, each bond issuance of the corporate family trades somewhat independently.

Utility bonds trade in secondary markets and are traded over-the-counter rather than in exchanges like equities. For bond issuance of less than $300 million, the secondary market is illiquid and not very robust. Smaller utilities are frequently forced into the private placement market with their small issuances and accordingly pay higher interest rates compared to similarly-rated larger companies. Even if these smaller issues are placed in the public market, there is a premium for the expected lack of liquidity.

Secured debt in the form of FMBs is common in the electric utility sector. Such bonds are usually secured by an undivided lien on almost all of the assets of an operating utility. Bond documentation (called an "indenture") prohibits the issuance of such bonds in an amount that exceeds a specified percentage (usually in the range of 60 percent) of the asset value of the collateral. The maturities of these bonds are frequently as long as 30 years, and in rare occasions longer). While the lien on assets may limit a company's financing flexibility, the interest rate paid to investors is lower than for unsecured debt. The proceeds from FMBs are usually used to finance or refinance long-lived assets.

Senior unsecured bonds can be issued at any maturity, but terms of five and ten years are most common. These instruments are "junior" to FMBs, so that, in an event of default, these debt holders would be repaid only after the secured debt. But these bonds are "senior" to hybrids and preferred stock. In a bankruptcy, senior unsecured bonds are usually deemed equal in standing with trade obligations, such as unpaid fuel and material bills.

Utilities typically have "negative trade cycles," meaning that cash receipts tend to lag outlays. IOUs' short-term payables such as fuel purchases, salaries and employee benefits are due in a matter of days after the obligation is incurred. In contrast, the utility's largest short-term assets are usually customer receivables which are not due for 45—60 days after the gas or electricity is delivered. Therefore, utilities have short term cash needs referred to as "working capital" needs. To finance these short term needs utilities have bank credit lines and sometimes trade receivable facilities.

For larger utility corporate families, these bank lines can amount to billions of dollars. For example, American Electric Power has two large bank lines of $1.5 and $1.7 billion that mature in 2015 and 2016, respectively. AEP's lines and most of those of other utilities are revolving in nature. While termination dates typically range from one to five years for these lines, the utility usually pays down borrowings in a few months and accesses the line again when needed.

Interest on bank lines of credit is paid only when the lines are used, with a much lower fee paid on the unused portion of the lines. For financially weak utility companies, banks often require security for bank lines . But because utility operating companies are rarely rated below BBB-/Baa3, bank lines are, for the most part, unsecured.

Some larger utilities have receivable facilities in addition to revolving bank lines. The lender in a receivables facility usually purchases the customer receivables. There is an assumed interest expense in these transactions which is usually lower than the rate charged by banks for unsecured revolving lines.

Although preferred stock is a form of equity, it is usually purchased by a bond investor who is comfortable with the credit quality of the issuer and willing to take a junior position in order to get a higher return on its investment. There are also hybrid securities. Although they are technically debt instruments, they are so deeply subordinate and with such long repayment periods that investors and the rating agencies view these instruments much like equities. Frequently, hybrids allow the issuer to defer interest payments for a number of years. Some hybrids can be converted to equity at either the issuer's or investor's option.

S&P is the most rigorous of the rating agencies in treating the fixed component of power purchase agreements (PPA) as debt-like in nature. Also, some Wall Street analysts look at PPAs as liabilities with debt-like attributes. That being said, those analysts who do not consider PPAs as debt-like still incorporate in their analysis the credit implications of these frequently large obligations.

EQUITY FINANCING

In order to maintain debt ratings and the goodwill of fixed income investors, utility managers must finance some portion of their projects with equity. Managements are usually reluctant to go to market with large new stock issuances. Equity investors often see new stock as being dilutive to their interests, resulting in a decrease in the market price of the stock. But if a utility has a large capital expenditure program it may have no choice but to issue equity in order maintain its credit profile.

For more modest capital expenditure programs, a company may be able to rely on incremental increases to equity to maintain a desired debt to equity ratio. While the dividend payout ratios are high in this sector, they are rarely 100 percent, so that for most companies, equity increases, at least modestly, through retained earnings. Many companies issue equity in small incremental amounts every year to fulfill commitments to employee pension or rewards programs. Also, many utility holding companies offer their existing equity holders the opportunity to reinvest dividends in stock. For larger companies these programs can add $300 - $500 million annually in additional equity. Since these programs are incremental, stock prices are usually unaffected.

OTHER FINANCING

Project finance (PF) can also be used to fund capital expenditures. These instruments are usually asset-specific and non-recourse to the utility, so that the pricing is higher than traditional investment-grade utility debt. Project finance is usually used by financially weaker non-regulated power developers.

