Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business

Inconsistent regulatory decisions continue to frustrate the establishment of a new ex ante *regulatory equilibrium that will serve to prevent unfair and inefficient* ex post *prudence disallowances. Extreme volatility in gas and power markets will continue to tax the uneasy regulatory status quo until a new equilibrium can be established.*

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I. Introduction

The roller coaster behavior of natural gas prices over the last few years has caused great anxiety for consumers, utilities, and their regulators. Gas prices are high and volatile, and are expected to remain so for the foreseeable future. Aggravating the effect of high gas prices is the fact that the electric utility industry has become increasingly dependent upon gas-fired generation. In most regions of the country, gas-fired electricity generation has become the marginal source of power, meaning that it is a primary determinant of market-based wholesale electricity prices. Gas-fired generation also has increasingly served baseload demand for electricity, affecting both peak and off-peak electricity prices. Thus, higher gas prices mean not only higher gas bills, but also higher electricity bills.

High and volatile gas prices can lead to serious economic injury, particularly for low- and fixed-income households, industries that rely heavily on natural gas for their production, and electricity consumers in

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regions where gas-fired generation is a major determinant of wholesale electricity prices. Under traditional regulatory pricing procedures, the price of retail gas and power corresponds to the utility's cost of service, which means that prudently incurred fuel and purchased power costs are recovered from retail customers. Most states have what is called a fuel adjustment clause which allows the utility to recover the changes in its wholesale gas costs on a periodic basis. Similar mechanisms are in place for the recovery of costs associated with wholesale power transactions.

State commissions have the authority to determine whether a utility will be permitted to recover 100 percent of its fuel and purchased power costs. Depending upon a state's interpretation and application of the prudence standard, regulators can and sometimes do deprive utilities of full recovery of their actual costs on the ground that those costs were not reasonable and reflective of prudent management. However, the standard for imposing such a disallowance is high and expenditures that meet the reasonableness standard in good faith should rarely be disallowed.

In the context of prudence reviews, hedging activities have presented a major challenge. State commissions have had to address difficult questions revolving around (1) whether retail customers want price stability, (2) the kind and degree of hedging that should be executed in order to provide the price stability that consumers want, and (3) how much consumers are willing to pay for the price stability that hedging instruments can provide.

This article suggests a critical need for regulators to establish clear *ex ante* guidelines for utility hedging in deregulated energy markets. It also provides guidance to utilities that, in the absence of clear *ex ante* guidance, must navigate the treacherous waters ahead.

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II. The Road to Regulatory Disequilibrium in Fuel and Power Cost Recovery

For most of the history of the electric industry, power and fuel acquisition was subject to regulatory control through vertically integrated, investor-owned utilities. Those utilities generally received pre-approval of new power plants that, when completed, would generally dictate fuel purchase patterns thereafter. State regulatory commissions would examine fuel purchases as part of those utilities' base rate cases and, if found prudent, the purchases would be passed along to ratepayers in the form of base utility rates. This is not to say that there was a detailed matching of fuel costs and electric customers' utility bills during this period. Much of the early history of electric utilities was typified by steady advances in the technology of power generation, with larger power plants producing power at lower costs at larger scale.[1] With costs declining, rate cases were not as common in those days as they are today. As such, there was no reason to expect fuel prices to be reflected contemporaneously in electric rates.

The volatility of fuel prices did hit electric utilities from time to time, stretching back to the early Twentieth Century. To deal with such movements and to separate volatile fuel prices from base rates to streamline cost recovery, regulatory commissions adopted fuel adjustment clauses (FACs). For the purpose of passing through fuel costs, such mechanisms worked rather predictably and well. The calls for a general restructuring of the electric utility industry and the creation of markets for generated power came later on.

Under the old electric industry structure, to the extent that utilities purchased power from other utilities, they were more than likely simply to share costs. The new electricity market requires purchasing utilities to pay market prices. Those market prices for

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power, combined with the volatile fuel costs in the also-newly-deregulated gas markets, have overtaxed the traditional pass-through mechanisms. Although the National Association of Regulatory Utility Commissioners (NARUC)[2] and state commissions[3] have initiated investigations and inquiries aimed at developing new tools for dealing with market volatility, no new consensus approach has emerged. Meanwhile, inconsistent decision making among and within regulatory jurisdictions has created significant regulatory risk, with adverse consequences for ratepayers and shareholders alike.

A. The electric industry restructures, then reverses

For U.S. energy markets, the 1970s was a turbulent decade that prompted a re-examination of both the electricity and natural gas industries. The ''triple threat'' to the electric industry (the end of scale economies in generation, inflation, and the OPEC oil embargo) caused electric rates to soar and electric utility finances to crumble.[4] At about the same time, the nation experienced severe shortages of natural gas, prompted mainly by low regulated wellhead prices.

Two legislative initiatives of the 1970s sought to deal with such problems: the Public Utility Regulatory Policies Act (PURPA) for electric utilities and the Natural Gas Policy Act (NGPA) for gas utilities, both enacted in 1978.[5] In the context of the rapidly rising costs for vertically integrated electric utilities, PURPA was designed to augment traditional electric utility generation with more efficiently produced electricity and to provide equitable rates for consumers. Section 210 of PURPA required a public utility to purchase power produced by ''qualifying facilities'' at the utility's avoided cost—that is, the incremental cost that an electric utility would incur for its own generated power. The NGPA raised the wellhead prices of natural gas to achieve a balance between supply and demand in response to the perceived price-induced shortages of interstate shipments of natural gas of the early 1970s.

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While both of these 1970s legislative initiatives foreshadowed greater competition in the supply of electricity and gas, neither was particularly prescient regarding how the two industries would actually look in the Twenty-First Century. Over the past 20 years, the power industry has changed from being almost totally dominated by vertically integrated electric utilities who shared power with each other—if at all—at cost, to having an increasingly large independent wholesale power business. Now, in the electricity business, about one-third of the nation's utilities are out of the energy business altogether—supplying regulated distribution services only. The rest of the industry purchases a high proportion of its electricity at market-based prices—*not at cost*. In gas, the nation's interstate gas pipelines abandoned their traditional ''utility'' status in a complex bargain, prompted by the Federal Energy Regulatory Commission, allowing local gas utilities and other large gas consumers to deal in a highly competitive market both for gas and interstate gas transport services.

Seventeen states and the District of Columbia have implemented retail competition. These states generally involve mature markets and have relatively high retail electricity prices, which have caused customers in those states to favor retail competition. Industry experts view these retail competition programs as initially slow to develop, leading to mixed results in those programs that have proceeded the furthest. A few years ago, Prof. Paul Joskow commented on the slow progress of restructuring around the U.S. by pointing to the common factors faced by ''pioneer states,'' which motivated them to lead the charge into retail competition. In one report Joskow explains that:

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. . . nearly two-dozen states decided to implement wholesale and retail competition reforms, though only about a dozen states have proceeded very far with the restructuring of their electricity industries. These states include five of the six New England states, New York, Pennsylvania, New Jersey and Illinois. Most of these ''pioneer states'' shared many attributes with California: high retail rates, excess generating capacity, expensive nuclear plants and QF contracts, and angry industrial customers.[6]

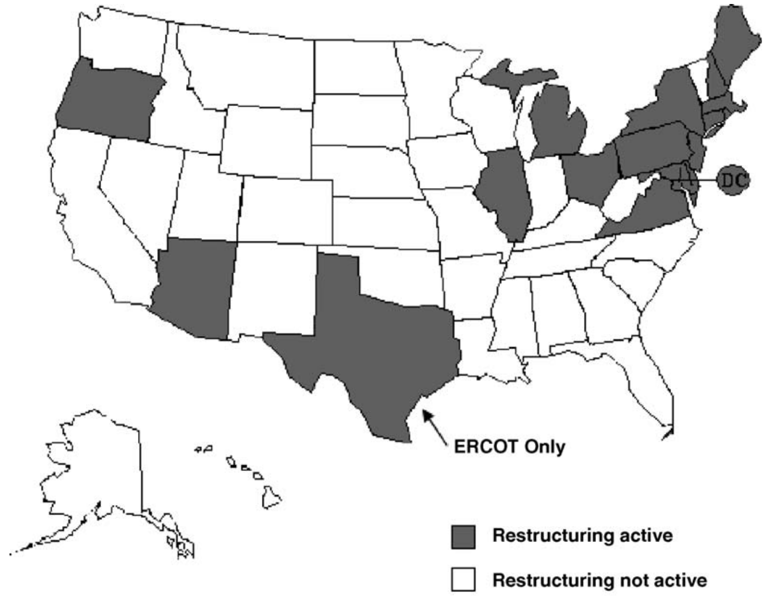

Figure 1: States that Have Active Restructuring

In the minority of states mentioned by Joskow that have undergone the transition to retail competition, actual competition has not always flourished. Although some states have experienced some success, there are many examples where customers have not realized the potential benefits predicted in the early stages of retail restructuring. Recognizing this and the risk of exposing customers to market-based prices, six states have reversed their decisions to introduce retail competition. These include Arkansas, California, Montana, Nevada, New Mexico, and Oklahoma. **Figure 1** illustrates the states that still have active retail restructuring.

