ELECTRIC UTILITY
AUTOMATIC ADJUSTMENT CLAUSES:

Benefits and Design Considerations

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INTRODUCTION AND OVERVIEW

Most states with traditional retail electric markets (*i.e.*, states in which retail service is provided by a regulated electric utility with an exclusive franchise service area), regulate the price of electric utility services using mechanisms that separate the review, approval, and recovery of certain frequently changing costs, such as fuel and purchased power costs, from the corresponding scrutiny of the more fixed and predictable capital and operating costs associated with financing and maintaining the assets of the utility. The more variable, unpredictable costs are recovered in rate components that are allowed to change periodically—at least every year and in many cases more frequently—without the need for a full rate case that reviews all of a utility's cost of service. Instead, these rate components are allowed to change roughly contemporaneously with changes in the utility's underlying related costs. (The remaining fixed or more predictable costs are recovered in "base rates" that are typically modified only every few years in formal rate cases.) These cost recovery mechanisms go by different names, but here we discuss them under the general appellation of "Automatic Adjustment Clauses" or AACs.

The typical motivations for AACs are three-fold:

1) *The underlying costs are often large and quite volatile*. As such, it is difficult to predict their expected level as to price or quantity accurately over long horizons and, at times, even over relatively short horizons. Inevitable prediction errors could result in significant cash and earnings shortfalls for the utility if those costs are not recovered in a timely manner (or unduly high cash burdens for customers when such costs happen to be lower than projected).

2) *The underlying costs are largely beyond the utility's control*, since they reflect, for example, market conditions in the wholesale fuel and power markets that individual utilities do not choose or influence. Accordingly, they often do not require the same depth or type of scrutiny as critical resource decisions with long-term cost implications, such as asset (ratebase) expansion and long-term power purchases, which are specific business choices customized to each utility. Furthermore, utilities earn no margin or return component on these expenses. Utilities should be primarily at risk for costs and performance factors they can control, and regulatory review should be focused proportionately on the same.

3) *To facilitate recovery of "pre-approved" items*, such as the costs of long-term power purchases in accordance with a commission-approved resource plan or the costs incurred in implementing approved environmental compliance plans.

Notwithstanding the general validity of these principles, there are some states that currently do not have or do not utilize AACs. Two states, Vermont and Wisconsin[1], explicitly prohibit the use of AACs. Vermont's prohibition of AACs arises from legislative strictures against "single issue ratemaking" -- evidently out of concern that this could result in ratemaking that places undue focus on one cost factor while failing to capture contemporaneous, offsetting reductions in other costs during the resetting of utility rates.[2] In addition, there can be concerns that adjustment clauses will reduce a utility's incentive to keep expenses down. But even in states that currently employ AACs, full recovery of the incurred costs is not assured simply because an AAC is in place. This is because AAC mechanisms may be designed to allow cost recovery only within certain limits, and most states also conduct periodic audits that can trigger AAC prudence reviews. For instance, Louisiana performs a comprehensive audit of fuel costs every 2-3 years, while Florida conducts a hearing every November to review the accuracy of filings made pursuant to its adjustment clause. Other states, such as Colorado, have AACs that are subject to various "deadbands" within which the variation in costs does not trigger a dollar-for-dollar adjustment, and they may then hold any costs outside of these bands in deferral accounts for subsequent review and amortization, if and when such costs are found reasonable. Thus, the degree of rapidity, administrative burden and assurance of cost recovery varies across a wide range of specific practices.

The purpose of this report is to clarify why AACs and their predictable administration have become very important for the financial stability of utilities and for the avoidance of indirect costs that will ultimately fall on consumers if such cost recovery is ineffective or inadequate. Indeed, we suggest expanding the scope of costs that should be eligible for recovery in AACs, recognizing that there now generally is more reliance than in the past by utilities on wholesale markets for short-term purchases and sales of diverse services such as short-term energy and capacity, ancillary services, and congestion relief. In addition, we discuss how the administration of AACs can be made both more predictable and compatible with other important regulatory objectives, such as rate stability, hedging, and incentives to control costs.

HISTORY AND CONTEXT

The Federal Power Act (Title 16 U. S. C. §824d(f)(4) of the U.S. Code) provides a working definition of an automatic adjustment clause as: "a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate." In fact, this language is a bit stronger than many AACs in practice, but the basic principle of allowing timely and relatively unchallenged recovery of certain recurring costs is a common feature. For this discussion, we will define an AAC as a cost recovery mechanism which meets the following criteria:

- Generally applies to volatile, financially material commodity costs that arise in wholesale markets, such as fuel and purchase power costs, with other, mostly fixed and long-term capital costs recovered under distinct, separate ratemaking procedures. However, certain capital costs associated with mandatory investments, such as the capital cost of environmental compliance investments, sometimes are recovered through an AAC as well, because such investments are beyond the utility's discretion.
- Recognition in allowable rates of incurred AAC costs does not require *a priori* review and approval, except to the extent of confirming the appropriateness of the type, procurement process, and accounting for such costs.
- Recovery of AAC costs is timely and assured enough that the risk of non-recovery is very low; in particular, such risk is low enough that it does not compromise the debt ratings and creditworthiness of the utility.

This definition leaves room for deadbands, provided their limits are reasonable, and deferred accounts, so long as eventual cost recovery is deemed highly likely by the financial community. It can also accommodate innovative arrangements, such as inclusion of hedging costs or basing allowed AAC costs on forecasted or forward prices for fuel, subject to the proviso that the total revenues eventually collected from customers are trued-up for any deviations (possibly outside of deadbands) between actual costs and initially estimated rates.

AACs for fuel costs arose in the US initially in response to escalating coal prices during World War I. They became prominent again in the 1970s, when the oil price shocks spurred by OPEC became large and economically critical. Such events dramatized the utilities' financial exposure to costs they could not control, and on which they earned no profits. (At that time, oil comprised a much larger portion of the electric generation fuel mix than it does today.) Traditional rate proceedings, in which months of preparatory analyses are required, followed by 6-12 months typically elapsing before a Commission acts upon a utility's rate filing, were deemed too slow to deal with volatile and rapidly rising fuel expenses. Indeed, in a world of constantly changing fuel costs, a utility may find itself filing for a fuel-related rate change before its Commission has acted upon a prior rate filing.

Since the 1970s, most states and most utilities have some degree of contemporaneous "flow through" of at least a portion of fuel costs, as well as fuel transportation costs, short term purchased power, and emission allowance costs. All but three of the thirty traditionally-regulated states (Missouri, Vermont, and Utah) have AACs to recover fuel and the energy portion of purchased power costs and the Missouri Commission is in the process of implementing a fuel adjustment clause after Missouri passed enabling legislation in 2005 allowing the Commission to do so.[3] Moreover, a recent survey performed by *The Brattle Group* found that, of the 27 traditionally-regulated states that currently have AACs, all allow the pass-through of the energy portion of purchase power costs, and at least 12 allow the pass-through of the capacity or demand-portion of purchase power costs as well. Eleven states allow rate adjustments for environmental capital costs and for the cost of emissions allowances and thirteen allow the pass-through of hedging costs. (Some utilities have separate rate riders to recover (and amortize) certain environmental compliance capital and operating costs on technologies that are mandatory, including environmental equipment bond financing costs.) A few states have, or are considering, similar recovery mechanisms for Regional Transmission Organization (RTO) participation costs that are variable and uncertain, such as ancillary service costs and congestion-related costs.