Some companies are looking to PF as a means of financing large projects so that risk to the utility is reduced. However, the potential of cost overruns, the long construction/development periods and use of new technology will make it hard to find PF financing for projects like new nuclear plants. This also applies to carbon capture/sequestration projects, as the technology is not seasoned enough for most PF investors. This means that, utilities may need to finance new nuclear and carbon capture/sequestration projects using their existing balance sheets.

In order to reduce risk, a utility can pursue projects in partnership with other companies. Currently proposed large gas transport and electric transmission projects are being pursued by utility consortiums. Individual participants in gas transport projects in particular have used Master Limited Partnerships (MLPs) as a way to finance their interests. MLPs are owned by general and limited partners. Usually the general partner is the pipeline utility or a utility holding company. Limited partner units are sold to passive investors and are frequently traded on the same stock exchanges that list the parent company's common stock. One big difference between the MLP and an operating company is that earnings are not subject to corporate income tax. The unit holders pay personal income tax on the profits.

Companies have used both capital and operating lease structures to finance discrete projects, including power plants. The primary difference between an operating and capital lease is that the capital lease is reflected on the company's balance sheet. The commitment of the utility to the holder of the operating lease is deemed weaker. Most fixed income analysts, as well as the rating agencies, do not view these instruments as being materially different and treat operating leases for power plants as debt.

TYPICAL UTILITY INVESTORS

The largest buyers of utility equities and fixed income securities are large institutional investors such as insurance companies, mutual funds and pension plans. As of September 2011, 65 percent of utility equities were owned by institutions. While insurance companies and pension plans own utility equities, both trail mutual funds in the level of utility stock holdings. For example, the five largest holders of Exelon stock are mutual fund complexes.

Most retail investors own utility stock and bonds indirectly through mutual funds and 401k plans. But many individual investors also own utility equities directly, including utility employees. Small investors tend not to buy utility bonds because the secondary market in these instruments is rather illiquid, especially if the transaction size is small.

Common stock mutual funds with more conservative investment criteria are most interested in utility equities. While the market price of these stocks can vary, there is a very low probability of a catastrophic loss. Also, utility stocks usually have high levels of current income through dividend distributions. Another attractive attribute of these equities is that they are highly liquid. Essentially all utilities in the U.S. are owned by utility holding companies that issue common stock. Due to extensive consolidation in the sector over the past 20 years, these holding companies are large and have significant market capitalization. For these reasons, utility stocks are highly liquid and can be traded with limited transaction costs.

Utility fixed-income investments are far less liquid than equities. Thus, the typical bond investor holds onto the instruments much longer than the typical equity investor. Bonds are issued both by the utility holding company and individual operating subsidiaries. Because bonds are less liquid in the secondary market, investors in these instruments, such as pension plans and insurance companies, tend to have longer time horizons. Four of the top five investors in Exelon Corp bonds due 2035 are pension plans and insurance companies. Mutual bond funds tend to buy shorter-dated bonds.

The buyers of first mortgage bonds (FMBs) are frequently buy-and-hold investors. As FMBs are over-collateralized, bondholders are comfortable that they will be less affected by unforeseen negative credit events. It is not unusual for a large insurance company to buy a large piece of an FMB deal at issuance and hold it to maturity. Retail investors in utility bonds also tend to be buy-and-hold investors, as it is hard for them to divest their positions which are typically small compared to the large institutions. The relative illiquidity of utility bonds means that transaction costs can be high and greatly reduce the net proceeds from a sale.

Utility employees frequently own the stock of the companies for which they work. Employees with defined benefit pensions, however, are not large holders of utility stocks because pension plans hold little if any of an employer's stock owing to ERISA rules and prudent asset management practices. Mid-level non-unionized employees frequently have 401ks that are typically invested in mutual funds or similar instruments. However, it is not unusual for company matching of the employees' 401k contributions to be in company stock. Finally, senior management's incentive compensation is frequently paid in the company's common equity, in part to ensure that management's interests are aligned with those of the shareholders.

RATING AGENCIES

Most utilities have ratings from three rating agencies: Moody's Investors Services, Standard & Poor's Ratings Services, and Fitch Ratings. Having three ratings is unlike other sectors, which frequently use two ratings—Moody's or Standard & Poor's. Most utility bonds are held by large institutional investors who demand that issuers have at least Moody's and Standard & Poor's ratings.