Eighteen jurisdictions are actively engaged in retail competition and electric restructuring. California was the first state to offer retail competition on Mar. 31, 1998, but abandoned it on Sept. 20, 2001. Since then, 23 states and the District of Columbia approved plans for retail competition, but six states indefinitely postponed or abandoned those plans.

The eighteen regulatory jurisdictions in the U.S. that currently embrace some degree of retail electricity competition are shown in **Table 1**.

Six states (Arkansas, California, Montana, Nevada, New Mexico, and Oklahoma) reversed or suspended their decision to implement electric retail competition primarily due to the perceived risk or political considerations by elected officials. Original restructuring legislation was approved in the 1996 to 1998 period, but the six states had indefinitely postponed or cancelled plans to introduce retail competition by 2003.

B. The role of fuel and power pass-through clauses in the restructured electricity market

Fuel and power cost pass-through clauses, or power cost adjustments (PCAs) are a standard and longstanding part of U.S. utility ratemaking.[8] In the 1970s, with increasing energy prices, uniform PCAs that allowed for rate changes on a routine schedule became common.[9] PCAs, however, were implemented well before that date in many states. FAC mechanisms, the precursor to PCAs, began to be established in the early 20th century, usually to deal with specific shocks, such as high coal prices following World War I. After the immediate war-related fuel cost increases diminished, state commissions decreased their use of FACs. Inflationary pressures during and immediately following World War II created a renewed need for FACs to be applied during rate cases.

As early as the late 1950s, FACs were found to ''have been incorporated in retail electric rate tariffs in 44 states.''[10] By this period,

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Table 1: Retail Competition/Electric Restructuring States (Tier I States)[7]

State	Retail Competition Implementation	Background
Arizona	Phased in by January 2001, based on ACC rules adopted in 1999	All residential customers have been eligible since Jan. 1, 2001.
Connecticut	July 2000	Full retail competition was phased in over the 1/1/00-to-7/1/00 period, in accordance with HB 5005, which was enacted in 1998.
Delaware	October 2000	In 1999, HB 10 was enacted, requiring retail electric customer choice for customers of POM subsidiary DP&L to be phased in by 10/1/00.
District of Columbia	For non-residential customers, retail competition began January 2001. Pilot program for residential customers began at the same time.	Phasing in retail competition for residential customers by Jan. 1, 2004.
Illinois	For large customers, began October 1999. For small customers, began May 2002.	
Maine	Retail choice for all electric consumers began in March 2000.	
Maryland	July 2000	PUC-approved plans for each IOUs provided for retail competition 2 years before retail legislation.
Massachusetts	Retail competition began in 1998	
Michigan	Direct access was phased in by January 2002	
New Hampshire	Retail access commenced in May 2001 in PSNH's service territory, which encompasses more than two-thirds of the state's electric load.	Legislation enacted in 1996 required implementation of retail choice for all electric customers in 1998, but litigation delayed implementation until May 2001.
New Jersey	In 1999, all customers were given the opportunity to choose an alternative supplier of electric generation.	
New York	Retail access was introduced for all electric customers in 1998.	Pursuant to the PSC's 1996 Competitive Opportunities (Comp Opp) order (C-94-E-0952).
Ohio	Retail access began January 2001 for all customers.	Pursuant to SB 3, enacted in 1999.
Oregon	Retail competition began 3/1/02, for non-residential large energy users.	Residential customers given innovative pricing options.
Pennsylvania	Full retail access was phased in statewide by January 2000.	
Rhode Island	Full retail access commenced in 1998.	
Texas	Phase-in of retail electric competition commenced 1/1/02.	Only ERCOT-member utilities have full retail competition. Status for non-ERCOT utilities in the state varies on a utility-by-utility basis.
Virginia	The SCC has approved plans under which retail access was phased in for all customers of the major IOUs by January 1, 2003.	State law called for retail access to be phased in over the 1/1/02–1/1/04 period, but authorized the SCC to adopt accelerated company-specific schedules.

Source: Regulatory Research Associates, ''Electric Industry Restructuring Update,'' with updates based on RRA's website and state PUC websites.

many FACs were in place, although actual FAC-related rate changes were infrequent. Following the energy crisis of 1972–73, state commissions paid increased attention to FACs. In terms of FAC design issues, the focus of ''at least 29'' states was on uniformity so that all utilities in a state would be able to change their fuel rates.[11]

Modern PCAs, shown in **Figure 2**, following this tradition of their FAC precursors, accommodate timely recovery of certain categories of costs that have three general characteristics: (1) they are large in proportion to a utility's cost of services; (2) they are volatile; and (3) they represent market prices outside of the ability of utility managements to control.

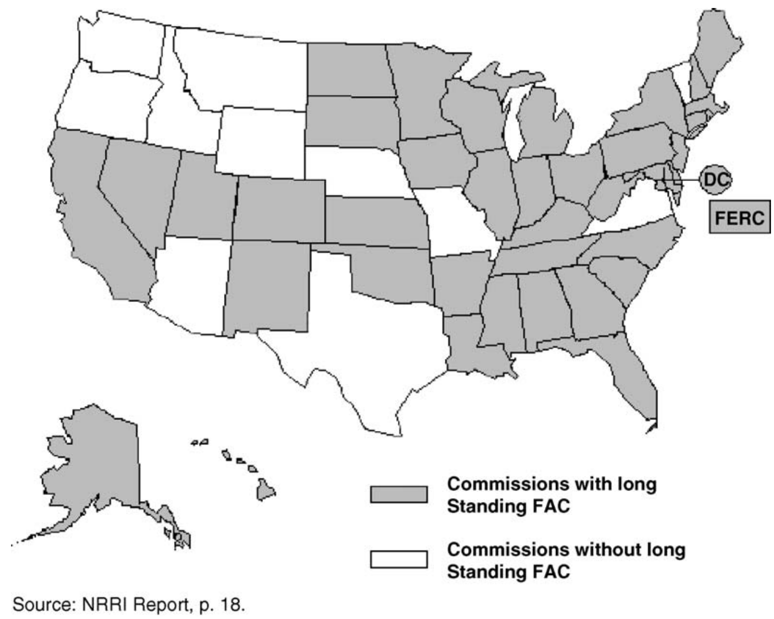

Figure 2: Commissions with Long Standing PCAs

1. Costs are a large component of the cost of service

Fuel and purchased power continue to constitute a large proportion of operating expenses for an electric utility. In its 1991 report, the National Regulatory Research Institute found that ''[w]hile fuel and purchased gas costs are generally down from their peak levels, they still constitute a significant proportion of a utility's operating costs [footnotes not included].''[12] It goes on to state that ''most other variable costs do not represent a significant proportion of a utility's operating costs, and hence, are not candidates for an automatic adjustment clause.''[13]

Fuel and purchased power costs continue to be a significant component of a utility's total operating costs. For all major IOUs in the U.S., the average proportion of fuel and net purchased power relative to total operating expenses ranged from 35.8 to 54.3 percent during the period 1992 to 2003, as shown in **Figure 3**.[14]

2. Cost changes are volatile and unpredictable

Fuel and power acquisition costs continue to be volatile and unpredictable. With wholesale (and, in some states, retail) competition, fuel prices and wholesale power costs can be volatile and

