



# Electric Utilities and Risk Compensation

Prepared for:

Edison Electric Institute

Prepared by:

Dr. H. Edwin Overcast, Ph.D.

Richard J. Rudden

Howard S. Gorman

Leonard S. Hyman

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Phone: 202-508-5000

Web site: [www.eei.org](http://www.eei.org)

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# EXECUTIVE SUMMARY

After a decade of minimal rate activity, investor-owned electric utilities are again filing rate cases. As they do, regulatory commissions are being challenged by new and emerging structural changes in the electric utility industry to approve rates that meet the Supreme Court’s requirement to balance:

- Investors’ rights to returns that are “sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital”; and
- Consumers’ rights to rates that are “just and reasonable.”

Achieving the balance is complicated by the significant setbacks to investor confidence that have occurred in recent years, and the need for utilities to meet load changes by funding continual distribution system improvements, expanding transmission capacity, maintaining and enhancing reliability and service quality, and meeting new capacity requirements.

This monograph addresses issues that are important to striking the proper balance. It addresses new issues related to: (1) determining the cost of capital in restructured markets, and (2) managing the cost of capital through proactive regulatory policies. Key conclusions are:

1. ***Policymakers should not assume that restructured utilities are less risky than the traditional utilities that preceded them.*** There are new risks in restructured markets. These risks may not be captured by traditional cost of capital methodologies, but investors are aware of them. This is why rating agencies have downgraded electric utility debt in recent years, and why investors are focusing on state regulatory policies and decisions to assess utility risk going forward.
2. ***Utility risk should be evaluated on a company-specific basis, using analytic frameworks that address the new risks in restructured markets.*** Among the possible new risks are:
  - **Increased earnings variability due to reliance on competitive wholesale markets**—Wholesale electricity prices can be extremely dynamic, leading to the potential for nonrecovery, or delayed recovery, of wholesale supply costs in regulated retail rates. Insolvency and/or nonperformance by third-party suppliers can exacerbate earnings volatility.
  - **Increased earnings variability due to new delivery infrastructure funding**—Cost increases for new delivery infrastructure, either at the transmission level, such as rising regional transmission organization (RTO) or independent system operator (ISO) costs, or at the distribution level, such as from replacement of aging facilities to maintain reliability, also can produce earnings volatility.
  - **Increased earnings variability due to increased customer switching**—In retail access environments, customer switching increases the volatility of retail loads incumbent utilities must serve pursuant to provider of last resort (POLR)-type service obligations. Increased load volatility can interact with the volatility in wholesale power markets and potential regulatory disallowances to produce increased volatility in earnings.
  - **Cherry-picking customers in retail competition states**—Some competitive models result in the loss of the utility’s most profitable customers (in combination with continued use of volumetric rates) and an increase in uncollectible accounts, further impacting earnings volatility.

3. ***Policymakers can control the cost of capital by controlling risk.*** By adopting policies that control utility risk exposure, policymakers can effectively manage utility cost of capital. Key risk-reducing policies include:
- **Pre-approved resource procurement**—Policies that ensure timely recovery of supply costs by (1) developing a shared understanding of reasonable supply-related resource strategies before costs are incurred, and (2) honoring costs reasonably incurred to implement such strategies. This would not mean an end to regulatory oversight and control, but rather an end to after-the-fact, “perfect hindsight” prudence reviews.
  - **Risk-mitigated POLR policies**—Policies that require large customers to pay stranded costs even when they leave regulated service, and observe minimum stay requirements if they come back to regulated supply from the market, or pay spot market prices when they return. (Note: If switching by small customers increases, similar requirements may be needed to manage risk.)
  - **Limiting counterparty exposure**—Policies that prevent third parties from shifting risk to incumbent utilities, such as by maintaining adequate creditworthiness standards for third parties, and by allocating partial payments to satisfy utility claims before satisfying claims by third-party suppliers.
  - **Timely recovery of infrastructure investments**—Policies and rate mechanisms that provide timely recovery between rate cases of costs incurred to make needed distribution and transmission system improvements. Infrastructure cost pass through must permit timely recovery of RTO/ISO costs as well.
  - **Updated rate design**—Policies that provide for the recovery of a substantial portion of distribution infrastructure costs through fixed customer charges, and increased use of automatic adjustment mechanisms to ensure timely recovery of costs that are highly variable and outside the control of utility management (e.g., fuel).

*Section I, Identifying and Quantifying the New Risks*, defines investor risk as the variation in utility cash flow, earnings and, ultimately, return on investment. It demonstrates why restructured utilities cannot be assumed to be less risky than the vertically integrated companies that preceded them. Restructuring exposes utilities to new risks, and corporate unbundling tends to magnify the financial impact of specific risks. A framework for evaluating the new risks is defined in terms of the major sources of new risk in restructured markets.

*Section II, The Influence of New Risks on the Cost of Capital*, examines the implications of the new risks of restructuring. Chief among these is the recognition that comparisons to “comparable” or “peer” utilities are becoming increasingly problematic. Given that the new risk factors vary by state and by company, there really aren’t any comparable utilities anymore. This calls into question traditional cost of capital methods, such as use of the capital asset pricing model (CAPM) and discounted cash flow (DCF) model, which rely on comparisons to peer groups, and suggests the need for new approaches that evaluate risk on an individual company basis.

*Section III, Potential Regulatory Policies to Estimate, Reduce, and Control Utility Risks*, addresses issues related to compensating and/or managing utility risk that are outside the scope of traditional cost of capital determination methods. In terms of compensating utilities for risk, one relevant comparison is the cost of any insurance product(s) that may be available to manage a specific risk; appropriate compensation is approximately equal to the insurance premium required for such insurance coverage. Another approach, for

new risks where no substantial empirical or experiential data yet exist, is to base premiums on financial simulations (e.g., Monte Carlo). A related issue is that customer preferences for compensated risk mitigation vary, so customers should be given choices, for example, of service packages that incorporate various levels of risk mitigation. In terms of managing utility risk, policymakers should consider the potential to manage utility cost of capital by calibrating regulatory policies to their impact on utility risk.

*Section IV, Conclusions*, reiterates that it is not reasonable to assume that restructured utilities are less risky than the integrated companies that preceded them. New risks are introduced by restructuring, and these need to be evaluated on a company-specific basis. Because the new risks are highly company- and jurisdiction-specific, the validity of traditional methodologies—which rely on comparisons to “comparable” or “peer” utilities—is called into question. Policymakers can manage utility cost of capital by managing utility risk.



## SECTION I: IDENTIFYING AND QUANTIFYING THE NEW RISKS

The investor-owned electric utility industry has changed significantly over the past decade. The industry has seen movement from traditional vertical integration to unbundling of generation, transmission, and distribution functions, and increased reliance on emerging competitive wholesale markets. It also has experienced the rise and fall of major energy trading businesses and independent generating entities. In addition, many states are in the midst of moving toward competitive retail markets, while others seek to slow down or stop the emergence of competition. Collectively, these events have changed the fundamental risk characteristics of many utilities, leading to increased investor risk.

