PROPOSED ALTERNATIVE RATE PLAN

FOR AN ELECTRIC UTILITY

Case No. 92-345
Maine Public Utilities Commission

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PREFACE

A recent rate case (Docket No. 92-345) involving Central Maine Power Company debated the question of whether it is appropriate to replace traditional cost-of-service (COS) regulation with some kind of comprehensive incentive-based mechanism. The Maine Public Utilities Commission, along with other parties to the proceeding, labeled these plans as "alternative rate plans" (ARPs).

During the summer of 1993, the Advisory Staff assigned to the above-mentioned proceeding, requested the services of the National Regulatory Research Institute (NRRI). The services would include assisting in the review of testimony filed by parties pertaining to ARPs, and assisting in the development of an ARP for consideration by all parties at a follow-up proceeding.

This report represents the product of the work done by the NRRI in conjunction with the Advisory Staff. It was adapted from a discussion paper written for the Maine Commissioners by the authors in October 1993. First, the report provides a rationale for why state commissions should, at this time, consider alternatives to COS regulation. Second, it reviews different incentive-based plans within the context of a new competitive environment for electric utilities. Third, the report summarizes the authors' review of the positions and proposals of parties to the rate case. Fourth, it presents an ARP proposed by the authors for consideration by the Commission. Finally, the report identifies several issues that need to be addressed more fully if the proposed plan were to be implemented.

In its Order for Docket No. 92-345 (dated December 14, 1993), the Maine Public Utilities Commission accepted the general principles underlying the ARP developed by the authors. The Commission felt that there is a need for a new rate-making mechanism during the period of transition toward fuller competition in the electric power industry. The Commission ordered parties to collaborate during the next several months on implementing the plan. Commission resolution of the implementation issues is expected by year-end 1994.

This report, although focusing on a single utility, has ramifications for other electric utilities and their state commissions. In view of the increased competition throughout the country, electric utilities will likely propose some form of ARP to their state commissions in the coming years. These plans will have four features: (1) pricing flexibility, (2) risk shifting to utility shareholders, (3) greater profit opportunities for utilities, and (4) infrequent formal price reviews.

In the authors' opinion, the incentive-based plan outlined in this report exemplifies these kinds of plans. It is mainly for this reason that the report should be of interest to state commissions around the country.

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FOREWORD

In the fall of 1993, the NRRI provided technical assistance to the Maine Advisory Staff and Commissioners regarding alternative rate plans (ARPs). The major tasks included reviewing testimony filed by parties in a pending rate case (Docket No. 92-345) and developing the configuration of an ARP for Central Maine Power Company. The proposed plan was based on the evidence presented by parties in the rate case.

This report represents the work of the NRRI in conjunction with the Advisory Staff of the Maine PUC. Because of its general applicability to the current developments in the electric power industry, the report should assist state public utility commissions around the country in responding to proposals for ARPs. These proposals will likely increase in number as the electric power industry moves toward competition.

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1. INTRODUCTION

The Maine Public Utilities Commission ("Commission") and several intervenors in Docket No. 92-345 articulated an interest in incentive-based ratemaking. Central Maine Power Company (CMP) and Commercial Customers Utility Coalition (CCUC) testified to price-cap mechanisms that they proposed to the Commission for approval in this docket. Although other parties have opposed Commission approval of a price-cap mechanism for CMP pursuant to this docket, they have testified to the problems associated with the continuation of cost-of-service (COS) regulation.[1] These problems include:

1. the high administrative costs for the Commission and intervening parties, resulting from the continuous filing of rate changes;

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[1] All intervenors have identified problems associated with CMP's management of its operations, such as its failure to focus on cost minimization. Not all intervenors have gone the next step to question whether traditional COS regulation, which can be characterized as modified cost-plus regulation, sends the correct signals to the Company. Some intervenors called for the Commission to exert more stringent control and supervision of the Company's activities. This position, in fact, would move the Commission toward tighter COS regulation.

COS regulation is generically defined in this report as a method of setting prices that allows a firm to recover its costs, including a fair rate of return that a commission has determined will yield investors in the firm a reasonable but not monopolistic profit. Under COS regulation, costs are allocated to individual classes of customers. Thus, prices are based on costs, in practice usually measured as historical or embedded costs. COS regulation has several characteristics: (1) in the long run, it resembles a cost-plus contract, (2) incentives for cost control rest largely with the presence of regulatory lag and retrospective reviews, (3) pricing flexibility responsive to market conditions occurs infrequently, (4) market risks are largely borne by consumers, (5) nonoptimal capitalization is highly likely, and (6) a firm's financial performance will tend to deteriorate under unstable and inflationary macroeconomic conditions.

2. the weak incentive provided to CMP for efficient operation and investments;
3. the ability of CMP to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions;
4. limited pricing flexibility on a case-by-case basis, which makes it difficult for CMP to prevent sales losses from competition offered by other electricity and energy suppliers; and
5. the general incompatibility of COS rate-making procedures with growing competition in the electric power industry.

As discussed later in this report, most of these problems will become more acute in the future. The electric power industry is moving away from an industry where all functions have natural-monopoly characteristics and are highly regulated, toward an industry where competition will be pervasive and regulation will be more light-handed or, in some markets, nonexistent. This evolution of the industry and regulation will result in the shifting of more risks to shareholders, as opposed to the risks being largely borne by ratepayers, which is generally the case under COS regulation.

In the new environment, as many parties in this docket recognize, the *status quo* in terms of both utility and Commission actions, will no longer serve the public interest. From CMP's perspective, tightly controlled regulation will hinder its efforts to compete with other electricity suppliers. From the consumer's perspective, the current form of regulation protects CMP from adverse events that are both inside and outside its control. Although there is general criticism of the current rate-making practice, disagreement exists over an appropriate replacement.

The objective of this report is to take what the authors believe are the best alternative rate plan (ARP) proposals and ideas presented by the parties in this docket, and develop the general features and underlying principles of an incentive-based plan for Commission consideration. The proposal presented in this report can serve as the starting point for discussion among the various parties. A number of "implementation" questions will still need to be answered prior to actual operation. This report identifies these questions as they should be addressed during the collaborative process. It is the authors' recommendation that the parties to this docket collaborate over the subsequent months to resolve the implementation issues associated with developing an appropriate incentive-based plan for CMP. Failing that, a follow-up formal investigation should proceed to resolve these issues.

2. THE COMPETITIVE FUTURE BRIEFLY CONSIDERED

The recent growth of competition in the United States electric power industry has already left its mark on Maine. Recently (Docket No. 92-331), the Commission allowed CMP to offer a special rate to retain one of its large industrial customers, Airco. This rate was in response to the threat by Airco to relocate to Connecticut. As a second example, the second phase of another Maine Commission proceeding (Docket No. 92-315) will deal with the issues surrounding rate design in a more competitive marketplace. Finally, CMP has asked the Commission to preapprove the creation of an exempt wholesale generating company (EWG). By forming an EWG subsidiary, CMP believes that it will be more competitive both inside and outside its service area.

The next several years will likely see major changes in the electric power industry. Bolstered by the Energy Policy Act of 1992 (EPAct), competition within the generation sector will intensify as new producers enter the industry and both producers and consumers have access to a larger power market.[2] EPAct lifts barriers to entry by both vertically-integrated utilities and nonutilities. Utilities, such as CMP, may decide to establish unregulated subsidiaries to compete with power generators in other service areas and states. Nonutilities may threaten a utility's franchise market if retail consumers are given the right to purchase power from electricity generators other than their local utility.

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[2] See The National Regulatory Research Institute, Electric and Gas Division, *A Synopsis of the Energy Policy Act of 1992: New Tasks for Public Utility Commissions* (Columbus, OH: The National Regulatory Research Institute, 1993).