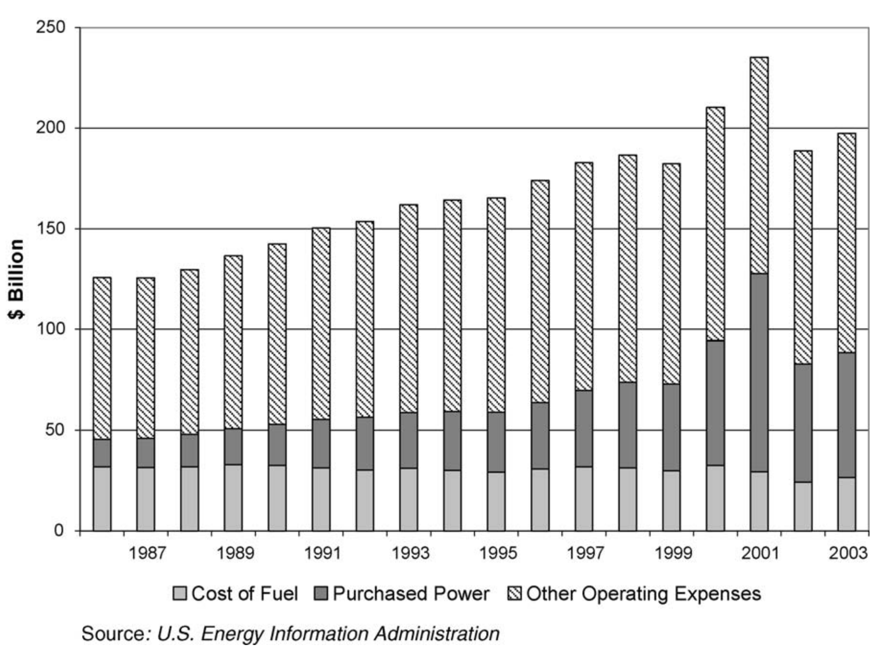

Figure 3: Fuel and Net Purchased Power Costs and Other Operating Expenses for U.S. Investor Owned Utilities, 1986–2003[15]

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unpredictable. Natural gas and wholesale electricity prices can spike based on market conditions. A major thrust of the focus on competition in both gas and power production over the last 15 years is that market-based prices should pass through to retail utility rates, leading, over time, to better resource allocation in the economy as energy consumers confront timely and correct price signals.

State commissions continue to cite the unpredictable nature of fuel and purchased power costs that, if unaccounted for, would leave the utility to bear the burden and financial risk of volatility. The Louisiana Public Service Commission states that the ''Fuel Adjustment Clause mechanism . . . has been established due to the materiality and historical and potential volatility of these costs.''[16] Similarly, the Florida Public Service Commission explains that:

> [A]s a result of the severe price fluctuations in fuel costs experienced during the Organization of Petroleum Exporting Countries (OPEC) oil embargo of 1973–74, the [Florida] PSC established a separate charge for fuel that can be adjusted in proceedings that do not involve base rates. These fuel proceedings were scheduled more frequently than base rate proceedings and a new line item on customer bills was established.[17]

An analysis of energy price index from 1960 to June 2005 illustrates the volatility in energy prices relative to the general Consumer Price Index (CPI) for all items (see **Figure 4**). Energy prices have fluctuated above and below the general price index.

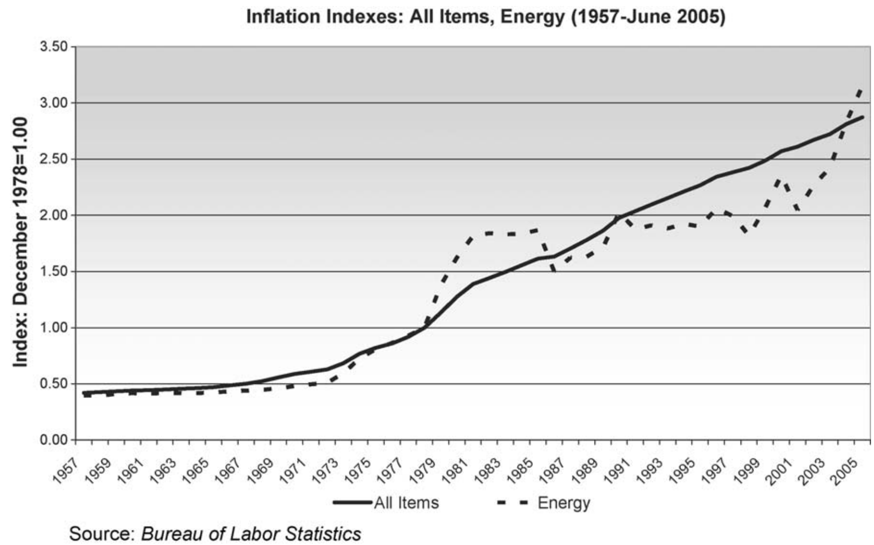

Figure 4: Change in CPI for All Items and Energy (1960–2005)[18]

In Appendix A we further illustrate the volatility of electricity, natural gas and coal prices during the past few years. The recent past has shown that events outside a utility's control (i.e., geopolitical and natural disasters) have increased volatility in purchase power and fuel prices.

3. *Price and need of purchased item outside utility's control*

Utilities procure fuel from markets and do not generally have the ability to control the price set in those markets. The NRRI notes that ''[u]nless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over the cost of the fuel.''[19] Similarly, the price of wholesale power is set in competitive markets. Moreover, the utility does not normally have the ability to control its customers' demand. It must procure the fuel and purchased power that is needed to meet customer demand as part of its obligation to provide safe and adequate service to the public.

The utility, of course, has an obligation to procure its fuel and purchased power from the energy markets in a prudent manner. The NRRI notes that the utility is not ''excused from hard-nosed, tough bargaining'' and goes on to explain that ''state public utility commissions often hold utilities to a standard of care of a prudent business man in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause.''[20]

C. Traditional pass-through mechanisms have not worked well in restructured electricity markets

Under the old electric industry structure, to the extent that utilities

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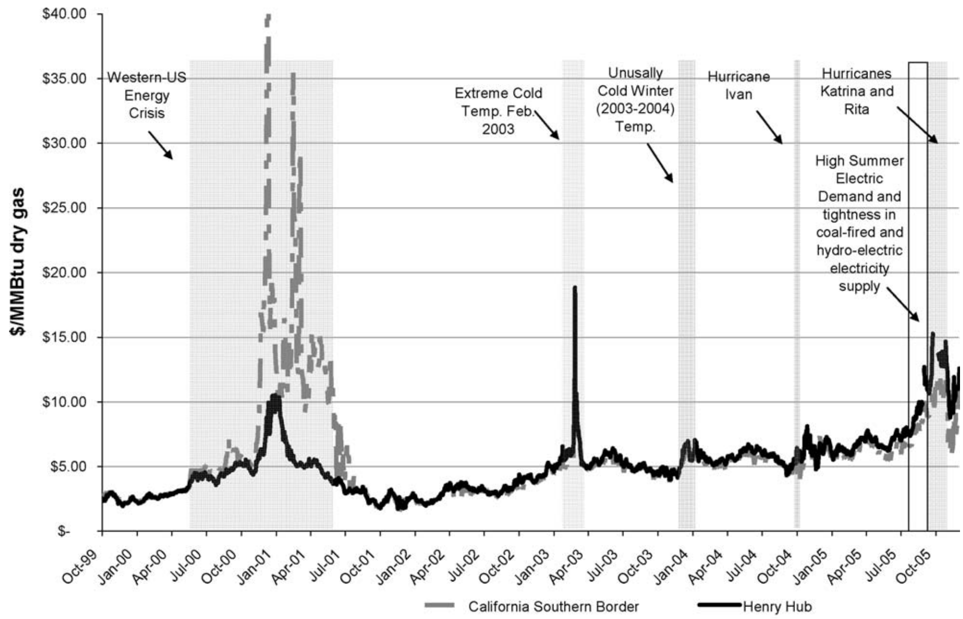


Source: *Natural Gas Intelligence* and *Energy Information Administration* "Natural Gas Weekly"

Figure 5: Henry Hub and California Border Gas Prices, 1999–2005

purchased power from other utilities, they were more than likely simply to share costs. The new electricity market requires purchasing utilities to pay market prices. Those market prices for power, combined with volatile fuel costs in deregulated gas markets, have overtaxed the traditional pass-through mechanisms.

These new markets have shown remarkable fragility to environmental and legal factors. **Figure 5** shows gas prices as the California Southern Border and at Henry Hub from October 1999 through October 2005. Extreme price spikes occurred in connection with the Western U.S. Energy Crisis, changes in weather, and Hurricanes Ivan, Katrina, and Rita.

In response to these events, many regulators have begun to encourage or even require that utilities take affirmative actions to manage market price risks. The most common way this has been done in restructured states is through auctions or RFPs for intermediate provider of last resort (POLR) supply contracts. Frequently these contracts are blended with previously procured contracts with overlapping terms. **Table 2** shows recent competitive procurement of POLR service designed to manage price risks.