The increase in risk is reflected in the pattern of declining credit ratings in recent years. During 2001–2003, downgrades of shareholder-owned electric utilities substantially outpaced upgrades, reflecting increased utility risk from energy trading and merchant generation.<sup>1</sup> During 2004, the trend toward declining creditworthiness leveled off, as utilities sold non-core businesses and strengthened balanced sheets; and in 2005 the process of financial recovery continued and creditworthiness began to be rebuilt. During these years, regulated electric shareholder-owned utilities with credit ratings below investment-grade (i.e., below BBB) grew from 23 percent of the sector in 2001 to 39 percent as of December 2003, then receded to 27 percent as of December 2005. Unfortunately, as we look ahead, utility credit is again under pressure; this time because of investor concerns about increasing risk within the regulated business. The issue now is the timely recovery of increasing fuel costs and new capital investments. As one group of analysts expressed it recently: “These fairly steep increases have a number of implications for utilities, as it is not clear if such hikes will be easily digested by ratepayers or their elected representatives. From a regulatory risk perspective, utilities may well face cash deferrals, harsh rate case treatment, and the specter of re-regulation.”<sup>2</sup> These same analysts also noted that “Historically, electric utility under-earning coincides with free cash turning negative (which happened in late 2005). When utilities as a group stop generating free cash flow, they earn approximately 225 Gps less than their allowed return on equity (ROE).”

Even where retail restructuring has not taken place, a new risk profile has emerged, requiring a comprehensive review of unique, utility-specific risks. This new pattern of risk has added complexity to estimating capital costs and establishing regulatory policies that mitigate risks, reduce the cost of capital to utilities, and reduce the cost burden to customers. Failure to recognize new risks or to underestimate the consequences of these risks will result in rates of return that are unsatisfactory for investors, a waning of interest in utility debt and equity issuances, and a decline in stock prices. Compounding the issue is the fact that rate designs often produce actual returns below those allowed.<sup>3</sup> It is earned return, not the allowed return, that forms the basis for investor evaluation. When returns are too low, inadequate amounts of capital are available and reliability suffers, even with prudent management of new investments.

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<sup>1</sup> EEI Credit Ratings, Q1 2006 Financial Update.

<sup>2</sup> *Capital Lessons*, Lehman Brothers, March 15, 2006.

<sup>3</sup> This paper will not address the ratemaking process *per se*, but will refer to elements of that process that directly affect a utility's ability to actually earn its allowed rate of return.

To determine cost of capital, regulators rely on the concept of comparable risks as espoused in the familiar *Hope* and *Bluefield*<sup>4</sup> cases. To use comparable risk, the risks themselves must be known or knowable, and quantifiable. Without an understanding of the industry's new risk profile, comparable risk approaches cannot work. Moreover, the estimation of risk in most utility cost of capital studies is developed at a high level of aggregation, i.e., over groupings of companies or industries. Such aggregation does not permit the consideration of unique and utility-specific risks that cannot possibly average into the capital cost from a sample of unrelated utilities. The fundamental flaws of the current methodologies are the impairment of comparability and the failure to incorporate differing risk profiles. Risks can differ by company within a single jurisdiction because of company-specific historical precedent, differences in state regulatory policy, and the interplay of federal and state regulation. As discussed later, certain risks are also asymmetric and not susceptible to analysis on any basis other than utility-specific.<sup>5</sup> Asymmetric risk holds the potential for destroying shareholder value to a greater degree than it does for enhancing value. The traditional implied assumption that companies with certain common characteristics face comparable risks cannot be justified.

## A. Defining Risk

In the simplest terms, the risk faced by equity investors is the volatility in actual and potential earned return. To fully define and understand the new utility industry risks and identify the changing impact of existing risks, it is useful to define a framework for analyzing utility risk by stating five fundamental postulates:

1. Rates are set on the basis of costs and assumptions that usually are out of date and rarely, if ever, match actual circumstances that occur throughout the rate effective period.
2. Investors make investment choices based on expected total return (the sum of the expected dividend plus expected stock price appreciation), and expected risk (the variability in returns).
3. Regulatory policies and procedures substantially affect utility risk and return.
4. Higher risk requires higher return to compensate investors for bearing such risk.
5. Actual equity returns result from the dollars available after all other costs are paid, including debt service costs.

In examining the risk profile of any given utility, particularly a utility that has been “restructured” (e.g., whose retail customers have been given competitive choice, and which has divested its generation), the essential question is whether the utility has become more risky, or less risky, than its pre-restructuring predecessor. If the returns the utility provides its shareholders have become *more* volatile, then the utility is riskier. If shareholder returns become *less* volatile, the utility is less risky. Numerous factors can bear on this question, and the analyst must exercise professional judgment in identifying and evaluating those factors that are most important in determining current and future return volatility for a given utility. Four factors likely to be of material influence, which are illustrated later with numeric examples, are:

1. Reliance on volatile wholesale markets for utility-provided power supply;
2. The need for new spending on delivery infrastructure;
3. Supplier of last resort (SOLR or POLR) obligations; and
4. The introduction of retail access after a legacy of social ratemaking.

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<sup>4</sup> *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works v. P.S.C.*, 262 U.S. 679 (1923).

<sup>5</sup> For a detailed discussion of the problem of asymmetric risks, A. Lawrence Kolbe, William B. Tye, and Stewart C. Myers, *Regulatory Risk*, (Kluwer Academic Publishers, 1993).

## B. Two Hypothetical Utilities

The importance, magnitude, and even the existence of each of the components of risk differ from state to state, and between utilities within a single state. For each of the four major risk factors listed above, numeric examples have been developed to illustrate their nature and impact on shareholder return. Two hypothetical electric utilities are used.

As shown in Table A, each of the two utilities serves the same number of customers (750,000), sells the same amount of power (20 billion kWh a year), and operates with the same total revenue requirement (\$1.2 billion).<sup>6</sup> The difference is that one is a traditional, vertically integrated utility providing bundled service to its customers (*integrated utility*), while the other has divested both its generation and transmission (*unbundled utility*).

The examples that follow are calculated using the information in Table A that describes each utility. Dollar values have been rounded for simplicity, but are representative of small to medium-sized investor-owned electric utilities in the United States. (This paper will use “M” or “B” to signify million or billions; i.e., \$25M is \$25 million dollars.)

**Table A: Basic Utility Data**

	Integrated Utility	Unbundled Utility
	Base Case	Base Case
Rate base	\$4.0 billion	\$1.0 billion
Capital structure	50% debt/50% equity	50% debt/50% equity
Shareholder equity	\$2.0 billion	\$500 million
Allowed/earned ROE	10%	10%
Equity return	\$200 million	\$50 million
Debt	\$120 million	\$30 million
Non-fuel O&M	\$330 million	\$150 million
Depreciation expense	\$160 million	\$35 million
Tax	\$140 million	\$35 million
Fuel	\$225 million	
Purchased power	\$ 25 million	Hedged \$720 million
		Unhedged \$180 million
Revenue requirement	\$1.2 billion	\$300 million
Customer costs	\$1.2 billion	\$1.2 billion

<sup>6</sup> The revenue requirement for both utilities is the sum of the cost of equity and debt, income taxes, non-fuel operations and maintenance (O&M), depreciation expense, and fuel or purchased power expense.

