Cost of Service Regulation In the Investor-Owned Electric Utility Industry

A History of Adaptation

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Executive Summary

This paper examines the history of cost of service regulation in the investor-owned electric utility industry. Its purpose is to provide perspective on the issues facing utilities, their customers, and their regulators today. Section I, "Introduction," describes Cost of Service Regulation (COSR) as an ongoing equilibrium process that is forever rebalancing the relationship between customers and investors. Although observers have periodically argued the need for "reform," COSR has proven remarkably resilient and useful—precisely because it has responded in a pragmatic fashion to new issues as they have arisen.

Section II, "The Structure of Cost of Service Regulation," describes the development, through the Supreme Court's *Hope* decision in 1944, of a core structure that has endured through the present time. The Court in *Munn v. Illinois* (1877) first acknowledged the need to protect the public from the exercise of monopoly power by railroads, although the means for such protection (what was to become COSR) was not available in 1877 and had to be developed through a process of trial and error. In *Hope*, the Court recognized that the regulatory contract involved a balancing of interests between investors and consumers. The Court recognized that regulators need to be free to employ a wide range of methods to ensure that the bargain is preserved under changing economic conditions. It is the end result, not the methods employed, that is the regulator's responsibility.

Co-evolving during the early days of regulation was a legal theory of the public service firm (i.e., the public utility). In *Smyth v. Ames* (1898) the Supreme Court found that a railroad is a *public* highway: even though the railroad was constructed and maintained by a private corporation, the railroad derived its existence and powers (e.g., of eminent domain) from the state. In effect, it was recognized as performing a function of the state.

The concept of the "Regulatory Compact" recognized a set of mutual rights, obligations, and benefits forming, in effect, a relational contract between utilities and their customers. The utility was granted an exclusive service franchise/territory, and in exchange, accepted the responsibility to serve everyone in the territory and submit to price (rate) regulation. The utility was obligated to supply service efficiently, but had the right to recover its costs, including an opportunity to earn a return/profit equal to its market-determined cost of debt and equity capital.

Required revenues—the total of all costs prudently incurred to provide service—is a key element of COSR. In order to establish a just and reasonable rate, regulators identify costs incurred during a "test year," which is a snapshot of ongoing utility costs. In general, required revenues are defined as:

$$TR = TC = [RB - D]ROR + OE + d + T \qquad (1)$$

Where:

TR = total revenue

TC = total cost

RB = rate base or value of capital

D = accumulated depreciation

ROR = rate of return

OE = operating expenses

d = annual depreciation cost

T = taxes.

Required revenues and the rates necessary to realize them are established via the rate case, which is a quasi-judicial procedure designed to provide due process to all affected parties (e.g., the utility, investors, customers) and produce rates which are just and reasonable. As part of the rate case process, regulators evaluate the prudency (i.e., recoverability) of costs after they are incurred.

In effect, regulation serves as an administrative replacement for the market in determining whether costs are efficient. Once the revenue requirement is established, the rates are applied to the real time, real world market place where a set of dynamic factors, including demand growth, inflation, and government mandates determines the actual cash flows and earnings of the utility. To the extent that the real world approximates the assumptions used to establish the total revenue requirements, the COSR model can operate effectively with regulatory lag serving as an incentive to control costs. However, if technical, economic, and financial shocks negate these assumed conditions, regulators have been required to search for pragmatic policy adjustments in order to re-establish the balance of interests.

Section III, "The Evolution of Regulatory Policy," reviews the administration of the foregoing regulatory structure in the decades since *Hope*, demonstrating that while the structure has changed little, key aspects of regulatory policy have changed a great deal. Key policy adaptations are summarized in Table 1.

Table 1. Changes to Regulatory Compact Over Time

	Assumptions for Initial Regulatory Bargain	**Major Issues**	**Adaptations**
Golden Age (1940–1970)	Growth in sales Economies of scale Stable input prices Management control over all cost factors	Expanding sales to fuel growth in economy Financially healthy utilities No major federal legislation	TRR, historic test years, and no post-test year ratemaking Historic depreciated cost valuation of rate base (as a result of *Hope*)
	Changes in Assumptions for Regulatory Bargain	**Major Issues**	**Adaptations**
Rise of Inflation (1970s)	Sales growth slows Unstable input prices Rising interest rates Economies of scale fading (construction cost increases)	Financial instability for utilities Higher prices for consumers Capital cost overruns and cancellations of major plant investment Nuclear safety	Construction Works in Progress Rise of fuel adjustment charges with more regulatory oversight Federal legislation (PURPA, Fuel Use Act, etc.) Changes in nuclear industry regulation

Excess Capacity (1980s)	Sales growth rebounds, but at lower levels Input prices begin to stabilize Economies of scale largely eroded	Public planning process for new generation capacity Demand-side management programs are emphasized Capital cost overruns and cancellations begin to affect rates Incentives for least-cost operation and investment questioned	Integrated resource planning Implementation of PURPA tariffs for buying power from non-utility generation sources FERC action on opening transmission networks to promote wholesale competition Experimentation with incentive regulation, bidding for new capacity, and programs to promote demand-side resources
Incentives and Markets (1990s)	Breakdown of trust in regulatory incentives to produce lowest long-run cost Input prices are stable Competition in wholesale generation markets proving to be effective at providing competitively priced power and energy.	Restructuring of some vertically integrated companies Opening of retail markets to competition Stranded costs of existing generation Fewer rate cases	Retail competition Provider of last resort service Rate freezes and transmission periods Incentive regulation Federal legislation to open markets and planning (EPACT)
Post Markets: Restoring Customer and Investor Confidence (2000–)	Partial market meltdown (gas and electric) Uncertainty concerning structure of industry Regulatory compact under stress Continued downward trend in sales growth	Bankruptcy and financial stress Wholesale prices volatile and increasing Concern over financing new power plants Concern over exposing retail customers to wholesale market prices Diminished trust in markets	Retail competition backtracking Competitive procurement for captive customers Pre-approval of construction costs of new generation Incentive regulation continues Tracking costs and decoupling mechanisms

From the 1940s through the 1960s a set of self-reinforcing events produced a virtuous growth cycle in which increasing electricity consumption was viewed as synonymous with the public good. As demand for electricity grew and technological change captured greater economies of scale, prices fell and earnings were relatively stable.

The oil shocks of the 1970s disrupted this virtuous growth cycle, escalating fuel costs, cutting demand growth dramatically, and producing unprecedented inflation in labor, capital costs, and construction materials. The result was a rapid deterioration in utility credit worthiness. Policymakers responded by extending the use of fuel adjustment clauses (FACs). A more fundamental problem was that, given a reliance on volumetric (kWh-based) rate designs to recover fixed costs from residential and small commercial customers, the sudden slowdown in demand growth meant that utilities were not realizing the incremental cash flows that had helped finance new construction in the past. Policymakers responded to this problem by approving the use of construction work in progress (CWIP) to provide additional cash flow during multi-year construction projects.[1] In effect, CWIP substituted for sales growth to restore balance to the compact.

During the 1980s the inflation and sudden slowdown in demand growth of the 1970s simultaneously produced excess capacity and dramatic cost overruns in both coal and nuclear units that were under construction. Policymakers responded by expanding oversight of the prudence (recoverability) of project costs: between 1975 and 1985 over 50 major cases were brought before state commissions, with the result that through 1989 some $14 billion in construction costs were disallowed. Policymakers also introduced phase-in plans to mitigate the rate impact of new generating units, and they emphasized "least-cost planning," and "integrated resource planning" to compensate for perceived limitations in utility planning methodologies. They also considered the need for explicit incentives for utilities to plan and operate their systems as efficiently as possible. Such policies took the form of either targeted or holistic general incentives.

During the 1990s the lack of confidence in utility planning, and subsequently, in the whole institution of COSR, led policymakers in a growing number of states to decide to rely on competitive markets for the supply of electric power. Regional disparities in rates contributed to customers' desire to shop the grid. Ultimately, 19 states, plus the District of Columbia, implemented retail choice, this typically required the incumbent utility to divest its generation and become a wires-only distribution utility.

In the restructured states, policymakers were presented with a host of new issues requiring significant policy responses. The first was stranded cost—whether and how to allow utilities to recover their unamortized investments in generating units that had been built under COSR—which now would be exposed to market prices. Given low natural gas prices, market prices would not allow utilities to fully recover their sunk costs. In virtually every jurisdiction stranded cost recovery was allowed, because it was necessary to honor the regulatory compact, and was consistent with the development of efficient competition. A second major issue involved the development of market rules for competition among regulated utilities, their unregulated affiliates, and third parties. A third major policy issue involved provider of last resort (POLR) service (i.e., regulated power supply to serve customers not supplied by the market). The cost of POLR supply became a dominant component of the revenue requirements of restructured (wires-only) utilities, creating new risk exposures. Policymakers responded with new authorities to recover energy and fuel costs through energy cost adjustment mechanisms (ECAM) and other new policy mechanisms.

During the 2000s the California energy crisis of 2000 and 2001 and the collapse of Enron triggered a flight of investors out of the electric sector. These events demonstrated to investors that the electricity business had changed in ways they did not understand, and that restructured markets presented substantially greater risks than they had faced in the traditional business. In order to regain investor confidence, policymakers adopted new approaches to resource planning and approval which were designed to mitigate perceived regulatory risk. Chief among these innovations was the adoption of pre-approval of the rate treatment to be accorded new investments—binding, by law, on future commissions. Another important innovation was the use of state-approved auctions to procure power supply by restructured utilities. Continued market evolution during the 2000s (e.g., reflecting technological change, financial deregulation, environmental programs, and energy efficiency concerns) placed additional categories of costs outside of management's control, rendering the traditional rate case mechanism inadequate and requiring new rate policies, including riders or surcharge mechanisms (Riders/Surcharge), trackers for special construction programs (Trackers), ECAMs, and additional safety mechanisms such as balancing accounts and true-up mechanisms (Balancing/True-up).

[1] CWIP allows for the recovery of construction-related interest expense as it is incurred, rather than capitalizing it on the balance sheet as AFUDC, allowance for funds used during construction.

Section IV, “Conclusions,” recognizes the foregoing history in arriving at six overall conclusions, as follows:

1. The Regulatory Compact, which lies at the heart of cost of service regulation, involves a set of mutual rights, obligations, and benefits that exist between the utility and its customers. Regulators’ objectives have been to preserve the balance between customers and stockholders through modifications and adaptations of COSR policies.
2. Beginning in the 1970s and continuing through the present time, economic, technical, and financial factors have threatened to disrupt the fundamental balance of the Compact. Chief among these has been the loss of sales growth, which traditionally provided revenues to help fund new construction, and offset other rising costs between rate cases.
3. Regulators have responded to the foregoing challenge by adopting new policies to restore balance by mitigating regulatory lag. Key innovations have included construction work in progress, cost trackers, riders, fuel and energy cost adjustment mechanisms, and balancing/true-up mechanisms.
4. Today, investor-owned electric utilities point to a “paradigm shift” caused by the need for large new capital additions at a time of declining sales growth and reduced credit worthiness. They urge the development of “new regulatory frameworks” which provide for cost recovery outside of the traditional rate case.
5. There is little doubt that new policies and frameworks are needed. The question is how to configure new frameworks so that they strike an appropriate balance between shareholders and consumers.
6. Regulatory leadership will be critical to negotiating new frameworks.

I: Introduction: Regulation as an Ongoing Equilibrium Process

> Much of the history of administrative regulation of utilities is a history of the perception of deficiencies and of crises, and therefore a history of a succession of official and unofficial inquiries and reports directed at reform.… The concept of crisis has been given the most kaleidoscopic substance, depending upon whose definition of the situation is being acted upon: different identifications of deficiencies have led to different perceptions of crisis and to different reform recommendations. The evocative establishment of a crisis is part of the complex process of public policy making, and attempts at crisis identification are not always successful. *Reform*, therefore, is itself kaleidoscopic in substance, as complex and variegated as the perception of deficiencies and solutions. (Samuels [64]:x–xi)

What is interesting about this observation regarding the regulatory process is how well it captures the truth that in the U.S. political framework regulation is under continuous pressure to adapt to changing perceptions of crisis. What is perhaps more remarkable is that even under this pressure the regulatory framework has played a stabilizing role while the process of public policy responds to the crisis *de jour*. The regulatory framework has been resilient in the face of the flux brought about by economic, technical, and financial shocks that often nullified one or more of the assumptions underlying the original framework, precisely because of the willingness to adopt incremental changes to the process. Like a set of genetic adaptations, the regulatory process retains its form but the substance has subtlety changed over time resulting in a more "fit" institutional structure.

These adaptations, in response to environmental stimuli, enabled the regulatory structure to maintain the fundamental risk-sharing arrangements that were part of the original regulatory bargain whose structure was effectively established in the early 19th century and solidified after the *Federal Power Commission v. Hope Natural Gas Co.* (*Hope*) decision in 1944 as described more fully below. For over 60 years the rate base–rate-of-return method of regulation has weathered many storms and been adjusted to better match the changing economic, legal, and social environment. In explaining how this pragmatic regulatory structure has adapted to a progression of financial, technical, and economic shocks, it has been the willingness of policymakers to modify existing institutional structures to maintain the balance of interests that has been the central characteristic of the modern history of regulation. While the central regulatory framework has remained intact, regulators have shown a willingness to make the pragmatic adjustments necessary to meet the threats raised by the variety of shocks that have buffeted the industry and the economy.

The paper is organized as follows: in Section II the fundamental structure of COSR is established, focusing on the objective of the regulatory contract of balancing the interests of customers and stockholders, the End Result Doctrine enabling regulators to employ pragmatic adjustments to regulatory methods in order to preserve that balance, and a brief examination of the special nature of the public service firm (public utility) within our capitalistic market structure. The paper then explores the special aspects of the regulatory contract outlining the trade-offs, obligations, and the relational nature of the compact between society and the public utility. In order to place this contract into operation, regulators established a set of core components that constitute the traditional regulation framework, including a characterization of the core economic assumptions and legal principles that have evolved in order to establish a well-functioning administrative process. Through the rate case process and the use of the total revenue requirement, regulators established a method for estimating the required revenues to ensure that the utility can meet its obligations to serve customers. If all of the assumptions underlying this snapshot estimate of costs hold, then a utility should have a reasonable opportunity to earn its allowed rate of return if it operates efficiently.

Section III examines the historic period from the late 1940s until the present and identifies periods when the model of regulation worked effectively and periods in which regulators were required to make pragmatic adjustments to their policies in order to maintain the necessary balance between customers and stockholders. This history of adaptation brought about by changes in the underlying conditions that deviate from the assumptions embedded within the traditional model can be seen as a natural outgrowth of the need to maintain the fundamental characteristics of the original regulatory bargain.

II. The Structure of Cost of Service Regulation

COSR represents an evolution in regulatory method designed to implement the regulatory bargain which has evolved through time starting with the Supreme Court's recognition that state regulation of price in certain markets was a necessary component of our modern economic structure. In the following subsections, the relationship between the legal and economic aspects of regulation are examined, tracing the history and characteristics of the regulatory bargain, the role of the public service firm, and the method of implementing the regulatory bargain up to the Supreme Court's decision in the Hope Natural Gas case.

A. The Origin of the End Results Doctrine

In *Munn v. Illinois* the Supreme Court established the legal basis for state regulation by recognizing that certain economic activities were so critical to the functioning of a modern society that government has the right to oversee the prices charged to assure that such services are provided to the public in a reasonable manner. Yet the Court's decision in *Munn* did not adopt a particular process for establishing the prices that could be charged by those entities deemed to be critical to the modern society (often we call these entities "utilities"). Indeed, it was not until the early 20th century that the commission-based regulation of public utilities that is so prevalent today was implemented. Regulation of private entities by expert commissions was something new and there were no "text books" to turn to for guidance. The process of regulation involved much trial and error and experimentation. For instance, the development of the uniform system of accounts, procedural due process, and economic and administrative theory all evolved concurrently to establish what has become the modern regulatory system (Covaleksi [11]).[2] By 1944 the Supreme Court articulated the now well-known premise that the regulatory process involved a balancing of customer and stockholder interests. The Court stated:

> [t]he rate-making process … i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interest. (*Hope* at 603)

This End Result Doctrine states that it was not the *method* employed in setting rates that controls whether a result is reasonable; rather it is the *end result* that matters for setting just and reasonable rate levels. The Court reasoned that:

> It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. (*Hope* at 602)

In *Hope*, the Court determined that *any* method of regulation that results in a balancing of the interests of customers and stockholders is permissible. No single method, formula, or ideal process will necessarily balance the interests of stakeholders under all circumstances. The Court in *Hope* opted for a method of "pragmatic adjustment," enabling regulators to adapt to changing conditions (Id.).