The point about these programs is that there is such sufficient analysis and process up front that the later prudence review of fidelity to the planned acquisition strategy can be brief. Without such *ex ante* analysis, fuel and power acquisitions, especially in the context of hedging, create a problem. The often misguided notion that utilities can ''manage'' market risks through hedging activities has changed a basic assumption underlying traditional FACs and PCAs, that utilities do not control the price of purchased power or fuel. Moreover, while the temptation to engage in hindsight review is ever present in rate litigation, it is a particular concern with respect to hedging transactions, for several reasons.

First, hedging, unlike any other purchase that is made by a utility, is *expected* to increase costs. In general, a hedging instrument transfers market risk from the purchaser of the hedge to the seller of the hedge. Counterparties must be compensated when they assume market risk by selling a hedge. The price of the hedge reflects the value of the risk that is transferred from the purchaser of the hedge to the seller of the hedge. In other words, it costs money to transfer risk from ratepayers to counterparties. Regulators have candidly admitted that they do not know how to establish up-front standards for determining the cost-effectiveness of

Table 2: Competitive POLR Procurement Designed to Manage Market Price Risks

State	T&D Utility	Bid Process	Duration of Contracts	Description of Procurement Practices	Sources
CT	CL&P	Auction	1 year	Prices reflect a blend of contracts auctioned off between 2003–05.	CT DPUC Docket No. 03-07-01 RE05
CT	UI	Competitive Wholesale Bidding	2004–2006	UI procured power for the entire transitional period of 2004–06, establishing a frozen rate effective until 2007.	CT DPUC Docket No. 03-07-15
DC	Pepco	RFP	1, 2, 3+ year terms	For residential customers, 40% of SOS supplied by contracts of 3+ years. For Commercial and Industrial customers, 40% of SOS supplied by contracts of 2 years.	Regulatory Research Associates – DC Electric Restructuring Summary
DE	Delmarva	RFP	13, 25, 37 months (in the future, only 36 month contracts)	On 10/11/05, the DE PSC finalized the format for SOS procurement/structure going forward, starting in May 2006. Large C&I classes receive hourly priced SOS from PJM; Residential, Small C&I can receive fixed-price SOS procured via RFP.	Pepco Holding Company RFP Overview; DE PSC Docket 04-391
MA	NSTAR	RFP	Previously: 6 months (Res), 3 months (C&I); Now: 1–3 years (Res).	The price of basic service is intended to reflect the average competitive market price for power. In a 12/30/05 rate case settlement, NSTAR Electric would agree to modify its basic service procurement for residential customers effective 7/1/06, so that 50% of its load would be procured under 1-year contracts, 25% would be procured under 2-year contracts, and 25% of its load under 3-year contracts.	NSTAR 10-Qfrom 11/9/05; Regulatory Research Associates (FN: 12//9/D5: NSTAR)
ME	Central Maine Power & Bangor Hydro	RFP	1–3 years (Res), 6 months (C&I)	Actual prices vary by month, but the Commission designates winning bid for a variety of service territories and classes based on price. Rates are blended from up to 3 POLR providers per service territory, so long as this blending does not increase rates by more than 1.5%. Residential POLR rates are determined similarly, expect the rates are fixed on a per-year basis and reflect a blend of 1- to 3-year contracts.	ME PUB Docket No. 2004-811
NJ	ACE, JCP&L, PSEG, RE	Descending Clock Auction	3 years	''The Board recognizes, that the staggered 3-year rolling procurement process currently in use for the BGS-FP Auction provides a valuable hedge to customers in a time of increasing energy prices.''	NJ BPU Docket No. EO05040317

Table 2: (*Continued*)

State	T&D Utility	Bid Process	Duration of Contracts	Description of Procurement Practices	Sources
OH	First Energy	Descending Clock Auction		Auction results were rejected by the Commission because the auction clearing price did not compare favorably to the rate stabilization price.	Regulatory Research Associates (FN 11/11/05: Columbus Southern Power/Monongahela Power)
OH	MonPower	Competitive Bidding	Jan 2006 Forward	MonPower did not file a Rate Stability Plan for the period after Ohio's market development phase, as encouraged by the PUCO, but instead sought to procure electricity for its service territory by a competitive bidding process. The PUCO then encouraged MonPower to transfer its service territory to another utility willing to institute a RSP. On 11/9/05, the PUCO approved the transfer of MonPower's Ohio service territory to Columbus Southern.	OH PUC Docket 04-1371-EL-ATA
PA	Duquesne	RFP	1/1/2005–5/31/2006	Suppliers were locked in during a 2004 RFP, but prices are updated and approved by the Commission on a quarterly basis.	Duquesne Tariff, p. 103-4
PA	Penn Power	RFP	Jan 2007–May 2008	Penn Power's transition plan ends in 2006, and the company has proposed an interim POLR plan under which it would issue RFPs for full requirements contracts covering the Jan. 1, 2007–May 31, 2008 period.	PA Competition Newsletter – Winter 2005
PA	Allegheny	RFP	2009–2010	Rates are frozen through 2010. An RFP was issued to procure power, but it will not directly impact generation rates for Allegheny customers.	Allegheny Power Investor Newsletter, 11/30/2005
RI	National Grid (Narragansett Electric)	RFP	Varies	Narragansett is required to file a supply plan with the Commission and once this plan is approved, any costs associated with it are recoverable. The SOS rate is set independent from the procurement process.	RIPUC Docket No. 3689, Order 18473

hedges. As the California PUC explained:

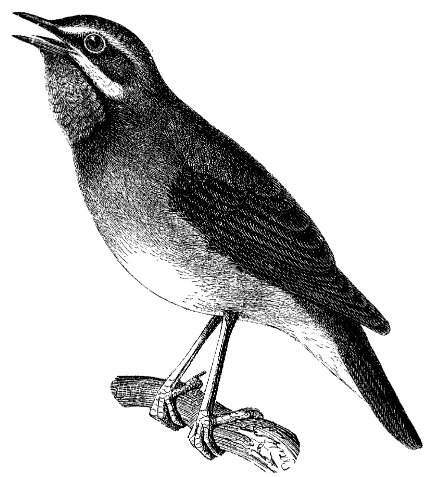
> In some cases, the transactions may be analogous to buying insurance, where a direct comparison between the cost of the insurance and the value of the risk cannot be made. While we prefer to adopt a reasonable up-front standard for cost-effectiveness in the future, we are not convinced that we have enough information to establish this standard or to choose particular models now.[21]

Second, while utilities in many jurisdictions have been encouraged or even required to hedge, regulators have sometimes been unwilling to provide meaningful guidance as to the amount of market exposure that customers can bear and the amount of risk that should be transferred to third parties (for the price of a hedge). Fundamentally, these are policy questions which should be answered by public officeholders. Different customers have different appetites for risk, making it literally impossible for utilities to develop a one-size-fits-all approach that will satisfy all of its stakeholders. As the Massachusetts Department of Telecommunications and Energy has explained, ''[c]ustomers differ in their aversion to price volatility and their 'willingness to pay' for the cost of price volatility management. Some customers may choose to go with the market, not caring about price volatility, while others may be willing to pay a premium to have more stable prices.''[22]

To date, regulators have sometimes been unwilling to provide sufficient *ex ante* guidance on these basic questions.[23] Instead, based upon an assumption that utilities have more expertise than their regulators with respect to hedging,[24] utilities have been instructed to develop their risk management strategies unilaterally, subject only to an after-the-fact prudence review.[25] Even in those jurisdictions where regulators approve a hedging strategy in advance, they have reserved the ability to make prudence disallowances after-the-fact based upon how the utility implemented the strategy, and whether the utility appropriately revised the strategy, after it was approved, in response to changing market conditions. Utilities have been left with insufficient guidance as to the amount of risk to hedge, and the price that should be paid for the hedges.

Third, and most troubling, some stakeholders seem to have the wrong idea that hedging can reduce not only price volatility but also total costs. Commissions have disallowed significant amounts where, with the benefit of hindsight, they have determined that specific types of hedges could have produced lower total costs.[26] This is a fundamental misunderstanding of the purpose of a hedge. As explained above, a hedge is expected to increase, not decrease, costs. While hedging can decrease costs in the event of unforeseen market events, this is not the expected result.