Utilities in some restructured states have AACs, usually to recover the cost of power purchased on behalf of retail customers that continue to purchase bundled generation service from the local utility. Some utilities in restructured states also have the ability to recover environmental compliance costs in an AAC-type mechanism (*e.g.*, certain Ohio utilities). However, some utilities in restructured states provide their generation services under rate caps or complicated settlements that provide them no or limited opportunity to adjust rates for rising fuel and other commodity costs. Other utilities in restructured states (*e.g.*, the Michigan utilities) regained their AACs upon the expiration of their rate caps.[4] Thus, it is hard to generalize about the situation of utilities in restructured states other than to point out that utilities that purchase all or most of their generation requirements face very substantial financial risks if those costs are not reliably recovered. Increasingly, utilities with divested generation procure their supplies through Commission-approved auctions or procurements and are then permitted to flow through the winning bidders' price(s) for those purchases in an AAC-like mechanism, particularly when they are no longer subject to a transitional rate cap. However, where a utility is subject to a rate cap, a portion of its power procurement cost may be deferred for later recovery or even written off, which can cause the company severe financial distress.

AACs can be used reliably in conjunction with other rate and regulatory policy mechanisms. In particular, they are very compatible with incentive regulation that involves risk-sharing between utility shareholders and ratepayers, once general agreements have been struck with regulators regarding how utilities can incorporate risk management (hedging) contracts into their AAC cost structures. This is likely to be an increasingly important aspect of AAC design and performance evaluation, because wholesale fuel and power spot price volatility has been increasing in the last few years.

Accordingly, unrestricted flow-through of all or most wholesale power costs at spot prices may result in rates that are too unstable for some customers.

The alternative to having an AAC is to attempt to recover these costs in base rates set every few years through full-fledged rate cases. This approach requires utilities to determine fuel and other volatile costs for an adjusted (historical or future) test year, include an estimate for these costs in base rates, and then the utility must hope that actual costs are not higher than the estimate (*i.e.*, both volumes and prices per unit of fuel or purchased power were fairly well estimated). Correspondingly, customers must hope that incurred costs are not much lower than the forecast, or else they will be overpaying. The utility will re-file for an overall review and resetting of its rates from time to time if and when these rates no longer cover actual costs. This recurring forecasting and refiling puts a substantial administrative burden both on the utility and its regulators (as well as interveners), and it may result in significant variance in rates billed relative to actual costs and/or financial distress for the utility. Administrative burden has a direct cost, of course, but also may have an "opportunity cost" as both regulatory and utility resources are diverted from the forward-looking analyses and planning necessary to develop creative new policies and to maintain economical and reliable service in the long-term.

THE CURRENT NEED FOR AACS

There are three main drivers of utilities' current, heightened need for AACs:

1) High volatility of many critical wholesale costs, causing increased financial risk if costs do not match revenues;

2) Increased vertical unbundling of supply functions, such that integrated rate cases reviewing all functions and costs are becoming inefficient or even dysfunctional; and

3) Down-graded credit ratings and reduced total capitalization of many utilities, especially those which divested their generation and now have substantially smaller base revenues with as large or larger variable costs than in the past

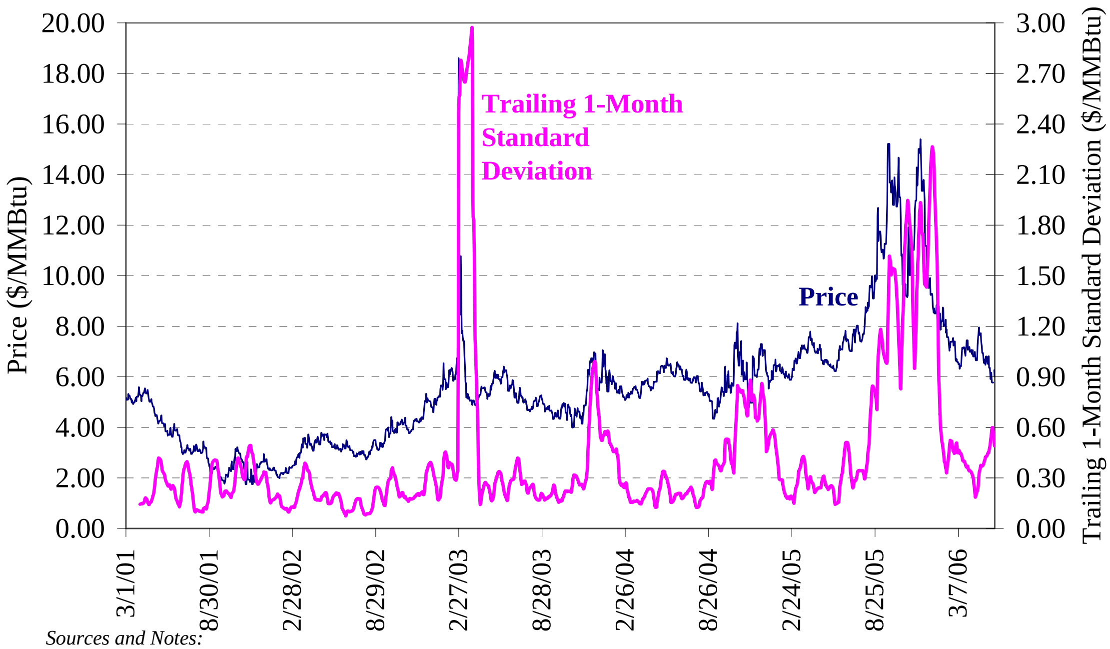
Some of the empirical evidence for these factors is discussed below.

INPUT COST VOLATILITY

The overwhelming majority of an electric utility's operating expenses is concentrated in two categories—fuel and purchased power. A review of FERC Form 1 data for all investor-owned utilities shows that, as of 2005, fuel and purchase power expenses accounted for 71 percent of total utility O&M expenses. To the extent that changes in the price of these items are not reflected in rates, a utility can be exposed to significant cash flow volatility. This point has been brought home by the highly volatile natural gas and wholesale power markets of 2005.

Fuel price levels and price volatility are seemingly at an all time high. Today, almost 70 percent of America's electric power is supplied by coal and natural gas. After being at $3/mmbtu for much of the 1990s, the spot price of natural gas in 2006 has been about $7-$8/mmbtu. (The spot price was even higher in late 2005—about $13/mmbtu—largely because of the production disruptions caused by Hurricane Katrina.) This generally is due to the end of the "gas bubble" of excess supply that was induced by well-head price deregulation under the NGPA of 1976, and which extended through approximately 1997. Since then, the US has had declining reserve-to-production ratios, and many newly developed wells have been smaller and shorter-lived than in the past.[5] In short, gas supplies are getting tighter, which has been aggravated by geopolitical concerns about the Middle East. Supply tightness causes both higher prices and more volatile prices than prevail in times of plenty.