Indeed, *Hope* was a turning point for ratemaking. Prior to *Hope*, in establishing the prudent total cost of service for a utility the focus of debate had been on the valuation of the capital component of service.

[2] Many of the accounting concepts were still controversial as late as 1965 (Price [59]).

Ironically, regulators' interpretation of *Hope* resolved that debate by permitting the use of historic (original) depreciated cost for capital investment, as opposed to an unobservable market valuation which had consumed many hours of debate in the prior 40 years. In the end, the End Result Doctrine resulted in most regulators adopting an accounting cost standard for valuation of utility property which remains the standard today in most cases (see, e.g., Seigel [68] and Copeland [10]).

B. The Utility as a Public Service Firm

As the regulatory framework evolved toward the End Result Doctrine, so too did the utility's role as a public service business. Since the inception of regulation, the symbiotic relationship between serving the public interest and private property rights represented one of the most unique aspects of modern capitalism. While it may not have been accepted by all parties at the time, the creation of this special purpose entity that was "clothed in the public interest," known as a public utility or public service company, did not exactly fit into the traditional definitions of a private firm in the *laissez-faire* world of turn-of-the-century America. The franchise arrangement and the obligation to serve have no analog in an unregulated market and with few exceptions the certificate of public convenience and necessity has no role in a market where free entry and exit are the norm. This new entity was created to serve a special public interest—to serve the public in proxy for the state serving the public. Justice Frankfurter expressed the idea as follows:

> No task more profoundly tests the capacity of our government … than its share in securing for society those essential services which are furnished by public utilities. Our whole social structure presupposes … dependen[ce] upon private economic enterprise. To think of contemporary America without the intricate and pervasive systems which furnish light, heat, power, transportation, and communication is to conjure up another world. *The needs thus met are today as truly public services as the traditional governmental functions of police and justice.* That both law and opinion differentiate from all other economic enterprise the economic undertakings which furnish these newer services is not the slightest paradox. The legal conception of "public utility" is merely the law's acknowledgement of "irreducible and stubborn facts." (Frankfurter [21]:81; emphasis added)

The "stubborn fact" that there are some private entities that are critical to the functioning of modern economic organization defines the condition for regulation. Justice Bradley recites the Court's precedent:

> The inquiry there [*Munn v. Illinois*] was to the extent of the police power in cases where the public interest is affected; and [the Court] held that, when an employment or business becomes a matter of such public interest and importance as to create a common charge or burden upon citizens; in other words, when it becomes a practical monopoly, to which the citizen is compelled to resort, and by means of which a tribute can be exacted from the community, it is subject to regulation by the legislative power. (dissenting opinion in *Sinking Fund Cases* [96])

Indeed, there is a recurring theme in the legal history of regulation placing the utility in the role of representative of the state. For instance, in *Smyth v. Ames* the Court explicitly stated as much:

> A railroad is a public highway and none the less so because constructed and maintained through the agency of a corporation deriving its existence and powers from the state. Such corporation was created for the public purposes. It performs a function of the state. Its authority to exercise the right of eminent domain and to charge tolls was given primarily for the benefit of the public. (*Smyth v. Ames* [113])

Justice Bradley, in another context, claimed that chartered by the state means "for the purpose of performing a duty which belongs to the state itself" (dissenting opinion in *Citizens, Milwaukee & St. Paul RR* [88]). Justices Brandies and Holmes argued that "[T]he investor agrees … that [the utility's] charges to the public shall be reasonable ... [and the utility] is a substitute for the state in the performance of the public service; becoming a public servant." (*Southwest Bell* [114] at 547). Finally, Justice Sanford, in writing for the Court, summed up the issue up neatly:

> Whether the use of the railroad is a public or private one depends in no measure upon the question of who constructed it or owns it. No matter who is the agent, the function performed is that of the state. Through the ownership is private, the use is public. (*Millheim v. Moffat Tunnel Improvement* [103])

For the Court the public utility concept represented an instrumentality—a tool—designed to adjust economic and social relations; its purpose to impose new balance where a maladjusted (i.e., natural monopoly) economic structure existed. That the *Munn* Court had already come to this conclusion many years before is attested to by Glaeser:

> … the doctrine of public interest referred to in the *Munn* case … [is the] recognition that the notion of a common necessity for civilized life underlies [it]. … The concept of a public utility thus becomes a legal instrumentality to achieve an improvement of the standard of life. (Glaeser [22]:179)

As a result, the institution of regulation creates a special relationship between the owners of the private property and the regulator (i.e., the agent of the state) where the lines between conventional notions of managerial prerogative are altered under the regulatory certificate. The public service aspect of the utility cannot be separated from the objectives of society. Indeed, to ensure that these objectives are met, society established the process of regulation where regulators have oversight over this special purpose entity. It is also necessary to examine the mechanism through which society and the special purpose entity codified their relationship.

C. The Regulatory Compact

In order to facilitate this relationship between society and the special purpose entity or utility, the concept of a regulatory contract, compact, or bargain has been employed to characterize the set of mutual rights, obligations, and benefits that exist between the utility and society. In order to induce a utility to commit private capital in the service of society we should expect that it would seek to clarify the terms and conditions under which service is rendered. As under any normal contractual relationship where both parties make tradeoffs in establishing their rights and responsibilities, the purpose of a contract is to establish terms and conditions to allocate risks.

That this relationship is a contract can be gleaned from the evolution of regulation from the 19th century. First, most strong regulation began with an explicit franchise contract that identified the specific terms of the deal, including price, duration, quality of service, and other conditions of service.[3] These franchise contracts later evolved into commission-based regulation in the early 20th century as a result of the inflexibly of the arrangement (Jones [30]). Second, the bargain between society and the utility is best captured by the Court's opinion in *The Binghamton Bridge Case* in 1865 where the Court noted:

[3] "Strong Regulation" refers to the commission-based regulation. Prior to the early 20th century, other forms of "weaker" regulation were attempted, but ultimately abandoned. See, e.g., McDermott [45].

> The … [capital needed is] beyond the ability of individual enterprise, and can only be accomplished through the aid of associated wealth. This will not be risked unless privileges are given and securities furnished in an act of incorporation. The wants of the public are often so imperative that a duty is imposed on the Government to provide for them; and, as experience has proved that a State should not directly attempt to do this, it is necessary to confer on others the faculty of doing what the sovereign power is unwilling to undertake. The legislature, therefore, says to public-spirited citizens: "If you will embark, with your time, money, and skill, in an enterprise which will accommodate the public necessities, we will grant to you, for a limited time period or in perpetuity, privileges that will justify the expenditure of your money, and the employment of your time and skill." Such a grant is a contract, with mutual consideration, and justice and good policy alike require that the protection of the law should be assured to it. (*The Binghamton Bridge Case* [80])

Under this contract both the utility and consumers give up certain rights, or in contract law terms, exchange detriments. Utilities accept the obligation to serve and charge regulated cost-based rates, and customers accept limited entry (i.e., loss of choice) for protection from monopoly pricing. This bargain represents an ongoing mutual relationship between the owners of the utility (and their agents) and the customers; in effect, a relational contract overseen by the regulator (Goldberg [23]). Under this agreement, the utility is provided the opportunity to recover its actual legitimate or prudent costs—determined by a public examination of the utility's outlays—plus a fair return on capital investment as measured by the cost of obtaining capital in a competitive capital market. Investors will only provide capital for provision of utility services if they anticipate obtaining a return that is consistent with returns they might expect from employing their capital in an alternative use with similar risk; customers will only accept utility rates if they perceive that the rates fairly compensate the utility for its costs, but are not excessive as a result of the utility taking advantage of its privileged position. Justice Holmes aptly described this process as finding the midpoint between protecting property and protecting customers from monopoly power:

> An adjustment of this sort under the power to regulate rates has to steer between Scylla and Charybidis. On one side, if the franchise is taken to mean that the most profitable return that could be got, free from competition, is protected by the Fourteenth Amendment, then the power to regulate is null. On the other hand, if the power to regulate withdraws the protection of the Amendment all together, then the property is naught. This is not a matter of economic theory, but of fair interpretation of a bargain. Neither extreme can have been meant, a midway between them must be hit. (*Cedar Rapids Gas Co.* [87])

The regulatory contract has a two-fold focus: (1) establish prices based on the actual prudent costs (i.e., avoid monopoly pricing); and (2) provide incentives to maintain a reasonable level of efficiency in serving the customers. Rates are set with reference to the Total Revenue Requirement (TRR), discussed in more detail in the next section. The TRR identifies the actual prudent costs necessary to enable an efficiently managed firm to operate effectively and allow the company an opportunity to earn a fair return on a forward going basis. Once the rates are set, the regulator becomes somewhat passive as the utility interacts with the forces of input markets and customers' demand to produce a flow of services, incur actual costs, and receive cash flows. If the flow of services, costs, and revenues reasonably reflect the conditions expected at the time the rates were set, then a fair balance is achieved where the utility can continue to operate as expected. Alternatively if market forces unexpectedly alter the actual costs or revenues from the expected levels, then an adjustment in the form of a new rate case is initiated. That is how the traditional regulatory framework ensures that investors continue to provide capital and consumers continue to receive universal service at reasonable prices.

Managers of unregulated firms face oversight from several different sources including pressure from competitors, competition for the control of the management of the firm, pressure from bondholders and banks, as well as explicit regulation truncating property rights such as labor laws, safety regulation, and environmental regulation, in addition to the implicit public regulation that private firms, especially large corporations, often face under the guise of corporate social responsibility. All of these factors impinge on the prerogative of management. The utility faces all of these same pressures, with the exception of the pressure from competitors i.e., market forces.[4] In managing the implementation of the regulatory compact, and the balance implied by the bargain, the regulator is placed in the same position as the market in an unregulated industry. The regulator—with the power to audit, investigate, confer, and evaluate—of necessity diminishes the prerogatives of management, just as market forces compel managers of unregulated firms to conform to operations that promote cost efficiencies. The Court has connected this efficiency standard to the fair return allowed to the utility investors:

> A public utility is entitled to such rates as will permit it to earn a return … equal to that generally being made … in other business undertakings which are attended by corresponding risks and uncertainties … it has no constitutional right to profits … [made by] highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate *under efficient and economical management*, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. (*Bluefield Water Works* [82]; emphasis added)

In modern regulation this "efficient and economical management" standard is implemented through the prudence standard.[5] Some will argue that the prudence review and oversight is a poor substitute for the market, perhaps because the prudence standard is not a market efficiency standard; rather it is a reasonableness standard. Yet markets are not, at all times and for every firm, an absolute efficiency standard either. There are many examples of unregulated firms operating inefficiently or managers in an industry making decisions that are not, strictly speaking, efficient. The reasonableness standard, then, may not be as far off from the market standard as many have supposed (although the notion that cost-based regulation may not be perfect in providing incentives for production efficiency is widely supported in the economics literature). There remains at least one major difference, however, between public utilities and unregulated firms: public utilities are, by extension, an arm of the legislature and, in turn, the people.[6] The people may, from time to time, make policy decisions that are designed to further the public interest, often over a longer time frame than private markets tend to utilize (e.g., energy efficiency investments, smart grid, environmental measures, etc.). The utility and its management serve as an instrument, through the regulatory contract, to achieve these goals and it is reasonable for regulators to provide an adjustment to the contract to take into account new duties that are assigned to the utility over time.

In sum, since the *Hope* decision regulation has created the terms and conditions of the regulatory contract, yet these terms and conditions are often not spelled out in an explicit way or may be implemented on an as-needed basis. Because the regulator is the arbiter of the on-going adaptation of the contract over time, the terms and conditions of the bargain must change as economic and other environmental conditions change. As

4 Although in many cases utilities may face competition, or potential competition (e.g., on-site generation) for portions of its customer base.

5 Despite the Court's use of the terms "efficient" and "economical" in *Bluefield*, the prudence standard has evolved as a "reasonable manager" standard which precludes regulators from "stepping into the shoes" of management. Prudence is discussed in more detail below.

6 Many will argue this is true of any corporation that obtains its right to operate from the legislature. This may be true, but the degree to which utilities are connected to the whims of the people is much stronger than with other corporations.

a result, no single set of terms and conditions will characterize the relational contract for all times under all circumstances. Yet no matter how conditions change, the regulator must always keep in mind the *Hope* End Result Doctrine—the aim of regulation is to preserve the balance of the original bargain between investors and customers. This process implies that utilities must be provided some assurance—on an expected basis, not necessarily in actual outcome—of cost recovery. One may say that this cost recovery process inherently allocates the risks associated with investment and that is a fair characterization, if by risk one means the possibility that rates will rise over time. The original bargain assigned the duty of cost recovery for prudently incurred costs to customers. If, alternatively, one thinks of risk as the normal business risk faced by the utility, then it is beyond doubt that the utility (i.e., investors) bear that risk and is compensated through the opportunity cost of capital.

The question for the regulator in implementing the regulatory contract becomes this: which types of risks are part of the normal cost recovery process and should be assigned to customers and which are normal business risks that are born by investors? It is this question that has confronted the regulatory process throughout history and has become more acute in recent years as some of the long-held beliefs about the operation of utilities have been challenged. For instance, the assumption that growth in sales will provide the necessary cash flow to support capital investment is, perhaps, no longer a reasonable assumption. Further, the belief that costs are stable over time or that utility mangers have control over those costs has, in some cases, been shown to be mistaken as a result of broader changes in the economy. Finally, since the utility is an extension of the state, policy changes requiring the outlay of costs further change the method by which the bargain is implemented. When these exogenous shocks disrupt the process, regulators have adapted by making pragmatic adjustments to re-establish the original bargain in order to preserve the original risk and cost allocations (i.e., the fair balance between investors and customers).

D. Total Revenue Requirement

The revenue requirement is typically given by the following equation:

$$TRR = TC = [RB - D]ROR + OE + d + T \qquad (1)$$

Where:

TRR = total revenue

TC = total cost

RB = rate base or value of capital

D = accumulated depreciation

ROR = weighted average cost of capital equals the cost of equity (profit to owners) multiplied by the percent of equity used to fund the firm plus the cost of debt (average interest rate paid on bonds) multiplied by the percent of debt used to fund the firm

OE = operating expenses

d = annual depreciation cost

T = taxes.

The equation above provides a simplistic exposition of the total revenue requirement required by the utility and masks the complexities of the administrative process. In practice, each cost component involves direct analysis of the costs in question as well as application of the regulatory policies and rules derived from legislation, rulemaking, legal decisions, and regulatory practice. Once all of the policies and practices are applied to determine the TRR, the total actual costs of supplying these services represent the total *prudently incurred costs* (implying that the prudence standard has been applied to all of the factors included in the TRR). The regulator must review all costs proposed to be included in the TRR and make judgments regarding the effectiveness of management decisions in controlling costs in lieu of the competitive market discipline. The rates or prices charged to customers should reflect the costs incurred by the utility on a prospective basis so that the prices, when they go into effect, provide sufficient revenue to cover the actual prudent costs incurred to supply the customers.

Legal Requirements: These concepts are generally imposed by legislation on utilities and must be taken into account by regulatory bodies in setting rates.

- ***Enabling legislation:*** All regulatory agencies are created by the legislature and delegated legislative authority. Regulators play the role of implementing the policies and procedures assigned to it by the legislature.
- ***Public intervention:*** The administrative process is a public process that must follow reasonable rules of due process. Any party having a legitimate interest in the outcome of the process may intervene and rebut evidence provided by the utility or present its own evidence to supports its own proposals.
- ***Obligation to serve:*** This is the requirement that the company plan to serve its customers' demands for services by providing safe, reliable, and adequate supplies under normal business conditions (Rossi [62]; Payton [54]).

Application of Legal Requirements: These are principles or concepts that have, generally, been read into the laws by courts reviewing administrative decisions.