The fact that the Federal Energy Regulatory Commission (FERC) will sanction broad transmission access for wholesale power participants means that the electric power industry, in the near future, will probably contain spot markets and, at some point, a futures market.[3] In any event, even in the absence of EPAct, the electric power industry would have followed a fundamental path toward competition. EPAct will accelerate the ongoing evolution that the industry has undergone, during the last several years, toward a more competitive future.

Although analysts and others can disagree over the merits of a more competitive electric power industry, the fact remains that it will happen. Given this expectation, two major questions for state regulators, including this Commission, ensue: (1) How will the future industry compare with today's? and, (2) What ramifications does this have for retail ratemaking?

One general reply to the first question would be that the actors in the future industry will be more affected by market forces and less by regulation. In the future, the pricing of generation services will increasingly be determined by what the market will bear rather than by cost-of-service criterion. Specifically, movement toward the *de facto* deregulation of wholesale commodity power will likely become widespread over the next several years. As the number of market participants increase and the benefits from trading rise, regulators will confront intense pressures to change their *modus operandi* by accommodating the growing special interests, particularly new power producers and noncore consumers, which stand to gain much from a more open and competitive environment.

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[3] Later this year, the New York Mercantile Exchange (NYMEX) plans to initiate trading in a standard futures contract.

What this implies is that regulators should immediately begin to reassess their current rate-making practices and policies. The FERC has already done so with regard to the pricing of bulk power and transmission services. Some state commissions, such as California and New York, have also made efforts toward changing their current rate-making policies for electric utilities. These commissions realize, with history supporting their positions, that if they do not take the initiative, someone else will. "Someone else" may include market forces, legislative bodies, or special-interest groups. From the Commission's perspective, it would be better to take the initiative than to be preempted by outside parties.

If one were to characterize a competitive electric power industry, it would have several features. First, customers would have options where they could acquire their electricity needs either from the local utility, self-generation, or from another electricity supplier. In a fully-developed competitive marketplace, retail wheeling would become a reality.[4] Under such an environment, it is important for the financial well-being of regulated utilities, such as CMP, that they have the opportunity to compete on an equal basis with other electricity producers. This may require regulators to give utilities broad pricing discretion (beyond that provided by a commission on a case-by-case basis), including contract pricing, as well as the opportunity to offer a wider array of services.

Second, a competitive electric power industry would be likely to devolve into vertical disintegration where generation, transmission, and distribution would tend to be provided by different owners under different forms of contracts. The passage of EPAct will bring about

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[4] See, for example, Charles M. Studness, "The Pressures of Competition," *Public Utilities Fortnightly* (June 15, 1993): 31-32.

broad transmission access that will provide the impetus for an expansive power market from the vantage point of both generators and consumers.

Third, the generation sector of the industry would be highly competitive. The trend toward competition has already begun and will likely continue as EWGs enter the marketplace, open transmission access becomes a reality, and economies of scale become less pronounced. For many utilities, the lower costs of new generation relative to current costs will make it difficult for "embedded" generating plants to compete, especially in a world of retail wheeling where regional generators would have access to end-use markets. In such an environment, competitors would have strong incentives to minimize costs, as low-cost generators would be winners in a competitive electric power market. Utilities would consequently be under great pressure to lower their prices in line with market conditions.

Even if the above scenario does not come to fruition over the next few years, it is clear that the electric power industry will not return to the past. The "monopoly" wall has started to crumble and it is highly unlikely that the pieces will be retrieved in order to rebuild it. At this point in time, arriving at a competitive future in the electric power industry is more of a "how long" rather than a "will it occur," question.

The relevant period for this docket, the years between now and the end of the century, will see a transition from a strongly regulated, mildly competitive environment, where regulation still dominates, to an environment where competition and regulation are more equally balanced. In response to the presence of greater competition, utility management should be expected to petition for an adjustment of their rate structures to enhance revenues, to reduce their costs, and to downsize or restructure their capital base to where the marginal rate of return is commensurate with those earned in other risk-comparable industries. Finally, as shown for a broad range of industries, if a firm cannot sustain an adequate marginal return on its base operations, it would be expected to diversify (of course, without guaranteed success) into new activities.

As will be discussed, it is highly questionable whether COS regulation would be able to accommodate the increased competition. COS regulation works best when macroeconomic conditions are stable, consumers have few choices, producers face little competition, and technology changes slowly. The fact that some electricity consumers now have more choices and generators face more competition calls into question the merits of COS regulation. COS regulation, by its nature, is unwieldy as an institutional mechanism for setting prices. Its inflexible and time-consuming features make it especially ill-suited to function in a competitive environment. This is one reason, for example, why countries, such as Great Britain and Argentina, have turned away from U.S.-style regulation for controlling the prices of newly privatized public utilities. Experiences in Great Britain, as well as in the U.S. telecommunications industry, have shown that incentive-based, rate-making procedures, such as price caps, can work well, especially in competitive environments. In Great Britain, for example, the productivity offset for British Telecom has continuously increased over time (benefitting consumers) to reflect the firm's high profits resulting from substantial cost-cutting activities.

The economics literature on sustainability has emphasized the importance, from an economic-welfare perspective, of allowing incumbent utilities pricing and service flexibility in order to compete on an equal basis with new entrants. Continuation of tightly-controlled regulation, exemplified by COS regulation, could not only hurt the utility but ultimately could hurt all customers including core customers (a subject that will be discussed in more detail later).

Cognizant of the problems associated with COS regulation in a competitive environment, the staff of the California Public Utilities Commission recently undertook a major study of the electric power industry at the request of its Commissioners.[5] The motive for the study was the recognition that a mixed competitive-regulatory system is poorly suited to deal with today's electric power industry. The study concluded that California should reform its regulatory procedures in view of prevailing market conditions and future trends that are likely to occur in the electric power industry.

The study makes the general point that, with the erosion of utilities' monopoly power in various markets, the case for continuing COS regulation becomes less persuasive. The study argues that the long history of COS regulation, together with monopoly control of the industry, leaves California utilities unprepared to operate in an increasingly competitive environment. The study (on page 2) noted that:

> . . .technological change, competitive pressures and emerging market forces exert increasing influence over the structure of the industry and the utilities' monopoly position has eroded as a result. . .. Consequently, the Commission should make appropriate reforms in order to establish greater comparability among the state's compact, the regulation used to uphold it, and the industry they govern.

In criticizing COS regulation, the California study argues that *status quo* regulation dulls incentives for efficient utility operations, provides unbalanced investment incentives (for

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[5] California Public Utilities Commission, Division of Strategic Planning, *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (San Francisco, CA: California Public Utilities Commission, February 1993).

example, it creates an "unlevel playing field" between internal generation investments, demand-side management (DSM) programs, and purchased power), and imposes high administrative costs on the commission, utilities, and intervening parties. As to its outcomes, the study concludes that COS regulation may prevent consumers from receiving the full benefits of a new electric power industry by failing to promote competition in the industry.

Finally, the California study identifies and evaluates the following four future regulatory strategies: *Strategy A -- Limited Reform*, *Strategy B -- The Price-Cap Model*, *Strategy C -- Limited Customer Choice*, and *Strategy D -- Restructured Utility Industry*. *Strategy B -- The Price-Cap Model*, is of particular interest to this Commission in this proceeding. This strategy, modeled after regulation of the telecommunications industry, emphasizes pricing flexibility and severing the link between a utility's prices and its costs.

The Price-Cap Model illustrated in the California study would operate in the following manner: the principles of COS regulation would be used to establish what is called the "fair starting point," and subsequent annual adjustment of rates would be based on changes in inflation, productivity, and other factors outside the control of a utility; the productivity offset would be determined at the initial implementation proceeding. Introducing a profit-sharing component, the Price-Cap Model would allow a utility to keep all earnings within a "dead band" region; earnings outside this region would be shared between the utility and consumers (with "low" earnings dictating an upward rate adjustment and "high" earnings dictating a downward rate adjustment).