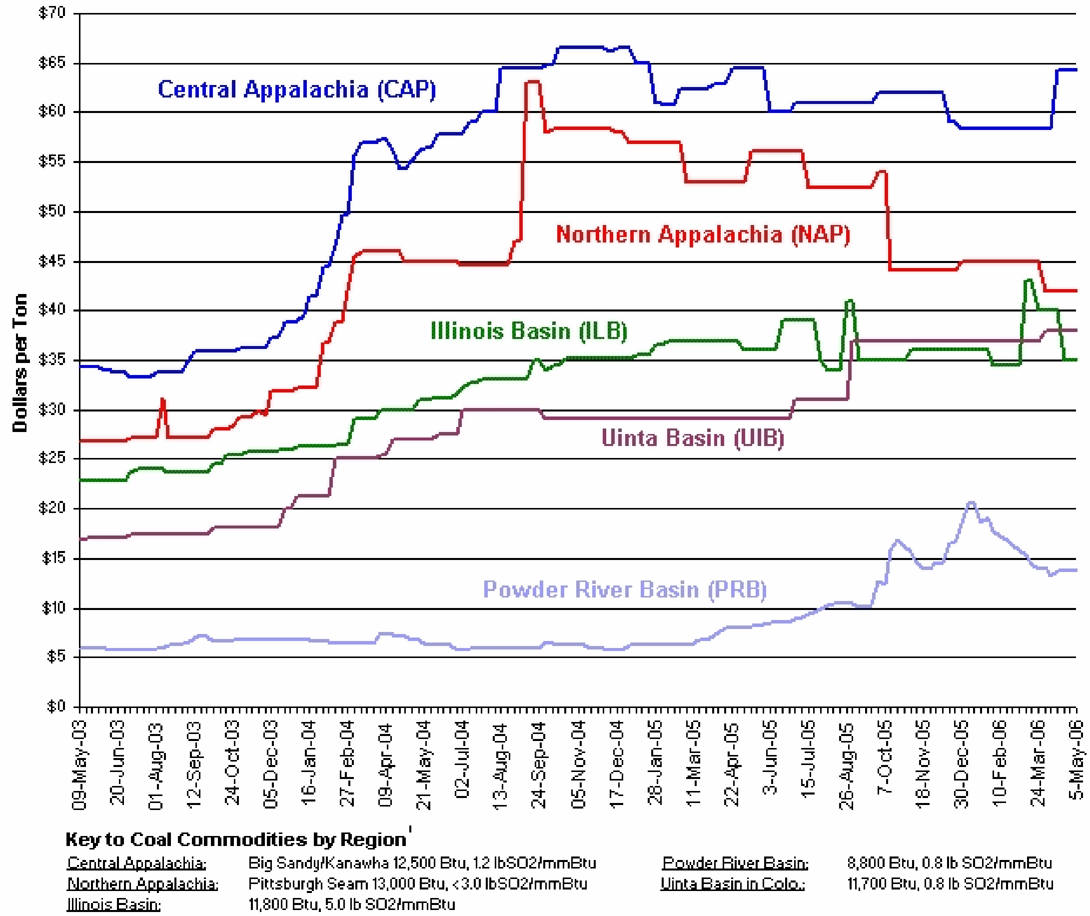
Figure 1
Henry Hub Spot Prices by Flow Date and Standard Deviation



Sources and Notes:
Platts Gas Daily.
Excludes 8/30/05, 9/27/05-10/7/05 when Henry Hub operations were disrupted due to damage caused by Hurricanes Katrina and Rita. Standard deviation calculated over current and previous thirty days.

Delivered coal prices to utilities, which reflect contracts that bind the majority of coal deliveries, declined in nominal terms starting in 1985 for approximately 15 years. However, between 2003 and 2005, delivered coal prices to electric generators increased over 20 percent. More dramatic increases occurred in the spot price of coal over this same period. For example, prices at the Powder River Basin have risen from $6/short ton in March 2003 to about $15/short ton in March 2006, an increase of well over 100 percent. Figure 2 below shows this recent trend in spot prices. As more long-term contracts begin to expire, the effect of this dramatic increase in spot coal prices will be borne by utilities and their customers.

Figure 2
Coal Spot Prices (March 2003 – May 2006)

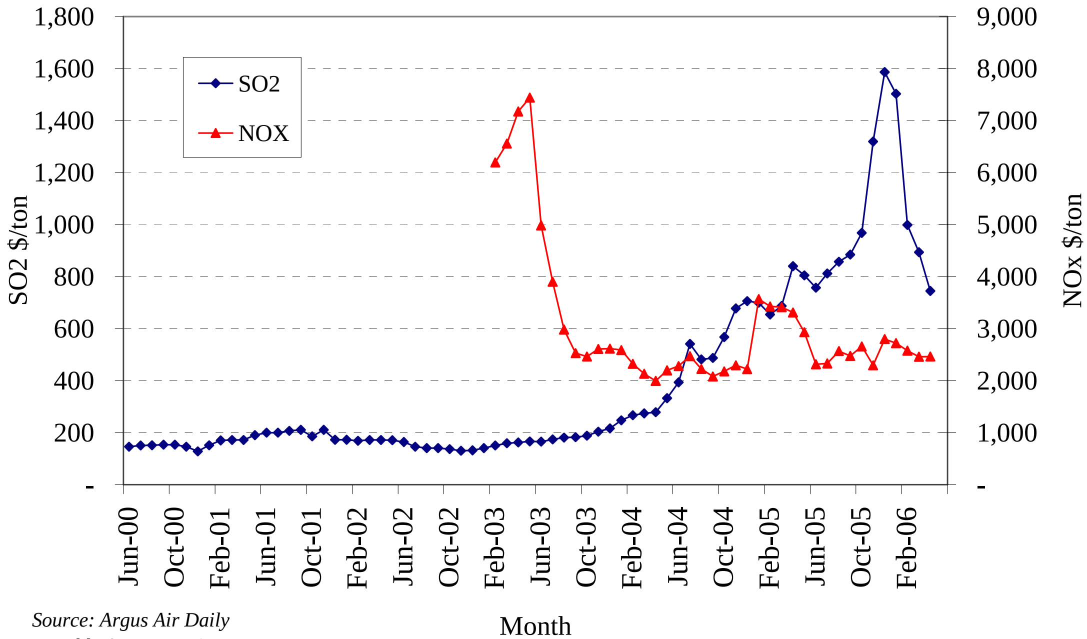


Source: EIA - http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot.

In addition to the rising costs of fuel for coal plants, the associated environmental allowance prices for SO_2 and NO_X have become quite high and volatile, in part due to impending new controls on coal-fired generation and much higher natural gas prices, which have encouraged higher levels of coal-fired generation. For example, the spot price of SO_2 allowances, which had been steady at about $200/ton during the early years of this decade, suddenly spiked to levels of nearly $1,600/ton in late 2005. While a $1000/ton increase in SO_2 prices raises operating costs for a modern, scrubbed pulverized coal plant with a 10,000 Btu/kWh heat rate by only about $1/MWh, the increase in operating costs for an un-scrubbed plant would be about \$5-\$15/MWh, depending on the sulfur content of the coal burned.