### C. Risks Related to Competitive Wholesale Markets

Competitive wholesale electricity markets produce prices that can be extremely volatile, escalating rapidly when demand begins to overtake supply, and falling equally rapidly when demand falls. This represents a risk factor for electric utilities, because purchased power costs typically do not flow directly into retail rates, but must be deferred for possible subsequent recovery. As the size of deferred purchased power balances grow, so too does the potential for prudence challenges. With this in mind, it is reasonable to view utility dependence on wholesale power purchases as a risk factor, depending on associated regulatory policies and procedures. As illustrated in Table B, the impact can be much greater for an unbundled (“wires-only”) utility, than for a traditional, vertically integrated utility.

As the examples illustrate, both traditional integrated utilities and unbundled utilities face a number of new risks resulting from a variety of regulatory and legislative changes in energy markets. The impacts of the risks vary from utility to utility and, contrary to the view that unbundled utilities are less risky, the examples illustrate that the unbundled utility, under the same rules as an integrated utility, can be more risky. The higher risk for unbundled utilities means that higher equity returns are required to compensate the owners of the utility for the risks.

**Table B: Basic Utility Data with 10 Percent Energy Price Increase Case**

	Integrated Utility		Unbundled Utility	
	Base Case	10% Energy Price Increase Case	Base Case	10% Energy Price Increase Case
Rate base	\$4.0 billion		\$1.0 billion	
Capital structure	50% debt/50% equity		50% debt/50% equity	
Shareholder equity	\$2.0 billion		\$500 million	
Allowed/earned ROE	10%	8.75% (12.5% decline)	10%	6.4% (36% decline)
Equity return	\$200 million	\$175 million	\$50 million	\$32 million
Debt	\$120 million		\$30 million	
Non-fuel O&M	\$330 million		\$150 million	
Depreciation Exp.	\$160 million		\$35 million	
Tax	\$140 million		\$35 million	
Fuel	\$225 million	\$247.5 million		
Purchased power	\$25 million	\$27.5 million	Hedged \$720 million	
			Unhedged \$180M	\$198 million
Revenue req.	\$1.2 billion		\$300 million	
Customer Costs	\$1.2 billion		\$1.2 billion	

Table B depicts the impact of a 10 percent increase in wholesale power and fuel prices on the shareholder returns of our two hypothetical utilities. In each case, a rate freeze is assumed.

Briefly, in a scenario in which the spot market price of fuel and wholesale power rises 10 percent, and in which neither utility can flow these increases into retail rates in a timely fashion, the financial return realized by shareholders of the *unbundled* utility declines about three times further than the return realized by shareholders in the *integrated* utility. This is because the unbundled utility is far more dependent on purchased power than is the integrated utility. A second reason is that the unbundled utility's equity base is one-fourth the size of that of the integrated utility, so adverse events have a much bigger impact on ROE. This shows that *unbundled* utilities can be significantly more risky than *integrated* utilities.

For the *integrated utility*, as shown in Table B, the cost of *fuel* is \$225 million, with a 10 percent increase of \$22.5 million resulting in a total of \$247.5 million. The cost of *purchased power* is \$25 million, with a 10 percent increase of \$2.5 million resulting in a total of \$27.5 million. Thus, a 10 percent increase in both wholesale power and fuel results in a total increase of \$25 million and a final combined cost of \$275 million ( $[\$225\text{M} + \$22.5\text{M}] + [\$25\text{M} + \$2.5\text{M}]$ ).

The change in cost must come out of the shareholders' equity return, since debt holders have a superior claim on earnings. So *equity return* declines by \$25 million, from \$200 million in the *base case*, to \$175 million in the *10 percent energy price increase case*. In percentage terms, the return on equity declines from 10 percent in the base case (\$200 million/shareholders' equity of \$2 billion<sup>7</sup>) to 8.75 percent (\$175M/\$2B), a *12.5 percent decline in equity return*.

For the *unbundled utility*, the cost of purchased power also increases 10 percent. For illustration, it is assumed that the unbundled utility *hedged* \$720 million of its purchased power expense under long-term purchase contracts, so the 10 percent price increase applies only to the *unhedged* portion, or \$180 million, of its purchased power expense. The 10 percent increase from \$180 million is \$18 million, for a total of \$198 million.

Again, increased operating costs are borne entirely by shareholders, since bondholders have a superior claim on earnings. As a result, the shareholders' return declines by \$18 million, from \$50 million in the *base case*, to \$32 million in the *10 percent energy price increase case*. In percentage terms, the *return on equity* declines from 10 percent in the base case (\$50 million/shareholders' equity of \$500 million<sup>8</sup>) to 6.4 percent (\$32M/\$500M), a *36 percent decline in equity return*.

Notice how much more severe the decline in shareholder return is for shareholders in the unbundled utility: 36 percent versus 12.5 percent. The impact on the unbundled utility is almost three times greater. Clearly, the unbundled utility is riskier than the integrated utility when it bears the price volatility risk of the market. There are two basic reasons for this.

First, the unbundled utility is far more dependent on purchased power than is the integrated utility. The risks discussed in this section (including price risk and related regulatory risk) are a function of wholesale purchases, so it stands to reason the unbundled utility is more exposed to these sources of risk than is the

<sup>7</sup> The rate base of the integrated utility is \$4 billion, which is funded half by equity.

<sup>8</sup> The rate base of the unbundled utility is \$1 billion, which is funded half by equity.

integrated utility. For the unbundled utility, power purchases can be almost as large as its rate base and have no associated rate base component because the recovery is a cost pass through. One might argue that the unbundled utility should have hedged the entire portfolio, not just the \$720 million. Such hedging, however, introduces another large risk, namely, that the market price falls and the regulators impose a penalty on the utility for imprudent purchases. In either case, the potential equity impact is large under a fixed-price SOLR obligation.

Second, the unbundled utility's equity base (shareholder capital) is significantly smaller than that of the integrated utility (\$500 million vs. \$2 billion), so a given reduction in net income has a much bigger impact on the unbundled utility in terms of reductions in ROE, than on the integrated utility. A relatively small disallowance of purchased power costs can have a huge impact on earnings and ROE.

It was assumed that no fuel adjustment mechanism was available to the integrated utility, so it had to absorb a 10 percent risk in fuel prices. Of course, such mechanisms are frequently in use. Had a fuel mechanism been assumed, the discrepancy in impact on equity return would have been even greater, with the unbundled utility appearing even more risky than the integrated utility. Unbundled utilities may also have fuel adjustment clauses. However, the existence of a fuel clause for competitive utilities creates both market risk and stranded cost risk, and while it may resolve short-term market fluctuations, it will also create larger, long-term issues of cost recovery.

It also is worth mentioning that there is a fundamental asymmetry in the unbundled utility's risk exposure that is not experienced by the integrated utility. The unbundled utility bears large risks related to purchased power transactions, but typically makes *nothing* on them; it simply passes procured power costs along to customers. Integrated utilities, on the other hand, serve customers from supply resources that are mostly in rate base, on which they earn an allowed return.