Failing to have two ratings would cause investors to demand a very high premium on their investments, far more than the cost to utilities of paying the agencies to rate them. Having a third rating from Fitch usually slightly lowers the interest rate further. While investors have become less comfortable with the rating agencies' evaluations of structured finance transactions, this dissatisfaction has not carried over greatly into the corporate bond market, and especially not the utility bond market.

The agencies usually assign a rating for each company referred to as an *issuer rating*. They also rate specific debt issues, which may be higher or lower than the issuer rating. Typically a secured bond will have a higher rating than its issuer; preferred stock is assigned a lower rating than the issuer. Ratings range from AAA to D.[80] The "AAA" rating is reserved for entities that have virtually no probability of default. A "D" rating indicates that the company is in default.

The three agencies each take into account both the probability of default, as well as the prospects of recovery for the bond investor if there is a default. Utilities traditionally are considered to have high recovery prospects because they are asset-heavy companies. In other words, if liquidation were necessary, bond holders would be protected because their loans are backed by hard assets that could be sold to cover the debt. Further, the probability of default is low because utility rates are regulated, and regulators have frequently increased rates when utilities have encountered financial

80 Standard & Poor's and Fitch use the same ratings nomenclature. It was designed by Fitch and sold to S&P. For entities rated between AA and CCC the agencies break down each rating category further with a plus sign or a minus sign. For example, bonds in the BBB category can be rated BBB+, BBB and BBB-. Moody's ratings nomenclature is slightly different. The corresponding ratings in BBB category for Moody's are Baa1, Baa2 and Baa3. The agencies will also provide each rating with an outlook that is stable, positive or negative.

problems owing to events outside of companies' control. However, there are a few notable instances where commissions could not or would not raise rates to avoid defaults including the bankruptcies of Public Service of New Hampshire and Pacific Gas and Electric.

It is unusual for a utility operating company to have a non-investment grade rating (Non-IG, also referred to as high yield, speculative grade, or junk). Typically Non-IG ratings are the result of companies incurring sizable expenses for which regulators are not willing or able to give timely or adequate rate relief. Dropping below IG can be problematic for utilities because interest rates increase markedly. Large institutional investors have limited ability to purchase such bonds under the investment criteria set by their boards. Another problem with having an Non-IG rating is that the cost of hedging rises owing to increased collateral requirements as counterparties demand greater security from the weakened credit.

In developing their ratings, the agencies consider both quantitative and more subjective factors. The quantitative analysis tends to look at cash flow "coverage" of total debt and of annual fixed income payment obligations, as well as overall debt levels. In contrast, the typical equity analyst focuses on earnings. The rating agencies are less interested in the allowed returns granted by regulators than they are in the size of any rate decrease or increase and its effect on cash flow.

That said, the rating agency may look at allowed returns to evaluate the "quality" of regulation in a given state. All things being equal, they may give a higher rating to a company in a state with "constructive" regulation than to a company in a state with a less favorable regulatory climate. Constructive regulation to most rating agencies is where regulatory process is transparent and consistent across issuers in the state. Also, the agencies favor regulatory constructs that use forward-looking test years and timely recovery of prudently-incurred expenses. The agencies consider tracking mechanisms for fuel and purchased power costs as credit supportive because they help smooth out cash fluctuations. The agencies believe that while trackers result in periodic changes in rates for the customer, these mechanisms are preferable for consumers than the dramatic change in rates caused by fuel factors being lumped in with other expenses in a rate case.

Analysts also will look to see how utility managers interact with regulators. The agencies deem it a credit positive if management endeavors to develop construct relationships with regulators. The agencies may become concerned about the credit quality of a company if the state regulatory process becomes overly politicized. This may occur if a commission renders decisions with more of an eye toward making good press than applying appropriate utility regulatory standards. Politicized regulatory environments can also occur when a commission is professional and fair, but outside political forces, such as governors, attorneys general or legislators challenge a prudently decided case.

The rating agencies themselves can at times act as *de facto* regulators. Because utilities are more highly levered than most any other sector, interest expenses can be a significant part of a company's cost structure. Ratings affect interest rates. The agencies will look negatively at anything that increases event risk. The larger an undertaking, the greater the fallout if an unforeseen event undermines the project. A utility embarking on the development of a large facility like a large generation or transmission project, especially if is not preapproved by the regulators, might result in a heightened focus on the company by the agencies. The rating action could merely be change in outlook from stable to negative, which could in turn have a negative impact on the market price of outstanding bonds, interest rates on new issuances and even on equity prices. Many utility stock investors are conservative and pay more attention to rating agency comments and actions than investors with holdings in more speculative industries.