Figure 3

SO_2 and NO_X Emissions Allowance Prices



Source: Argus Air Daily Monthly Average Prices.

While not yet a factor in US fuel markets, there is a non-trivial possibility of CO_2 taxes or allowance costs also becoming part of the variable costs of burning fossil fuels, which provides over 70 percent of the total electric energy in the US. Since a \$1/ton of CO_2 corresponds to roughly \$1/MWh of increased operating costs for a baseload coal unit and about \$0.40/MWh for an efficient gas combined cycle gas turbine (CCGT), a material carbon reduction target could add another very large and volatile element to utility costs in the next few years.

VOLATILITY OF PURCHASE POWER COSTS

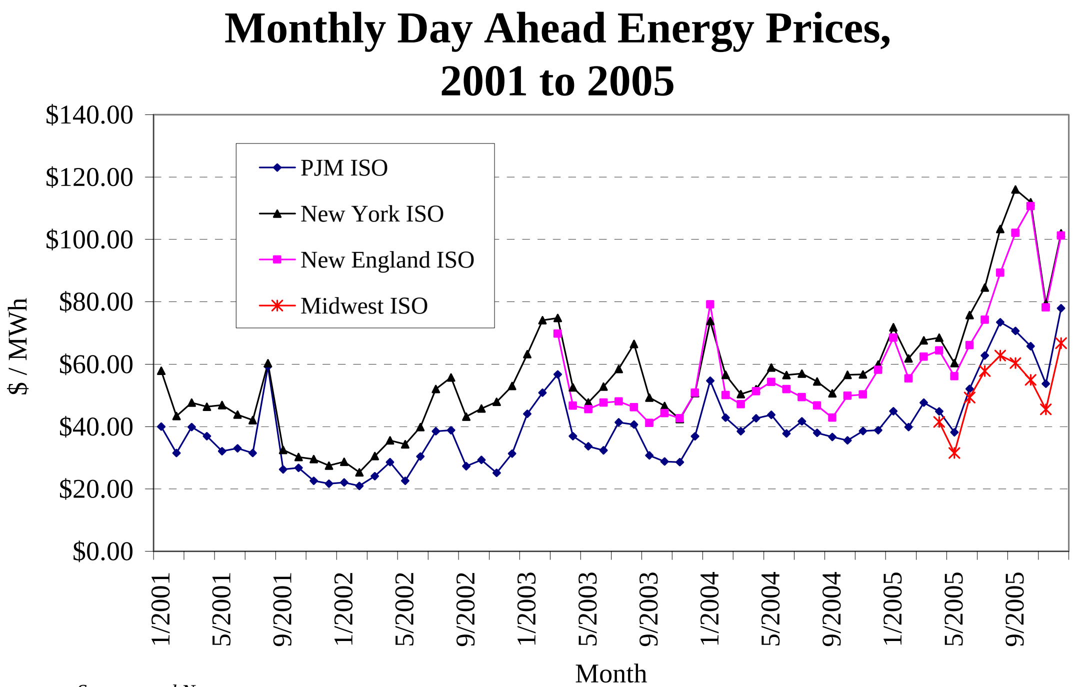
Today's wholesale power markets are much more volatile than those that existed throughout most of the 1970s to mid-90s.[6] Prior to the early 1990s, most of the power transacted in wholesale markets was sold at cost-based rates. Around 1990, the FERC began to permit wholesale power providers, including vertically-integrated utilities, to sell at market-based rates as long as the seller showed that it did not have market power or, if it did, that it had sufficiently mitigated such market power.[7] For example, in 1990 FERC approved a proposal by PSI Energy to sell up to 450 MW of long-term, firm power at market-based rates in exchange for a commitment by PSI to open its transmission grid.[8] The Energy Policy Act of 1992 encouraged the trend toward market-based pricing by creating a class of generators known as Exempt Wholesale Generators (EWGs), who were permitted to sell in wholesale markets at unregulated rates.

As the 1990s progressed, sales at market-based rates became common in wholesale power markets. The market-based price of power is generally at or above the operating cost of the most expensive unit needed in a given hour to serve load. It will tend to be equal to the marginal cost of the last plant dispatched (or willing to trade) if there are many sellers; it may be above this level if capacity is tight enough for sellers to be able to obtain a premium for their output. In any event, in wholesale power markets hourly prices are set by the interplay of demand and supply rather than by any particular seller's average cost of service. Whereas cost-based rates tend to be fairly stable because a seller's average costs do not change significantly, particularly in the near-term, market prices can fluctuate dramatically from hour to hour based on sudden changes in fuel costs for the marginal plants, demand, generation unit availability, and transmission constraints, among other factors. If a utility should need to make a large quantity of purchases on a day when market prices are high, its monthly costs can rise significantly.

Today, there are five centralized energy markets in the U.S. – the markets operated by the California ISO (CAISO), the Midwest ISO, PJM, the New York ISO (NYISO), and ISO New England (ISO-NE).[9] The Southwest Power Pool (SPP) is implementing a real-time energy market that will have some of the attributes of the centralized markets cited above. Texas, via its statewide reliability council (ERCOT), has initiated the development of a centralized nodal market scheduled for the beginning of 2009.[10] RTO charges add, sometimes substantially, to a utility's cost of purchased power. These additional elements include congestion premiums for dispatching around transmission constraints affecting certain areas (especially “load pockets” that are often urban areas), ancillary service charges for grid management (such as operating reserves, voltage support, and the like), and capacity obligations levied against load-serving entities. Some RTOs offer short term markets (daily, weekly, monthly, seasonal) in which these capacity obligations can be satisfied, and the observed prices tend to be quite volatile. In less centralized markets, the value of these grid support and reliability services can be embedded in the spot price for firm energy, making that power both more expensive and often more volatile than the underlying fuel costs.