Even where an approved hedging strategy is in place, critics have proposed significant disallowances based upon arguments that the utility should have purchased the hedges on different days, or that it should have purchased different hedging products, or that it should have hedged a different percentage of the physical requirements. Based



upon such arguments, these critics are able to argue that, had their strategies, developed with the benefit of 20/20 hindsight, been adopted, total ratepayer costs would have been lower. Due to the inherently result-oriented nature of these criticisms, utilities have struggled with inconsistent prudence disallowances. Thus, for example, some regulators have concluded that long-term forward contracts place too much risk on ratepayers,[27] while others have concluded that market-based pricing provisions are unacceptable on precisely the same grounds.[28] In the not-distant past, California implemented a regulatory structure that required utilities to rely on the spot markets for purchased power; another jurisdiction, however, rejected a proposed utility strategy that would have purchased economy energy at spot.[29] If a utility executes forward contracts and prices later decline, it could be criticized for not purchasing indexed products; if, on the other hand, a utility elects to rely on the indexed products, and prices go up, it could be criticized for not fixing the price during an earlier period.

Traditional FACs and PCAs may not be well-suited to addressing the complex issues that arise when a utility seeks to recover costs associated with hedging. As the Minnesota Public Utilities Commission stated:

> While the advantages of FACs are understood, their disadvantages have not been carefully examined since their initial adoption. Furthermore, since that time the kinds of costs recovered through the fuel clause have significantly changed. Purchased power costs and the costs associated with the practice of ''hedging,'' for example, are very different from the straightforward fuel costs the fuel clause was originally designed to recover. As the Department notes, these new costs may pose different issues in terms of risk management, price signals, oversight and accountability.[30]

III. Risk: Regulatory, Supply, Price, and Hedges

Hedging supply inputs is increasingly perceived as an integral part of risk management

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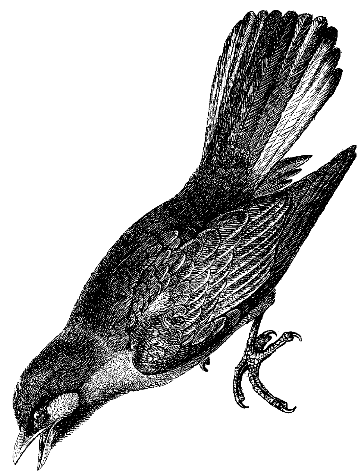
planning, particularly for businesses that rely on large-scale use of energy commodities, because these commodities can exhibit large price volatility.[31] However, the nature of energy risk hedging differs substantially between non-regulated and regulated industries.

In non-regulated activities, firms must be able to continuously respond to competitive pressures. The hedging of input costs can play an important role in the market strategy of a company, while simultaneously protecting shareholder value. The airline industry provides a good example of hedging in an unregulated setting. Since the industry was deregulated in 1978, it has become evident that an airline's profitability and survival ultimately depend on its ability to control costs. Jet fuel is the second-highest cost component (after labor). Even relatively moderate changes in fuel prices can have substantial impacts on a company's earnings. Because jet fuel prices are very volatile, they represent a very tangible source of risk for airlines. Even if fuel costs increase substantially, because of the intensity of competition in the airline industry, companies are not always able to pass on these costs to consumers.

Many airlines have chosen to hedge a large portion of their fuel requirements. Hedging offers a degree of protection, particularly when the objective is to prevent huge swings in operating expenses and profitability. Companies that do not hedge are forced to absorb fuel cost increases, either by lowering their margins or sacrificing sales. In contrast, those airlines that do hedge are often able to navigate around price spikes and even gain market share at the expense of their more risky competitors. They are able to charge low prices when



fuel costs increase, even when others cannot cover their costs at those prices. Lufthansa, Southwest Airlines, and other carriers have managed to integrate fuel hedging into successful business models to dampen fuel-related earnings volatility. Their decision to hedge is largely influenced by their goal of profitability and the need to remain competitive. Thus, they do not forego fuel hedging because the exposure to large price swings can prove devastating, if not fatal, for their business future.

In regulated industries, hedging has a different set of objectives. In particular, it is not primarily geared to protect the shareholders' investment (which is already achieved, in a basic way, by the "regulatory compact") or to respond to competitive forces (which are minimal).[32] In the utility distribution business, input price hedging is used mainly to protect customers from rate volatility. While hedging is an effective tool for reducing price volatility and risk, its expected effect is to increase total costs. A publication from the NRRI states that:

> Hedging, in its purest form, does not provide a means to reduce the expected price of gas for a utility. Rather, from the consumers' perspective its primary function is to stabilize prices. Generally, risk-averse consumers should be expected to pay extra for shouldering less risk, such as exposure to volatile prices.[33]

The Western energy crisis changed the market perception of the importance of price stability for regulated utilities. Since the 2000–01 price spike, many utilities have increased their efforts to achieve stable prices for their customers, and they have received more support from state regulators. For instance, in a 2002 study of gas market prices GAO noted:

> state regulatory officials from 29 of the 48 agencies that we spoke with told us that they consider it very important or extremely important for gas utility companies to work towards achieving stable prices for their residential customers. Before the gas price spike in 2000–2001, only 14 agencies surveyed considered this goal to be very important or extremely important.[34]

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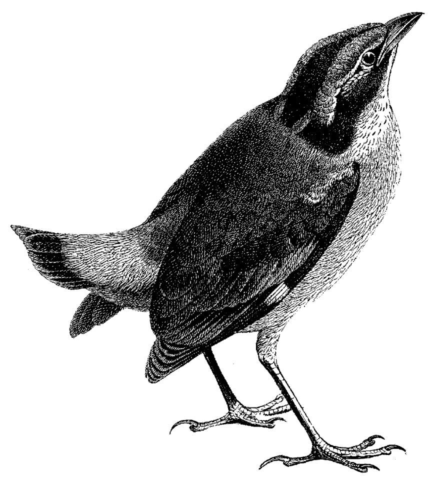
The GAO study also found that gas utility companies have increased their use of hedging. For example, before the Western energy crisis, between 20 and 30 percent of the gas companies surveyed had not planned to hedge any part their gas supply. After the crisis, 90 percent of all the gas utility companies had decided to hedge some portion of their supply needs.[35]

Hedging may cause a utility to lock in a price that turns out to be higher than the prevailing market price for a particular time period. Notwithstanding this potential outcome, the value of hedging is the *ex ante* value of mitigating risk. The NRRI points this out:

> Hedging is one of those activities, similar to the purchasing of insurance, where by design it is expected to result in a net loss to consumers . . . But, in view of the intent to avoid large losses or harm—a ''peace of mind-type'' benefit—hedging with the result of higher prices to consumers or lower profits to a utility can still be regarded as successful and prudent. A proper prudence review would recognize that.[36]

A decision to hedge implies a willingness to pay relatively higher prices over time, in exchange for avoiding the risk of a much larger price increase at single point in time. However, there is no unambiguous economic guide to determine how much ratepayers should be expected to pay for the price stability that hedging can provide. There is a lack of useful data as to the willingness of residential and small commercial customers to pay the costs associated with hedging the fuel component of electricity bills, because such customers generally do not hedge other commodities (like food and gasoline) that they purchase in unregulated markets. In the absence of clear economic principles or at least a consensus among the



utility's stakeholders as to the appropriate degree of hedging, the temptation to second-guess utility decisions, based upon result-oriented, hindsight review, will persist.