Finally, wholesale counterparty risk (i.e., the potential for financial loss due to nonperformance by parties with whom the utility has a wholesale supply relationship) probably has increased for both integrated and unbundled utilities. This is due to the rise in natural gas prices in recent years, which has left many merchant generating companies in a weakened (less creditworthy) financial position. Again, since unbundled utilities are far more dependent on purchases than integrated companies, they tend to be more exposed to counterparty risks.

#### **D. Risks Related to New Delivery Infrastructure**

Cost increases for new delivery infrastructure, either at the transmission or distribution level, also can produce variation in utility earnings and shareholder return. The size of the financial impact can be much greater for unbundled utilities than for traditional, vertically integrated utilities. This is a new risk factor to the extent that the sources and scale of new delivery cost increases are unprecedented.

At the transmission level, significant costs are being incurred to build new infrastructure to support the operation of restructured transmission systems. These costs tend to be associated with the development of new data processing systems (hardware, software, and personnel).<sup>9</sup> Of course, there also is the potential for

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<sup>9</sup> Concerns about the lack of efficiency incentives for RTOs/ISOs, and about the lack of adequate financial oversight by participants in RTOs/ISOs, are raised in EEI comments in FERC Docket No. RM04-12-000, Financial Reporting and Cost Recovery Practices for Regional Transmission Organizations and Independent System Operators, November 9, 2004.

new transmission lines to be built, if a host of siting and other issues can be resolved. RTOs allocate new costs to transmission customers (e.g., regulated utilities), who must then recover them in retail rates. However, if a state has implemented a rate freeze, any increase in transmission-related revenue requirements may be difficult to implement in retail rates, at least not before the freeze expires. (The Federal Energy Regulatory Commission has jurisdiction over transmission revenue requirements, but states have jurisdiction over retail rate designs.) Even without an explicit freeze, timely recovery may be difficult if the state uses an historic test year. Furthermore, states may seek to offset transmission revenue increases with decreases in other legitimate revenues. Table C illustrates the differential impact of a \$10 million increase in RTO operating costs. Assuming these costs are not immediately flowed into retail rates, they will come out of shareholder returns.

Briefly, in a scenario in which the utility's share of RTO costs increases \$10 million, and in which these costs cannot be flowed timely into retail rates in a timely manner, the financial return realized by shareholders of the *unbundled* utility declines about four times more than returns realized by shareholders of the *integrated* utility. This is because the unbundled utility's equity base is one-fourth the size of that of the integrated utility, so the \$10 million hit has a bigger impact on an unbundled utility's equity return. This shows, again, that unbundled utilities can be significantly more risky than integrated utilities.

For the *integrated* utility, this scenario means a reduction in return on equity from 10 percent to 9.5 percent, or a 5 percent decrease in return on equity. For the *unbundled* utility, it means a reduction from 10 percent to 8 percent, or a 20 percent decrease in return on equity. As before, the impact on the unbundled utility is four times greater, because its equity base is four times smaller.

**Table C: Impact of a \$10 Million Increase in RTO Costs**

	Integrated Utility		Unbundled Utility	
	Base Case	\$10 M RTO Increase Case	Base Case	\$10 M RTO Increase Case
RTO costs		\$10 million more		\$10 million more
Equity return	\$200 million	\$190 million	\$50 million	\$40 million
Allowed/earned ROE	10 %	9.5 % (5% decline)	10%	8% (20% decline)

At the distribution level, cost increases are being driven by the need for new facilities to replace aging infrastructure, support demand response, enhance power quality, and support the digital economy, or to serve new customers. Taken together, the scale of the investment required may be unprecedented. As with transmission costs, rate freezes and/or use of an historic test year can impede timely recovery and produce negative financial shareholder impacts.

Briefly, in a scenario in which a \$75 million capital investment in the distribution system is needed, there is no effect on the *integrated* utility's ROE, but there is a 42-basis-point decline in the *unbundled* utility's ROE. This is because the integrated utility's rate base is four times the size of that of the unbundled utility, so it can fund the new investment out of annual depreciation expense. The unbundled utility cannot do so and

must sell new debt, the service of which reduces returns to shareholders. Again, unbundled utilities can be more risky than integrated utilities.

Table D illustrates the differential impact of a required \$75 million investment to rebuild distribution facilities to maintain reliability. This example deals with long-lived assets, as opposed to annual operating expenses in the previous RTO example, so depreciation expense becomes relevant. (Depreciation expense is the amount by which an asset is depreciated each year. It does not affect cash flow, but it does reduce taxable income.) The *integrated* utility, with a rate base of \$4 billion, has an annual depreciation expense of \$160 million (\$4 billion/25-year asset life). The *unbundled* utility, with a rate base of \$1 billion, has an annual depreciation expense of only \$40 million (\$1 billion/25-year asset life).

The *integrated* utility can fund the \$75 million from depreciation expense, so no net new rate base is required and the impact on earnings is negligible. The *unbundled* utility, however, cannot do this, because \$75 million is substantially more than its annual \$40 million depreciation expense. So, either the unbundled utility uses \$35 million in current earnings to pay for the rebuilding, or it sells new debt for this purpose. It is assumed the unbundled utility sells additional debt.

**Table D: \$75 Million Distribution Investment**

	Integrated Utility		Unbundled Utility	
	Base Case	\$75 Million Distribution	Base Case	\$75 Million Distribution
Rate base	\$4.0 billion		\$1.0 billion	
Annual depreciation	\$160 million		\$40 million	
Debt	\$120 million		\$30 million	\$ 65 million
Cost of new debt at 6%				\$2.1 million
Equity return	\$200 million	\$200 million	\$50 million	\$47.9 million
Allowed/earned ROE	10%		10%	9.58% (4.2% decline)

The bottom line is that for the *integrated* utility, the same \$75 million infrastructure replacement event has no effect on shareholder returns since it can be paid for out of annual depreciation. However, for the *unbundled* utility, the cost of new debt must be paid for out of equity returns, so shareholder returns *are reduced by 4.2 percent, from 10 percent to 9.58 percent.*

## E. Risks Related to Provider of Last Resort Supply Obligations

Retail access can create significant new risks for utilities which have divested their own supply resources, but must nevertheless stand ready to supply those customers not served by the market. Such supply obligations are known generically as provider of last resort, or POLR, supply obligations.<sup>10</sup> In addition to price risk, described above, POLR obligations can create more material risks for utility shareholders.

The most important of these is probably volume risk, or energy imbalance risk. This is the risk that the utility will suffer a financial loss because it purchases too much, or too little, power to serve retail customers. Volume risk increases as customers shift from regulated supply to the market, and back to the utility. Such customer shifting increases the variability of POLR loads and makes it harder for utilities to know how much energy to procure.

Briefly, in a scenario in which POLR load drops 20 percent, the *unbundled* utility's equity return declines 288 basis points. This is because the utility realizes a loss when it sells power it bought via a long-term contract that it no longer needs. The *integrated* utility is not involved in this scenario, because POLR supply obligations are associated with retail access markets in which the integrated incumbents typically have divested their generation.