- ***Prohibition on single-issue ratemaking:*** Regulation is designed to focus on the total net cost of service to avoid piecemeal or single-issue ratemaking. That is, regulators are generally required to review all costs included in the TRR to assure that the net result includes all cost increases and decreases as well as productivity changes (*Citizens Utility Board* [89]; *Business and Professional People* [83]; *Utility Consumers Council of Missouri* [115]; *Pennsylvania Indus. Energy Coalition* [110]).
- ***Prohibition on retroactive ratemaking:*** The revenue requirement and, in turn, rates are set prospectively in order to attempt to match the costs that are embedded in the rates with the time period in which the rates are in effect. There is no attempt to rectify past outcomes by making up for lost or excess profits. Conceptually, prices are intended to reflect the costs of the utility at the time service is provided (Kreieger [36]).
- ***Prudent investment standard:*** Prudence is generally defined in terms of the "reasonable manager" standard. The standard does not allow the regulator to substitute its judgment for management judgment; rather the regulator determines that, given the information known or that should have been known at the time a decision is made, the decision could have been made by a reasonable management team (i.e., prudence is *not* a 20/20 hindsight review). Costs that are not the result of prudent management are excluded from the TRR (Allison [1]).
- ***Used and useful standard:*** Utility assets must be sized such that at any given time they are, or can be, used to provide service to customers (*Union Stock Yard* [116]; *Jersey Central Power* [99]; *Duquesne Light Co.* [92]; Lesser [38]).

Regulatory Practices, Assumptions, and Parameters: The following principles or concepts guide the process by which regulators oversee utility rates and service offerings.

- ***Test year:*** The test year is used to ensure a matching of revenues and costs; that is, the test year is for the purpose of setting rates based on the costs expected to be incurred when the rates come into effect. If revenues and costs are mismatched in the TRR, the resulting rates will either over or under recover costs, causing rates to not be just and reasonable (*Iowa Public Service Co.* [97]). Traditionally, regulators employed an historic test year under the assumption that recent costs are a fair predictor of future costs. If costs are changing, however, perhaps due to rapid capital investment or input cost inflation, the historic costs may not be a good predictor of future costs. Recognizing this problem, many regulators have moved to a forecasted or future test year in an effort to more closely match rates with costs (Downs [13]).
- ***Normalization:*** For capital costs, the utility is allowed recovery of all prudently incurred costs. For expenses, the utility is allowed recovery of all prudently incurred costs in the test year. This means that expenses must represent normal operations, not extraordinary conditions. As rates can be in place for a significant period, if extraordinarily high or low costs were used to set prices, windfalls or losses could be created that do not reflect the normal course of business operations (Moss [49]). Legitimate expenditures that are prudent, but fall outside the realm of normal costs within the test year, can be included in rates and are generally amortized over a specific period and recovered in rates. Often such costs are associated with legislative, legal, or regulatory mandates.
- ***Allowance for Funds Used During Construction (AFUDC):*** During construction projects, utilities book interest expenses associated with funding the project until such time as the regulator determines that the project's costs are prudent and should be included in rates. The carrying costs of the capital expenses are a legitimate cost of doing business and compensate investors for providing the funds (Pomerantz [57]).
- ***Market-based cost of capital:*** The cost of borrowed funds—cost of capital—is determined by examining the market rates of return for investments of similar risk. Bondholders (debt) generally receive the market rate of return set through the market process by which bonds are floated. Stockholders (equity)—the residual claimants after bondholders are paid—are allowed a fair profit (cost of equity) set by the regulatory body.[7] The cost of equity measured by the regulator is the return that stockholders expect going forward and is not related to any actual returns the utility may have earned in the past. Its role is two-fold: first, it sets the profit level embedded in the test year TRR. Second, it is used as the benchmark profit level by which to judge the firm's actual returns. Generally, the cost of equity will change with market conditions as well as the change in the risk profile of the utility.
- ***Zone-of-reasonableness:*** While the cost of capital for equity holders used in the TRR equation must be set, at a minimum, such that it compensates investors for the opportunity cost of funds invested, the actual earned levels of profit may fluctuate within a range or zone and still be considered fair.[8] There are many reasons for this variability. Good (or bad) luck may result in higher (or lower) actual returns, but some utilities may be adept at cost containment and earn at the high end of the zone

[7] The market-based cost of capital for equity is a little more complicated than the cost of debt to determine. Regulators generally use economic and financial models utilizing market data to determine the appropriate profit levels for equity holders.

[8] The zone of reasonableness may also be applied within a rate case as cost of equity analysts generally provide the regulator with a zone (e.g., 10.5–11 percent) in which the analyst is willing to claim the fair profit level lies. Regulators may then use other factors, such as the efficiency of the firm, to choose a cost of equity close to the top end of the zone or toward the lower end of the zone.

while others may be less skilled and earn at the lower end of the reasonable range. This zone of reasonableness may not be stated explicitly by the regulator, but is used by the agency when reviewing annual results from operations to determine whether a utility is earning an unfair profit level.

- ***Capital structure:*** As important as the cost of capital is the amount of debt and equity capital used to fund utility operations. This combination of debt and equity capital is called the capital structure and is often determined by the historic or embedded levels of different capital types.[9]
- ***Regulatory lag:*** The primary incentive for cost control is due to the prohibition on retroactive ratemaking: utilities can retain any revenues from cost savings between rate cases. This allows the utility to also retain any additional revenue associated with sales growth beyond the level assumed when prices were set.
- ***Administrative lag:*** Rate setting proceedings generally take between six and 12 months to complete. During this time, in most jurisdictions, the utility is prohibited from modifying its prices, yet costs continue to change and investment occurs. Administrative lag can cause gaps in the ability of utilities to recover prudently incurred costs or, depending on the circumstances, may cause costs in the test year to be overstated.
- ***Known and measurable changes:*** Due to administrative lag, most regulators have allowed utilities to adjust test year costs for those costs that are certain to be expended within (or perhaps up to a number of months after) the pendency of the rate case that would otherwise not be captured by the test year calculation. The notion here is that costs that are certain to occur when the rates go into effect should reflect the costs incurred. This avoids unfairly penalizing the utility for on-going investment and could potentially force the utility to immediately file a new rate case.
- ***Cancellation policy:*** Utilities are required to plan for all future demand, but there are major sources of uncertainty: (1) demand may fail to materialize as anticipated; (2) investment tends to require significant lead time; (3) generally projects require large up-front capital requirements; (4) investment tends to be "lumpy" and technology tends to be unique rendering the investment inflexible (i.e., invested capital has no other use). Given these problems, typical long-term contracting often cannot achieve adequate investment levels. The regulatory contract addresses these issues by providing a method of cost recovery for some or all of the prudent investment of projects that are abandoned or cancelled as a result of unforeseen events (e.g., unrealized demand growth, technological change, excessive input price inflation, etc.). Recovery of prudently incurred costs may be amortized over a number of years and the amortization may or may not include the carrying costs of the unamortized balances (Zimmerman [78]).
- ***Managerial control:*** It is assumed that management has some significant control over the costs included in the TRR. That is, mangers generally have some prerogative to choose different levels of costs by choosing maintenance or investment schedules, implementing cost reducing technologies or business processes, etc. These decisions, and the resulting cost levels, are subject to the oversight of the regulator. There are, however, some categories of costs that may not be within the control of management and such costs may fall outside the TRR concept (Welch [77]; *Standard Law Review* [69]; Dowling [12]).

[9] Regulators have even imposed hypothetical capital structures on utilities under the theory that there is an optimal capital structure that minimizes the cost of financing the firm. A debate on this issue can be found in Volume 8 of the *Wm. Mitchell Law Review* 1982.

- ***Costs included in rates are associated with supplying a current service:*** Customers should only be paying the costs associated with providing the service that they receive in the current billing period, when they receive a benefit from this service (*Illinois Bell Telephone* [95]; *Candlewick Lake* [86]).
- ***Cost-based rates:*** Rates should be based only on the prudent total costs of service.
- ***Fairness of outcomes:*** The result of a rate case should be a just and reasonable rate that balances both parties' interests.
- ***Efficiency of outcomes:*** Where possible, rate designs and incentives should promote efficient allocation of resources for society.

While perhaps not comprehensive, it can fairly be said that these major principles, assumptions, concepts, and practices constitute a large portion of the traditional regulatory framework. In the implementation of the regulatory bargain over time, however, it is the deviations from these assumptions, concepts, and principles, caused by the changing economic, technical, financial, or regulatory conditions that cause the regulator to search for modifications in the framework in order to restore the balance struck in the original bargain. Later sections of this paper will document the changes regulators have been forced to make to the parameters of the bargain to address changes in certain long-held assumptions.

E. Implementation of the Bargain via the Rate Case

The main process for adapting the regulatory contract over time is the rate case. The outcome of a rate case results in the establishment of *base rates* or the prices based on the actual normal costs of providing service determined by the revenue requirement. A rate case is a formal administrative process in which the utility provides support for its proposed cost of service and the public, including the regulatory body, is provided the opportunity to scrutinize the data, policy arguments, and any other relevant information. The rate case timing is influenced by factors such as the forecast demand for services, input prices, capital needs, operational expenses, regulatory and legal mandates, and policy choices that either the utility is proposing to implement or that the regulator has encouraged as a matter of policy. (For example, a utility may propose to implement new technology in order to improve service to customers or the regulator may signal that it wishes the utility to do so. The utility supports that proposal with evidence indicating that such a policy movement is in the public interest and is reasonable.)

Once the rate case has begun all of the principles and practices noted in the last section come into play, notably the *test year* costs proposed to be included in the TRR (i.e., Equation (1)). In many states an historical test year is employed which assumes that past costs are a fair predictor of future costs. If the cost environment is stable, this assumption may be reasonable. If the cost structure is less stable, some states have adopted a *future test year* with the aim to fairly match costs with prices going forward. The test year costs are *normalized* to remove the effect of extraordinary events not expected in the test year. Again, this approach is just another example of how the process is aimed at fairly representing the actual costs recovered through rates. In addition, it is also assumed that all cost categories are under the control of management in the process of delivering services to customers. The degree of cost control depends upon a number of factors, ranging from the structure of the firm (the degree of integration) to the firm's interaction with markets (fuel, labor, and capital) where they have no power to influence price and the utility is a price taker.

Another major influence on the outcome is the application of the *prudence standard*. The commission standing in the place of the market will be required to evaluate the cost effectiveness of major plant investments. Traditionally, the prudence review used to achieve this outcome is a *post hoc* review of the utility's capital projects that are proposed to be included in rates. This places the regulator in the uncomfortable position of potentially having to second-guess utility management during the prudence process. Several principles are applied to prudence reviews in order to minimize second-guessing. First, and foremost, the regulator is not a utility manager; it cannot substitute its judgment for the judgment of utility management. The U.S. Federal Energy Regulatory Commission (FERC) has stated this concept as follows:

> … we reiterate that *managers of a utility have broad discretion* in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a *reasonable utility management ... would have made, in good faith, under the same circumstances, and at the relevant point in time* ... in hindsight it may be clear that a management decision was wrong, our task is to review the prudence of the utility's actions and the costs resulting there from based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses. (*New England Power Co.* [107]; emphasis added)

Moreover, as FERC notes, management decisions must be evaluated as of the time the decision was made. The danger of an after the fact review is the possibility of the commission employing 20/20 hindsight which places management, and investors, in a difficult position. Unlike markets where, if investments turn out to be extremely effective in lowering costs, the market would yield super-normal profits, under regulation the investors of utilities are restrained to earn only normal profits and at best earn a temporary profit due to the lag in rate adjustments. Alternatively, if an investment, with hindsight, turns out to be ineffective, both the market and regulators' 20/20 hindsight review would penalize investors by disallowing these costs. The difference is that under regulation the firm must still serve customers; and the regulator, rather than creating bankruptcy for the inefficient firm, seeks to identify the level of imprudent costs. The goal is to avoid turning these situations into a "heads I win, tails you lose" situation which is inconsistent with the regulatory contract. Yet, as one might expect, these decisions are difficult; if, for example, a power plant, which at the time it was conceived and built provided the potential for large cost reductions, turns out to have been a poor choice, the sheer size of the investment confronts the regulator with the difficult decision, which like the market, punishes management (and investors). Given the discretion that most courts afford regulatory bodies, it is not difficult (and perhaps quite understandable), for regulators to look for evidence in the record to support disallowance, lacking the clear benchmarks that a market process might have provided. In some cases the size and justification for the disallowance maybe more difficult to discern; in other cases, a disallowance may occur when, strictly speaking, no disallowance should occur. Whether this actually happens on a broad basis in practice is beside the point; the fact that it *could* happen can spook investors. If you put yourself in an investor's shoes it is easy to understand the apprehension. As a result, some regulatory bodies have adapted to this concern by instituting mechanisms that commit the body to a fair, unbiased review by applying the prudence standard at the time the decision is made, as opposed to after the cost are sunk. This has been accomplished in a number of ways, including explicit contracting (Wisconsin), pre-approval of ratemaking approach (Iowa), and pre-approval of costs (Alaska and Colorado).

A related but different test is the *used and useful* standard, which implements the principle that customers should only pay for costs that support operations or investment that is being used to provide current service. This test was used to support the methodology to determine which assets were "taken for public use." Today, used and useful is generally applied as a method of determining what assets are used for providing service today or in the near future and therefore included in the rate base in determining the TRR.

While determining the operating costs and rate base is not without controversy, the calculation of the firm's cost of capital is generally one of the most contentious issues in a rate case. The rate of return (ROR) is determined by the utility's *weighted average cost of capital* (WACC). The WACC weights each source of capital by its respective amount and cost. To determine the WACC, the regulator must first determine the appropriate amount of each source of capital, called the *capital structure,* and then determine the cost associated with each source. In general, the sources of capital are debt and equity. Debt is similar to a home mortgage in which the utility signs a contractual agreement to return the lender's money plus an interest rate. The interest rate is the profit the lender makes from the transaction. Equity capital is the value created by retaining earnings after all expenses, including the interest expense paid to debt holders, are paid—the value of the firm to the owners (i.e., the shareholders). As the owners have provided capital by purchasing shares of the firm, this value must provide a competitive return to the owners or they will have no incentive to provide capital. (The return is a combination of growth in the value of the firm and the money returned to the owner over time as a payment, called a dividend.)

Next, the cost of each source of capital must be established. In general, debt costs are measured by the (average) interest rate paid to the debt holders. The cost of equity, or the profit to the common stockholder, is normally much more contentious. The cost of equity is an expectation held by the "marketplace" and is therefore not directly observable. As a result it must be estimated and the question of what is a correct assessment of the market's true value is partly what makes this issue so contentious. Determining the cost of funds, especially those provided by the owners, is not an obvious exercise. While economic theory provides some general guidance, the "devil is in the details" of the actual data used to make calculations. Often analysts who recommend radically different levels of profit for the utility may well agree on both the theory and even the implementation of the theory. One of the "details" facing analysts is determining the appropriate profit level as it is related to the risk the utility faces; it is often argued that utilities face little or no risk and therefore profit levels should be low.

In addition, there are likely several other reasons why the level of profit results in a greater level of scrutiny by the regulatory process. First, financing costs have a special place in the cost of doing business. As noted above, one cannot see the cost of equity as one can see a distribution transformer (or even the interest rate stated on a bond held by a debt holder). It is easy to imagine such costs as ethereal. Second, there is a natural tension between the economic function of profit as a positive incentive toward efficient behavior, and the possibility that profit represents an ill-gotten gain, the result of an exclusive franchise and the suspicion that monopoly power cannot be effectively detected or stopped.

Moreover, profit is often thought of as a zero sum game; that is, if shareholders gain more profit, it must have come at the customers' expense. Indeed, the natural monopoly model itself focuses on the economic profit resulting from the market inefficiency suggesting regulation in the first place. Finally, there is a common misunderstanding that utilities are guaranteed a set profit level. The regulatory process does not guarantee the profit level, only a fair opportunity to earn a set profit level once rates are determined.