IV. A New Regulatory Equilibrium

In order to establish a new regulatory equilibrium, it is essential that policymakers provide clear *ex ante* guidelines regarding the degree of price risk customers should be expected to bear, and the amount of money that customers should be expected to pay for the rate stability that hedging can provide. Because the ongoing risk management activity undertaken by a utility is primarily on the behalf of its customers, *ex ante* risk guidelines should reflect the desired risk tolerances which customers – and the regulators that act on customers' behalf – will accept. In *ex post* prudence reviews, a utility should be required to demonstrate that it hedged to limit risks to the pre-approved levels, prudently administered its contracts, and reasonably dispatched the overall portfolio of resources. Regulators must vigilantly resist the temptation to select different risk limits during the prudence review, by comparing the actual cost to serve with the hypothetical costs that would have been experienced if a different hedging program, developed with the benefit of hindsight, had been implemented instead. As one regulator recently explained:

> As is the case with hindsight, any after the fact assessment makes it easy to determine whether or not a particular hedging decision worked to the best interest of consumers. Established parameters will help to eliminate many concerns that may arise based upon such hindsight evaluations of the Company's hedging decisions.[37]

Until a new regulatory equilibrium is achieved, there are a few steps that utilities can take to help manage the regulatory risks associated with hedging. These include:

- *Education*. Utilities should educate key stakeholders regarding the implications of risk

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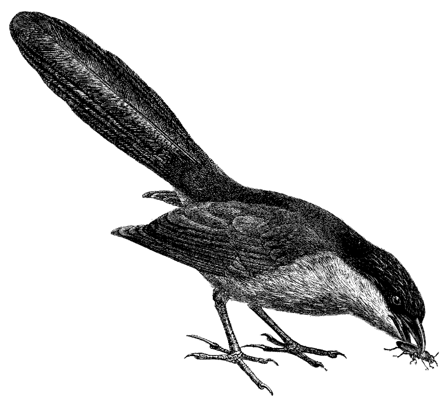
management. Hedging is not designed to minimize costs. The Commission and consumers should remain mindful of the fact that the primary benefits of hedging are rate certainty and rate stability. A properly managed hedging program should help to produce predictable rates over time. Stable rates insulate consumers from rate spikes, and allow customers to budget for their energy needs. In many respects, a hedging program functions like an insurance policy in that it allows the utility to manage its customers' rate risks and exposure to rate shock. The rates resulting from a hedging program may be higher or lower than market rates at any given point in time. However, the value of a hedging program is not diminished when market rates are lower than rates derived from a hedging program. Rate certainty, rate stability, and risk management are the primary goals of a hedging program. One utility recently executed a stipulation with its regulatory agency and the consumer advocate which explicitly acknowledged that, "The Parties agree that reasonable price volatility mitigation efforts may not result in the absolute lowest priced gas being purchased for the period."[38] Even in the absence of a formal stipulation, it is critical for utilities to educate stakeholders about the objectives of hedging and the fact that hedging should *not* be expected to minimize costs.

- *Promote legislative or regulatory reform*. Utilities should be taking the lead to educate key stakeholders regarding the critical importance of establishing clear *ex ante* guidelines for developing, implementing, and evaluating a hedging program. In the absence of such guidelines, utilities will continue to be vulnerable to unreasonable *ex post* review of their hedging decisions, or their decisions not to hedge. Significant regulatory risk involving the recoverability in rates of fuel and purchased power costs can have very negative consequences for a utility's credit rating, cost of capital, and access to capital markets.



- *Prepare Written, Detailed Hedging Strategies*. Utilities should, on an annual or seasonal basis, prepare detailed hedging strategies for future periods. The strategies should address the degree of hedging (i.e., whether the utility will hedge 1 percent, 50 percent, or 100 percent of its physical requirements), the hedging instruments to be used (i.e., swaps, calls, or collars), and the timing of the purchases (i.e., three years ahead, one year ahead, one season ahead). These strategies should be supported by solid, well-documented analytics, and should be approved at the highest levels of management.

- *Seek Regulatory Pre-Approval of the Strategy*. To the greatest extent possible, hedging strategies should be pre-filed with a request for regulatory pre-approval. Some hedging strategies are more amenable to regulatory pre-approval than others. For example, if a utility elected to hedge one-third of its portfolio each year with staggered three-year contracts, the contracts themselves generally would be subject to regulatory review as long-term arrangements. If there is no formal procedure in place for pre-approval of the chosen hedging strategy, consider an informational filing, which will provide all parties an opportunity to comment on the strategy *before* it is implemented. Informal opportunities for key stakeholders to comment on hedging strategies also should be pursued. Even if neither pre-approval nor a consensus approach can be achieved, it will be more difficult in a subsequent prudence review for stakeholders to criticize the strategy on the basis of concerns that were never raised at an earlier opportunity, when the utility might have been able to adjust the strategy in response. Indeed, such circumstances can help highlight the hindsight nature of the criticisms that are leveled against the strategy at a later date.

- *Document Everything*. Recognizing the vulnerability of hedging decisions to hindsight

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review, carefully document all decisions regarding the hedging strategy, the implementation of the strategy, the procedures in place to monitor implementation of the strategy, and the criteria to be used to measure the effectiveness of the strategy. Specifically address the reasons why the decision to hedge or not hedge was made, the reasons for the selected degree of hedging, the reasons for purchasing particular hedging instruments, and the timing of the purchases. Several utilities have established separate risk management committees to document decisions for possible audit in prudence investigations, and these committees have worked very well.

- *Monitor Implementation of the Strategy Using Appropriate Metrics*. Carefully monitor the hedging program, and implement modifications as appropriate in light of changing market conditions, after consultation with key stakeholders. As part of the monitoring activity, key metrics, such as value-at-risk, should be tracked and reported. Always remember that the purpose of the hedge is to reduce price volatility. It is not a directional bet on future prices. Mark-to-market metrics, like other *ex post* analyses, can be useful for some purposes, such as credit management, but should have no role in evaluating the effectiveness of the hedging strategy. The use of mark-to-market metrics to evaluate the effectiveness of a hedging strategy can create a mis-impression that the utility is trying to ''beat the market'' or is ''speculating'' in energy commodities. Any such impression can be extremely damaging if, at a later date, it appears that the utility made the wrong ''bet.''

- *Manage the Procurement Process*. The company must conduct all of its procurement decision even-handedly and in a non-discriminatory manner. This requires good project management and advance planning. The use of a structured Q&A process, supported with a public Web site, can be very positive. In addition, adequate resources need to be devoted to bid evaluation, particularly where companies are bidding dissimilar resources.

Regulators have not always provided clear guidelines to utilities with respect to these questions of policy. The lack of clear *ex ante* guidelines can create opportunities for unreasonable *ex post* review of utility hedging decisions. In rising markets, utilities can be criticized for failing to execute fixed price contracts, which 20/20 hindsight shows would have been the least cost option. But in falling markets, utilities can be criticized for having locked in supplies at high rates, again based upon

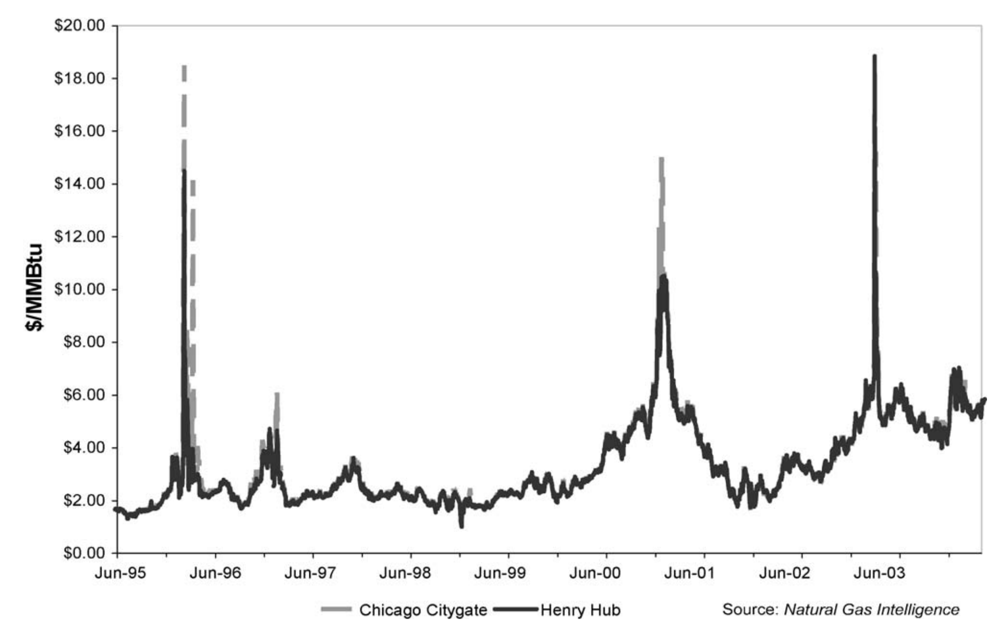

Figure 6: Daily Natural Gas Prices at Major U.S. Pricing Points (June 1995–March 2004)[40]

hindsight review. At its worst, this would be a classic ''heads ratepayers win, tails shareholders lose'' situation, with devastating consequences for utilities and their shareholders and customers as well.

Appendix A. Volatility in Energy Fuel Sources

Prices for natural gas and crude oil, which accounted for about 20 percent of U.S. net electricity generation in 2003, fluctuate on a daily or weekly basis.[39] **Figure 6** shows the volatility of natural gas from June 1995 to March 2004. During the past 10 years, natural gas prices have experienced extreme volatility, highlighting the need for PCAs.