The price-cap strategy would avoid the need for conventional rate cases but would include a performance review to be held every three years. The review would, among other things, examine the reasonableness of the parameters contained in the price-cap formula, a utility's actual earnings, and the rates charged to different customers.

The price-cap strategy, as proposed in the study, would eliminate any existing alternative adjustment mechanisms, such as the fuel adjustment clause and the electric revenue adjustment mechanism (ERAM). Retrospective prudence reviews would also be abolished.

With regard to resource acquisitions, the price-cap strategy discussed in the California study would retain the current integrated resource planning process, under which interested parties have the opportunity to scrutinize, before-the-fact, a utility's resource plan. The strategy, however, would change the incentives for resource acquisition: new utility investments would be excluded from rate base, the utility could earn higher profits by lowering the costs of purchased power, and the utility would have less incentive to invest in energy conservation. To compensate for the last effect, the strategy proposes the addition of a shared-savings mechanism to promote energy conservation.

The California study points to several advantages of the price-cap strategy over traditional or modified COS regulation: (1) although up-front implementation costs would be incurred, subsequent administrative costs should be lower; (2) the utility would face a strong incentive for reducing operating costs; (3) the utility would have a more balanced incentive for resource acquisition, especially between purchased power and internal plant construction; and (4) prices would be more efficient, since the utility would have more pricing flexibility (although it would be constrained from charging any price below marginal cost).

The above discussion on the proposed Price-Cap Model illustrates two major points. First, alternatives to COS regulation are being conceptualized for the electric power industry.

Until recently, less consideration was given to the application of price-cap regulation to the electric power industry. Rather, much more attention was placed on applying price caps to the telecommunications industry.[6]

Second, the price-cap strategy seems most appropriate at this time for Maine: CMP faces growing competition; pricing flexibility has become increasingly important in retaining load; retail wheeling has not yet emerged; and there is intense public and intervenor pressure for CMP to become more accountable for its actions. Price-cap regulation, as discussed later, can represent an important transitional mechanism as the electric power industry moves toward more competition. Price-cap regulation recognizes that some form of regulatory constraint is required in an environment where a utility continues to exercise some degree of market power. For the foreseeable future, it seems that CMP and other Maine electric utilities will be operating in such an environment.

By giving utilities more flexibility and greater opportunities to earn higher profits, and symmetrically to be burdened with higher risks, price-cap regulation frees the utility from the constraints of COS regulation. The utility is consequently in a better position to compete and to improve its overall economic performance.

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[6] The basic principles of price caps, however, can be applied to other utility industries. See, for example, Lorenzo Brown, Michael Einhorn, and Ingo Vogelsang, "Toward Improved and Practical Incentive Regulation," *Journal of Regulatory Economics* 3 (1991): 323-38; and Thomas Lyon and Michael A. Toman, "Designing Price Caps for Natural Gas Distribution Companies," *Journal of Regulatory Economics* 3 (1991):175-92.

3. THE PATH TOWARD GREATER COMPETITION:

NEW RATE-MAKING OPTIONS

A Reassessment of COS Regulation

The previous discussion touched on the fact that COS regulation is likely to create inefficiencies and other distortions in a competitive or quasi-competitive marketplace. Specifically, it constrains utilities from competing with new entrants and other energy suppliers, provides weak incentives for cost control, shifts much of the risks associated with bad outcomes (as distinct from bad management decisionmaking) to ratepayers, imposes high administrative costs on all parties involved in rate proceedings, and induces utilities to over- or under-capitalize.[7]

The above-mentioned problems with COS regulation will become more acute as utilities begin to operate in competitive markets. For example, rigid regulatory pricing (or time-consuming, case-by-case review of special-rate proposals) in a competitive market may lead to uneconomical bypass,[8] as well as high "administration costs." Another problem occurs when

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[7] Averch-Johnson suggest overcapitalization. Regarding undercapitalization, in recent years, starting around 1980, the risks associated with cost recovery of major generation investments may have induced utilities to purchase power rather than build even when it was uneconomical (since purchased power putatively has less cost-recovery risk).

[8] Uneconomical bypass occurs when a customer leaves the local utility for a substitutable service with a lower price but with a higher economic cost. It is widely viewed as undesirable: it can result in costly duplication of capital facilities and, potentially, higher prices for core customers. Most economists would argue that allowing the utility sufficient pricing flexibility would virtually eliminate uneconomical bypass.

new technologies are the driving force behind competitive conditions: utilities may need the opportunity to receive higher earnings from adopting these often risky technologies than what they would otherwise receive under COS regulation.

Supporters point to the following benefits of COS regulation: (1) assuring high quality of service, (2) preventing excessive price discrimination, (3) avoiding extreme utility financial performance, and (4) achieving fairness in that prices correspond to the cost of service. One can question whether these benefits are attained at a too high cost. For example, while high quality of service *per se* is an enviable goal, it may be achieved only by a utility incurring high costs in the form of redundant capacity. On net, high quality may impose a cost both on consumers and society at large. One also can question the fairness of cost-of-service pricing, given the typically arbitrary allocations of common costs among classes of customers. While excessive price discrimination should be avoided, COS regulation may go too far in preventing milder or tolerable forms of discriminatory pricing. Price discrimination in certain situations, for example, may improve economic welfare, especially when the utility faces different degrees of competition in its various markets. Finally, by shifting both the risks and benefits of cost-reducing activities to consumers, the utility would have a disincentive to control costs. Consequently, its cost of service may exceed what it would otherwise be, with consumers shouldering much of the burden of unsatisfactory utility performance.

In sum, the benefits of COS regulation are likely to be greater under certain circumstances, for example, when markets are highly concentrated because of technological conditions. In a competitive environment, however, continuation of COS regulation can have the perverse effect of harming consumers and society at large. As the parties to these proceedings realize, COS regulation works less well when electricity consumers have choices and a utility faces some degree of competition. More importantly, COS regulation provides utilities with weak incentives to achieve cost minimization and with pricing flexibility that is inadequate to allow the utilities to compete with other electricity and energy suppliers.

Incentive-Based Ratemaking

Most of the current incentive systems for the electric power industry focus on a utility's performance in a specific area of operation, such as fuel costs, DSM activities, and power plant productivity.[9] Partial incentive systems generally were adopted in response to evidence of poor utility management or to political pressures to control rising electricity prices; they were not rationalized on the basis of accommodating a competitive environment for electric utilities. Generally, partial incentives are better-suited for regulated industries where utilities have strong and comprehensive monopoly powers in their markets. Some analysts have criticized partial incentive systems for distorting a utility's incentive to minimize its total cost of service. Experiences with partial incentives for electric utilities, in addition, have demonstrated that they need to be closely monitored, micromanaged, and frequently adjusted. The little empirical

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[9] See Edison Electric Institute, *Types of Incentive Regulation: A Primer for the Electric Utility Industry* (Washington, D.C.: Edison Electric Institute, April 1993).

evidence available shows mixed results regarding the overall effect of partial incentives on consumer well-being.[10]

Broad-based incentive systems that have received the most attention in the regulatory arena include price caps, profit-sharing, and yardstick regulation.[11] Each of these systems has the similar feature that a firm's prices are not strictly linked to its overall profits and costs. The distinctions between the three incentive systems are somewhat blurred as actual price-cap regulation of U.S. and British telecommunications industries include a rate-adjustment review every three to five years. During this review, regulators consider, among other things, a firm's recent level of earnings. Consequently, incentive systems, such as price caps or yardstick regulation would unlikely achieve maximum efficiency gains because of regulatory intervention whenever profits are considered to be either "too high" or "too low."