The final step in the process transforms the total prudent costs into a set of final prices (rates) that customers will pay for each unit of energy consumed, or what is often called the rate design phase of a rate case. Interestingly, this part of the rate case is often extremely contentious because it involves splitting up the entire revenue pie. This transforms the debate from being the utility against customers to a debate that pits customers against customers. This does not mean that the utility is completely indifferent; the method of rate design can affect the ability of the utility to recover its allowed revenues. For example, prices may depend on the volumetric throughput, i.e., sales of energy, where the total prudent costs, both fixed and variable, are divided by the expected sales quantity (also known as the billing determinants) in order to generate the price for the unit of service. By employing this volumetric rate, the level of profit becomes linked to sales. This link creates significantly different incentives from rate designs where fixed costs inclusive of profit margins are recovered through fixed charges and not through sales volumes. The incentive issues associated with this rate setting process will be discussed in the next section in our examination of regulatory lag.

F. Operationalizing the Bargain: A Framework for Analysis

To recap our discussion of the traditional regulatory process, we can summarize the main points as follows: utility rates are established to recover actual prudent costs, including both used and useful capital and operating expenses identified in the total revenue requirements equation. (These costs are sometimes referred to as *base costs*, as they form the basis of the *base rates* set by the regulator.) Between rate cases a utility's rates are fixed and, unlike firms operating in competitive markets, utilities cannot raise prices to ration demand or, in most cases, even to reflect cost changes. For the snapshot approach to work, regulators assume that costs fluctuate up and down but the net effect on base costs is roughly neutral. The period when rates are effective, however, could be many years depending on the stability of costs and consumer behavior.

This snapshot method of revenue requirement masks the reality of a utility's operating environment; utilities face a number of issues that are not explicitly addressed in the snapshot determination of rates. For example, the ratemaking process sets rates to recover the entire revenue requirement including a reasonable level of profit, but also sets prices for services on a volumetric basis despite the fact that a large portion of any utility's costs are fixed (that is, they do not change as output changes). This implies that the price per unit exceeds the variable cost incurred to produce that unit. During periods of *demand growth*, actual sales that exceed forecast sales (that is, the quantity used to set the variable price in the rate case) provide the utility with a source of cash to fund operations. If costs increase a bit or capital needs exceed depreciation expense, customers fund those cash needs through purchasing more electricity. In a very real sense, customers have been prefunding at least some portion of utility expenditures for most of the history of the industry. When a utility undertakes construction of new plant, investors are compensated for the time-value of their money through "allowance for funds used during construction" (AFUDC), which is an accounting entry that tracks the cost of the funds used and is subsequently incorporated into rates in the next rate case after (prudent) construction is completed.[10]

As is well known, the best plans of a utility may not work out as expected. Changes in the overall economy or the cost of a particular project may cause a prudent utility to rethink its investment decision and cancel a project. Regulators often use a reasonable *cancellation policy* that provides an incentive for the utility to invest when current information indicates investment is the proper course, but cancel the project when updated information indicates cancellation is the least-cost approach. These policies generally allow recovery of, and even potentially on, the capital expenditures of prudently cancelled projects through amortization of these expenses. The reason for this policy stems from the utility's obligation to serve all demand and the fact that utility investment often has a long lead time (in the case of large generation units that might be as long as a decade). The cost of prudently cancelling a project is similar to buying insurance against an uncertain outcome (i.e., demand exceeds supply sometime in the future which results in outages) and, as utilities are legally required to meet all demand, prudent cancellation costs are a legitimate cost of doing business as a utility.

There are also subtle economic issues that face utilities. For example, the incentive properties of rates depend largely on the timing of rate setting—called the lag. Two types of lag are important: (1) the lag between rate cases which will be termed *regulatory lag*, and (2) the lag during the pendency of a rate case, which we will

[10] It may seem contradictory that utilities are provided funds through sales growth and obtain a return on capital investment over time. One must remember, however, that as with any investor-owned company any revenues that exceed costs, inclusive of interest payments to the bondholders, belong to the shareholders (the so-called residual claimant). Utility management has the obligation under corporation law to return that money to shareholders either through direct payments, e.g., dividends, or by investing the money for shareholders (e.g., in its system). If the utility does not directly return the excess cash to shareholders, the utility must compensate shareholders for the use of their money. As this is a legitimate cost of doing business it should be included in the rates charged to customers.

term *administrative lag*. Regulatory lag creates what some economists argue are incentives similar to competition. For example Harold Wein, a former chief economist at the Federal Power Commission (predecessor of the FERC), observed:

> For it is not only lag in regulation which provides incentives and penalties towards improvement. It is lag in the non-regulated world which does the same. If all competition was perfect and all readjustments instantaneous in the competitive world, there would be no financial incentives to change. … The advantage which the innovator gets is time: his competitors cannot imitate him too quickly. (Wein [76]:63)

In most states administrative lag is set by legislative mandate not to exceed some maximum period (generally between six and 12 months). In periods of rapid input price inflation, administrative lag can cause losses for investors as costs exceed revenues during the pendency of the case. Further, most states employ a mechanism for adjusting the total revenue requirements for known and measurable changes that occur during the pendency of a rate case. These modifications are made to attempt to update stale data to more current data, and in the case of capital additions, to compensate investors for on-going investments that would otherwise be lost as a result of the lag in setting rates.

If this real time framework operates as expected then the utility is compensated for its prudently incurred cost of service, inclusive of interest on construction and the prudent cost of any cancelled project, and the extra revenue represented by growth in sales beyond the expected levels can be used to finance the additional capital projects necessary to serve the new demand on the system. Under this approach, the utility has a reasonable opportunity to earn the allowed return granted in the hearing process. To the extent that the capital markets look favorably on this regulatory process, the benefits would manifest themselves in a lower cost of capital over time, and therefore, lower rates for customers. This approach comports with that enunciated by Justice Brandeis as early as 1923, where he noted:

> The compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business. Cost includes not only operating expenses, but also capital charges. Capital charges cover the allowance, by way of interest, for the use of the capital, whatever the nature of the security issued therefore; the allowance for risk incurred; and enough more to attract capital. (*Missouri* [105])

Under this regulatory bargain the utility surrenders its opportunity to earn "super-competitive" returns from the market in exchange for a process where the customers bear the risks associated with providing sufficient cash flows to cover the costs of serving them. Cost based regulation is a bargain where customers are expected to pay for *all* the reasonable costs associated with being served.

This above description translates regulation from a static snapshot in time to a more dynamic framework that incorporates the realities of commercial operation. Regulatory lag, demand growth, and instability of costs establish a framework within which the utility must operate in real time. It is in this real time framework where one or more of the assumptions underlying the snapshot of the rate case process tend to be violated and either the utility will be forced to engage in more frequent rate cases or the regulator must modify the regulatory process in some way to address the violated assumptions. Yet, even within the snapshot approach, problems still exist. Questions of incentives and the need to continually monitor the utility to ensure prudent behavior were and, still are, a major source of regulatory concern. These and other issues will be addressed as we examine the history of adaptation as regulation evolved after *Hope*.

III: The Evolution of Regulatory Policy

The history of regulation is a history of adaptation to the stress on the system as a result of changes in the operating environment that created an imbalance in the regulatory compact and, more than once, threatened its continued existence. During these stressful times policymakers responded with pragmatic adjustments to regulatory policy in order to restore balance to the compact and allow the institution of regulation to continue to serve the public interest. Any division of the history of the industry will be, at least somewhat, arbitrary. Indeed, before the proto-modern utility industry (prior to the 1940s) is all but ignored. This period was characterized by competition, then regulation, then consolidation and collapse. As a historical matter this period is fascinating, and many of the themes of the pre-1940s industry—for example, the build and grow themes—will characterize the later so-called "Golden Age" with which this discussion will begin. Such policy themes had been part of the 1920s and later New Deal policy debates that had spurred LaFollette, FDR, and Pinchot among others to discuss the ideas of Giant Power, and establish both the Tennessee Valley Authority (TVA) and the Rural Electrification Authority (REA) in order to spur economic growth with lower cost electric power which in turn spur electric demand (Hughes [27]; Field [20]; Tobey [73]). As the historian David Nye has remarked, electricity

> … was a new force Americans had introduced into everyday life, one embedded in social processes. It was this promise of transformation that lay behind the proud enumeration of kilowatt hours generated, homes wired, or new appliances sold; the United States prided itself on using half the world's electricity. (Nye [52]:386–87)

From a public policy perspective, since the 1930s government viewed the growth in electricity consumption as an essential component of improving the standard of living for households and the economic productivity of industry. The efficient production of electricity accelerated the transformation of our modern industrial society both in the workplace and the home. It is with this realization of this "build and grow" policy that the discussion will begin with the "Golden Age" of the electric industry.

A. The Golden Age: Build and Grow, 1940 through 1970

The Golden Age was characterized by four main drivers: (1) the U.S. was the undisputed economic leader of the world economy; (2) sales growth was strong and stable; (3) input prices were largely stable; and (4) generation technologies became ever lower cost as sales growth allowed the exploitation of economies of scale. Public policy encouraged electric supply growth in order to fuel the booming economy and rates were largely designed to encourage growth by providing volume discounts (so-called declining bloc rates with demand charges for large customers) (Field [20]). In addition, supply growth was fueled by the ideological struggle between communism and capitalism. This may have been best exemplified in 1959 when Richard Nixon engaged Nikita Khrushchev in the famous "kitchen debate" arguing the merits of the American standard of electrical living against the charges in the Soviet press that only the rich could afford such "luxuries." Nixon argued that capitalism creates freedom, noting that "To us, diversity, and the right to choose, the fact that we have a thousand different builders, that's the spice of life." It was argued that electrification transformed the American home: "for the most part, consumers used a rational process to decide which products to buy. A comparison of product successes and failures illustrates how city dwellers exercised discretion in making choices from the cornucopia of electrical devices" (Tobey [73]).

New larger generating units were built, capturing increased economies of scale, driving down costs, and stimulating more demand for electricity. The risk of demand forecasting error was mitigated by the fact that excess capacity arising from the construction program of any one utility could be matched with the needs of a neighboring utility. The interconnection of the transmission system grew after the Northeast blackout in 1964. In effect a set of self-reinforcing events, linking economies of scale and lower prices, generated a virtuous growth cycle that hid the potential problems that utilities and regulators faced if the economic conditions no longer coincided with the assumptions underlying our historic test year representation of actual prospective costs.

B. 1970s: The Rise of Inflation and the Crash in Growth

By the end of the 1960s growth in military spending (associated with the Vietnam war) was pushing overall inflation rates up. Energy prices were hit especially hard, driven first by the October 1973 Arab Oil embargo resulting from the U.S. decision to re-supply Israel during the Yom Kippur war, and later as a result of growing world oil demand. A second oil market disruption occurred when the U.S.-backed Shah of Iran was disposed by revolutionaries in 1979. Oil prices rose to levels not seen since before the German engineer Karl Benz built the first modern automobile in Mannheim, Germany in 1885. By 1980 crude oil reached a sustained price of roughly $100 a barrel (in 2010 USD) or over 800 percent higher than its average 1970 price. Moreover, the U.S. place in the world capitalist system was beginning to decline. War-torn Europe had made a remarkable recovery and Asian and even some South American economies were beginning to grow. As a result, the Golden Age came to an abrupt end, changing electricity markets in ways that threatened the continued viability of the regulatory compact. There were four significant effects on electric utilities that are worth exploring: (1) fuel price inflation; (2) rising interest rates and construction costs; (3) declining demand growth; and (4) alternative regulation.

1. Inflation and Adjustment Clauses

By the 1970s oil played a major role as a boiler fuel in generating electricity, supplying close to 20 percent of total fuel use. It is perhaps understandable that oil would be used in this way given that for the 33 years from 1940 to 1972 oil prices stayed remarkably stable (and indeed were falling for much of that time)[11] (EIA [16]). For example, the average 1972 price of a barrel of oil on the world market was $12.93 (in 2010 USD), nearly 20 percent *lower* than the average world price in 1940 and over 30 percent lower than its post-War high. With this type of input price history, it is easy to see why the snapshot approach to regulation appeared to be a simple and accurate method of setting prices. As energy prices escalated, however, doubt was cast on two main assumptions behind the snapshot approach. First, utility managers plainly had no control over world oil markets and when prices began to increase dramatically, one of the key drivers of the cost structure of the utility began to increase irrepressibly. Second, rapidly increasing input prices rendered the traditional rate case ineffective as a price adjustment mechanism because administrative lag created an inability to recover the prudent and reasonable costs of producing electricity in a timely manner. The rising price of oil resulted in an increase the cost of generating electricity with the cost of substitute carbon fuels, such as coal and natural gas, increasing as well.

This process undermined the traditional assumption of managerial control and diminished the incentive properties of regulatory lag. Without some process to recover prudently incurred costs in a manner consistent with the regulatory compact, utilities faced untenable decisions concerning investment that would jeopardize their ability to perform essential duties under the compact, i.e., provide reliable service to all customers. The adaptation that regulators embraced was a mechanism first used during the price inflation in the coal market

[11] As prices for oil rose, the share of oil as a boiler fuel fell from a high of 17 percent in 1977 to 2.5 percent by 1997 as utilities substituted lower cost and less volatile coal and natural gas for oil.

after World War I, namely, the fuel adjustment clause (FAC).[12] The FAC adjusted rates at regular intervals to reflect actual costs incurred.

While often called "automatic" fuel adjustment clauses, as more regulators accepted this practice an issue of just how "automatic" the FAC should be and which customers would be subject to such adjustments came to the forefront. Prior to the 1970s, the FAC often had limited applicability, e.g., only for industrial customers. In the 1970s the FAC was expanded to apply to all customers. The renewed emphasis on FACs was not without its critics. Naturally, some viewed the FACs as striking at the heart of the matching principle (i.e., as embodied in the historic test year concept). In effect, the use of a true automatic FAC was viewed as undermining the prohibition against single-issue ratemaking. Other observers claimed the automatic nature of the adjustment undermined the incentives for efficient fuel procurement embodied in regulatory lag or even skewed resource acquisition decisions.

In order to address the concerns raised regarding the use of adjustment clauses, regulators recognized the need for a test to identify appropriate conditions for their use. Regulators identified three factors necessary before a cost could qualify for a pass-through type ratemaking mechanism: the cost should be (1) large (2) volatile, and (3) outside the control of management (Burns, et al., 1991). The Kansas Corporation Commission recognized the need for such criteria when they noted that the FAC costs are

> … largely outside the control of the utility. … [And] ultimately must be passed through to the consumer, and an appropriately designed … [FAC] with proper safeguards, is the most efficient method to accomplish this pass-through. (KCC [100]:14)

A summary of the fundamental public interest reason for a fuel adjustment type mechanism is provided by the Federal Power Commission (the predecessor of the FERC):

> We recognize the need for a fuel adjustment clause. Properly administered fuel clauses can accomplish legitimate public interest objectives. Fuel clauses serve as a cost of service type mechanism to pass through changes in actual, reasonably and prudently incurred costs of fuel (decreases as well as increases), ensure appropriate and timely cash flow to electric utilities by eliminating "regulatory lag," and reduce regulatory expense, administrative process costs, and the number of formal rate proceedings. These features of the fuel clause inure to the benefit not only of the public utility but also the customers and taxpaying public. However, improperly administered or inadequately regulated by governmental authority, fuel clauses can be inequitable and unfair. (40 Fed Reg. [79])

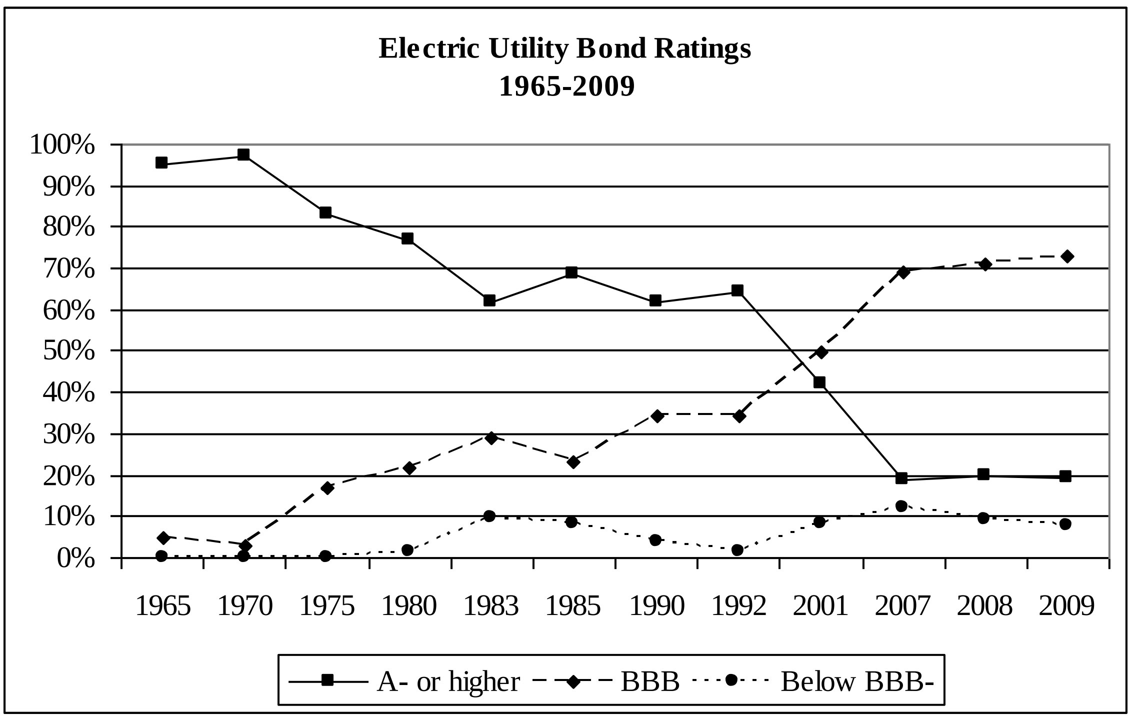
Beyond the principle that both sides of the bargain—utility customers and shareholders—should be treated fairly, there is nothing in that bargain which excuses customers from paying for prudently incurred costs. Utilities (more accurately, utility investors) were willing to enter into the bargain because under traditional regulation the expected cost was nearly equal to actual cost. When this assumption failed, regulators needed to substitute another measure of cost for the expected level embedded in the revenue requirement and most chose to use actual cost.