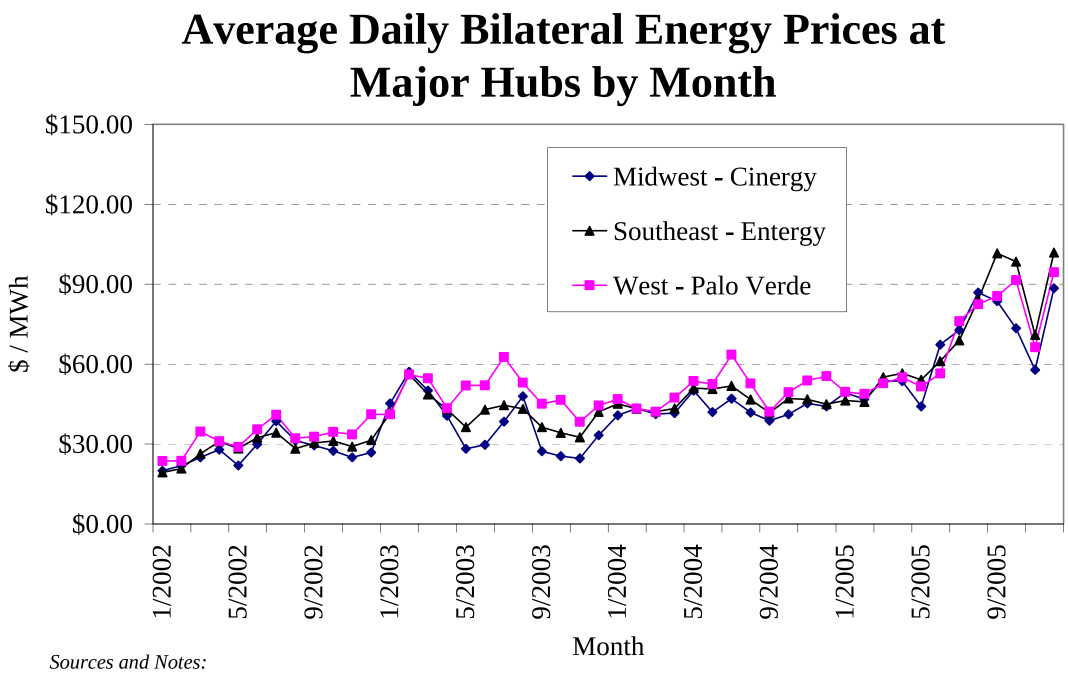
Figure 4 demonstrates the recent growth in levels and volatility in market energy prices for various locations around the US. Shown are average monthly energy prices in PJM-West; Cinergy, Entergy, and Palo Verde 5-year period 2001-2005. Average monthly prices have varied from about $21/MWh to over $116/MWh in the Eastern power markets. If a utility were buying 1000 MW for all 730 hours of a typical month, this could entail a cost variation of roughly $15 million to $85 million, depending on the month. While certain seasonal patterns are predictable, the price levels themselves have varied significantly from year to year. Ranges and volatility are comparable for the Midwest, Southeast, and West (though the latter had much more dramatic price levels in 2000 and early 2001).

Figure 4



Sources and Notes:
Global Insights' Energy Velocity database. Prices represent mean LMP prices within each market.
Midwest ISO begins in April 2005. New England ISO begins in March 2003.

Figure 5



Sources and Notes:
Global Energy Decisions.
The Midwest region was organized into the Midwest ISO in April of 2005, and for this reason the datasource for Cinergy changed between March and April of '05.

As a rule, wholesale prices did not fluctuate to this extent prior to market-based pricing. This is not to say that price volatility is either bad or unexpected. Price volatility is normal in commodity markets and is a facet of market efficiency -- providing market participants with useful signals regarding constantly changing market fundamentals. Electricity markets, however, are particularly volatile, often exhibiting a higher degree of volatility than many other commodities, such as agricultural products and metals. Electricity prices are highly volatile primarily because, unlike most other commodities, electricity cannot be stored, and its short run demand is highly price inelastic. Electricity production is also very capital-intensive, with a few years of lead-time required to significantly expand capacity. This makes electricity prices particularly sensitive to changes in market conditions, such as changes in the price of the marginal plant's fuel, the loss of a large generating plant or large transmission line, or the occurrence of a long, seasonal drought. Some of the hourly or daily manifestations of this volatility can be hedged away via purchasing of monthly or longer term forward contracts, but even those positions will reflect average (and shifting) expectations for future supply scarcity (or surplus), recurring patterns of congestion, and seasonal fuel price variability. Further, it is not possible to completely hedge retail electric requirements. Electricity demand itself varies enough to require some degree of supplementing forward purchases and sales with spot market transactions that are fully exposed to the above risks. With very volatile prices, even a few extreme hours of the month can cause a significant average cost increase.

UTILITY FINANCIAL EXPOSURE

At the same time that fuel and purchase power costs are becoming more volatile and, thus, more risky, many utilities have less capability to bear significant price risks. There are several reasons for this. Many utilities in states with restructured markets divested most if not all of their generating assets, which exposes them to significant risks associated with Provider of Last Resort (POLR) service in the context of having reduced overall capitalization.[11] Initially, the expectation for retail restructuring was that many customers, including residential customers, would leave the local utility and purchase service from an alternative supplier. For the most part, this has not happened. Most small customers in retail access states continue to purchase bundled service from the local utility. Competition has failed to develop for small customers, in no small part because most electric distribution companies in retail access states have been subject to rate caps during a "transition period" beginning with the implementation of retail choice.[12] These frozen rates have, in many cases, turned out to be below the going market price for generation service. The absence of a competitive market means that utilities will, for the foreseeable future, be responsible for procuring generation to serve such customers.[13] Since many of these utilities no longer own generation, they have to buy generation supply in the wholesale market at market-based prices. Generation procurement costs will be by far the largest operational expense incurred by such companies. The absence of full and timely recovery of generation procurement costs could be financially damaging to such companies.[14] Such firms no longer have the larger earnings base that generation asset ownership had provided, so the magnitude of their net power cost variability can be large relative to their relatively smaller earnings base. An AAC that includes recovery of all purchase power costs will reduce the electric distributor's exposure to cash flow volatility significantly.

This power procurement, risk problem does not apply solely to utilities in retail access states. Some utilities in traditionally-regulated states also rely on purchased power to meet a material portion of their supply requirements, and they remain exposed to the aforementioned volatile fuel and RTO costs for the generation they own and the power they purchase from the market. An inability to reflect changes in the price of fuel and purchase power costs in its rates—whether caused by a rate freeze or the absence of an AAC—can expose a utility to significant cash flow volatility.[15]

The financial risk created by volatile commodity costs is often felt first in the cost of debt. Bondholders receive fixed payments, so they do not participate in the financial upside performance of a utility if or when it has a highly profitable year. As a result, they are primarily concerned about avoiding the possibility of an unprofitable year, or period within a year, during which revenues do not significantly exceed operating costs. They rely on those operating margins to adequately cover debt service payments. Bond ratings agencies closely scrutinize the depth and stability of each utility's ability to sustain significant debt service coverage. A rate freeze, coupled with volatile operating costs, is a particularly unwelcome combination. An AAC that roughly synchronizes revenues with costs greatly improves the situation, reducing risk and reducing the cost of debt.

A poor debt rating has more consequences than simply adding a few basis points to interest rates imposed on the utility. It can significantly constrain operations and expansion, thereby raising costs and risks to customers. For instance, utilities are able to buy fuel and power under long-term, fixed prices that would eliminate much of the volatility problem only if they are deemed creditworthy by the sellers. Typically this requires a good bond rating, or the ability to post lots of cash as collateral for the long term purchase whenever forward prices move to new levels that are below the contractual price. The inability to do so may result in no sellers being willing to enter long-dated contracts – forcing the buyer into mostly short-term, volatile purchases that continue the utility's exposure to significant risk! Central Vermont Power Corp. faced this predicament when its credit rating was decreased by both S&P and Fitch Ratings in June of 2005.[16] Similar downgrades were also issued to Ameren Corp. and Commonwealth Edison due to regulatory uncertainty about post-2006 cost recovery[17] and most recently Empire District Company.[18] The financial strain of operating in this "catch-22" environment may also cause that utility to forego or defer cost-saving or risk-mitigating investments. Thus ratepayers may incur direct costs (interest rates) and indirect costs (constrained operations) if their utility is not authorized to operate with an AAC.