Table E describes the impact on shareholder return of a scenario in which the spot market price of electricity falls 10 percent, prompting customers to leave POLR service and shift to the market because they can get a better price. It is assumed that the utility's POLR load declines by 20 percent as a result. To meet this reduced load, the utility continues to buy \$720 million worth of power pursuant to its multiyear supply contract, which is now above the spot market price, and another \$130 million worth of power in the spot market.

**Table E: Volume Risk—Market Price Decrease**

	Integrated Utility		Unbundled Utility	
	Base Case	20% POLR Load Decline	Base Case	20% POLR Load Decline
Purchased power	\$ 25 million		Hedged \$720 million	Resale \$129.6 million with a \$14.4 million loss
			Unhedged \$180M	Unhedged \$130 million
Total purchased power			\$900 million	\$720.4 million
Equity return	\$200 million		\$50 million	\$35.6 million
Allowed/earned ROE	10%		10%	7.12% (28.8% decline)

<sup>10</sup> In some jurisdictions this is called default service, basic generation service, etc.

The *unbundled* utility must continue buying in the spot market because its load varies throughout the day. If it didn't, the utility's multiyear contract, which represents 80 percent of its supply in the base case, would exactly meet its needs. However, the utility's load is not constant, but varies throughout the day: there are hours in which it is greater than 80 percent of the base case, and hours in which it is less. Therefore, to meet its peak load, the unbundled utility must buy \$130 million worth of power in the spot market.

It is assumed that the 20 percent reduction in load translates equally into a 20 percent reduction in the need for power purchased via the multiyear contract, and a 20 percent reduction in the need for power purchased in the spot market. So, of the \$720 million incurred to buy hedged power, 20 percent, or \$144 million worth, is not used and must be resold in the spot market. This power is sold at a loss, since the spot market price is now 10 percent lower than the price the utility paid under its multiyear contract. As a result, the utility resells its unused power for  $(\$144M \times 0.9M =)$  \$129.6 million, realizing a loss of  $(\$144M - \$129.6M =)$  \$14.4 million. Return on equity declines accordingly, from  $(\$50M/\$500M = 10\%)$  in the base case, to  $(\$50M - 14.4M)/\$500M =)$  7.12 percent.

This example illustrates how a relatively small change in spot market price can produce a large swing in ROE. As noted in Section C, the *unbundled* utility can experience much larger variation in equity return (i.e., is more risky) than an *integrated* utility, because it is far more dependent on procured power and has a smaller equity base than an integrated utility.

Of course, spot market prices can move in the other direction as well. Table F illustrates a scenario in which spot prices rise above the rate for POLR service. In this case, it is assumed that the spot market price rises 5% above the utility's POLR rate, and that the POLR load grows 2%, because customers switch back to POLR service to get a better price.

**Table F: Volume Risk—Market Price Increase**

	Integrated Utility		Unbundled Utility	
	Base Case	2% POLR Load, 5% Cost Increase	Base Case	2% POLR Load, 5% Cost Increase
Purchased power	\$ 25 million		Hedged \$720m	\$720 million
			Unhedged \$180m	\$207.9 million
Total purchased power			\$900 million	\$927.9 million
Equity return	\$200 million		\$50 million	\$22.1million
Allowed/earned ROE	10%		10%	4.4% (55.8% decline)

As customers shift back to POLR, the utility must buy additional supply in the spot market, at prices that now exceed the approved POLR rate. The utility needs a total supply of  $(\$900M \times 1.02M =)$  \$918 million at the old (base case) price. Of this amount, \$720 million worth is available from the multiyear supply contract. This leaves  $(\$918M - \$720M =)$  \$198 million of new power cost under the base case price that must be

procured in the spot market. This additional power now costs ( $\$198\text{M} \times 1.05\text{M} =$ )  $\$207.9$  million. So total purchased power cost rises to ( $\$720\text{M} + \$207.9\text{M} =$ )  $\$927.9$  million under the new scenario. POLR rates are frozen, so these additional supply costs must come out of shareholder earnings. Return on equity declines from 10 percent in the base case, to 4.4 percent in the new scenario. A very small rise in market prices and POLR load has produced a huge drop in return on equity—at least, unless and until these costs can be recovered.

In addition to volume risk, POLR obligations can create two other risks for utilities. One is credit risk, which is the risk that the utility will suffer a financial loss because its customers don't pay their bills. Credit risk can increase in retail access markets because, as solvent customers switch to market-based suppliers, the concentration of "bad debt" customers in POLR loads tends to increase. Moreover, commissions may, in the interest of "jump starting the market," require incumbent utilities to take over bad debt customers from market-based retailers.

The second is retail counterparty risk, which is the risk that the utility will suffer financial loss because market-based retailers (serving end-use consumers) become insolvent and cease operations. The utility may suffer a loss because a supplier fails to deliver power and the utility must go into the market and purchase replacement power under unfavorable terms and conditions. Alternatively, a utility may experience a loss because a retailer fails to reimburse the utility for distribution and/or customer care services that the retailer has purchased on behalf of the customer.

Neither of these two additional risks is illustrated with a numeric example, but they are just as real. Considering all three POLR-related risks together, it is understandable why rating agencies are looking at POLR policies as a key risk driver for unbundled utilities.<sup>11</sup>

## F. Earnings Volatility Due to Social Ratemaking

When retail access is implemented, it becomes increasingly difficult, if not impossible, to administer subsidies, no matter how well intentioned they may be. This is because retail access forces rate unbundling, which allows customers to see what they are paying for various components of electric service. If regulatory policy has led to inter-class return differentials (e.g., where large customers are paying more than the cost of service, and small customers less), this creates another risk for utility shareholders. There are two possible components of this risk.

Briefly, in a scenario in which there are inter-class return differentials in the incumbent's regulated rates, and in which 10 percent of the load in the highest-return customer class (i.e., the large commercial and industrial customer class) shifts to market-based suppliers, the incumbent *unbundled* utility experiences a reduction in realized ROE of 74 basis points. This is because the loss of high-margin customers produces a disproportionate reduction in equity return, and high-margin customers are easy for third-party suppliers to serve at lower cost.

First, there is a class of service that produces a higher than average return for the utility. Marketers are able to attract away these customers, which produces a disproportionate loss of contribution to margin. Consider

<sup>11</sup> See for example, Standard & Poor's Keys to Success for U.S. Electricity Transmission and Distribution Companies, March 11, 2004.

the case where an integrated utility is allowed a 10 percent return overall, but a single class of customers that represents 30 percent of the load provides a 15 percent return. The loss of those customers reduces the return by the percentage of return related to services other than delivery (here assumed to be 75 percent) times the portion of customer that the class represents (here assumed to be 30 percent). This equals a reduction in utility return of 22.5 percent (75 percent x 30 percent). This also assumes that return is uniform for delivery and production services. Of course, if the utility can resell the power, it can mitigate the impact of a 22.5 percent reduction in earnings as long as the regulatory climate allows those returns to be credited to the shareholders. In many cases, off-system sales have no impact on return and/or are in part shared with ratepayers.

Second, this same result may occur even if the rate classes all produce the system average return. In this case, customers within a class with the more profitable load profile will be attracted away. The same analysis as discussed above applies and the utility's return will decline. Thus, cherry-picking opportunities that result from subsidies that are sustainable only under complete regulation cannot be sustained in the open market. The existence of those subsidies in an unbundled market with integrated utility service cause added earnings volatility.