Price Cap Plans

Price-cap plans, as mentioned above, were adopted for AT&T's interchange (long distance) services, the Regional Bell Holding Companies' local exchange services, and for the

[10] See the contrasting results contained in Sanford Berg and Jinook Jeong, "An Evaluation of Incentive Regulation for Electric Utilities," *Journal of Regulatory Economics* 3 (1991): 45-55; and Robert J. Graniere, Daniel J. Duann, and Youssef Hegazy, *The Effects of Fuel-Related Incentives on the Costs of Electric Utilities* (Columbus, OH: The National Regulatory Research Institute, 1993).

[11] See Mohammad Harunuzzaman, Kenneth W. Costello, and Daniel J. Duann, *Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure* (Columbus, OH: The National Regulatory Research Institute, 1991), 77-79.

British natural gas, electric power, and telecommunications industries, among others.[12] The limited empirical evidence on price caps suggests that they are likely to benefit both regulated firms and their customers.[13] For example, large cost savings have resulted from the institution of price-cap regulation in the British telecommunications industry. Initially, these savings benefited shareholders and, ultimately, consumers in the form of lower prices. Although it is likely that much of the efficiency gains resulted from privatization, *per se*, it is arguable whether these large gains would have transpired under a COS regulatory regime.

In addition, the performance of price caps suggests that they can be effective in controlling the prices of a firm with some market power, even when profits are left unregulated. Further, price caps allow regulated firms to compete on an equal basis with other suppliers. Finally, under price caps, firms are given wide pricing discretion and the opportunity to offer new services in the absence of case-by-case regulatory approval.

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[12] See John E. Kwoka, Jr., "Implementing Price Caps in Telecommunications, " *Journal of Policy Analysis and Management* 13, 4 (1993): 726-52; and Bernard Tenenbaum, Reinier Lock, and James Barker, Jr., "Electricity Privatization: Structural, Competitive, and Regulatory Options," *Energy Policy* (December 1992).

A stylized price-cap formula includes an economy-wide price index deducted by a productivity parameter; it can be expressed as

$$\mathring{P} = PI - X,$$

where the allowed percentage increase in price, $\mathring{P}$, equals the percentage increase in the selected price index, PI, minus the percentage increase in productivity, X. Section 5 presents a fuller discussion of price-cap plans.

[13] See, for example, Ronald R. Braeutigam and John C. Panzer, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," *American Economic Review* 83, 2 (May 1993): 191-98.

Another benefit of price caps is they tend to protect the so-called "core customers" from competition encountered by the regulated firm in other markets. For example, if separate price caps are placed on each class of customer, whatever revenues the firm is able to earn in industrial markets should not affect the price it can charge residential customers. Actual prices to residential and other core customers should, however, lie closer to the allowed price ceiling than what would be the case for industrial and other more price-sensitive customers.[14] In contrast, under COS regulation a firm is generally given the opportunity to receive revenues that correspond to its revenue requirement. This implies that whenever the firm receives fewer revenues from one group of customers, it has the right to petition for increased revenues from others by proposing to raise their prices.

When price-cap regulation achieves its potential benefits, the economic-welfare gains to both the regulated firm and its customers can be significant: the firm has a strong incentive to be cost efficient, customers share in the benefits of a more efficient firm, the firm can compete on an equal basis with other suppliers in price-sensitive markets, the firm's prices will move toward efficient ("second best") levels,[15] and the regulator will encounter infrequent price reviews. Overall, proponents point to the important role of price-cap plans in serving as a transitory step on an industry's path toward deregulation and fuller competition.

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[14] The argument here is that competitive pressures would force actual prices in noncore markets to lie somewhere below the allowed price ceiling. If this does not happen, it can be questioned whether the identified noncore markets are actually workably competitive.

[15] "Second best," or what is sometimes called Ramsey pricing, would allow the firm to remain financially whole by shifting more of the fixed costs to customers with few supply options.

In this docket, price-cap plans have a number of advantages: (1) electricity prices continue to be regulated; (2) the plan should be understandable to the layman; (3) rate predictability and stability are likely; (4) regulatory "administration" costs would likely be reduced, thereby allowing other important regulatory activities to be carried out and allowing the utility to expend more time and resources in managing its operations; (5) risk can be shifted to shareholders and away from ratepayers in a way that is manageable from the utility's financial perspective; and (6) perhaps most importantly, proper incentives for cost-minimization exist.

As with other rate-making systems, price caps have their own problems. Some of the following problems are more likely to occur than others. First, the utility would have an incentive to provide a lower quality or reliability of service.[16] Second, the firm could engage in cross-subsidizing competitive services with revenues earned from noncompetitive services (this assumes a broad-based price cap covering both competitive and noncompetitive services). Third, the firm may encounter conditions between formal performance reviews that would result in excessively high or low earnings. Fourth, prices would become more discriminatory over time. Finally, consumers may benefit little from a firm's actual productivity improvements (that is, the actual improvements may far exceed the targeted improvements established at the last price review).[17]

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[16] The concern over deterioration of the quality of electric service stems from the argument that under price caps a utility would have greater incentive to control its costs, including those incurred to improved reliability or to minimize the number and severity of outages.

[17] Assume that the regulator sets a productivity-offset value of 1 percent at the time of a formal price review and the actual productivity turns out to be 4 percent. The utility, in effect, retains three-fourths of the actual productivity gains, at least until the next formal price review.

In the economics literature, a general concern with price caps is that they may not maximize the long-term interest of consumers. Especially in a volatile and uncertain environment, higher price ceilings would have to be set to assure a firm's financial viability, the firm's earnings would be more likely to fall outside some "normal" or "reasonable" range, and actual prices would tend to deviate farther from a firm's actual costs.[18] Consequently, price caps in an unmodified form may pose both economic and political problems.

Profit-Sharing Plans

Profit-sharing enables the firm to permanently retain a prespecified portion of earnings outside a certain range. The certain range may be called a "dead band" region, within which the firm would retain all the profits earned. Profits outside the region would trigger an automatic price adjustment. Local exchange carriers in several states and a few energy utilities currently operate under a profit-sharing mechanism.[19]

Illustrating how profit-sharing would operate, assume that the "dead band" is specified in terms of an 11 percent to 15 percent rate of return on equity (with the mean 13 percent representing the firm's cost of equity); and that a sharing arrangement distributes the rates of return outside this range to consumers and shareholders on a 80 percent to 20 percent basis. If, for example, the utility earns 18 percent for a particular period, the utility would lower its prices

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[18] See Richard Schmalensee, "Good Regulatory Regimes," *RAND Journal of Economics* 30 (Autumn 1989): 417-36.

[19] See John E. Kwoka, Jr., "Implementing Price Caps in Telecommunications;" and Harunuzzaman et al., *Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure.*

to "give back" to consumers 2.4 ($0.8 \cdot 3$) percentage points out of the 3 percentage points it initially earned beyond the "dead band" region.[20] After the price adjustment, the utility's actual rate of return on equity would be 15.6 percent (15 percent + .2 (18 percent - 15 percent)).

Proponents argue that profit-sharing has several benefits. First, within the "dead band" region the utility would have the same cost-savings incentives as under price caps. Outside the region, the utility would still have stronger incentives to control costs than under COS regulation. This is because it would permanently keep a share of the incremental COS. Symmetrically, the utility would also share in losses when its earnings fell below the "dead band" region.

Another benefit of profit-sharing is that it would allow consumers to explicitly and directly benefit from actual earnings beyond the "dead band" region. By specifying up-front price adjustments at different levels of actual earnings, profit-sharing should reduce the likelihood of a utility earning extreme profits.