The importance of AACs is highlighted by the fact that the industry's financial condition, while generally sound, has declined somewhat over the last several years, as evidenced by declining credit ratings. The fraction of utilities rated BBB+ or above by Standard and Poor's, which was 75 percent prior to the 1990s, is now only about 40 percent. As of 2005 nearly 20 percent of all utilities were below investment grade. These companies cannot weather greater financial impairment. In addition, the operating cash flows of utilities in 2005 were insufficient to cover their capital expenditures and higher operating costs. Utility cash flows were about $10 billion less than the sum of operating and capital costs in 2005, and this gap could widen significantly during the next several years as regulated utilities undertake expenditures for infrastructure development and environmental improvements.[19] Utilities without AACs will have trouble maintaining stable cash flows in an environment of rising and volatile fuel and purchase power costs.

BENEFITS OF AACS

AACs provide several important benefits to utilities, customers, regulators and other stakeholders. For one, AACs ensure that costs are assigned to those customers that benefit from the incurrence of the costs and thus are consistent with the principles of "cost causality" and "inter-generational equity." The lag between rate cases can be significant, and fuel market conditions can change significantly over such periods. AACs enable a better alignment of cost recovery with the customer demands that cause the costs to be incurred. If variable costs are only estimated and placed in base rates, or if significant imbalances in the recovery of variable costs are deferred for long periods and amortized only infrequently and slowly, they may well be assigned to some customers who did not consume much or any of the power that caused those costs to arise. This is both inefficient and inequitable. Conversely, a timely flow-through shows customers the prevailing social, avoidable cost of their consumption decisions, thereby encouraging conservation and energy improvements (or allowing more enjoyment of energy-intensive services, when prices are low).

Second, AACs streamline the regulatory process by eliminating the need for formal, adjudicatory proceedings to review rate adjustments for changes in fuel costs and other variable costs that are largely outside the utility's control. This reduces the regulatory costs imposed on all parties. Moreover, "base rate" proceedings can become more infrequent as a result of the AAC. This will give utilities stronger incentives to control costs that are not included in the AAC. That is, "regulatory lag" will provide utilities an incentive to manage effectively those costs that are largely within their control. By allowing the pass-through of costs beyond the company's control, an AAC enables utility management to focus on those costs and factors over which it has substantial control.[20]

Third, AACs reduce the volatility of a utility's operating margins by shortening the lag between costs incurred and receipts earned to pay such costs. This allows the utility to pay its bills in a timely manner and, just as importantly, reduces the financial markets' perceived risk of the utility having inadequate cash flow. Lowering the perceived risk of inadequate cash flow and, at the extreme, bankruptcy, in turn, will prevent the utility's cost of debt from rising, or may even lower it. This will be an objective benefit, publicly observable in its debt rating and embedded interest rates. (Note that the cost of equity will likely <u>not</u> be altered by an AAC, because it reflects a different kind of risk. This is discussed further in the next section.) In addition, having a more assured cash flow will prevent the utility from having to raise its working capital allowances to compensate for the volatility of unpredictable and largely uncontrollable expenses. As previously described, this financial health also assures the utility's ability to make ongoing investments to maintain and improve the quality of service. Such investments are likely to be increasingly important in the near-future, as there is a growing consensus that utility infrastructure needs expansion and improvement.[21]

Finally, having an AAC in place will avoid exposure to occasional large rate shocks that can arise if rising commodity costs are deferred and accumulated over long periods of time. This may not seem to be an advantage, but it is akin to the benefit of paying credit card bills when they arise rather than running up a large debt of unpaid balances. Customers can make spending and consumption adjustments over time if they have a steady signal of timely information about costs; they cannot do this for sudden, large increases.

These benefits accrue both to utilities and their customers. Lower debt costs and lower working capital requirements enable lower rates—a direct benefit for customers. In addition, a financially healthy utility is better able to make investments in new infrastructure that will reduce expenses and rates in the long-term and better enable the utility to meet the service requirements of a modern economy (*e.g.*, digital-quality power). Indeed, quasi-AACs for immediate rate-basing of mid-sized, one-off capital expenditures such as may be needed for environmental controls might allow the use of more debt financing for such assets. AACs also provide a convenient mechanism to credit profits from off-system power sales to customers, thereby ensuring that customers enjoy the benefits of high wholesale market prices (to the extent their utility makes such sales) as well as incur their costs. While AACs do shift some price risk to customers, this will benefit customers during periods of declining fuel and power costs. Moreover, the dollar-for-dollar recovery provided by an AAC ensures that customers never pay more than the actual costs incurred by the utility.

POSSIBLE CONCERNS ABOUT AACS

While there is a very sound economic basis for endorsing AACs, they are opposed by some who are skeptical of their need or usefulness. A number of issues against the use of automatic adjustment clauses have been raised in various forums; these are described and discussed below. Generally, it is our view that the typical criticisms are either out of date, reflect an incomplete view of the consequences of <u>not</u> having an AAC, or assume an unduly limited model of AAC design. Below, we discuss five common concerns:

1) *Preference for bundled, all-cost ratemaking; possibility of missing offsetting costs in other line items if single issues are analyzed and allowed separately.*

   This concern may have had merit in the past, when utilities were fully integrated and focused fairly narrowly on their local franchise, but this model no longer applies. The modern separation of functions between generation and retail service is strong and growing, even where no retail restructuring has occurred, due to the FERC's policies of fostering transparent, liquid wholesale power markets and insisting that affiliated supply transactions be comparable to available wholesale market alternatives. In addition, bundled, all-in ratemaking may entail <u>less</u> effective oversight of utility costs, since it will involve many more cost items. Indeed, the methods of scrutiny for just and reasonable AAC items are different than for base rate items: AAC items are reasonable to the extent the quantity and type of items purchased correspond to needs (e.g., no speculative positions), and to the extent competitive procurement without affiliate favoritism has been used. They are often easily benchmarked or validated against posted market prices. On the other hand, base rate items involve investment prudence, sizing and timing, and long run (unhedgeable) risk exposure choices, with few standard benchmarks against which they can be compared. They must be evaluated for cost-effectiveness using sophisticated long-term operational and financial planning models.

2) *Loss of incentives by the utility to control fuel costs if they are automatically recoverable*

   While it is true that complete insulation from all volumetric revenue and cost risk could make a utility largely indifferent to the level of such costs, retaining some appropriate risk does not require that a utility be prevented from timely recovery of its AAC-type costs. This would be overkill, for two reasons. First, such cost variations can be very large compared to the allowed equity returns on invested capital. All that is needed to keep utilities intent on cost management is for a modest fraction of the equity return to be volumetrically sensitive. In general, this is already the case for most utilities, even if they have a very efficient AAC, because some portion of fixed costs is typically recovered in variable charges. Accordingly, volume matters to utilities, and this creates a desire to avoid any adverse influences on volume, such as price spikes from the fuel component of rates. Second, the fuel component is largely uncontrollable, so putting it strongly at risk cannot induce meaningful defensive, pro-customer practices. It simply makes the utility's other jobs more difficult, financially.