[12] Trigg claims that by "the middle of the 1920s [the FAC] was a recognized and widely accepted method of utility rate-making …" (Trigg [74]). The Edison Electric Rate Book for 1957 indicates 40 states plus Washington, DC, were employing FACs and 37 states plus DC had adopted Purchased Gas Adjustment clauses.

2. Interest Rates, Construction Costs, and Financing Pressure

A second effect that followed the oil shock was the impact of inflation on financing costs. Coming on the heels of the Vietnam War, a period of double digit inflation ensued with concomitant impacts on capital financial markets. Inflation and nominal interest rates rose sharply, reaching roughly 20 percent by 1981. The rise in interest rates, combined with the elongation of construction schedules, due to a combination of environmental regulations, a significant percentage of new plants consisting of nuclear units and the delays introduced in attempting to match supply with load growth resulted in ever larger amounts of AFUDC on utility balance sheets. For projects still under construction, AFUDC began to grow as a percentage of utility earnings. AFUDC, while in theory earnings, is not actually earnings until placed into rates. The financial industry and investors began to become concerned that utilities with high levels of AFUDC on their books where riskier investments because the actual cash from the AFUDC was contingent on future regulatory approval at a time of increasing rates. This financial strain contributed to deteriorating utility credit ratings as can be seen in Figure 1. The number of utilities with the highest debt ratings began to fall after 1973, stabilizing somewhat by the mid-1980s. These financial issues were further exacerbated by the simultaneous decline in demand growth, which reduced utilities' cash flow to support construction projects.

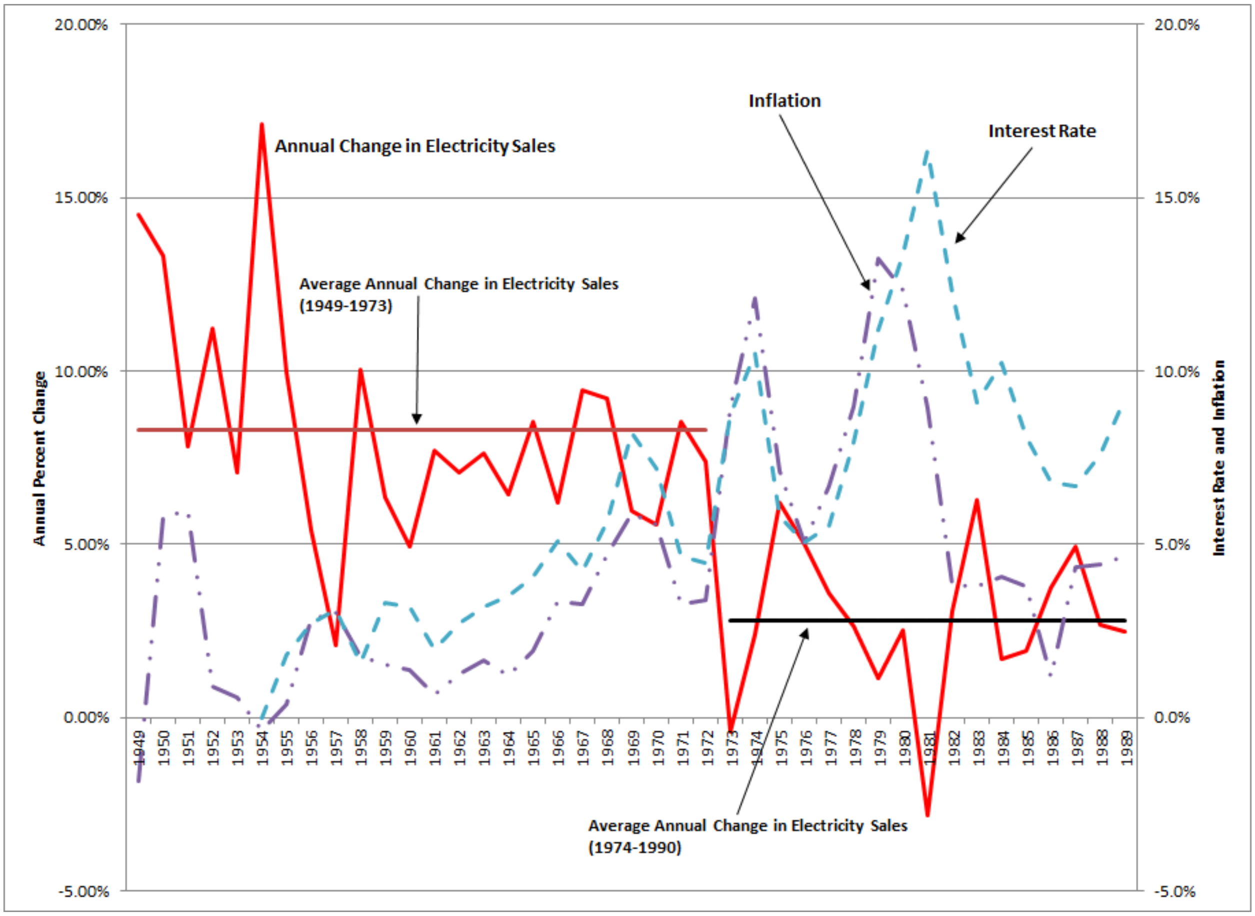
Figure 1. Electric Utility Bond Ratings (1965–2009)



3. Decline in the Rate of Growth and Construction Work in Progress

The third major effect of the oil shocks of the 1970s was the sudden and dramatic slowdown in the growth in electricity demand. Figure 2 illustrates the level-effect in sales of the oil embargo on the average growth rate of electricity sales. The immediate effect on electricity demand resulted from consumers reducing purchases in response to higher prices and relatively stagnant (real) household disposable income. The longer term effects were more systemic as fewer households were formed, customers in basic industries cut back production, went bankrupt, or moved production off shore. In addition, and for the first time in the history of the industry, customers began to actively seek to lower energy costs by reducing or economizing on energy purchases based on the economic benefits of cutting consumption. Moreover, a newly formed conservation ethic began to appear, causing some customers to buy less electricity, reflecting the recognition of the external costs of electricity production as well as overall preference to conserve resources. This process would continue to develop over the next few decades.[13] As a result of all of these factors, electricity demand growth shrank from approximately 7 percent a year prior to 1973 to approximately 2.5 percent a year after 1973 (Figure 2).

Figure 2. Electricity Demand Growth, Inflation, and Interest Rates (1949–1990)



This reduction in sales growth violated one of the major assumptions of the Golden Age of regulation and the regulatory contract. Sales growth was assumed to make up for both increases in costs and provide a ready source of funds for expansion. With the dramatic slowdown in both sales growth and, in turn, revenue growth, utilities and regulators were faced with several unpopular options. Utilities would have to enter the capital market more often, subjecting regulation to greater scrutiny concerning the fairness to investors of the regulatory bargain. Indeed, it was during this time that investors began to concern themselves with

[13] California and Wisconsin became the first states authorizing utility sponsored energy efficiency programs in 1975. The *National Energy Conservation Policy Act of 1978* recognized energy efficiency as a viable alternative to the production of electricity (Eto [18]).

regulatory risk, that is, the risk that a particular state public utility commission was more likely than the average commission to disallow costs and in turn make it more difficult for investors to obtain a fair return. Regulators faced the prospect that, if the regulatory bargain was not seen as fair by investors, they would stop providing funds and systems would begin to collapse. Regulators were trapped in unusual circumstances; while demand for electricity fell in real time, reducing cash flow, it was not certain that the demand reduction was permanent. The obligation to serve still prevailed and there was uncertainty regarding the necessity of these construction projects to meet the future demands. Without an adjustment to the regulatory framework, the utility would have difficulty financing construction. As a result customers would have to be asked to explicitly shoulder their part of the bargain, which meant higher prices and a modification of the traditional approach to setting rates.

One response of regulators was to replace the reliance on AFUDC and sales growth with a process called Construction Work in Progress (CWIP) which allowed on-going construction costs to be placed into the rate base before completion of the project (i.e., to allow the utility to recover related financing costs). The aim of this policy was to provide the necessary cash flow that once was provided by growth in sales. The adoption of CWIP did not reflect any explicit re-allocation of risk to the customer; rather, it simply replaced one customer-driven financial process (increasing sales growth) with the revenues generated from customers by allowing CWIP. Although CWIP was not unknown to the regulatory environment, its application to revenue generating assets represented an innovative use of the policy.

As with FACs, the new CWIP policy was not without its critics. Traditionally, investment was only paid for after it became "used and useful." Qualitatively, many saw a difference between paying for a project after service was being provided and one where customers paid for the plant before it was physically used to provide service, despite the fact that customers had been doing this over time through growth. The fact that customers paid potentially the same amount under each scenario could not be reconciled with the principle that customers be required to pay only for those costs that are used to provide current service (Makhija [42]). Much of the concern arose due to the timing of the shift to CWIP, occurring as it did when many plants were being cancelled and costs were escalating. Moreover, the increasing size of the CWIP requests caused customers to question the efficacy of such a policy when they saw no direct and immediate benefit, especially if the plant were to be cancelled at some future time. A closer examination of the regulatory bargain weakens, to some extent, this argument. Under the traditional approach if a project was considered prudent when it was undertaken on behalf of customers and it was later canceled, the direct cost of the plant, and in certain cases, a return on the investment, was typically allowed in rates. Until the early 1980s, the typical policy for abandoned plant allowed the utility to recover the remaining plant balance, without carrying charges, over some number of years. (Zimmerman [78]). With the low interest rates, however, say 2 percent, the company would recover approximately 90 percent of its investment over a 10 year recovery period. Indeed, under the original balancing act, customers paid for all reasonable actions undertaken on their behalf. As the regulatory bargain required utilities to meet all future customer demand, and the lead time for major capital additions was often many years, the utility, of necessity, was required to undertake projects that, at the time, would have been reasonably expected to provide service. Customers provided the necessary cash in three ways: 1) growing sales revenue, 2) CWIP, or 3) the recovery of prudent costs associated with plants that were cancelled.

There was not a reallocation of risk, however defined, under the bargain; rather the change in the utility operating environment weakened the existing risk allocation that was already embedded in the regulatory bargain. This allocation had originally been addressed in a fashion that was palatable to customers but largely invisible to them—the provision of cash to the utility through the growth in demand which the customer desired. The fact that customers were the major risk bearers was not revealed until growth stopped. Moreover, it is interesting to observe that returns were relativity high in the "Golden Age" and yet regulators typically did not call utilities in for rate cases. In effect there was an implicit insurance premium paid by customers, but one that was easily ignored by customers because they chose to purchase more electricity, presumably because each additional purchase provided a higher value than the price paid. When the premium became explicit *and* the marginal cost increased due to high fuel costs, the ultimate effect on prices attracted customer attention. The difference this time was that customers were asked to give up some of the surplus gained through consumption in order to assure that capacity would be sufficient in the future. The recognition of the "insurance premium" that customers had been paying in their rates and more importantly, the fact that this premium seemed to be increasing steeply, caused considerable frustration for the public. The public was asking: who made these decisions? What input did I have as a consumer? And were these "insurance costs" reasonable? All of these questions became a focus of regulation in the 1980s and again during the industry restructuring of the late 1990s.

4. Regulatory Responses: Alternative Regulatory Models and Legislation

The decade of the 1970s resulted in three major trends. First, some regulators recognized that treating all utility costs as equal no longer fit the circumstances, which led to the loosening of the prohibition on single issue ratemaking. Second, new procedural and regulatory adaptations such as higher-powered incentives, audits, and prudence reviews became necessary. Indeed, by 1975, 30 audits were ordered by 14 commissions. By 1981, 28 regulatory bodies ordered 69 management audits (Krasneiwski [33]). Third, the federal government attempted to develop an energy policy by the end of the decade that emphasized energy conservation, alternative fuel use, and efficient use of existing resources. The shock of inflation led some states to examine incentive- and performance-based forms of regulation to replace the traditional revenue requirements process, including fuel adjustment clauses, interim rates, future test years, performance, and other incentive-based regulatory models. (Joskow [31]). Included among the regulatory policy innovations stimulated during this period were the following:

- **Fuel adjustment clauses:** These mechanisms change the fuel cost component of revenue requirements as the market price of fuel changes. FACs had been in use since the end of World War I, but were often considered automatic in the sense that the regulator relinquished formal oversight in favor of a rule or formula. By the early 1980s, however, many states had implemented more formal proceedings to audit fuel purchasing decisions prior to allowing prices to change. This more formal oversight process attempted to counter the perceived poor incentives and automatic rate increases associated with automatic adjustment clauses.[14]

- **Alternative regulatory plans:** These plans employed a mechanism different than the test year total revenue requirement approach to set rates. Two notable mechanisms were the Cost of Service Indexing plans (COSI) in New Mexico and Michigan (Cohen [8]).[15] In New Mexico the regulator established a zone-of-reasonableness for the rate of return and adjusted allowed revenues (rates) to keep the utility's realized returns within this zone. If actual returns exceeded the upper bound of the zone prices, revenues/rates were adjusted down; if actual returns fell below the zone prices, revenues were adjusted up.[16] The program lasted from 1975 until 1981 with some modifications. The Michigan plan represented a more detailed form of incentive regulation with three main components: a fuel and purchased power clause with a 90 percent pass through, an availability incentive that tied rate of return adjustments to meeting plant availability targets, and a cap on the adjustments of non-generation related operation and maintenance expenses (Schneidewind [67]). This plan lasted from 1978 to 1982.

[14] Between 1973 and 1978 35 of the 50 regulatory commissions that oversee electric utilities investigated fuel adjustment clauses (NARUC [50]:6 and Table II-A).

[15] These plans were a resurrection of the service at cost plans used in the 1920s (Barnes [3]).

[16] The commission cited the *Hope* End Results Doctrine for authority.