Finally, profit-sharing would be fairly simple to apply. In contrast to price caps, it requires no selection of a "correct" price index and productivity offset. Overall, profit-sharing is viewed by its proponents as an effective incentive-based mechanism. It allows regulators to commit to a rate-making procedure that places some degree of constraint (less than under COS regulation but more than under pure price caps) on the profits that a utility could earn.

On the negative side, profit-sharing, *per se,* would not improve pricing efficiency. Combined with the allowance of market-based pricing, however, profit-sharing can improve both operating and pricing efficiencies. In addition, as with practically all incentive mechanisms that

[20] For example, the utility may distribute an annual check to consumers that reflects a "consumer productivity dividend."

take into consideration earned profits, it would be vulnerable to "gaming" by firms. For instance, a utility may increase its costs in the short term with the hope of triggering a formal price review. "Gaming" under profit-sharing would be less severe as the utility retains a larger share of the benefits and encounters less frequent formal price reviews. These two factors would help to mitigate against perverse incentives when the utility is operating near the "bandwidth," as might be the case under CMP's proposed alternative rate plan. As a third deficiency, a utility would have less incentive for controlling costs than under price caps.[21] The magnitude of weaker incentives relate directly to the share of increases in the actual rate of return that the utility would be required to "give back" to consumers. In the extreme case where the share equals one, profit-sharing reduces to a cost-plus contract. At the other extreme, when the share equals zero, the incentives created by profit-sharing are comparable to those under price caps.

Finally, at least compared with price caps, profit-sharing would generate more price volatility. As a general principle, a tradeoff exists between earnings volatility and price volatility. For example, the electric revenue adjustment mechanism (ERAM) stabilizes earnings at the cost of price volatility. Pure price caps, at the other extreme, stabilize prices at the cost of earnings volatility. The preference of the Commission would dictate what this tradeoff should be.

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[21] See Dennis L. Weisman, "Superior Regulatory Regimes in Theory and Practice," *Journal of Regulatory Economics* 3 (1993), 364.

"Yardstick" Regulation

Under "yardstick" regulation, an individual utility's performance is assessed against a sample of comparable utilities. As an example, CMP could be compared with other electric utilities in New England or in the Northeast. Last year, the New York Public Service Commission (NYPSC) approved yardstick incentive mechanisms for Rochester Gas and Electric Corporation, Niagara Mohawk Power Corporation, and New York State Electric and Gas. The mechanisms include a profit-sharing component.[22] Under the mechanisms, the changes in average cost for a utility will be compared with changes for the other investor-owned electric utilities in the state. The sharing component will divide-up the differences between the utility's performance and the average performance of the other utilities.

Yardstick regulation has the advantage of simulating competitive market, where a firm is able to earn above-normal profits if it outperforms other firms in the same industry. If, for example, an unregulated firm could control its cost increases better than its competitors (assuming other things held constant), it could expect higher profits. Yardstick regulation attempts to create the same effect on a utility's profits. In practice, it can become part of a price-cap-type equation. For example, changes in annual prices (in percentage terms) can be limited to the change in an average cost index for a selected group of regional electric utilities. In a price-cap formula, such an application may have some advantages over an economy-wide price index and productivity offset. For example, the average cost index should better track cost changes for a utility than an economy-wide index. This would cause the utility's profits to fluctuate less from

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[22] For example, last year the Commission approved of a 50/50 profit-sharing arrangement for New York State Electric and Gas.

the targeted (normal) profits, and prices would also deviate less from the utility's actual costs. Consequently, the stability of the price caps may be enhanced, if only by the fact that regulators would be less likely to intervene when profits varied less from the targeted level.[23]

From a practical perspective, yardstick plans have some potential drawbacks: (1) the index would not be as "understandable" to the layman; (2) the layman could not predict with high accuracy what future rate increases would be (the Consumer Price Index (CPI), on the other hand, is avidly discussed on television news programs, in the print media, and elsewhere); (3) probably most importantly, high administration costs could result from controversies related to the selection of the index, the selection of the comparable companies, and the calculation of the price-change number; and (4) the link between electricity "price" and electricity "cost" for an individual utility would be less broken, thereby diminishing the expected cost-efficiency benefits of an incentive-based plan.

Hybrid Plans

The last incentive-based mechanism discussed here represents what can be called a "hybrid" price-cap/profit-sharing plan. Such a plan combines the pricing flexibility exhibited by price-caps and the explicit recognition of a utility's actual profits. Although constraining profits may weaken the utility's incentive to control costs, it adds some stability to the incentive plan --

[23] The stability effect is based on the argument that when a utility's actual profits lie farther from normal profits--for example, profits corresponding to the utility earning its cost of capital)--it is more likely that the price-cap plan would either be rescinded or modified in some form to reduce the likelihood of similar future profit volatility.

thus, a major reason for the profit-sharing component. In part, the plan does this by directly returning a share of the utility's increased profits to consumers.

The hybrid plan is more defensible when regulators have little information on the future productivity of a utility. In such an environment, the profits of a utility would more likely deviate farther from normal levels. Compared with price-caps, the hybrid plan also would require less-frequent performance reviews. This is because the utility's earned rate of return would be expected to stay within a narrower range.

4. THE PROPOSALS AND POSITIONS OF PARTIES

The parties to this proceeding generally support the Commission's consideration of different alternative rate plans (ARPs). Although all intervenors identify areas where CMP's cost-cutting performance could be improved, some do not acknowledge that the COS rate-making mechanism is the source of the problem.

There is a general recognition by the parties that the electric power industry has undergone major changes in recent years and that this trend will continue in the future. Specifically, the industry will become more competitive, thereby warranting consideration of new regulatory practices and policies. Most parties testified to deferring the approval by the Commission of any ARP until after this proceeding. One party, the Commercial Customers Utility Coalition (CCUC), proposed an incentive-based plan for approval by the Commission in this proceeding. The proposal was presented as a more desirable alternative to the price-cap plan proposed by CMP.

The concerns over CMP's proposed plan cover a wide spectrum. The Maine State Legislative Committee of the American Association of Retired Persons (AARP), in addition to recommending deferral of any ARP until after this proceeding, raised the following concerns and questions regarding CMP's proposed plan: (1) the broad nature of the price index, (2) no up-front productivity offset, (3) the likely negative effect on the Company's demand-side management activities and long-term planning decisions, (4) the possible negative effect on the Company's quality of service, (5) the complexity of CMP's proposed allocation of rate increases between fuel and nonfuel costs, and (6) the likely promotion of uneconomical sales. The witness for

AARP also questions the role of a fuel cost adjustment (FCA) mechanism in view of the Company's proposal. Finally, the witness believes that the Commission should learn from the experiences of incentive-based regulation in other states and locations before approving an incentive-based plan for CMP.

A witness on behalf of the Committee on Lower Electric Rates and the Industrial Energy Consumer Group testified to the urgency for regulatory change in terms of promoting economic development in Maine. The witness argued that CMP's high electricity prices are an impediment to the state's economic growth. Specifically, he points to the problem of high electricity rates in Maine, compared with those of other New England states and other regions of the country. According to the witness, this causes the state to lose jobs and to experience less economic development.

A change in regulatory rate-making practices from COS regulation to incentive-based regulation, as recommended by this witness, would give CMP stronger incentives to reduce both its costs and its rates. In line with his support for an incentive-based regulatory system, the witness argued that CMP should shoulder a greater burden than in the past for the poor performance of Maine's economy. Under cross-examination, the witness pointed to the fact that competitive pressures generally require unregulated firms to restructure and reduce their costs to improve their financial positions. CMP has instead proposed to increase its prices.