The main opportunity utilities have to "control" AAC-type costs is to hedge them. This does not reduce their expected costs, but it does reduce their potential variability. Incentive mechanisms for this kind of control can easily be built into an AAC. The utility can then use forward purchases, options, or other hedges to try to stay within the bands.

A less plausible variation on this theme is the fear that an AAC that permits full recovery of fuel costs will incline utilities towards generation technologies that are less efficient, *i.e.*, less expensive in terms of capital costs and more costly in terms of fuel (because those costs are ostensibly easier to recover). The risk of exposure to this kind of distorted decision making is very small, because the utility would still have to obtain regulatory approval for its generation technology choices, (*e.g.*, at resource plan hearings, planning reviews, siting reviews, and financing approvals,) typically well before the plans would be irreversible. The utility would face disallowance penalties or rejection of plans for alternatives that simply shift risk to favor the utility's preferences, rather than satisfying a least cost standard. In other words, regulation has other effective tools that address this directly.

3) *Wholesale purchased power costs are often significantly controllable, via appropriate timing and type of purchases*

   This is only partially true: Volatility can be reduced by forward purchasing of power, though not eliminated, but any secular[22] trends in the value of power (such as a general increase due to fuel costs, persistent congestion, or lack of capacity reserves) cannot be hedged away. In general, expected future costs cannot be avoided by any kind of clever contracting, because hedging contracts traded in the market reflect expectations about future supply conditions, which in turn reflect beliefs about underlying market fundamentals that will be manifest in the spot market. Forward trading does not alter these expectations, it just prices them. Even if a utility is using significant hedging to limit volatility, the costs of hedges themselves are the uncontrollable market prices of traded derivatives, which should be recoverable through the AAC. The relevant criteria for determining that such hedges were appropriate are much like those for approving the commodity costs in an AAC: affirming that the right type, procurement process, and accounting for those instruments were used. These are not the least-cost planning criteria that should be applied to base rate items.

   In addition, some risk is pretty much unhedgeable, especially volume uncertainty -- which tends to aggravate price risk, since unexpectedly high demand invokes unexpectedly high prices.[23]

4) *Capacity prices are typically recovered in base rates, often under statutory rules, and such components of purchased power costs should be eliminated from AACs*

   This concept, somewhat like bundled ratemaking, arose when “capacity costs” were quite consistently associated with demand charges in long term contracts that offered firm service backed by either specific units, or by curtailment priority equal to the native load of the supplier. Load requirements themselves were quite stable in that pre-restructuring era as well. Today, however, capacity has become a highly fungible aspect of wholesale electric power, traded over short intervals to satisfy the shifting needs of a shifting mix of buyers and sellers whose daily obligations can be quite inconstant. A highly desirable, efficient outcome in such a market is for capacity to be traded, either explicitly or implicitly in a firmness premium for delivered power. It is neither useful nor appropriate to attempt to separate out such costs from other fuel and purchased power costs, for three reasons:

a) These costs are every bit as volatile and uncontrollable as the corresponding fuel and "energy" components of purchased power, such that omitting them could cause a significant financial hardship of exactly the same character as we prevent with fuel in AACs

b) Attempting to infer precisely how much of what purchased power price ought to be deemed "capacity" is fraught with imprecision, potential bias, and extreme difficulty. It is not the case that the embedded capacity price is simply the total price less the energy cost of some hypothetical marginal source of capacity, such as a peaker. Such a unit may not even be on the margin for much or any of the contract delivery period. The transaction in which a "capacity premium" appears to be included may have been contracted at an earlier time, such that spot prices at the time of delivery do not describe its terms or expected performance conditions. It may also have complex contingencies and degrees of firmness or performance restrictions that do not make the service equivalent to owning and operating a peaker (*e.g.*, dispatch scheduling restrictions, or features that actual peaking technology would not enjoy, such as a hedged energy price. Accordingly, the "capacity premium" may be a payment for several kinds of complex features.)

c) The incentives created by attempting to exclude imputed capacity in AACs are potentially perverse and undesirable for ratepayers. In particular, they would lead a utility to over-invest in physical capacity, to the point where all energy could be bought on a non-firm basis. This would be very expensive and uneconomic, akin to trying to build the transmission grid to the point where it experienced no congestion. It is far more efficient to purchase a bit of capacity on the spot market when it is unexpectedly needed than to always carry reserves, much like it is often more convenient (and lower cost) to take a cab than to rent a car or drive your own car.

5) *The risk of variable cost recovery is already compensated in the allowed cost of equity*

This is a common misperception, which in its general form holds that virtually any kind of risk of regulatory disapproval is already part of the set of possibilities that shareholders should expect could happen, therefore they must be being compensated for this exposure in the risk premium they demand in the price of the stock. Despite the rhetorical appeal of this view, it misconstrues the nature of a stock's risk premium and is not correct.

The cost of equity capital includes a risk premium that compensates investors for the tendency of the stock price to move up <u>and</u> down in tandem with the stock market and the macro-economy as a whole. To the extent that a stock price moves with the broad market, the returns on the stock have a non-diversifiable character and so require compensation above the risk-free (government bond) rate. To the extent the stock moves up or down independently, that risk is diversifiable across a portfolio of many stocks and so does not require a risk premium. In stock markets, the price of the stock will adjust until it is centered on a level that involves a balance of potential up and down future movements; if it were expected to move in only one way, it would not be priced properly.

The normal valuation in fuel costs over time could be symmetric (up and down) around some fixed rate. But a problem arises if fuel costs move systematically up and become controversial to recover. The risk of regulatory disallowance of a large deferred balance of fuel or purchased power costs (absent an AAC) does not involve both up and downside prospective returns for investors. Rather, it only involves a downside possibility, the effect of which is to drive down the stock price until it offers a fair return to new investors, despite the likelihood of partial cost disallowance. This fair return will be the same as it would be for a similar company that was not exposed to a disallowance, because both stocks have the same prospective tendency to gain or lose value in synchrony with the stock market as a whole. Thus, measurements of the required rate of return consistent with those depressed stock prices will not show a premium. Rather, the stock will have been discounted to where no premium is required.

However, that does not mean it is appropriate to simply disallow such costs. Utilities need an unbiased opportunity to earn a fair return on all of their prudently invested capital as measured at <u>book</u> value, in order to keep attracting capital. If a portion of operating expenses is disallowed, with no offsetting opportunity for earning a superior return being created somewhere else, then the utility can no longer expect to earn its cost of capital. This is simply uncompensated value expropriation. The first result of that will be to block the utility from reinvesting in its own infrastructure; the second will be to force it to find ways of becoming capital-intensive. Fiduciary responsibilities to its investors demand that the utility managers not “throw good money after bad.”