APPENDIX 2:

TOOLS IN THE IRP PROCESS

REGULATORS HAVE SEVERAL TOOLS AT THEIR DISPOSAL IN THE IRP PROCESS. ONE OF THE MOST IMPORTANT IS THE UTILITY REDISPATCH MODEL. THIS IS A COMPLEX COMPUTER PROGRAM THAT SIMULATES THE OPERATION OF A UTILITY'S SYSTEM UNDER INPUT ASSUMPTIONS PROVIDED BY THE USER. THE TERM "REDISPATCH" REFERS TO THE FACT THAT THE SOFTWARE MIMICS THE OPERATION OF AN ACTUAL UTILITY SYSTEM, "DISPATCHING" THE HYPOTHETICAL GENERATION RESOURCES AGAINST A MODEL LOAD SHAPE, OFTEN HOUR-BY-HOUR FOR MOST COMMONLY USED MODELS.

Three examples of these models are Prosym, licensed by Henwood Energy Services; Strategist, licensed by Ventyx; and GE MAPS, licensed by General Electric.

A model typically creates a 20- or 40-year future utility scenario, based on load projections provided by the user. The utility's energy and peak demand is projected for each hour of the time period, using known relationships about loads during different hours, days of the week and seasons of the year. The model then "dispatches" the most economic combination of existing or hypothetical new resources to meet the load in every hour of that time period.

The operating characteristics of each generating resource is specified as to its availability, fuel efficiency, fuel cost, maintenance schedule, and, in some models, its emissions profile. The resources available to the model will be a mixture of existing plants, taking note of their future retirement dates, plus any hypothetical new resources required by load growth. The model incorporates estimates of regional power purchases and their price, transmission paths and their constraints, fuel contracts, the retirement of existing facilities, etc.

In this way, the user of the model can test various combinations (scenarios) of proposed new generating plants, including base load plants, intermediate and peaking plants, intermittent renewable resources, etc. The model will calculate the utility's revenue requirement, fuel costs, and purchased power expenses in each scenario. The model might be used to estimate the cost of operating the system with a specific hypothetical portfolio, predict the level of emissions for a portfolio, measure the value of energy efficiency programs, test the relative value of different resources, measure the reliability of the system, etc.

The reader might analogize this modeling to "fantasy" baseball, where hypothetical teams play hypothetical games, yielding win-loss records, batting averages and pennant races.

As powerful as these modeling tools are, they are *production* models, first and foremost. As such, they are not particularly good at dealing with assumptions about energy efficiency and demand response. In using such models, the regulator must insist that the utility gives appropriate treatment to demand-side resources. It may be possible to re-work models to do this, or it may be necessary to conduct extra sensitivity analyses at varying levels of energy efficiency and demand response.

IRP SENSITIVITY ANALYSES

A redispatch modeling tool allows a utility and the regulator to test the resilience of portfolios against different possible futures. For example, a regulator might want to know how five different generation portfolios behave under situations of high natural gas prices, or tougher environmental regulations. By varying the input assumptions while monitoring the relevant output (e.g., net present value of future revenue requirements) the regulator can assess the risk that contending portfolios pose to future rates if, for example, fuel prices vary from their predicted levels.

To illustrate this idea, consider the following material from a case in Colorado. **Figure Appendix - 1** is a page excerpted from Xcel Energy's 2009 analysis in support of a resource plan filed before the Colorado Public Utilities Commission. The page shows the results of sensitivity analyses for the price of natural gas (high and low) and the cost of carbon emissions (high and low) for twelve different portfolios being considered by the Colorado PUC.

In all, the Colorado PUC studied 48 different generation portfolios in this IRP case. The portfolios differed based on how much natural gas generation was added, how much wind and solar generation was added, the schedule for closing some existing coal-fired power plants, the level of energy efficiency assumed, etc. (The actual generation units in each portfolio are not identified in this public document.