The testimony on behalf of the Commission's Advocacy Staff identified both broad and specific concerns with CMP's price-cap proposal. The testimony recommends that the Commission should not adopt the Company's plan until enough information is available to assess both the benefits and risks. The Advocacy Staff's witnesses argued that, prior to approving an incentive-based plan, the Commission should first consider whether it wants to promote competition in CMP's markets, and what effect this would have on core customers. Price caps, for example, may conflict with Commission goals directed specifically at the electric power industry (for example, promoting DSM activities and complying with environmental regulations). The witnesses pointed to the problem of extrapolating from the experience of the telecommunication industry in assuming that price caps would be appropriate for the electric power industry. The witnesses recommended a follow-up proceeding to address these questions.

Expressing more specific concerns, Advocacy Staff warned that pure price caps are rare and should be supplemented by some profit-sharing component to provide a "social safety net." Profit-sharing also can mitigate against a quality-of-service problem by reducing the volatility of earnings on the downward side.

The witnesses for the Advocacy Staff pointed to six specific problems with the Company's proposed ARP: (1) no good reason exists for setting a 2 percent price floor -- an improved economy and the restructuring of existing contracts with PURPA-Qualifying Facilities are likely; (2) the GNP Implicit Price Deflator is too broad an index to use -- it may, over time, cause prices to drift from CMP's actual costs, and earnings to deviate far from the targeted level; (3) an up-front productivity offset should be incorporated into the price-cap formula in order to keep CMP's earnings closer to "reasonable" levels; (4) CMP would have a disincentive to promote the DSM goals of integrated resource planning and pollution-abatement goals; (5) the current FCA mechanism, as well as CMP's proposal, would provide the Company with weak incentives to minimize fuel and purchased-power costs; and (6) it excludes an annual performance review to evaluate the success of the price-cap plan.

The Company and CCUC presented the only complete proposed ARPs in this proceeding. In various ways, their plans are similar, as testified to by a CCUC witness. They both involve: indexing, treating fuel-cost recovery within the price cap, a periodic review of the plan's performance, and the possibility of CMP lowering prices to certain customers.

Major differences in the two plans exist, however. First, the CCUC plan includes the CPI and a productivity offset of one-half percent. The Company's plan, in contrast, includes the GNP Implicit Price Deflator and no up-front productivity offset.

Second, the CCUC plan contains no annual price-change ceiling or floor. The Company's plan has a price floor of 2 percent and a price ceiling of 6 percent.

Third, CCUC's plan allows for more pricing flexibility than the Company's plan. CCUC proposes that prices should be adjusted downward when dictated by competitive pressures. It proposes, however, to restrict CMP from being compensated for revenue losses suffered in competitive or quasi-competitive markets by increasing prices to other customers.

Fourth, CCUC's plan includes fuel costs in the price-cap formula to the extent they can legally be included. The Company proposes to apply a certain portion of any index-related price change to both fuel and nonfuel costs.

Fifth, the CCUC proposal would give the Commission the discretion to terminate the price-cap plan at any time. Further, it would require an annual performance review to assess the price-cap plan and, in addition, would allow any party to petition the Commission for a rate investigation at any time. CCUC argues that the review should exclude consideration of the sufficiency of the Company revenues. CMP's plan, in contrast, calls for a general performance review during 1996.

Finally, CCUC's plan rejects the Company's "off ramp" proposal that would allow the utility to file for a price increase if its earned rate of return (ROR) is more than 300 basis points below the most recent allowed ROR. Under the Company's plan, parties could petition the Commission for a price decrease anytime the Company earns more than 300 basis points above the allowed ROR. CCUC proposes instead an annual review and the right for any party, including the Company, to petition for a price adjustment at any time.

5. THE PROPOSED INCENTIVE PLAN

Evaluation of Proposals and Positions

After reviewing CMP's and CCUC's proposed price-cap plans, the authors believe that each one contains certain strengths that can be incorporated into an acceptable ARP. The Company's plan contains three positive elements: (1) the requirement of a general performance review to evaluate the past operation of the plan, as well as to reset new base prices; (2) an up-front rule for triggering a price review (although it would be preferable to have a profit-sharing mechanism that triggers when the Company's earned ROR on equity lies outside a prespecified range; and (3) separate customer-class price caps, which would help to protect core customers against revenue deficits encountered by the Company in more competitive markets.

The Company's plan also includes some shortcomings: (1) as CCUC pointed out, an implicit zero up-front productivity offset is uncharacteristic of most price-cap plans and would allow CMP to receive more revenues during the period 1993- 1998 from its proposed rate plan, than under traditional ratemaking; (2) excessive pricing constraints -- CMP proposes a 2 percent to 6 percent range on allowable annual price increases, in addition to a price-triggering mechanism that would suppress the Company's actual ROR; (3) a somewhat hard-to-understand fuel and nonfuel cost recovery mechanism; (4) a lack of specificity regarding cost passthroughs outside the price-cap formula; (5) the exclusion of an annual review, whose scope should be restricted but should include such activities as verification of price-cap/profit-sharing adjustments, monitoring the Company's quality-of-service performance, and determination of automatic cost passthroughs; and (6) the application of an economy-wide price index, which may trigger frequent price reviews, wide earnings fluctuations, or prices deviating far from costs if CMP confronts inflationary and productivity conditions differing from the economy as a whole.

The CCUC's proposed price-cap plan has the following strengths: (1) an up-front productivity offset; (2) a narrow list of mandated costs: (3) no annual price-adjustment floor or ceiling; (4) an annual review (although, as discussed later, the scope of relevant issues should be more narrow than what CCUC proposes); and (5) protection of core customers from revenue deficits suffered by the Company in noncore markets. The plan's major weaknesses include the exclusion of an up-front price-triggering rule and an annual-review process that would encompass a too broad array of activities.

A survey of the record for this proceeding reveals several points of general agreement. First, several parties argue for a Commission review of ARPs subsequent to this rate case. Other parties, namely, the Company and CCUC, support the Commission's approval of an ARP as part of the Order for this rate case. In either case, parties generally support the position that the Commission, for various reasons, should seriously consider ARPs.

Second, in conjunction with the previous point, parties agree that the electric power industry will become more competitive in the coming years. As most parties to the proceeding correctly acknowledge, changes in the industry warrant at least the Commission's consideration of ARPs. Parties agree that one objective of an ARP would be to improve the Company's competitive position in the new electric power industry.

Third, some parties argue that CMP should become less insulated from market forces and general economic conditions. The abolition of ERAM will lead in that direction, but parties generally concede that more should be done. For example, parties agree that a performance-based rate-making mechanism such as price caps can hold the Company more accountable for its actions both beyond and within its control. Some parties correctly argue that the alternative -- the dollar-for-dollar passthrough of mandated costs and fuel and purchased-power costs -- would diminish the effectiveness of any ARP to control CMP's costs.[24]

There seems to be general support for an up-front productivity offset. Such an offset, among other things, would help to assure that the efficiency gains made by CMP would benefit consumers, as well as the Company's shareholders. In most price-cap applications, a productivity offset is included largely for this reason. Any approval of an ARP by the Commission should foremost be conditioned on the expectation that CMP consumers would benefit as a group.[25]

Parties generally agree that any ARP should constrain the level of profits that the Company could actually retain. Two general approaches were discussed: a profit-sharing plan

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[24] Critics of fuel adjustment clauses (FACs) argue that automatic passthrough of changes in fuel costs to consumers diminishes the incentive of a utility to minimize its overall cost of operations. For example, FACs would tend to motivate a utility's management to expend less resources in controlling its fuel costs and to overuse fuel in relation to other inputs employed in the generation of electricity. In other words, a utility may substitute fuel for other inputs even when the total costs of generation increase.