The risks described in this section are associated with both bundled and unbundled utilities under certain assumptions regarding regulatory treatments. The examples illustrate that risks may vary materially for utilities operating in restructured markets, and underscore the assertion (above) that utility risk must be assessed on a utility-specific basis.

## SECTION II: THE INFLUENCE OF NEW RISKS ON THE COST OF CAPITAL

Traditional cost of capital estimation methods can only partly reflect the new risk profiles and risk-related costs of the utility industry. The industry changes and related risk factors described in the previous section suggest a variety of issues pertinent to the adequacy of traditional approaches to determining the cost of capital to enable utilities to actually earn adequate returns on equity.

### **A. Loss of Peer Group Relevance**

Traditional approaches to the cost of capital rely on comparisons of one utility's risk profile and earned returns to an aggregate group of "comparable" or "peer" utilities. The discounted cash flow (DCF) method, capital asset pricing model (CAPM), or comparable earnings models use a set of comparable companies to develop the estimate of a market-based equity return. However, many utilities no longer derive their earned returns solely from the regulated utility business. Financial market data drawn from such "peer" utilities reflect the earnings of the total, consolidated enterprise, and not necessarily of the "pure play" utility subsidiary.

Added to the complexity are differing legislative and regulatory mandates and policies in various states, which result in differences in earnings volatility of each peer utility. Many regulatory policy factors distinguish the risk profiles of individual utilities within a group of peers that would otherwise appear homogenous. Examples include differences in the levels of fixed cost recovery within the fixed components of the rate structure, line extension policies, test period assumptions, regulatory lag, use of hypothetical vs. actual capital structures, and POLR/SOLR obligations. These other factors have a direct effect on the utility's real financial and operating risk profile, its income volatility and, perhaps most important, its ability to actually earn its allowed return. Traditional cost of capital approaches rarely, if ever, take these factors into account.

### **B. Asymmetric Risks**

Any determination of the cost of capital must also address counterparty and other asymmetric risks identified in Section I. Further, the evaluation of asymmetric risks requires a detailed analysis of the individual utility and the legislative and regulatory policies applicable to the utility. Many institutional investors who are focused on steady returns, dividend growth, and the preservation of capital are very much concerned about avoiding "downside" risks, and are willing to give up the "upside" potential.

Traditional cost of capital theory does not address asymmetric risks. Worse, aggregated peer group analysis, without a deep analysis of regulatory practices, can easily mask risk asymmetry. Importantly, the basic premise of cost-based regulation and the ability of regulatory agencies to initiate rate cases causes the asymmetry to destroy, rather than enhance, shareholder value.

### **C. Capital Market Risks**

For many years, utilities' use of capital markets has been primarily to refinance debt, and occasionally capital expansion, because few utilities faced the need to build new production or transmission capacity, or expand the distribution system. As a result, they benefited from financial flexibility since their capital requirements were largely discretionary. However, changes in load and the need to reinforce infrastructure are requiring utilities to turn to capital markets to finance system expansion. As the need for capital has increased, utilities face a new challenge related to liquidity in energy markets as well as the perception of changing credit risk. Since 2002, the number of downgrades in power sector debt has far exceeded the number of upgrades, although recently the rate of downgrades began slowing.

Access to capital markets at a reasonable cost is a critical component for investing in the utility infrastructure required to maintain safe, reliable, utility service. The cost of capital includes both debt and equity costs. Further, there is a direct relationship between the cost of equity capital and the portion of debt in the capital structure. The existence of leverage increases the cost of equity.<sup>12</sup> Where retained earnings are insufficient to maintain the debt equity ratio, new equity issues may be required. If the allowed return is less than the market requires, issuing equity dilutes the value for current shareholders. It is difficult to support an equity issue in that event. As a result, the cost of both debt and equity is likely to rise as the debt-to-equity ratio increases. When coupled with the competitive market for new capital to fund the growth in infrastructure replacement, inadequate returns in the short run will significantly increase the long-run cost of replacing existing facilities and refinancing debt.

There is no question that utilities must compete for new debt, not only among themselves but also with the growing investment in other markets worldwide. Maintaining investment grade bond ratings in the "A" range is critical to financial flexibility. At this level, utilities have broader access to capital and can finance debt at lower interest rates because of the stronger financial position. Since many utilities are currently rated below the "A" level, it will be necessary to allow higher equity returns over a long period to restore the credit needed to efficiently replace the existing infrastructure and to expand capacity where the utility must own and construct new generation.

### **D. Commodity Risks**

The liquidity or lack of liquidity of the wholesale markets for power and for financial hedging products is another new source of risk. To the extent that markets are not liquid, the risk associated with fixed price, physical or financial contracts increases. This risk is borne directly by the party, usually the utility, required to provide a fixed price product to the market. As discussed more fully below, there are opportunities to mitigate the risk to the utility. However, there is no way to mitigate this risk for the consumers of the fixed price product.

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<sup>12</sup> See, for example, Kolbe, Read, and Hall, *The Cost of Capital*, pp. 16-19.

## SECTION III: POTENTIAL REGULATORY POLICIES TO ESTIMATE, REDUCE, AND CONTROL UTILITY RISKS

### **A. Non-traditional Approaches to Risk Compensation**

Two methods offer a reasonable basis for calculating the level of compensation (in absolute dollar terms) necessary to match risk and reward for specific risks arising from changing conditions:

- Market-based tests
- Rate impact simulation

#### *Market-based Tests*

The use of the cost of market-based insurance instruments to estimate the costs of various risks is an accepted process for certain utility risks, since the cost of insuring against a risk is an acceptable O&M expense for a utility. Thus, if insurance products are available to manage risk, the required compensation is approximately equal to the insurance premium and the risk is mitigated by the purchase of the insurance product. Many insurance companies now offer, or will develop on a tailored basis, products that insure against relatively exotic factors such as weather and liability-specific litigation risk, or more mundane, everyday matters, such as errors and omissions, and directors and officers liability insurance. Typically, these products are offered where the risk is either known through significant experience, or is susceptible to analysis by business, subject matter, and underwriting experts.

The cost of insurance, that is, the premium, would ordinarily be considered as a regular cost of doing business. The utility should be indifferent between: (a) a revenue requirement that permits the inclusion of such an equity risk premium, and (b) an adjustment that compensates the utility for the risk directly through an upward adjustment to its return. Similarly, regulators should allow the utility to recover the cost of hedging power supply prices.

Both hedging and insurance provide for risk mitigation on an incomplete basis. Insurance deductibles require the utility to absorb some of the insured loss. Similarly, the hedged product may have some portion of the cost of power where no compensation is paid. Regulators must ensure that these costs are recovered in rates.