Monthly Mid-Continent electricity wholesale prices for June 1995 to March 2004, adjusted to constant 2003 dollars using the Consumer Price Index, shows high volatility, as shown in **Figure 7**. Real power prices have been fluctuating at around $30/MWh except during the Western power crisis period (between June 2000 and May 2001), when prices increased to hundreds of dollars. During peak demand, utilities may turn to purchasing wholesale electric power. However, the price for purchase power can fluctuate to hundreds of dollars per kWh in a matter of weeks or months. Utilities must be able to recover these high costs for meeting consumer demand for electricity.

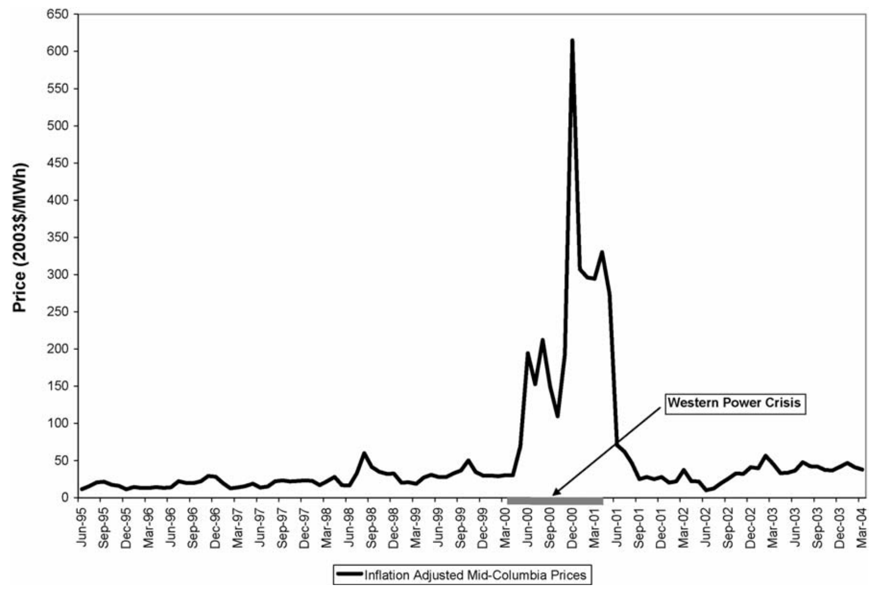

Figure 7: Mid-Continent Average Monthly Real Electric Wholesale Prices (June 1995–March 2004)[41]

Figure 8 shows that major U.S. coal prices have experienced sharp increases from August 2002 to July 2005. Some perceive coal as a cheap alternative to high natural gas and purchase power prices. However, the recent past has shown sharp

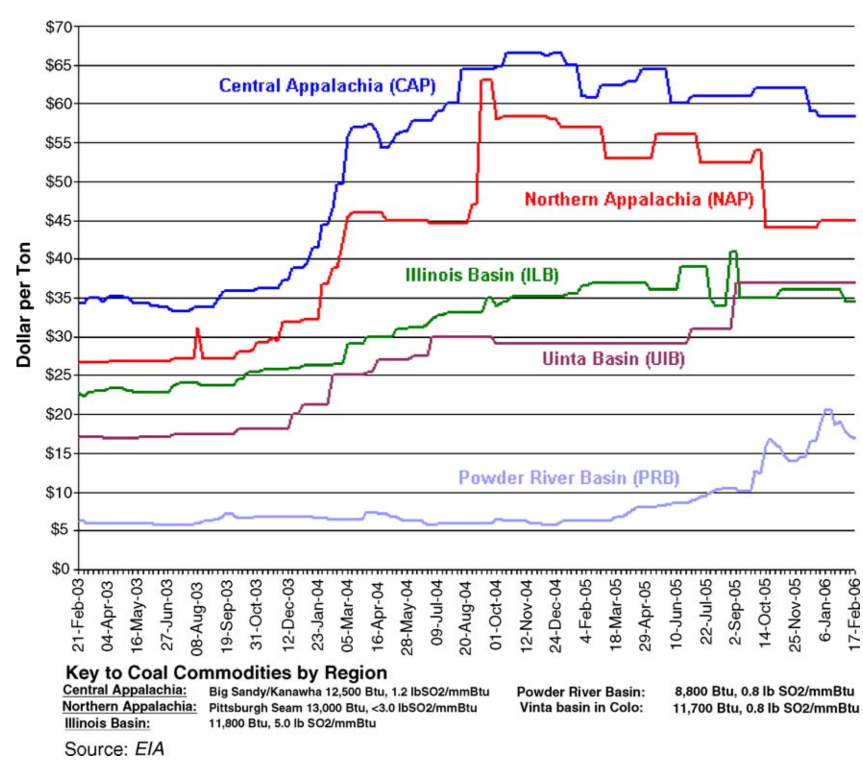

Figure 8: Coal Prices by Region (August 2002–July 2005)[42]

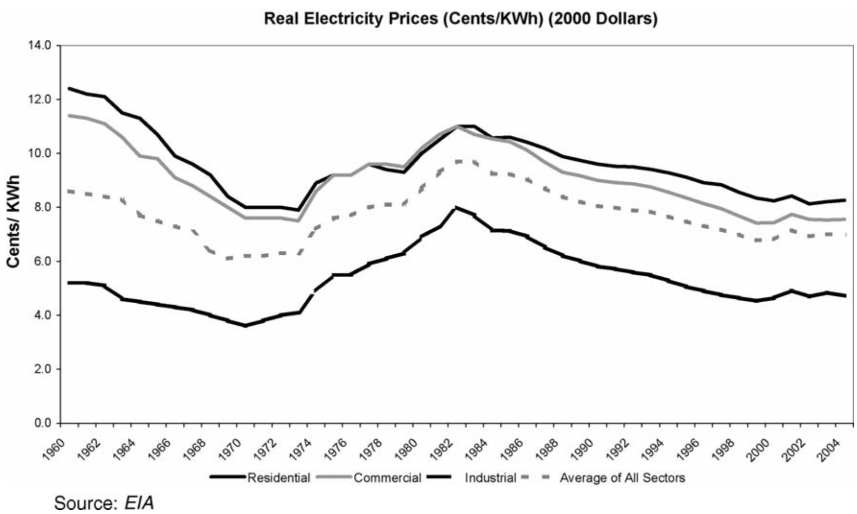

Figure 9: Average Real Retail Price of Electricity Sold by U.S. Electric Power Industry (1960–2003)—Indexed to 2000 Dollars[43]

increases in coal prices from all sources. Even a historically relatively stable fuel commodity like coal has experienced some volatility and prices increases in the past few years.

Despite fluctuating prices for fuel and purchase power, retail electric prices have generally decreased and not experienced similar volatility. **Figure 9** shows that real prices of electricity sold by the U.S. electric power industry have steadily decreased since 1982 despite higher fuel and purchased power prices.■

Endnotes:

1. This period of scale economies in power generation lasted only until the late 1960s. The loss of advances in generation scale economies, combined with the advent of comparatively high inflation and the 1973 OPEC oil embargo, led to an era of rapid price escalations and frequent rate cases.

2. In November 2003, NARUC's Natural Gas Task Force issued a ''tool kit'' for the use of state commissions in addressing high natural gas prices and high price volatility. *See:* http://www.naruc.org/goto.cfm?returnto=displayindustrynews.cfm&industrytopicnbr=380&page=http://www.naruc.org/associations/1773/files/gas_toolkit03.pdf.

3. *E.g.*, Bill Risk Management for Natural Gas Customers, 2003 WL 22472190 (Iowa Utilities Board Oct. 9, 2003) (Iowa Utilities Board Docket No. NOI-03-05); Order Approving Proposal, Requiring Compliance Filing, and Opening Investigation into the Continuing Usefulness of Fuel Clause Adjustments for Electric Utilities, Minnesota Public Utilities Comm'n Docket No. E-999/CI-03-802 (June 4, 2003); Gas Price Hedging, Fixed Price Options, and Other Alternative Mechanisms, Arkansas Public Utilities Comm'n Docket No. 01-023-NOI (Apr. 23, 2001); Risk Management Techniques to Mitigate Natural Gas Price Volatility, 221 PUR4th 391 (Mass DTE 2002); Gas Price Hedging, Fixed Price Options, and Other Alternative Mechanisms, 2001 WL 306225 (Ark. PSC 2001); Establishing Policies and Cost Recovery Mechanism, 2003 WL 24455105 (Cal. PUC Oct. 16, 2003); Levelized Gas Adjustment Clause Proceedings, 216 PUR4th 444 (N.J. PUC Mar. 7, 2002); Gas Price Hedging, 220 PUR4th 368 (Iowa Util Bd July 5, 2002).