[25] The presumption is that since regulation was instituted to protect consumers from the monopoly power of utilities, the major goal of regulation should be to promote the economic interests of consumers.

and a discrete mechanism where the Company would retain all profits up to certain limits. Any additional profits would trigger a formal price review.[26]

Finally, some parties expressed concern that a price-cap plan would diminish the incentive of CMP to promote energy conservation. Such a plan would clearly provide CMP with incentives to make short-term sales anytime that prices exceeded marginal costs; between rate cases, the same incentive would be present, although less intensively, under COS regulation as well. It is less clear whether the Company would, in the long term, invest less in energy conservation under a price cap plan if the Commission continues to give strong support for DSM activities and integrated resource planning.

The Basic Plan

On the basis of the previous discussion, the authors propose the following ARP:

(1) Price-cap component (primary)

$$\dot{P} = (PI - X) + Z$$

where $\dot{P}$ = annual allowable electricity price change for any customer in percentage terms,

PI = actual CPI for the latest reporting period,

X = productivity offset (which can be defined as a residual parameter that would reduce the expected prices under the price-cap plan to

[26] Alternatively, the creation of a "safety net" to prevent excessive profits can be done by setting a high productivity offset, holding frequent price reviews, or establishing low base rates.

below those predicted under COS ratemaking); the authors recommend a minimum value of *1 percent*, and

Z = mandated costs (as a percentage of total costs); these costs would be defined up-front and in a way that would narrow their scope; such costs should be limited to those unique to the electric power industry or CMP; passthrough of these costs by the Company would be determined at the annual review.

(2) Profit-sharing component (secondary)

$$\gamma = \gamma_e - g(\gamma_e - \gamma_a),$$

where γ = actual ROR on equity after price adjustment,

γ_e = earned (price-unadjusted) ROR on equity,

γ_a = ROR on equity at the boundary of the "dead band" region (determined at the last formal rate review), and

g = varying sharing ratio (equal to the share of the difference between the earned ROR and the boundary ROR that is subject to a price adjustment); g equals zero when the value of γ_e lies within the "dead band" region; for incremental differences outside the region, g equals 0.5.

The profit-sharing component adds a second price adjustment to the ARP plan that would be made at the annual review. Technically, the adjustment would take place by lowering or increasing the latest prices to reflect the required revenue changes consistent with the profit-sharing component. Within the "dead band" region (where g equals zero), no such price adjustment would occur as the Company would keep all the profits it earns when the earned ROR does not exceed the allowed ROR by more than 200 basis points. Setting a "dead band" region avoids an annual price adjustment, excluding the price-cap adjustment, unless the Company encounters more than normal deviations in the earned ROR. The profit-sharing mechanism is symmetrical in that the Company could not increase its prices as long as the earned ROR falls within 200 basis points of the allowed ROR.

A sharing ratio of 0.5 or greater outside the "dead band" region allows for price adjustments that would tend to mitigate against the Company earning what some might characterize as "extreme" profits on both the high and low ends. As an alternative design of the profit-sharing component, a formal price review may be triggered whenever the earned ROR falls outside a specified range (similar to what CMP has proposed). The problem with such a design is that it could lead to uncertainty over the filing of future rate cases. The 0.5 value should give the Company a fairly strong incentive for improving its operating efficiency. The proposed sharing ratio would work by "giving back" (for example, in the form of an annual rebate) to consumers 50 percent of the ROR that the firm initially earns beyond the upper boundary of the "dead band" region.

Although no simple rule can be applied to determine the "best" value of "g," economic theory provides the insight that "g" should be larger as uncertainty over the future condition of a firm increases.[27] In other words, assuming that other things remain constant, the more uncertain

[27] See, for example, Richard Schmalensee, "Good Regulatory Regimes;" and Jean-Jacques Laffont and Jean Tirole,"Using Cost Observations To Regulate Firms," *Journal of Political Economy* 94, 1 (1986): 614-41.

the future costs and demand of a utility, the more defensible cost-plus-type regulation becomes. Equity and other Commission goals, for example continuity of the rate plan, would ultimately influence the proper value of "g." It is common for regulatory sharing arrangements for electric utilities to allocate most of the benefits and risks to consumers: a 60 percent to 80 percent reallocation to consumers is typical.[28] Of course, a high sharing parameter also increases ratepayer risks from poor utility performance. Alternatively, a three-tier plan with two bands in addition to the "dead zone" band could be crafted. For example, the second band could have a 50/50 split arrangement ($g = 0.50$), while the third band could have a 75/25 split ($g = 0.75$).

Finally, under the ARP proposal, CMP would gain pricing flexibility: the rates that the Company could charge would become *maximum* prices or "caps." Price differentiation would likely result; but the proposal would constrain the Company from shifting revenue deficits, caused by competitive conditions or caused by any reason, to other customers. The Company could price below the cap so long as the price remained above marginal cost. A marginal-cost price floor would help to minimize the possibility of CMP using below-cost prices to drive out actual or prospective competitors.[29] Lost revenues would be entirely borne by shareholders.

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[28] See, for example, National Economic Research Associates, Inc. (NERA), *Incentive Regulation in the Electric Utility Industry* (n.p.: NERA, 1990).

[29] Such prices, commonly called predatory prices, would be highly unlikely in most circumstances. Cost-shifting, where CMP would improperly allocate costs to core markets, is a constant problem under COS regulation, however. One benefit of the proposed plan is that CMP would have little incentive for cost-shifting. The reason for this is that the plan would break the linkage between CMP's prices and its actual or reported costs. Consequently, cost-shifting would do little if anything to benefit CMP shareholders.

Consequently, the Company would have to cut costs to offset the lost revenues. It could not recover those lost revenues from other ratepayers.[30]

Pricing flexibility, along with a prohibition against the Company recovering lost revenues from customers, would provide three major benefits. First, the Company, by having the ability to compete to retain customers with options, could earn greater revenues against which the Company could spread its fixed costs. Second, the Company would have a strong incentive to avoid giving special contracts to "free riders," that is, those customers who would not have reduced their load in the absence of a discounted rate. Third, the high administrative costs associated with the case-by-case Commission approval of special-rate contracts and other forms of discounted rates would mostly be avoided.

The proposal to prohibit CMP from recovering lost revenues from other customers is compatible with the workings of competitive markets. In a competitive environment, a firm's profits suffer anytime it loses customers or is forced to lower prices to retain existing customers. From the Commission's perspective, the competitive model would be appealing in that core customers would become insulated from competitive forces operating in noncore electricity markets. The Commission, in adopting the competitive model, would pressure CMP management to minimize profit losses in noncore markets by improving overall efficiency or else facing the prospect of strong opposition from shareholders. Therefore, cost-cutting would become more important for CMP if it hopes to recover its fixed costs and reestablish prior profit levels. Cost-cutting would also, in the longer term, result in both core and noncore customers

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[30] This means that CMP could not petition the Commission to increase prices for core services anytime its profit margin earned in noncore markets falls below a "fair" return.

paying lower prices than they would otherwise pay. If the Commission takes this position, it should recognize the added risk it imposes on the Company. It could be argued that the Company's benchmark (cost- of-capital based) ROR should be adjusted upward to compensate for this additional risk.

Concerns About Price-Cap Plans

The above ARP plan represents the authors' recommendations for an incentive-based, rate-making plan that they believe should be given immediate consideration by the Commission. Several concerns were raised by parties in the current rate-case proceeding regarding a price-cap plan. Listed below are the authors' positions and questions as they relate to these issues:

- *Effect on DSM activities*: The central question here revolves around whether there is a need for the Commission to develop stronger incentives to promote CMP's energy-conservation activities in order to compensate the utility for the added incentive under an ARP to promote sales? Because of the longer regulatory lag that would be expected under an ARP, the Company would profit more from making additional sales. Therefore, it seems that a need exists for additional DSM incentives.[31] On the other hand, it can be argued that additional incentives

[31] One objective of such incentives would be to compensate the utility for presumably inadequate incentives for DSM incentives under either COS or price-cap regulation. Supporters of DSM incentives argue that both regulatory and market barriers discourage a utility from carrying out all cost-effective DSM activities. See, for example, *Investigation into Electric Utility Incentives for Acquisition of Conservation Resources* (Salem, OR: Oregon Public Utility Commission, 1991).

are not needed. Maine already has DSM incentive mechanisms; and the Commission would have the same authority that it now has over the integrated resource planning process. In other words, the resource planning obligation of the Company and the Commission's current policy goals with regard to integrated resource planning would remain intact. As testified to by a witness for AARP, a collaborative process for integrated resource planning could help to assure that the Company continues undertake cost-effective DSM activities.