- **Federal Energy Policy Legislation:** In 1978 the *Public Utilities Regulatory Policy Act* (PURPA) established several major policy themes that would preoccupy regulators throughout the 1980s. First, PURPA envisaged an increased role for energy efficiency, demand-side management, and the use of an alternative to central station electricity production (namely, co-generation) to achieve energy independence. Second, PURPA introduced a greater reliance on market forces through the adoption of avoided cost pricing for energy purchased by utilities from third party suppliers and the use of competitive bidding for new sources of electric supply (Miles [47]). Third, the federal government became more willing to prohibit certain fuels and technologies, and to implement policy mandates that limited the choices formerly available to utilities in meeting their obligation to serve.[17]
- **The Three Mile Island incident** resulted in questions being raised about the safety of nuclear power. The Nuclear Regulatory Commission (NRC) responded by extending the scope and breadth of its regulation and oversight that fundamentally changed the way the nuclear industry operates to this day.[18]

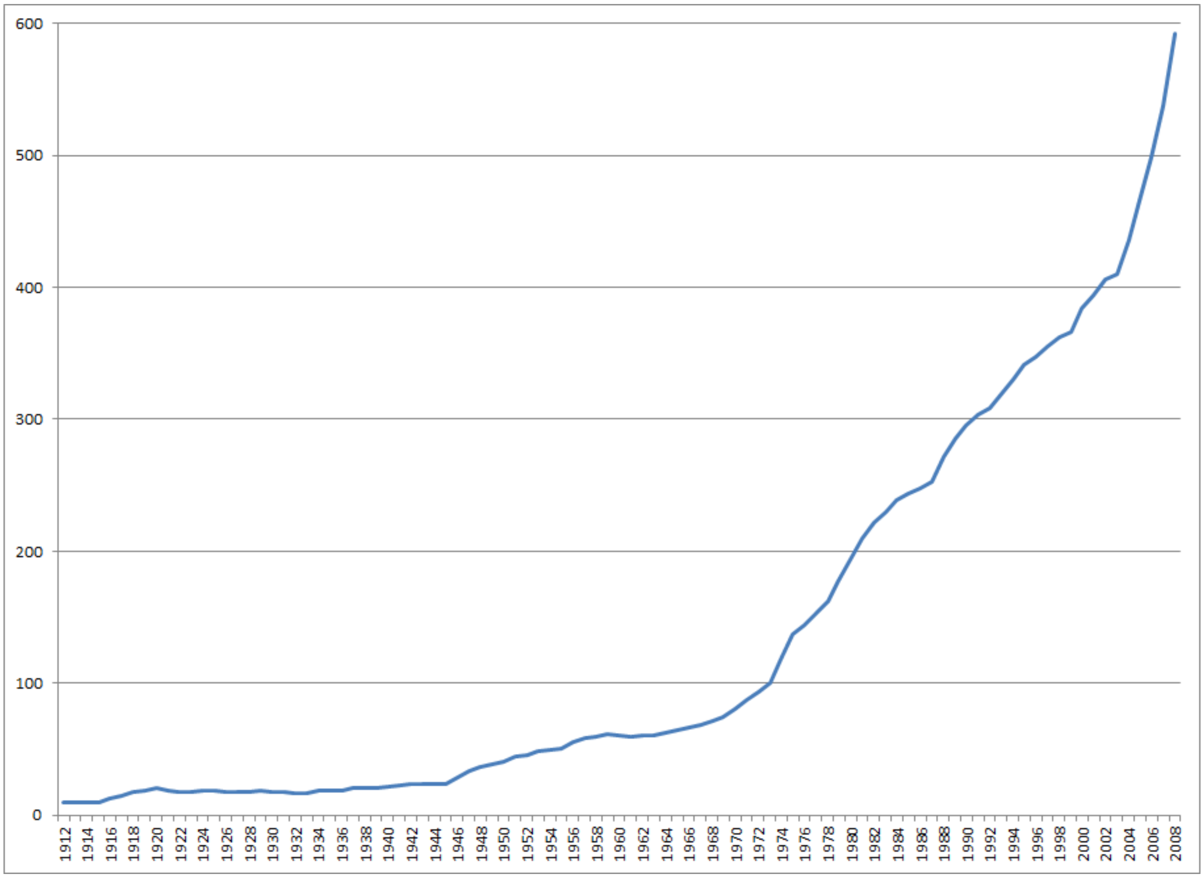
C. 1980s: Issues of Nuclear Prudence and Plant Cancellation

The economic dislocations of the1970s fed directly into the 1980s, where the beginning of the decade saw massive inflation in the cost of construction materials and labor along with double-digit financing rates, helping to produce dramatic cost overruns in both coal and nuclear plants which were under construction. Figure 3 illustrates the increase in the Handy-Whitman Index of construction costs for steam generation. In some cases, cost overruns may have been exacerbated by changing design requirements from the Nuclear Regulatory Commission as a result of the 1979 Three Mile Island incident as noted above. In other cases the continued uncertainty over future electricity demand caused some projects to remain under construction, the delay resulting in higher AFUDC costs. All of these factors led to increasing costs for plants that were ultimately cancelled and substantial rate shocks as plants were completed and entered the rate base. The sheer size of some of these cases represented conditions that the regulatory process had never faced before. In terms of the regulatory compact, this represented a new kind of challenge by creating a need on the part of regulators to ensure that only the prudent costs of cancelled plants and the cost associated with completed plants that may represent excess capacity were paid by customers.

[17] The *Powerplant and Industrial Fuel Use Act* of 1978 also limited the use of natural gas and oil for the production of electricity in favor of coal, nuclear, and other alternative fuels.

[18] For more details on the specific changes by the NRC, see http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/3mile-isle.html.

Figure 3. Handy Whitman Index of Steam Costs (1912–2008)



1. Prudence Reviews and the Impetus for Planning

Regulators responded to the challenge of construction cost overruns by expanding their oversight of the prudence of project costs. Historically, prudence reviews had not been required very much. Between 1945 and 1975 state regulators engaged in fewer than a dozen major prudence cases regarding construction costs of power plants. However, from 1975 through 1985 over 50 major prudence reviews were conducted (OEP [53]; Burns [6]). Indeed many, if not most, of these prudence reviews were unlike previous reviews in the sense that significant sums of money were at stake and the parties became increasing hostile toward one another as a result. A typical case might begin with an independent audit of the utility's project, focusing on the reasonableness of the utility's actions, with the resulting recommendation that the regulator disallow substantial sums of money.

What happened in this period to change the regulators' and intervenor's attitudes toward employing prudence reviews in a more vigorous way? Perhaps the most obvious reason is the sheer magnitude of the costs at issue. By 1987, 33 nuclear power plants were under construction. Of these, 28 were expected to be completed at a total cost of $92 billion; the other units were expected to be cancelled. Of this $92 billion, some analysts expected as much as $40 billion to be at risk for prudence disallowances (Salomon Brothers [63]). Regulators needed a process that could adequately explain to the public which costs were prudent. In effect, regulators were reacting to the public's increasing loss of faith in the effectiveness of regulation to perform its critical function of serving as the disciplining feature of a competitive market. Through 1989, prudence reviews resulted in more than $15 billion in construction costs being disallowed from rates (EEI

[14]). As regulators did with the fuel adjustment clause, a pragmatic instrument was found that suited the industry and economic conditions and preserved the regulatory bargain by limiting the increase in rates for customers to the prudent cost of service.

Yet even with these unprecedented disallowances and project cancellation costs, customers still faced significant rate shock. Where once electricity had been the engine of economic growth due to stable or even falling prices, it was now clear that electricity, much like oil, could increase in price and become a drag on economic growth. Where once the regulatory body was viewed as the necessary check on monopoly power, it now came under fire as a broken institution, outflanked by the utility and by changes in the economic system. The growth of the electric industry helped usher in the modern age and customers and regulators had grown accustom to electricity serving as the foundation for achieving an ever higher quality of life. Having established this unsustainable standard, it was, perhaps, inevitable that the industry would be marred by the soaring price of its product. Regulators had to once again become innovative in order to preserve the terms of the regulatory bargain.

Regulators faced what may be considered an ironic problem. New capacity was more efficient than existing capacity, but had longer lead times and was becoming more costly (in terms of capital costs). Yet older capacity was still needed for reliability while the new capacity came on line. This *lumpiness* of new capital investment meant that any discrete plant could not be removed from the rate base as there was nothing to replace it during construction of new plants. Lumpiness of capital also helped contribute to excess generation capacity. Given this situation, a strict application of the used and useful doctrine would result in under recovery of cost for plants that had still some useful life. One policy response was the requirement for phase-in plans for new nuclear and coal assets. This approach attempted to remove the lumpiness of the capital, at least in terms of rate impacts, and protect customers from rate shock during a time of excess capacity. These policies took several different forms, as follows:

- **Tie-in to reserve margin:** Under this approach a percentage of the new plant is allowed in the rate base; the percentage is based on the size of the reserve margin necessary to maintain reliable service to the customer. This created an automatic mechanism whereby the company periodically presented evidence to the commission on the status of the reserve requirements and, through this process, slowly increased rates, thereby avoiding rate shock for customers.
- **Bifurcating rate base:** Here a portion of the plant found used and useful would be placed in the rate base and receive a full return of the weighted cost of capital while those portions found not used and useful might still receive a return based on the debt portion of the cost of capital (that is, a return of the capital, as opposed to a return on the capital found not used and useful). The utility continues to have the ability to meet interest payments and avoids the negative financial implications of potential bankruptcy. Over time, as more of the plant becomes used and useful, it is phased into the full return component of the rate base and rates customers pay gradually rise over time.

In effect this last approach recognized the insurance function that building in anticipation of demand provides. Regardless of the phase-in approach, an immediate impact on regulators' thinking was that there was a need to plan to avoid these situations and to search for smaller increments of supply or demand reductions. The Least Cost Utility Planning (LCUP) and Integrated Resource Planning (IRP) processes were part of the response to this need.

2. Planning Process as a Potential Regulatory Solution

Primarily because of the rate increases resulting from the inflation and construction of the 1970s, parties were losing confidence in the competence of utility planning and the regulatory approval process. Indeed, for the first time in the history of the industry, anti-utility coalitions emerged and began to participate in the regulatory process. The parties included nearly every form of consumer advocacy group: Attorneys General, industrial customers, and environmental and other special interest groups. It was at this time that a more public and formal planning process in the form of LCUP and IRP began to appear, primarily as a legislative response to the rising cost of energy. These processes were designed to take into account the broadest range of information, produce demand forecasts in a public process (as opposed to internal utility forecasts), and attempt to evaluate supply and demand options on an equal footing. Accordingly, much of the late 1980s saw efforts to establish more effective formal planning frameworks in an attempt to avoid the mistakes that occurred in the 1970s. Regulators embraced this process to varying degrees, attempting to integrate the planning and rate case sequences together in a way that reinforced them both from an information and implementation perspective. This adaptation was in some cases handicapped by the existence of the excess capacity and volumetric rate designs employed in most states. It was argued by utilities that employing energy efficiency measures could erode the ability of utilities to recover the current allowed fixed costs as many utility rate designs recovered a large fraction of fixed costs in the variable charge. Further, if excess capacity exists the planning process will not avoid any new generation as it would not be necessary for many years to come. As generation was largely unnecessary, in many regions of the country the planning process began to focus on energy efficiency measures (referred to at the time as demand-side management programs or DSM programs) to reduce demand in the future such that new plants would be unnecessary or at least delayed for a number of years. In response to these concerns, regulators once again adapted the compact to assure that utilities were fairly compensated for revenues lost as a result of new DSM. The first programs were run in California beginning in the early 1980s. California utilities participated in general rate cases every three years in which a level of fixed cost recovery was determined. An ERAM (Electric Rate Adjustment Mechanism) was used to “true-up” the allowed revenues with actual revenues between cases.

While worthy of consideration as a public policy, IRP suffered from addressing the right problem at the wrong time. Although some states kept the process and were able to use it to address new capacity choices years later, others found the process cumbersome or even partially irrelevant and recognized that economic incentives should play a larger role in allocating industry resources in an attempt to keep costs as low as possible for consumers. Additionally, the *Fuel Use Act* of 1978 forbid the use of natural gas as a boiler fuel in new power plants and was not repealed until 1987. With oil and natural gas limited, the fuels of choice were coal and nuclear. This may help explain the need to complete the high cost coal and nuclear units under construction during the 1980s. It also helps explain the potential excess capacity problems that occurred. Ironically these fuel restrictions were later lifted, at which time certain fuels were avoided while others, like natural gas, became the fuel of choice, but one subject to significant price swings. While the new planning processes had a certain appeal, they are only as robust as the choices that were included in the portfolio and the restrictions of the 1980s ironically worked against good IRP.

3. Regulatory Lag and the Incentives Question

The experience of cost overruns and excess capacity suggested that without effective regulatory incentives utilities would not plan and operate their systems as efficiently as possible. Some economists had long alleged a bias toward excessive capital investment among firms subject to rate base rate of return regulation. The experience of the 1980s seemed to bear this out when many came to the conclusion that regulatory authorities needed to implement explicit incentive policies (Averch [2]). Indeed, at the core of the traditional regulatory framework was the assumption that regulatory lag would provide the incentives to control costs. The experience of the 1970s and 1980s seemed to undermine this assumption. As one critic noted:

> The notion that utilities will respond to regulatory lag as an incentive to cut costs rests on three unspoken premises: that costs actually can be cut by increased efficiency without degrading service standards, that inflation will cause production costs to rise, and that the total possible cost cuts will approximate increases in cost due to inflation over the lag period. (Warren [75]:347)

As Warren goes on to point out,

> Regulatory lag simply acts as a squeeze on the utility. The need for the squeeze, the degree of the squeeze, and when the squeeze should be applied are not issues that the commissions consider when they permit lag. Interestingly, as a utility becomes more efficient, it has more to fear from regulatory lag. An inefficient utility has many cost reductions available to offset inflation during the interim.… By contrast, an efficient producer has few cost cuts yet to be made. High inflation during a regulatory lag period may impair the efficient producer's financial integrity. (Id.:348)

Regulatory lag, as Warren notes, is at best an "inadvertent," "crude," and "clumsy" tool to promote utility efficiency (Warren [73]:348; see also Posner [58]; Bonbright [5]:54; Strasser [71]:522–23; and Morgan [48]).[19]

After reviewing the history of the industry to date, Richard Pierce made four key observations:

> …[First] the regulatory process itself sometimes creates an incentive to overinvest in assets .… [Second] the correct regulatory treatment of mistakes in retrospect would seem to involve both counteracting this incentive by preventing utilities' recovery of the costs associated with plants built in response to this incentive and creating incentives for correct forecasting and decision-making similar to those present in an unregulated market.… [Third] the difficulty of quantifying the effect … means regulatory agencies … [rely] on approximation.… [Regulation] precludes the adoption of pure "market incentives" for correct forecasting .… [Fourth] new plant designed to serve several regulatory jurisdictions offer significant opportunities to improve the operation of the industry. (Pierce [56]:499–500)

This last observation was quite prescient, in some sense, as it forms part of the basis for the movement to large wholesale markets for electric power that was only beginning at this time. From a pragmatic perspective, however, it must be recognized that a public utility—as any for-profit privately-owned company—must work within its budget. Events beyond management's control can dramatically increase expenditures. In a non-regulated entity, that increase results in a restriction of supply; a utility, however, does not have that option and something else must give. It is true that this process also forms the logic for the prohibition on single-issue ratemaking—if costs increase in one area, costs may go down in another area—and managers are assumed to be able to improve productivity to meet these challenges or, at a minimum, rates can be adjusted with sufficient speed to preserve operating budgets. In an era of significant inflation in uncontrollable costs, regulatory lag forces management to consider cutting investments or other expenses that could jeopardize the ability of the firm to fulfill its obligations to serve customers reliably.

This discussion reveals two key points: first, as an incentive to reduce costs, regulatory lag can only work when the effects of inflation and innovation operate across all, or at least a large number of, cost categories.

[19] Kahn [34] provides an alternative view on the importance of lags and incentives within the traditional regulatory framework.

Second, regulators can effectively harness lag by targeting those cost categories under management's control while addressing other costs outside the lag process (that is, outside the revenue requirement setting process or post-test year). By dividing costs into separate categories, with some categories using FAC-type mechanisms and other categories subject to fixed budget levels and the forces of regulatory lag, regulators may be able to have the best of both worlds by tracking actual costs outside managements control and harnessing the incentives of lag where they are under management's control.

Ultimately, the regulatory process faces a triage problem. The set of issues in a rate case typically exceeds the resources available to address each sufficiently. Parties to the case and the commission must "pick their battles." The overall policy question revolves around whether adjustment mechanisms, or other post-test year modifications of rates, can provide a more appropriate level of regulatory scrutiny.