Figure Appendix - 1

EXAMPLE OF IRP SENSITIVITY ANALYSES

Base Scenario Assumption: High Efficiency, Medium Solar

Representative of Preferred Plan

Primary Scenario
High DSM (130% Goal)
Medium Section 123 (200 MW)
Base Load

Portfolios 1-12

PVRR & Rank

Key Portfolio Characteristic		Portfolio Number											
		1	2	3	4	5	6	7	8	9	10	11	12
		Portfolio Rank within Scenario (PVRR)											
		1	2	3	4	5	6	7	8	9	10	11	12
Wind (MW)													
Solar (MW)													
Intermittent (MW)													
Solar Storage (MW)													
Gas (MW)													
Other (MW)	1												
Total (MW)		1,872	1,902	1,907	1,932	1,977	1,966	1,911	1,860	1,936	2,039	1,982	2,078
Owned %													
Owned MW													
Total 123 (MW)													
CO2 (M ton)	2	26.8	26.7	26.8	26.7	26.6	26.8	26.8	26.8	26.9	26.6	26.5	26.6
% New Build	3												
Externalities	4	2	2	2	2	2	1	2	2	1	2	3	2
PVRR rank		1	2	3	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	49,344	49,361	49,365	49,387	49,402	49,478	49,490	49,526	49,645	49,675	49,675	49,822
PVRR Delta ($M)	6	-	17	21	43	58	134	146	182	301	331	331	478
PV Rate ($/MWh)	7	71.87	71.90	71.90	71.94	71.96	72.07	72.09	72.14	72.31	72.36	72.36	72.57
CO2 Delta (M ton)	8	-	(0.30)	(0.02)	(0.50)	(0.68)	1.79	(0.09)	(0.04)	0.80	(0.57)	(0.81)	(0.65)
$10/ton CO2 Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	43,695	43,722	43,716	43,758	43,786	43,805	43,845	43,877	43,981	44,054	44,080	44,203
Change ($M)	10	(5,649)	(5,638)	(5,649)	(5,628)	(5,616)	(5,673)	(5,645)	(5,649)	(5,664)	(5,622)	(5,596)	(5,619)
PVRR Delta ($M)	11	-	27	21	63	91	110	150	182	286	358	384	508
$40/ton CO2 Sensitivity													
PVRR rank	9	3	2	5	4	1	7	6	8	11	10	9	12
PVRR ($M)	5	60,066	60,061	60,087	60,067	60,056	60,247	60,204	60,250	60,392	60,311	60,285	60,451
Change ($M)	10	10,723	10,701	10,723	10,680	10,654	10,769	10,714	10,724	10,747	10,636	10,610	10,629
PVRR Delta ($M)	11	10	5	31	11	-	191	148	194	336	255	229	395
Low Gas Price Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	10	9	11	12
PVRR ($M)	5	47,935	47,959	47,956	47,992	48,016	48,055	48,075	48,118	48,234	48,230	48,318	48,371
Change ($M)	10	(1,409)	(1,402)	(1,409)	(1,395)	(1,386)	(1,423)	(1,415)	(1,407)	(1,411)	(1,445)	(1,357)	(1,451)
PVRR Delta ($M)	11	-	24	22	57	81	121	140	184	299	295	383	436
High Gas Price Sensitivity													
PVRR rank	9	5	4	6	3	1	7	8	10	9	11	2	12
PVRR ($M)	5	57,122	57,091	57,144	57,070	57,025	57,295	57,326	58,234	57,421	58,268	57,059	58,464
Change ($M)	10	7,778	7,730	7,780	7,684	7,623	7,817	7,836	8,708	7,776	8,593	7,384	8,642
PVRR Delta ($M)	11	97	66	120	46	-	270	302	1,209	396	1,244	34	1,439

Otherwise, it would have created problems for the competitive bidding process used to award contracts to supply the power to the utility.)

Each column in the table represents a different portfolio, numbered 1 to 12. Portfolio 2 is the Xcel's preferred plan. The rows show the modeling results for each portfolio. For example, the Present Value of Revenue Requirements (PVRR) is calculated for each portfolio and is shown the line indicated by the first PVRR arrow, along with the ranking of that portfolio. The lower half of the chart shows the cost of each portfolio under different assumptions about the cost of carbon emissions (higher or lower than base case predictions) and for natural gas prices (higher or lower than base case predictions).

CAVEATS

Models are a terrific way to keep track of all the moving parts in the operation of a utility portfolio. But it is one thing to know that each resource has certain operating characteristics; it is quite another to see these qualities interact with each other in dynamic fashion. And while utility modeling tools, such as production cost models can be helpful, care must be taken with their use.

Obviously the models are helpful only to the extent that the inputs are reasonable and cover the range of possibilities the regulator wishes to examine. Load forecast must be developed with care; assumptions about future fuel costs are really educated guesses, and should be bracketed with ranges of sensitivity.

Because there are so many possible combinations, variations and sensitivities, the regulator in an IRP case must make a decision early in the process about the scope of the portfolios to be examined. The utility should be directed to analyze and present all scenarios requested by the regulator, together with any portfolios preferred by the utility.

Finally, the model's best use is to inform judgment, not substitute for it. The amount of data produced by models can be overwhelming and may give a false sense of accuracy. The risk-aware regulator will always understand the fundamental uncertainties that accompany projections of customer demand, future fuel costs and future environmental requirements.

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