The best way to prevent this is to assure a fair opportunity to recover all reasonably incurred operating expenses, not to add some kind of *ad hoc* premium to other return allowances. A viable AAC is one of the best ways of achieving this. Importantly, the above also implies that it is not appropriate to reduce the cost of equity if/when an AAC is created or made more “automatic.” Generally, that will not affect the required rate of return on equity – though it may improve (reduce) the cost of debt. If say that reduced cost of debt will be objectively evident when it occurs, as seen in enhanced credit ratings and lower interest rates on future debt issues or refinancings. Again, on immediate rate adjustment to reflect this possibility is needed or appropriate, until it is a realized outcome.

Many of the above doubts about AACs can be addressed through alternative designs. For example, AACs with risk-sharing and incentive clauses can be easily created, by agreeing in advance with regulators about how much risk to try to protect ratepayers from, and on how the associated hedging costs will be recovered. The result can be rates that are fairly stable for customers and cash flow that is not unduly volatile for the financial managers. The key to such an arrangement is to understand that hedged costs will not necessarily turn out to be lower than spot, but they will be less volatile. The hedge costs themselves will arise from wholesale market transactions; like the commodity costs they are written against, these will be uncontrollable. Accordingly, they should be given a timely pass-through in the AAC itself.

Similarly, rate riders for mandated environmental expenditures can be implemented that do not undermine either utilities' incentives to be efficient or regulator's opportunity (and obligation) to review and approve costs. Simply allowing a targeted, timely rate increase for audited expenditures that are imposed via other regulations will increase utilities' readiness to perform such system improvements that otherwise have no direct or indirect cost recovery mechanism (absent a full base rate review, which may not be otherwise necessary).

CONCLUSIONS

- The circumstances justifying AACs as beneficial to utilities and their customers are more pronounced today than ever: more volatile fuel and wholesale power prices, more vertical unbundling and consequent out-sourcing of supply needs, reduced credit ratings of many utilities, and an increasing number of new or emerging cost items which utilities cannot control and from which they do not profit.
- While it is understandably tempting to try to protect customers from material increases and volatility in utility operating costs, doing so one-sidedly is self-defeating and therefore is not in the interest of consumers. Placing uncontrollable costs at risk of long deferral and potential disallowance will inevitably raise costs, either directly through higher costs of debt, or indirectly through impaired maintenance and reduced investment in improving the utility's infrastructure and support services.

- It is unnecessary to place a utility strongly at risk for fuel and similar AAC-type costs in order to be confident the utility will attend to cost management opportunities. A vast literature on incentives shows that imposing too much risk is generally counterproductive.
- The cost of debt may fall with an effective AAC, while the cost of equity is unlikely to be affected. Other customer benefits of AACs arise from having steady, timely price signals for managing their personal finances, and from the utility having steady cash flow from operations to maintain the appropriate quality of service.
- It is possible to have both financial security for the utility and tolerable rate stability for customers, with AACs that include explicit agreement on how a utility can hedge and can recover the costs associated with those risk management positions through the AAC itself.

[1] Wisconsin State Statute 196.20(4)(b) states that: "An electric public utility may not recover in rates any increase in costs, including fuel, by means of the operation of an automatic adjustment clause."

[2] This prohibition may be circumvented, indirectly, if cost indexing in rates is pursued in conjunction with alternative ratemaking practices, such as incentive ratemaking. *Central Vermont Public Service Corporation*, Vermont Supreme Court, 473 A.2d 1155, January 13, 1984.

[3] Vermont is the only state that does not permit AACs. Utah has a settlement under which utilities refrain from using an AAC.

[4] See *U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery*, Fitch Ratings, February 13, 2006, p. 7.

[5] Annual Energy Review 2005, published by the Energy Information Administration (EIA). In particular, see Table 6.2 (Natural Gas Production, 1949-2004) and Table 6.6 (Natural Gas in Underground Storage, 1954-2004). In Table 6.6, we define reserves as Base Gas underground storage only.

[6] There were occasional excursions of high price volatility in the 1970s and early '80s due to the Mid-East oil crises.

[7] See, for example, Boston Edison Company Re : Edgar Electric Energy Company, 55 FERC ¶ 61,382 (1991), and Heartland Energy Services Inc ., 68 FERC ¶ 61,223 (1994).

[8] *Electricity Transmission Access*, National Energy Strategy Technical Annex 3, U.S. Department of Energy, 1991/1992, p. 9.

[9] The CAISO only has a real-time energy market, whereas the other centralized markets have both a real-time and day-ahead energy market.

[10] http://www.ercot.com/news/press_releases/2006/ERCOT_at_a_Glance_News_Update_-_February_9%2C_2006.html#Fee%20Case%20Hearing

[11] POLR is bundled generation service provided by the local utility to retail customers unable or uninterested in finding an alternative retail supplier.

[12] See, for example, Frank C. Graves and Joseph B. Wharton, "Provider of Last Resort Service Hindering Retail Market Development", *Natural Gas*, Volume 18, Number 3, October 2001.

[13] See, for example, Johannes P. Pfeifenberger, Joseph B. Wharton and Adam C. Schumacher, "Keeping Up with Retail Access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service," *The Electricity Journal*, December 2004, pp. 50-64.

[14] To mitigate rate shock, purchase power costs could be deferred for a period. Rate deferrals are covered in a monograph

[15] See, for example, *Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets – U.S. Electric Utilities to Watch, Standard and Poor's*, March 22, 2006.

[16] See Dow Jones and Reuters, "S&P Downgrades CVPS Corporate Credit Rating", 14 June 2005. Also see, Dow Jones and Reuters, "CVPS Hit with Second Downgrade", 21 June 2005.

[17] See St. Louis Business Journal, "S&P cuts long-term credit rating on Ameren", 3 October 2005. Also, see Dow Jones and Reuters, "Wary About Cost Recovery, Moody's Cuts Debt Ratings of Ameren, ComEd", 19 December 2005.

[18] See Standard & Poor's, "Research Update: Empire District Electric Downgraded To 'BBB-' on Expected Tight Financials", 17 May 2006.

[19] *Why Are Electricity Prices Increasing?: An Industry-Wide Perspective*, The Brattle Group, Prepared for the Edison Foundation, June 2006, p. 4.

[20] David E.M. Sappington, Johannes P. Pfeifenberger, Philip Hanser, and Gregory N. Basheda, "The State of Performance-Based Regulation in the U.S. Electric Utility Industry", *The Electricity Journal*, October 2001, Vol. 14, No. 8, pp. 71-79.

[21] See, for example, *The Emerging Smart Grid: Investment and Entrepreneurial Potential in the Electric Power Grid of the Future*, Center for Smart Energy, October 2005.

[22] See, Meyer, Peter B. (Ed.) 2001. *Glossary of Research Economics* [online]. Available: http://econterms.com.

[23] Finally, if a utility is going to be asked (or forced) to find a hedging strategy that allows it to operate without an AAC, then the local Commission must also make the utility's complete recovery of complex hedging costs very reliable. Few utilities have reached this degree of regulatory accord with their Commissions.