4. More Formal Incentive Regulations

It is a testament to regulators' willingness to experiment with incentives that a range of incentive regulation programs were adopted to address cost control issues. These programs took one of four basic forms:

- **Targeted incentives:** These programs addressed one or a few categories of costs or areas of operation such as availability of power plants (i.e., capacity factors), energy efficiency spending, procurement of fuel, sale of power in wholesale markets, or other specific cost areas of concern (Johnson [29]; Iulo [28]; Stoft [70]).
- **General incentives:** These programs focused on the overall cost performance of the utility (generally as measured in unit cost), and left the utility free to manage its investments and operations as it thought best. Some of the most sophisticated incentive plans compiled indexes of measured performance on multiple parameters of the utility's performance (e.g., occupational safety, reliability, rate levels, customer satisfaction) and adjusted profit (allowed return on equity) to reward or penalize overall performance (Joskow [31]; Navarro [51]; Lowry [41]). Other general incentive plans adjusted allowed unit rates based on changes in external cost indices (as opposed to the utility's own costs) and can be best described as price caps that use some measure of the changes in costs (e.g., inflation minus productivity increases) to escalate prices year-to-year (Schmidt [66]).
- **Decoupling plans:** In California, a different approach was taken to the issue of conservation and the implications for utility cost recovery. This approach was called the Electric Rate Adjustment Mechanism (ERAM). Adopted in 1982, this approach was designed to "adjust base rate (non-fuel) revenues for changes in revenue due to unexpected fluctuations in sales during the test period." The stated advantages of this approach were the promotion of conservation and energy efficiency, innovative rate designs, and the improved opportunity for the utility to recover its cost of capital. By the mid-1980s, the threat of uneconomic by-pass led the commission to pragmatically adjust the mechanism to apply only to the commercial and residential customers and not the industrial customers who were faced with co-generation opportunities and other options to reduce consumption in a period of excess supply. The commission modified the ERAM in 1987 to recognize these market changes in another example of pragmatic management (Marnay [43]; Eto [17]).
- **Rate stabilization plans:** Alabama initiated a plan similar to the service-at-cost plan that New Mexico had employed in the mid-1970s. This plan was in effect an operationalizing of the zone-of-reasonableness concept where rates are periodically adjusted up or down based on the actual earnings compared to a target zone-of-reasonableness. This plan is still in effect and involves the close examination of the utilities' accounts on a regular basis, confirming that the threat of prudence reviews is as powerful if not more powerful than the concept of regulatory lag in creating an incentive for performance.

Incentive or performance-based regulatory models were deployed by regulators to address a large set of problems, ranging from the specific (encouraging conservation or DSM investments, power plant operating characteristics, construction costs, quality of service, and fuel costs) to the more general (earnings sharing mechanisms, rate stabilization plans, rate moratoriums, and decoupling mechanisms). The changes to the economic environment undermined the traditional sources of incentives embodied in the regulatory lag mechanism, requiring the pragmatic adjustment of the regulatory process to find new ways to provide incentives for utilities to control costs while maintaining the regulatory contracts balance.

5. Mergers and the Move to Markets

Perhaps the two most important changes in the economic environment that took place in the late 1980s involved separate, but interrelated issues. First, utilities began to see that larger generation portfolios could reduce generation costs and this provided an incentive for electric utilities to merge (Peterson [55]). Second, there was an increasing interest on the part of regulators and legislators to rely on market forces as opposed to strict command-and-control regulation. The reliance on markets was a larger political issue exemplified by the Reagan (U.S.) and Thatcher (United Kingdom) movements toward deregulation and privatization, yet also specific to the electric industry. The merger activity resulted in the FERC conditioning mergers by requiring open access transmission, thereby allowing non-utility owned generation to be transmitted over utility-owned lines to customers (generally wholesalers that redistributed the power to end users) (PacifiCorp [109]). The move to greater reliance on markets was accelerated by FERC's 1988 pre-construction rate approval in Ocean States Power as well as the notice of proposed rulemakings on market based pricing of electricity (Tenenbaum [72]). All of these factors were layered on top of the incentive provided for non-utility generation by PURPA.

A. PURPA and Independent Power

A central purpose of PURPA was to employ markets to stimulate the production of electricity by non-utility generators (NUGs). In some instances utilities themselves started new affiliated power production companies (APPs) to take advantage of the developing wholesale power markets. Under PURPA states were required to develop tariffs from which utilities were mandated to purchase the NUG output at the utility's avoided cost, providing an incentive for new NUG sources of electric supply. The avoided cost represented the cost the utility purchasing the power would have incurred had it generated or purchased the power itself. PURPA, in effect, created a demand for alternative supplies from the wholesale market. By 1983, 3,500 mega-Watts (mW) of capacity had entered the market; this grew to 59,857 mW by 1987 (FERC [19]; *Electric World* [15]). While still a relatively small portion of overall generation, this rapid growth in the wholesale market created a dichotomy for utilities: they could either build generation to sell electricity to customers under retail rates, or build facilities and sell power in the wholesale market. Depending on how these markets were regulated, the incentives to invest in one or the other market can be significantly affected. Furthermore, if a utility built wholesale plants and engaged in affiliate transactions where the retail arm of the utility purchased the power from the wholesale arm of the company, concerns could be raised over the competitiveness of the purchase price. These issues were addressed in the market-based pricing cases before the FERC.

B. Market-Based Rates

The prudence disallowances that occurred at the state level of regulation in the late 1980s and early 1990s forced many utilities to consider moving more of their generation assets into the FERC-regulated wholesale market. In 1988 the Ocean States plant received an order from FERC that guaranteed cost predictability for Ocean States' wholesale customers by fixing in advance the costs of the plant and its on-line date, with Ocean States absorbing any cost overruns. In other cases, utilities asked to sell power at market-based rates and the FERC would grant this request if the utility could show it had no market power, would cap the rates at avoided cost, or would provide non-discriminatory transmission access to competitive generators. This form of regulatory rate treatment was viewed by many in the industry as superior to the risk of building a new unit under traditional regulation at the state level. By 1991, FERC had received 40 of these market-based pricing requests. As this wave of enthusiasm for wholesale markets evolved, so did the enthusiasm for mergers (Tenenbaum [72]).

C. Mergers and Open Access Conditions

The earliest waves of mergers were primarily a set of contiguous mergers between neighboring companies. These provided the greatest immediate benefits in the form of synergy savings. Often, as part of the process, a holding company would be formed where the accounting, legal, and other administrative and general functions of the utility would be housed. The operating companies very often remained separate. The outcome of this evolution from the state regulators' perspective was a concern over affiliated transactions and how to allocate the benefits of the merger (Peterson [55]). From the FERC perspective, the issue was how to prevent mergers from creating too much market power in the wholesale generation markets. In one of the first major mergers of this period, the FERC conditioned the merger of Utah Power and Pacific Power by imposing open access transmission tariffs on the new company (Utah Power and Light [117]). This mitigated the potential market power of the generation arm of the utility; for states employing competitive procurement policies for new sources of supply, this would provide greater access to more potential suppliers of power. The trend toward a reliance on markets would only accelerate in the following decade and present further challenges to the traditional COSR model.

6. Regulatory Response

The 1980s represented a decade of experimentation by state regulatory commissions. In an attempt to adapt to conditions ranging from rising construction costs to excess capacity and changing federal rules, states experimented with more sophisticated planning processes, more explicit incentive regulation, and regulations to accommodate a greater reliance on market procurement processes. The seeming break down of the incentives associated with regulatory lag renewed regulators' interest in regulatory mechanisms that could improve the incentives to control costs and stabilize prices for customers. As utilities sought to lower costs through mergers, many state commissions imposed incentive regulation conditions on these mergers as a means of capturing the benefits of the mergers for customers. The continued growth in the wholesale market for electricity meant that states were required to devise procurement processes that would enable utilities to secure long and short term supply contracts at competitive market prices. One implication of the shift toward greater reliance on markets was that a greater proportion of utility costs would become subject to market price fluctuations. This implied that a greater percentage of costs could become subject to volatile price movements in violation of COSR's traditional assumptions.

D. Market Restructuring in the 1990s

The 1990s witnessed an increasing recognition that the scale economies in generation were nearing or at an end—which seemed to imply that competitive generation markets, or alternatively, some combination of planning and markets, could reduce costs and increase consumer welfare. These twin themes of markets and incentives continued to dominate the 1990s regulatory environment (McDermott [46]). Reinforcing this trend was the continued consolidation in the industry. As mergers continued, state regulators and the FERC used their authority to condition the mergers to open markets and to impose incentive mechanisms, including performance standards and quality of service criteria, to protect retail customers. By the end of the decade one of the greatest changes to the regulatory environment to ever occur happened in the form of industry restructuring and the problem of transition (stranded) costs as states moved toward competitive markets.

1. Embracing Markets

The forces motivating a reliance on markets came in a number of forms in this decade. One of the most significant was the passage of the federal *Energy Policy Act of 1992* (EPACT). This law created a number of incentives for market development. First, it created a new class of electric suppliers, the exempt wholesale generator (EWG), which formally embraced the trend started by FERC with the market-based rate policy and its approach to open access on the transmission system. This further facilitated traditional utility movement of assets to the wholesale market. In addition, it required states to conduct an IRP process and evaluate the impact of purchase power contracts on the local distribution company. A look back at Figure 1 showing the electric utility bond ratings indicates a significant drop in high quality ratings in 1992 which may be explained, at least in part, as the financial markets' uncertainty regarding the implication of introducing market forces into the electric generation market. In addition, the *Clean Air Act Amendments of 1990* moved away from command and control environmental regulation toward relying on market forces through the creation of tradable pollution rights. This law created the need for special capital expenditures to meet clean air standards. Many state commissions approved special tracker mechanisms to allow for a more timely recovery of these significant investment costs.

Moreover, due to the investment issues in the previous decades there was the perception that the long-run performance of the industry, e.g., generation investment, could be improved through the promotion of competition at the retail and wholesale levels. The primary manifestation of long-run performance in the U.S. electric industry is in the rates charged by utilities.

Table 2 presents a snapshot of 1995 average end-use electricity prices for selected states.[20] The side variation in rates reflects the experience of the electric industry through the 1970s–80s. As some utilities experienced excess supply, the average cost of production rose, while other more fortunate utilities faced little pressure to increase rates. The growing regional disparities in power prices at the retail level motivated customers in some jurisdictions to demand the ability to shop for better power prices. To some observers this result confirmed the idea that traditional regulation could not duplicate the effects of competition or the market.

[20] 1995 was chosen because many states began discussions concerning retail competition around this time.

Table 2. Electric Prices in Selected States, 1995 (cents/kWh)

State	All Sectors	Residential	Industrial	Beginning of Restructuring
Massachusetts	10.3	11.4	8.6	1996*
Connecticut	10.5	12.0	8.1	1995**
New York	11.1	14.0	5.6	1996
Virginia	6.3	7.9	4.2	1999
Florida	7.1	7.8	5.2	—
Indiana	5.3	6.8	3.9	—
Wisconsin	5.4	7.2	3.8	—
Illinois	7.7	10.4	5.3	1997
Texas	6.1	7.7	4.0	1999
Arizona	6.2	9.1	5.3	1998
Oregon	4.7	5.5	3.5	1999***
California	9.9	11.6	7.5	1994
South Dakota	6.3	7.1	4.5	—
Minnesota	5.7	7.3	4.3	—
U.S. Average	6.9+	8.4	4.7	—

Source for prices: Table 27, Electric Power Annual, 1995, Vol. 1, Energy Information Administration.
+The "All Sectors" prices do not match due to differences in calculation techniques.
*Regulator issued first restructuring plan. Final plan issued in 1997.
**Regulator issued report calling for restructuring.
***Legislation allows for partial retail access.

2. Retail Choice

By 1995 many state legislatures were preparing legislation to bring competition to the retail electric market, or at a minimum studying the issue. Retail choice in many cases would require the electric utility to divide itself between generation and delivery (distribution and transmission) functions. In most cases, states either required divestiture of utility-owned generating assets or provided attractive incentives for utilities to move generation to a separate subsidiary in order to create a competitive marketplace. The delivery function remained subject to cost of service regulation at the state level (or FERC for the majority of the transmission function), but generation became subject to the discipline of the market and the oversight of FERC. Consumers would no longer be asked to bear financial responsibility related to the construction of generating capacity as they did under the original regulatory bargain; such risks would be borne by investors.

The design of the retail choice programs varied considerably across the states, but in virtually all of them the issue of stranded costs was addressed. Stranded costs generally referred to the portion of the original fixed generation costs incurred to meet the obligation to serve retail customers while there was still a retail monopoly that would be lost if the utility was immediately forced to sell at the market price. In addition, restructuring involved a so-called *transition period* to allow a gradual movement to retail competition. This was designed to serve two purposes. First, the incumbent utility would be given some time to undertake the necessary business transformation. Second, mass-market customers would continue to be served by the utility, providing stranded cost recovery for the utility and a safety net service for customers until retail markets had evolved sufficiently to serve the mass markets. In some cases, this period lasted as much as a decade and in others just a few years. In addition, regulators also created a service know as provider-of-last-resort (POLR) or standard offer service for customers who did not choose a competitive retail supplier (Graves [24] and [25]). In establishing these rates, some commissions used this as an opportunity to encourage competition by setting these rates above the market prices while in other states it was set below the market price. The problem this created was that competitive suppliers could use this service for price arbitrage (e.g., when the cost of serving customers rose above the POLR price, the competitor could return the customers to the utility). In response to this behavior regulators adopted minimum customer stay provisions and or exit fees to discourage customers from jumping back and forth between the utility and competitive supplier during periods of high market prices.

Finally, many restructuring plans included retail rate freeze provisions that protected customers from rate increases during a number of years during the transition process. These rate freezes acted in many ways as a form of price cap regulation that created strong incentives to reduce costs and improve profitability. Also, depending on how the price cap was set, it could create a disincentive for customers to search for competitive suppliers. The move to restructuring took many forms and the success or failure of the transition was clearly linked to the design of the transition process. Ultimately 20 jurisdictions, including Washington, DC, restructured the retail electric industry, representing approximately 44 percent of the U.S. electric demand.[21] Some states that adopted competition faced market conditions that resulted in the abandonment of restructuring and a return to traditional regulation.

3. Planning and Incentives

Somewhat ironically, at the same time that some states were exploring market processes other states were examining new ways of introducing integrated resource planning into the regulatory process and better incentives into the traditional regulatory framework. The irony arises in the fact that the EPACT legislation of 2005 embodied both market and planning concepts for regulators to explore.

- **Planning Issues**

  On the planning side, the issues regulators addressed were often associated with how to create incentives for greater demand-side and energy efficiency programs while simultaneously facing the legacy excess capacity from the 1980s. Many states experimented with policies designed to give rate base treatment to investments in conservation and DSM in order to place those decisions on par with traditional supply side options within the utility business model. At the same time, some state commissions were addressing the need to implement special contract rates and economic development rates in order to retain or build load in the face of excess capacity. Clearly the problems facing states were similar and at the same time qualitatively and quantitatively dissimilar. This explains the wide ranging set of policy responses to the changing economic environment facing utility regulators in this decade.

- **Incentive Programs**

  By 1995 many states, utilities, and the National Association of Regulatory Utility Commissions (NARUC) were investigating the potential for incentive regulations on both targeted and comprehensive level (Biewald [4]; Lowry [40]; Comnes [9]). Both performance regulation and incentive regulations were being examined. Performance regulation was designed to link rewards to improved performance either for a targeted activity, such as power plant productivity, or more generally on quality of service or total cost reductions. Incentive regulation often encompassed performance regulation and linked profit to specific activities such as energy efficiency targets. One of the primary incentive mechanisms was the earnings sharing mechanism (ESM) (McDermott [44]). This mechanism was considered simpler and in some sense more elegant than the more complex plans.