#### *Risk Impact Simulation*

Where risks are specific to a utility, and where there is no substantial empirical or experiential risk data, the analyst must rely on financial simulation modeling. The exact form of this kind of analysis varies widely, although Monte Carlo simulation techniques are frequently used. While knowing the distribution of outcomes may be problematic since many events in the utility industry are new, through simulation based on expert knowledge an analyst can estimate the possible range of risks and associated costs that would be incurred under various business, regulatory, and environmental scenarios. In turn, those estimates can become the foundation for fixing an absolute dollar-equity risk premium, or establishing a revenue

requirement add-on that would compensate the utility for the risks not captured through the traditional cost of capital analysis.

## **B. Importance of Customer Choice in Risk Compensation**

The recognition and estimation of risks is the initial step in determining the appropriate strategy for managing them. Ultimately, the process must incorporate the required risk-adjusted return, risk compensation, the cost of risk mitigation, or some combination of all three into the rates paid by consumers. Regardless of the method chosen, utilities incur costs that must be recovered. For example, the use of hedge products to fix energy prices over the long run raises the delivered cost of energy. In return, customers get a stable, albeit slightly higher, price.

In a competitive market, consumers choose the level of price stability that fits their risk preferences and pay for the hedge through the market. Under a regulated rate, the preferences of customers will not be identical. As a result, choosing the optimum hedging strategy under a one-size-fits-all model cannot produce an optimum outcome for all consumers. Risks often suggest regulatory solutions for mitigating them. Where risk mitigation is accomplished through policies and procedures that maintain the integrity of rate regulation and permit broad stakeholder input, utilities and consumers benefit.

Care must be taken, however, that risk mitigation not create new risks or inappropriate incentives for the utility. One consequence of the traditional, adversarial rate-setting process is the tendency to develop win/lose solutions rather than solutions that benefit all parties. As a result, regulators often must choose between conflicting positions that create the possibility for unintended outcomes. These outcomes include the inability to earn the allowed return, excess returns, incentives to game the system at the expense of efficient outcomes, and other suboptimal behavior.

## **C. Regulatory Options for Controlling Utility Risk**

In addition to measuring utility risk and determining fair compensation for investors, policymakers should think about the potential to control the cost of capital by controlling utility risk. Indeed, institutional investors and rating agencies are focusing on regulation as the dominant driver of risk for utilities, and are differentiating among regulatory jurisdictions as never before. By calibrating regulatory policies to control risk, jurisdictions can obtain new capital (e.g., for needed investments in infrastructure) on more reasonable terms and conditions. Since consumers ultimately pay for this, reducing the cost of capital obviously is in the public interest. Among the policies to focus on in this regard are the following.

### Resource Procurement

Timely recovery of costs incurred to supply retail customers probably is the best, most effective way to stabilize utility revenue and earnings, and achieve lower cost of capital. Industry experience since the California market “meltdown” of 2000 and 2001 suggests that there are five keys to providing greater regulatory certainty in this area. They are:

1. **Develop consensus resource strategies**—Recognizing the new uncertainties inherent in resource planning and procurement, utilities and regulators should agree (prospectively) on what the most important resource-related uncertainties (risks) are, and how they are going to manage them.

2. **Understand the implications of risk management**—Utilities and regulators need to understand that risk management cannot be used to minimize cost; it inevitably adds cost. For this reason, customers may want choices about the amount of risk management they pay for.
3. **Provide regulatory commitment**—Once reasonable resource strategies have been identified and agreed to, regulators should honor the recovery of associated costs in rates. The reasonableness of resource strategies, including hedging strategies, should not be subject to after-the-fact prudence review.
4. **Institutionalize regular communications**—Utilities should communicate regularly with regulatory staff. Regular meetings (e.g., regularly scheduled progress reports) can help regulators keep abreast of market developments and avoid surprises.
5. **Support new construction** – To be sustainable over the long term, new regulatory planning and approval policies must support long-term investments in new generation and other needed infrastructure.

### Provider of Last Resort

POLR-type service, known variously as supplier of last resort, default, standard offer, basic generation, and provider of last resort service, represents a call option for customers that can create huge risks for utilities and their investors. Policies that reduce the risk incurred by utilities in providing POLR service include:

- Continuation of stranded cost payments for customers who leave regulated service;
- Minimum stay requirements for customers who come back to regulated service after having gone to the market; and
- Flow through of spot wholesale prices to customers who come back to regulated service.

While these are important for all customers, they are especially important for larger customers or smaller customers if the number of customers is large.

### Counterparty Risk

Policies that shift risk from third parties to incumbent utilities also increase the utility's overall risk profile. To ensure that this does not happen, policymakers should examine policies in the following areas, where applicable:

- **Creditworthiness standards** that suppliers must meet in order to be eligible to participate in auctions and other competitive procurement programs. The stronger such standards are, the less utilities will be exposed. A related issue is the imputation by rating agencies of additional debt into the utility's capital structure to reflect the risk that is transferred to utilities when they enter into long-term power purchase commitments. Recognition of this added risk and the impact on capital structure is required to determine the capital cost of the utility. This imputation of debt has a real impact on the cost of capital and must be taken into consideration in determining allowed rate of return. Where utilities purchase power under these contracts, regulators must either impute additional equity to the traditional capital structure or allow a larger equity base for the utility.
- **Supplier consolidated billing policies**, which make utilities dependent on the performance of third parties to remit revenues. Supplier consolidated billing should not be used on a mandatory basis without providing sufficient credit protection to assure that the utility receives payment for its portion of the customer bill from the third party.

- **Payment-processing policies** that require the utility to buy receivables from third-party marketers. This can shift significant risk to utilities, if third parties lower their own credit standards, knowing they can sell delinquent accounts to the utility. Utilities should be allowed to negotiate such purchases voluntarily, but should not be required to do so.
- **Policies governing the allocation of partial payments** between the utility and a third-party marketer. To the extent marketer charges are satisfied before those of the utility, the effect is to shift risk to the utility.

### Infrastructure

The degree of regulatory support for new spending on needed distribution system improvements is another factor that affects the utility's overall risk profile. Wise, risk-reducing policies in this area may start with revised planning procedures that focus on the distribution system, recognizing that distribution system engineering on a stand-alone basis becomes more important as the system is unbundled. As distribution system needs are identified, new policies should be considered to support spending on approved projects between rate cases. This can be accomplished by indexing distribution revenues to customer growth or other parameters that are correlated with distribution capacity needs. It also can be accomplished with an automatic adjustment mechanism that tracks approved infrastructure projects. To the extent financial incentives are tied to defined parameters of service quality, it is important that such incentives be symmetric by having an upside that balances the downside. Asymmetric incentives such as penalties-only approaches increase utility risk. Other issues, such as depreciation rates that reflect the economic life of the assets, are equally important in assuring adequate investment in infrastructure.

### Automatic Adjustment Clauses

The most common risk mitigation measures are automatic adjustment clauses, which offer a means to mitigate the price volatility from wholesale markets and fuel prices. An appropriate fuel clause requires regulatory review of the strategy underlying the provision of energy to be recovered. Prior to implementation, automatic adjustment clauses undergo regulatory scrutiny and modification based on stakeholder input. As long as the utility follows the provisions of the plan, it is assured full cost recovery. If the utility deviates from the plan, recovery is not guaranteed. Where the utility produces lower costs for consumers, in many cases the utility is rewarded with a predetermined share of the benefits produced.