4. *E.g.*, the summer of 1974 marked a watershed event in the electric power business in the U.S., as Consolidated Edison eliminated its quarterly dividend payment. Shareholders at the annual meeting sobbed and shouted for the chairman's ouster, and some had to be driven from the room by security guards.

5. 16 U.S.C. §2601, P.L. 95–617, 1978 (PURPA); 15 U.S.C. 3301 *et seq.*, (NGPA).

6. Paul L. Joskow, ''U.S Energy Policy During the 1990s.'' Prepared for the conference ''American Economic Policy During the 1990s,'' sponsored by John F. Kennedy School of Government, Harvard Univ., June 27–30, 2001.

7. Includes all Tier 1 restructuring states and Oregon. Restructuring efforts in Arizona, Oregon, and Virginia have been limited and should be considered a separate case from the other Tier 1 states that have experienced restructuring to a greater extent. *See*: Regulatory Research Associates, ''Electric Industry Restructuring Update,'' with updates based on RRA's Web site and state PUC Web sites.

8. Michael Schmidt provides a useful summary of the early history of PCAs. *See*: MICHAEL SCHMIDT, AUTOMATIC ADJUSTMENT CLAUSES: THEORY AND APPLICATION (East Lansing, MI: MSU, 1980), at 10–11.

9. Schmidt explains that ''[t]he purpose of an automatic adjustment clause is to allow a utility to adjust its revenues to accommodate changes in actual costs for a major expense item(s) *over which it generally has little or no control*. The objective is to mitigate the effect of relatively volatile cost items the firm purchases on a continuous basis.'' *id.*, at 10–11.

10. R.S. Trigg, *Escalator Clauses in Public Utility Rate Schedules*, UNIV. PENN. LAW REV. 106 (May 1958), at 973.

11. Schmidt, *supra* note 8, at 60.

12. Robert Burns, Mark Eifert, and Peter Nagler, *Current PGA and FAC*

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Practices: Implications for Ratemaking in Competitive Markets*, National Regulatory Research Institute, Nov. 1991, at 2. [Hereinafter referred to as ''NRRI Report.''].

13. *Id*.

14. Energy Information Administration, *Electric Power Annual 2003*, at 49, Table 8.1 Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1992 through 2003, Dec. 2004. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

15. Energy Information Agency. *Electric Power Annual, Vol. II*. Contacted EIA and compiled from hardcopies of past editions of the Electric Power Annual report tables titled ''Revenue and Expense Statistics for Selected Investor-Owned Electric Utilities'': Table 8.1 (1992–2003), Table 11 (1990–1994), Table 34 (1986–1990).

16. Before the Louisiana Public Service Commission, ''Development of Standards Governing the Treatment and Allocation of Fuel Costs by Electric Utility Companies,'' General Order, Docket No. U-21497, Oct. 1, 1997.

17. Braulio L. Baez, *Customer Bulletin*, Florida Public Service Commission, Apr. 2004.

18. U.S. Department of Labor, Bureau of Labor Statistics. ''All Items'' and ''Energy'' CPI for all urban consumers. *See*: http://www.bls.gov/cpi/home.htm.

19. NRRI Report, *supra* note 12, at 4.

20. *Id*.

21. Establish Policies and Cost Recovery Mechanisms Rulemaking Proceeding, 2003 WL 22455105 (Cal. PUC Oct. 16, 2003).

22. Risk Management Techniques to Mitigate Natural Gas Price Volatility, 221 PUR4th 391 (Mass DTE 2002).

23. *E.g.*, in Madison Gas and Electric Co., 227 PUR4th 388 (Wis. PSC 2003), the Wisconsin PSC explicitly acknowledged that ''financially settled hedging can act like insurance,'' and that ''how much insurance is necessary will always be an issue when dealing with financial hedging techniques.'' However, the agency failed to provide the utility any meaningful up-front guidance, stating simply that, ''MGE must also act in a way under its ERMP so as to not over-insure.''

24. *E.g.*, Establish Policies, *supra* note 21 (''In general, we expect SCE and California's other investor-owned electric utilities to have extensive knowledge of natural gas markets and

more expertise about hedging in those markets than we do in the regulatory sphere'').

25. *E.g.*, District of Columbia Natural Gas, 234 PUR4th 236 (2004) (''we remove the constraint on hedging gas volumes and encourage the company to make whatever hedging decisions it believes are prudent, subject of course to its current limits for operational flexibility and the possibility of a future prudence review''); see also id. (Dissent of Commissioner Anthony M. Rachal III) (''The uncertainty of what may be deemed appropriate after a prudence review looms larger without any guidance'').

26. North Carolina Natural Gas, 2004 WL 1708998 (NCUC June 30, 2004) (accepting stipulation in which ''the parties agreed that, if NCNG had a more effective hedging program in place during the review period, gas cost savings could have been realized by NCNG's customers, and the parties agreed on an adjustment to NCNG's deferred account''); see also *id*. (Dissent of Commissioner J. Richard Conder) (''Respectfully I must disagree with my colleagues in this matter. I think that hedging natural gas prices is an excellent tool if you are successful. However, if you didn't guess right on gas prices it could be very costly. In retrospect, if NCNG had hedged they would have made money. But in reality they could have lost money.'')

27. Wisconsin Power & Light Co., Docket No. 6680-UR-110 (Wis. PSC June 19, 2001).

28. Wisconsin Power & Light Co., Docket No. 6680-UR-110, Finding of Fact #5 (Wis. PSC June 19, 2001). Cf. *Washington Gas Light Co.*, 2005 WL 1349965 (D.C. P.S.C. June 2, 2005) (Formal Case No. 1020) (requiring the utility to respond to criticism regarding its failure to hedge with forward contracts).

29. Electric Restructuring Issues, 225 PUR4th 8 (Az Corp Comm'n Mar. 14, 2003).

30. Permit Electric Energy Cost Adjustments, 2003 WL 23279860 (Mn PUC Dec. 19, 2003).

31. The degree of volatility is addressed in detail in the Appendix A.

32. The literature on regulation of investor-owned utilities refers consistently to the concept of the ''regulatory compact,'' presented by Prof. Charles F. Phillips Jr., an authoritative writer in utility regulation, as follows (*The Regulation of Public Utilities, Theory and Practice*, Public Utilities Reports, Inc., Arlington, VA (1993), at 21):

> First, in return for a monopoly franchise, utilities [accept] an obligation to serve all customers. Second, in return for agreeing to commit capital to the business, utilities [are] assured a fair opportunity to earn a reasonable return on that capital.

33. Kenneth Costello and John Cita, National Regulatory Research Institute 01-08, ''Use of Hedging by

Local Gas LDCs: Basic Considerations and Regulatory Issues,'' May 2001, at VII.

34. United States General Accounting Office (GAO), ''Natural Gas: Analysis of Changes in Market Price,'' Report to Congressional Committee and Members of Congress, Dec. 2002, GAO-03-46, at 41.

35. *Id.*, at 7.

36. Kenneth Costello, *Regulatory Questions on Hedging: The Case of Natural Gas*, NRRI, Feb. 2002, at 17. A version appeared in ELEC. J., May 2002, at 51.

37. *District of Columbia Natural Gas*, 234 PUR4th 126 (2004) (Anthony M. Rachal, III, dissenting).

38. *City of Indianapolis*, 2004 WL 1170025 (In. U. Reg. Comm'n Mar. 17, 2004)

39. U.S. Generation by Energy Source for 2003 was as follows: natural gas and petroleum 20 percent, coal 51 percent, nuclear 20 percent, and hydroelectric and other 9 percent. *See*: Energy Information Administration, *Electric Power Annual 2003*, Dec. 2004. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

40. Natural Gas Intelligence Press, Inc.'s Daily Gas Price Index. *See*: http://intelligencepress.com.

41. Data derived from *Bloomberg* LP software.

42. Energy Information Administration, *Coal News and Markets*, Aug. 4, 2005, http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html.

43. Energy Information Administration, *Electricity Infocard 2003*. *See*: http://www.eia.doe.gov/neic/brochure/elecinfocard.html.

Carefully monitor the hedging program, and implement modifications as appropriate.