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[21] A current summary of retail restructuring programs can be found at http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

Table 3. Selected Examples of Incentive Regulation

Jurisdiction and Company	Time Frame	Plan
CA—SoCalEdison	1998–2001	Price cap with ESM (distribution)
CA—SDG&E	1994–1997	Revenue cap (integrated utility)
	1999–2002	Price cap with ESM (distribution)
IL—All electrics*	1997–2007	
IA—MidAm	Through 2010	
DC—PEPCO (dist.)	Through 2007	Rate case moratorium/rate freeze
NY—RG&E	Through 2008	
Ohio—All electrics	2000 through end of MDP**	
PA—PECO (dist.)	Through 2006	
AL —APC	Ongoing	
CT—CP&L	2003–	Earing sharing mechanisms (ESMs)
GA—GPC	Through 2007	
LA—Entergy (NO)	2003–	

Sources: Sappington (2001) and authors' research.
*Includes ESM and benchmark for residential rates.
**Different utilities had different market development periods (MDP).

Another twist of fate during this period was a result of negotiation by a number of utilities to freeze their rates and in some cases to eliminate the existing FAC clauses as part of their bargain to restructure the industry. With fuel input prices stabilizing during this time period, utilities sought to minimize rate case expenses inclusive of fuel cost reviews. Fixing rates and eliminating fuel adjustments was also viewed as positive by consumer and government interveners and negotiated as part of the restructuring of the industry. As a result, the importance of the FAC in the revenue equation diminished in a number, but not all, of the states. This changing fuel market condition allowed state regulators to employ rate freeze incentives to keep customer rates more stable in this period.

4. Responding to Government Mandates

The Clean Air Act and other environmental laws required a number of actions on the part of utilities that involved the incurrence of considerable investment and operating cost expenditures. Two examples from this period come readily to mind: the scrubbing of coal fired power plants and the need to remediate old manufactured gas plant sites. Both of these situations created expenses that were not necessarily associated with any benefit to customers from the electricity supplied, but did provide a public good benefit of cleaner environments. What confronted regulators was another set of costs that were large, sometimes volatile, and outside of management control. State regulators reacted to this by employing adjustment clauses or surcharge (rider) mechanisms for the recovery of these special or extraordinary costs.[22] These mechanisms functioned as a separate means of cost recovery without the necessity of incurring a full rate hearing. The costs passed through in these mechanisms may be adjusted monthly or annually, and are typically subject to a prudence review, with customers receiving a rebate if imprudent expenditures were discovered. The changing nature of the economic environment was resulting in a larger number of categories of costs being addressed via "non-normal" processes and therefore not adequately treated within the typical rate case. The expanded use of

[22] For example, Pennsylvania authorized regulations that accelerated cost recovery through riders for capital costs to upgrade existing coal units, see 52 PA Code Ch. 57. In the case of coal tar remediation a number of states adopted rider mechanisms for the recovery of these costs.

rider or surcharge mechanisms to address these new categories of cost was a natural adaptation of the traditional rate case model.

E. Post Markets: Restoring Customer and Investor Confidence

The first decade of the 2000s would see a new set of challenges including a transition from stable prices to renewed inflation, a temporary return of energy growth that had not been seen since the pre-oil embargo days, and at the end of the decade, one of the worst economic down turns since the Great Depression. On the market front, competition experienced both major meltdowns in some states and continued success in others. This chaotic world presented regulators with a constant set of challenges and led to a renewed search for tools to improve their control over utilities in order to maintain cost effectiveness while meeting customers' needs. The continued mixture of markets and regulation resulted in a set of regulatory tools, including the creation of a set of codes of conduct to prevent cost shifting and cross subsidization between regulated and competitive services, the expanded use of single issue or post test-year rate mechanisms, and greater focus on procurement processes and pre-approval mechanisms to address the risks associated with large investment projects.

1. Markets and Meltdowns

Unfortunately, restructuring did not work as planned in a number of states. In California, the state which led the nation toward competitive retail electric markets, restructuring policy suffered from an over-reliance on spot markets. Utilities were required to sell all of their power into, and buy all of their load-serving power out of, the California Power Exchange (PX), which operated a day-ahead hourly spot market, holding auctions and matching bids for purchase and sale. From its inception in April 1998 until May 2000, spot prices were reasonably stable and on the order of $30/mWh. However, beginning in May 2000, average monthly PX prices began to escalate in dramatic and unprecedented fashion, peaking at over $300/mWh during January 2001. The central problem facing the utilities was that on the retail side of the business the rates were frozen. As a result, California utilities incurred huge costs which they were not allowed to flow through to retail customers, leading to the insolvency of the two largest utilities in the state. As a result the state was forced to step in and procure the utilities' "residual" power requirements that could not be met by utility-retained generation.

The melt-down of the California market, together with the December 2001 bankruptcy of Enron, sent shock waves across the country and the industry. For state policymakers, it demonstrated that there was political risk in electricity restructuring; for investors, that restructured markets presented new risks that were not present in the traditional regulatory bargain. Restructured utilities were, as the saying goes, "not your father's utility"; they were different in ways investors did not yet understand. As a result of this uncertainty many states continued to place on hold any further exploration of introducing retail competition into their utility markets.

The result was a great flight to safety, and not without reason. During the 1990s, utility operating environments had changed in ways that subjected utilities (and their investors) to increased uncertainty and risk. At the wholesale level, the divestiture of rate-based generating assets made restructured utilities far more dependent on wholesale purchases than ever before. Even utilities that remained vertically integrated have faced uncertainties about future state restructuring policy, leading many to rely on wholesale purchases rather than commit new capital to build rate-based facilities. At the same time, the development of competitive wholesale markets (open access transmission, market pricing authority, the introduction of spot markets) brought unprecedented volatility in energy prices, leading to major new uncertainties about the optimal timing of purchases. Fuel prices also became more volatile, at least in part because of declining fuel diversity, a legacy of PURPA and other legislation which continued the search for a silver bullet fuel to satisfy environmental as well as cost concerns. (Incidentally, during the 90s nothing was built except gas-fired generation, which was subject to considerable price fluctuation.) And then there was retail access, which contributed new uncertainty about the loads utilities were (still) obligated to serve. All together, these effects translated into major new planning and procurement uncertainties that either were not present under traditional regulation or markets, or at least not present to the degree they were by 2000.

The flight of investors was clear evidence that they viewed the compact as unbalanced. What regulators were searching for were new ways to measure and manage risk, new resource planning and approval procedures to provide increased regulatory certainty regarding costs recovery, and new mechanisms for keeping up with volatile costs over which the utility had little control.

2. Procurement

In response to these changes in the economic environment, regulators experimented with a number of new resource procurement processes. Two basic approaches were examined, with a number of state-specific variations of each. The first involved the development of competitive procurement rules that established the prudence of acquired resources; the second experimented with "pre-approval" processes for new resource investments within the traditional regulatory process.

A. Competitive Procurement

Competitive procurement is a market-based process in the sense that it structures a competition among market-based suppliers. It mitigates regulatory risk by defining a procurement model (e.g., the criteria by which winning bids will be selected) which the regulatory commission reviews and approves as reasonable—before it is used. This creates a presumption that the results coming out of the process (e.g., costs associated with winning bidders) will be prudent and recoverable without further review. Variations of this basic approach have included competitive RFP (request for proposal) processes in which winning the competition is used to support application for a certificate of convenience and necessity (i.e., used as evidence that it is the best, most economic option available to meet agreed-to needs) (Louisiana Public Service Commission [101]:201–9]). Another variation is a "closed auction" in which the utility issues a request for a defined quantity of supply, would-be suppliers bid a price, and the utility selects winning bids based on cost (Massachusetts Department of Telecommunications [102]). There are also "open auctions" in which the utility offers a price, sees how much the market (suppliers) are willing to offer at the price, and adjusts subsequent price offers until supply equals the utility's demand.

3. Pre-Approval Mechanisms

Pre-approval processes seek to obtain regulatory review and approval (i.e., the prudence of costs), before they are incurred (Regulatory Research Associates [61]). The purest form of this approach may be a statutory scheme that provides for the determination of the rate treatment to be accorded new projects before they are undertaken, with results binding on future commissions (Iowa [98]). Variations include pre-approval of an affiliate lease that provides for the recovery of costs associated with a new plant (Public Service Commission of Wisconsin [111]:17).[23] Other variations have sought to define acceptance criteria (i.e., prudence criteria) for resources being procured to implement an approved resource plan (California Assembly [84]). Still others have sought to create the presumption of prudence for costs incurred to procure, or develop, resources identified in a public utility approved resource plan (Colorado Public Utilities Commission [90]). All of these innovations were designed to improve the cost estimates and prudence of the rate base and fuel costs recovered in the traditional revenue requirement calculation. The twist on traditional regulation in this

[23] Additional leases were approved in 2003 for the construction of two coal-based generation facilities to be located in Milwaukee County.

approach is moving the bulk of the prudence discussion to the front end (*ex ante*) of the regulatory process as opposed to the traditional (*ex post*) review upon completion of the plant. It also involves the use of incentives such as price caps to protect customers from cost overruns which in turn force the pre-approval process to be as accurate as possible in forecasting costs. Like the idea of breaking regulation into components (base rate, fuel adjustment, environmental adjustment clauses) and reviewing them in some sequential fashion, pre-approval rearranges the order and effort expended in the regulatory process. It represents a change in kind, not in quality. The same levels of effort and review are utilized but in a different order than under the traditional approach.

4. Markets and FAC Evolution

During this decade, fuel price volatility resurfaced along with a greater reliance on markets for the procurement of both power and fuel. Regulators recognized that fuel costs were evolving into more generic energy costs. This was especially true as power markets and natural gas fired generation became an important part of the utility supply portfolio. The inherent volatility resurrected the concern that FACs or, more broadly, energy adjustment mechanisms (ECAMs), were needed. Indeed, the experience of California, in which utilities had fixed retail prices but faced escalating input prices, helped focus regulators on the problems raised by an imbalance in the method of procurement and the process of pricing. Several new fuel adjustment clauses have been implemented in recent years as a result.

Table 4. Recently Enacted Fuel Adjustment Clauses

State	Utility	Date
Arizona	Tucson Electric Power	Dec-08
Missouri	Empire Electric	Jul-08
Missouri	AmerenUE	Feb-07
Missouri	Aquila	May-07
Montana	MDU Resources	Apr-08
New Mexico	PS New Mexico	May-07
Oregon	Portland General	Jan-07
Vermont	Central Vermont PS	Sep-08
Virginia	Potomac Edison	Apr-08
West Virginia	Monongahela Power	May-07
West Virginia	Potomac Edison	May-07

Source: author’s research.

5. Incentives

For a number of states, the perennial issue of incentives was addressed through the implementation of earnings sharing mechanisms (ESMs). Between 2003 and 2005, 16 states adopted some form of ESM; in some cases these were specifically aimed at the activity of off system sales and/or procurement which recognized that a greater reliance on wholesale markets for supply procurement implied an opportunity to make more sales and generate revenues to offset system cost increases or create incentives to minimize the cost of procuring resources.

In addition to these newer mechanisms, states also have re-examined the use of CWIP, Trended Original Cost (TOC) rate base, sale and lease back, and turnkey contracts. The focus on the risk sharing and cost recovery methods stemmed in part from the significantly different financial conditions of most electric utilities as they entered this new potential round of construction as opposed to the past. Utilities were significantly financially healthier back in the 1970s when the last construction boom occurred.

6. Trackers and Decoupling Developments

The first decade of the 2000s has seen a marked increase in the need to replace aging infrastructure and the potential for modernization of the network through the use of digital and smart grid technology. In some states new government mandates to improve energy efficiency and the ability to address growing costs of environmental control have all placed greater pressure on the utility and commissions to adopt alternative cost recovery programs for these targeted expenditures. These new and old stresses have once again threatened the regulatory bargain as large capital investments or operating costs are imposed on the utility. Regulators have experimented with the use of tracker mechanisms in situations where the costs of the specific activity are identified and recovered as incurred, and the prudence of associated costs is reviewed periodically. This allows the timely recovery of costs, which maintains the utility’s financial integrity and protects the level of service provided to customers. In addition, these mechanisms will often involve a true-up process. Since the process of granting rate increases ahead of the completion of the project involves a risk that customers will over pay for the final product, true-up mechanisms represent an appropriate retroactive method for providing customers a rebate should expected costs not materialize. If the rebate is inclusive of interest then the customer is held harmless under this process.

Similarly, recent government mandates regarding renewable portfolio standards (RPS) have resulted in new costs for wind, solar, and bio-fuels that may be above market and have been treated as a separate cost category for recovery through a rider or adjustment clause mechanism. Likewise, the costs associated with mandated energy efficiency programs will not be related to the factors driving infrastructure replacement or the variable costs associated with new emission controls. For that matter, the costs associated with market driven pension and health care costs may be isolated as cost categories outside of the normal categories typically addressed in rate cases. In some cases, economic downturns have caused some cost categories that have been relatively stable and predictable (such as bad debt expenditures) to become volatile and larger than in previous experience. Treating these costs through new recovery mechanisms does not imply that review and justification are rendered nil. Regulation is a process of safeguarding, and any new process must have concomitant protections to assure that customers are only paying for reasonable actual costs. The evolution that has taken place in the regulatory process has simply reflected the pragmatic need to match rates with actual costs; the powerful incentive of prudence reviews and commission audits will continue to play an essential role in providing a surrogate for the market discipline necessary to induce efficient behavior on the part of the utility and maintaining the parameters of the regulatory bargain in the process. Regulators have not eliminated their traditional tools of management audits, prudence reviews, or even traditional rate cases if the situation warrants those tools be employed. The following list is just a sample of the programs that regulators have adopted:

- interim rates (Utah Public Service Commission [118]);
- trackers for recovering specific expenses such as bad debt (Vectren Energy Delivery [119]);
- pension costs (NSTAR [108]);
- environmental costs (Commonwealth Edison [91]);
- storm damage costs (Florida Public Service Commission [94]);

- certain capital items, such as smart grid or advanced metering investments (California Public Utilities Commission [85]);
- formula rates (Alabama Public Service Commission [81]; Mississippi Public Service Commission [104]);
- earnings sharing mechanisms;
- decoupling (Lesh [37]); and
- rate phase-in plans for major capital investments (Public Service Commission of Wisconsin [112]; Regulatory Research Associates [60]).

Each of these mechanisms has been employed by commissions to maintain the balance between customers and stockholders according to the original regulatory bargain. The continued growth in environmental regulations, the introduction of smart grid into the utility network, continued sluggish growth in demand and low natural gas prices will continue to confront state regulators with regulatory challenges. History, however, if it is any indication of the robustness of the regulatory institution; shows us that regulators will be able to rise to these challenges and adopt pragmatic solutions to these real world problems.

IV. Conclusions

1. The Regulatory Compact, which lies at the heart of cost of service regulation, involves a set of mutual rights, obligations, and benefits that exist between the utility and its customers. It is, in effect, a relational contract that balances the allocation of risks and benefits between the parties. The compact was designed for a financially healthy utility with reasonable cash flows to sustain a construction program and deliver the services it was obligated to supply under the regulatory bargain. It also assumes that the various categories of costs associated with providing services to customers were similar in character and stable over time. Analytically, the traditional ratemaking formula for determining total (base) costs of service was given by:

   $$TR = TC = [RB - D]ROR + OE + d + T \qquad (1)$$

   Where:

   TR = total revenue

   TC = total cost

   RB = rate base or value of capital

   D = accumulated depreciation

   ROR = rate of return

   OE = operating expenses

   d = annual depreciation cost

   T = taxes.

2. Beginning in the 1970s and continuing through the present time, economic, technical, and financial factors have threatened to disrupt the fundamental balance of the Compact. Chief among these has been the loss of sales growth, which traditionally provided revenues to help fund new construction and offset other rising costs between rate cases.

3. Regulators have responded to the foregoing challenge by adopting new policies to restore balance by mitigating regulatory lag. Key innovations have included construction work in progress, cost trackers, riders, fuel and energy cost adjustment mechanisms, and balancing/true-up mechanisms.

4. Today, investor-owned electric utilities point to a “paradigm shift” caused by the need for large new capital additions at a time of declining sales growth and reduced credit worthiness. They urge the development of “new regulatory frameworks” which provide for cost recovery outside of the traditional rate case.

5. There is little doubt that new policies and frameworks are needed. The question is how to configure new frameworks so that they strike an appropriate balance between shareholders and consumers.

6. Regulatory leadership will be critical to negotiating new frameworks.

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