Utilities can use adjustment clauses to mitigate the price risk from more than just fuel and energy. They are useful wherever the level of cost associated with a service or program is beyond the control of the utility and inherently uncertain, or the evidence points to the likelihood of asymmetric outcomes. They may be appropriate for uncollectible accounts expense, conservation program costs, and other specific risk factors for a utility.

*Formula and Special Purpose Rates*

In addition to the mitigation provided by adjustment clauses, formula rates, special purpose rate options, and other rate mechanisms limit risk. For example, a rate mechanism that can adjust retail rates based on the level and cost of infrastructure replacement investments enables a utility to upgrade transmission and distribution and recover those costs more quickly. Through a collective process, regulation offers a variety of options for mitigating risk as opposed to determining the return requirement needed to compensate for the unique risk elements.



## SECTION IV: CONCLUSIONS

1. ***Policymakers should not assume that restructured utilities are less risky than the traditional utilities that preceded them.*** Some advocates argue that all the risk in the utility business is in the generation segment, and that utilities that have divested their generating assets are less risky than they were before. As this discussion demonstrates, the truth is more complicated than that. Utilities that have divested all, or much, of their own generation usually retain a POLAR-type supply obligation. This puts them in the position of having to procure resources at wholesale in markets where prices can fluctuate wildly, to serve loads that also can fluctuate wildly. Such utilities are still in the generation business; they just have much less control over costs than they used to. Moreover, all utilities can be exposed to new risks at the wholesale level. Many have increased their dependence on purchased resources, and may be exposed to counterparty risks. They also may be procuring transmission services from newly formed RTOs or ISOs, whose costs may be rising well ahead of approved retail tariffs.
  
2. ***Utility risk should be evaluated on a company-specific basis, using analytic frameworks that consider possible exposures to new risks in restructured wholesale and retail markets.*** That is not to say that every utility is riskier, but rather that every utility's risk profile needs to be evaluated objectively in relation to the new risks, and that such evaluation needs to be done without reference to comparison groups. Restructuring has *increased* the differences among electric utilities, so analyses based on groups of "like utilities" are increasingly unreliable. The risk profile of each utility must be evaluated on its own, based on exposure to the new risks in restructured wholesale and retail markets. These risks can include:
  - **Competitive wholesale markets**—Exposure to volatile wholesale energy prices. These prices fluctuate far more than they used to when they were cost-based. As a result, there can be huge uncertainties about the optimal timing of purchases (e.g., decisions to buy today, next week, next month; one year out, five years out, 10 years out). Another exposure can be to nonperformance by third-party suppliers, forcing utilities back into the market (to replace supplies) at times when prices are very high.
  - **Delivery infrastructure**—Exposure to rising transmission costs, which may not be recovered in a timely manner in retail rates. Transmission costs may be rising because RTOs/ISOs are building new hardware/software systems, and hiring new personnel, to operate restructured transmission systems. Transmission costs also may be rising to reflect congestion on the transmission system. At the retail level, utilities also may be exposed to increased costs, which may not be recovered in a timely manner in retail rates. Distribution costs may be rising because utilities are making needed investments to serve new customers, improve reliability, or for other reasons.
  - **Retail competition**—Exposure to earnings erosion as customers leave the utility and take service from third-party suppliers. The potential for such erosion is larger if distribution costs are recovered through volumetric (kWh) rates, and if there are inter-class rate of return differentials. An example is if the return realized from commercial customers is larger than from residential customers. In this event, commercial customers have an added incentive to leave the utility. Another retail exposure can be to an increase in uncollectible accounts, perhaps because the utility is required to buy uncollectibles from marketers.

- **Provider of last resort**—Continued service obligations in the context of customer choice expose utilities to wholesale energy price volatility, and retail load volatility due to customers' ability to leave with little or no notice. These risks are compounded by the potential for after-the-fact cost disallowances and/or rate freezes that limit recovery.
  - **Customer service policy**—Exposure to earnings erosion due to the introduction of asymmetric (penalties-only) service quality incentives. Another exposure can result from a failure to update policies regarding service deposits. For example, if the size of the required service deposit was established many decades ago (when energy rates were much lower), it is likely the utility will be forced to absorb losses when customers are in default, because the value of the energy consumed exceeds the value of the deposit.
3. **Controlling utility risk can control utility cost of capital.** Cost of capital is a function of risk: capital markets determine the price of investor capital (i.e., the required return on stocks and bonds) based on the riskiness of a borrower in relation to other would-be borrowers. The lower the risk, the lower the market-determined cost. Since investors see regulation as the dominant risk driver for regulated electric utilities, it follows that by calibrating regulatory policies to manage the utility's risk exposure, cost of capital can be managed. Policymakers who pursue this path should consider the following kinds of policies:
- **Resource procurement**—The timely recovery of costs incurred to supply retail customers probably is the best, most effective way to stabilize utility revenue and earnings, and achieve a lower cost of capital. The goal should be to minimize total risk, not shift risk to customers or shareholders. To do this, utilities and regulators must work together to identify key resource-related uncertainties (risks), and to decide how best to manage them. This needs to be done prospectively, before costs are incurred. Once resource strategies are agreed to, regulators should honor costs incurred. The reasonableness of resource strategies, including hedging strategies, should not be subject to after-the-fact prudence reviews.
  - **Provider of last resort**—Regulated supply service can be provided in the context of retail choice in ways that do not shift large uncompensated risks to incumbent utilities. The key is to reduce utility exposure to opportunistic behavior by large customers, who will tend to go to the market when prices are low, and come back to regulated service when market prices are high. This can be done by requiring exit fees for large customers who leave regulated service, and by imposing minimum stay requirements on large customers seeking to return from the market to regulated rates.
  - **Counterparty risk**—To prevent third parties from shifting risk to incumbent utilities through financial relationships, policies are needed to establish adequate creditworthiness standards for parties seeking to bid on utility procurements. Other policies are needed to avoid mandatory consolidated supplier billing (i.e., where a third party processes customer bills and remits funds to the utility), and to allocate partial payments to satisfy utility claims first, before they are allocated to satisfy third-party claims.
  - **Infrastructure**—Policies that ensure the timely recovery of costs incurred for needed distribution system improvements also contribute to stable utility revenue and earnings. Utilities with an ongoing need to connect new customers and replace aging facilities need to recover costs between rate cases. Use of a future test year in conjunction with a rate adjustment mechanism to recover costs for approved projects is one approach. Another is to index distribution revenues to defined growth parameters (e.g., new customers, cost escalation).

- **Pension benefits**—Policies that provide for recovery of minimum pension liabilities also will contribute to stable utility revenue and earnings.
- **Rate design**—Rate policies have a direct effect on the stability of utility revenue and earnings (or lack thereof). Rates that recover a substantial portion of distribution facility cost through fixed customer charges, and which rely on adjustment mechanisms to track costs that vary significantly and over which the utility has little or no control (e.g., fuel, uncollectible accounts, and conservation program costs) will reduce the utility’s risk profile.

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701 Pennsylvania Avenue, N.W.  
Washington, D.C. 20004-2696  
202-508-5000  
[www.eei.org](http://www.eei.org)