The Commission, as the New York Commission recently did, could institute additional DSM-incentive plans at the same time that an alternative rate plan was approved. The Commission could also choose to give CMP additional incentives for DSM activities in the future if circumstances dictate so. For example, the Commission could allow the Company a higher share of the cost-savings from DSM activities than what it currently allows.

- *Selection of a price index*: The proposed incentive plan includes an economy-wide index, the CPI. As discussed earlier in this report, a good argument can be made for applying a less-broad index, such as an average cost index for regional electric utilities. This index would explicitly take into account actual inflationary (or deflationary) conditions and productivity improvements for the selected group of regional utilities. Although such an index has theoretical appeal, it would require agreement by the parties on how the index should be precisely defined and calculated. In addition, a regional industry index may reflect the efficiency of a group of utilities subject to the same weak incentives currently faced by CMP.

Finally, the regional industry cost index would more closely track, than an economy-wide index, the actual cost changes of CMP, a condition that would tend to make resultant incentives similar to those under COS regulation.

- *Creation of a "safety net"*: The profit-sharing component presented above should provide a constraint on the Company earning either excessively high or excessively low profits. CMP's proposal represents a different approach for achieving the same objective: it is more discrete and may lead to more frequent formal rate reviews than the proposed profit-sharing component. CCUC's suggestion of having an annual rate review to "true-up" profits has the serious problems of (1) eliminating much of the incentive for cost efficiency under a price-cap plan and (2) imposing high administration costs on the Commission. A plan that frequently, for example yearly, evaluates the parameters of the price-cap formula and the Company's actual profits would create incentives similar to those under COS regulation.
- *Demonstration that the plan would likely benefit consumers as a group*: One alternative would revolve around developing a methodology to set a productivity offset. This productivity offset could, on the basis of "best guess" forecasts, cause price increases (decreases) to be less (more) than what they would be under COS regulation. No matter how the productivity offset is defined or perceived, it would affect the share of actual productivity gains going to CMP shareholders and to consumers. Although finding a productivity offset to make the consumers better-off would almost always entail some margin of error, it can provide the

credibility to an ARP that may be necessary for public-wide acceptance. The Commission may want to add a "stretch factor" to the productivity offset in order to minimize risks to consumers and to place more pressure on CMP to improve its cost efficiency. The authors recommend a minimum productivity offset of 1 percent. In any event, further investigation of an appropriate productivity offset in a follow-up proceeding would likely be necessary.[32]

- *After-the-fact adjustments*: The Commission's response to the Company earning profits far removed from targeted levels (for example, the cost of capital) would have an important effect on the incentive aspects of any ARP. The profit-sharing component would establish up-front rules. This would mitigate against the Commission arbitrarily changing the rules, which can lead to (perverse) strategic behavior by the Company in a way that would be incongruous with promoting cost efficiency. The Commission should determine the treatment of "extreme" profits (profits, for example, that deviate from the latest decided cost-of-capital profits by a prespecified amount) prior to its approval of an ARP; and that any consideration of those profits would be done at the multiyear performance review, rather than at the annual review. One recommendation is to hold these reviews

[32] The productivity offset can reflect a number of considerations: (1) the long-term total factor productivity trend of the electric power industry or an individual utility; (2) the difference between the long-term total factor productivity trends of the electric power industry and the economy as a whole (if an economy-wide price index is applied); (3) expected profits of a utility; (4) protection of consumers, for example, by inclusion of a "stretch factor" or "consumer dividend" to assure benefits to consumers under a price-cap plan; and (5) performance targets for individual components of a utility's operations (for example, number of employees per kilowatthour sale).

every four years. The precise mechanics of the profit-sharing plan would be a follow-up issue.

- *Flow through of amortizations to ratepayers*: Amortizations for cancelled plant that end during the price-cap period should be passed through to ratepayers.
- *Scope of annual review*: The annual review should be restricted to determining the mandated cost that can be passed through to consumers, verifying the profit-sharing and the price-cap rate adjustments, and evaluating whether the Company's quality of service deteriorated over the previous year. Any performance-evaluation, base-rate resetting activity or other activities that could fundamentally affect the operation of the rate-making plan should be done only at the Commission's multiyear (four-year) review.
- *Termination option*: Once approved, the Commission should be strongly committed to an ARP. If not, the Company may discount the benefits it could receive from improving its long-term performance and concentrate instead on only those activities that would improve its near-term performance. The Commission can help to make this commitment by stating, at the time of approval, that it will end the plan and return to COS regulation only under "extreme circumstances." The Commission would, therefore, have the discretion to terminate a plan. If possible, the Commission should specify early the meaning of "extreme circumstances." To reduce the chances of plan termination initiated either by a future Commission or the Company, the Commission may want to consider some incentive measure. For example, such a measure could penalize

CMP for backing out of the plan, as well as compensate the Company for an unanticipated Commission decision to terminate the plan.

- *Monitoring of quality of service*: Concerns over the effect of an ARP on the Company's continued incentive to provide high quality of service may need to be addressed. If the Commission believes this to be the case, it can at one extreme establish explicit incentives to more intensively monitor the Company's activities (such as those instituted in New York).

  The Commission's current authority, which would continue under the ARP proposal, to punish the Company for an excessive number of consumer complaints or safety and reliability negligence, may provide an effective regulatory stick to the Company. It is also not clear that the Company would lower its quality of service even in the absence of Commission oversight (which, incidentally, may not be economically bad if the resultant cost savings exceeded the lost consumer benefits). The reason for this is the likely adverse effect on the Company's revenues and competitiveness, not to mention the potential exposure to lawsuits. In any event, further discussion of this issue is warranted prior to Commission approval of an ARP.

- *"Dead band" region*: In the proposed profit-sharing component, an actual rate of return on equity within 200 basis points of the latest Commission-allowed rate of return would require no additional price adjustment. Some parties may consider the 200-basis-point spread as being too high or too low. As said earlier, the appropriate "dead band" region would account for the tradeoff between the

Commission making annual price adjustments (weakening the Company's incentive for cost efficiency) and preventing the Company from earning fortuitous profit surpluses or shortfalls.

- *Definition of mandated costs*: These costs should be kept to a minimum. Almost any category of cost that the Company incurs, with the possible exception of taxes, can be affected by management actions. The ability of the Company to pass through large cost items would reduce the effectiveness of any ARP to reduce the Company's costs. Parties should agree on a narrow list of items that would qualify as mandated costs. These costs should be limited to those costs that affect only CMP or the electric power industry. Costs that affect other industries, such as general tax increases and broad-based new government regulations (for example, higher health-care costs), would be reflected in an economy-wide price index. Passthrough of mandated costs would be determined in the annual review process.
- *Determination of sharing ratios in profit-sharing component*: The *preliminary* recommendation of a 50/50 split between consumers and the Company gives some recognition to current practices regarding partial incentive systems for the electric power industry. It presumes that the proposed "dead band" region would give the Company ample opportunity to earn higher profits from cost-saving activities. Parties, however, may believe that a different sharing value would be more appropriate. Arriving at a consensus on the "optimal" sharing ratio(s), however, will not be possible.

- *Financial Accounting Standards Board (FASB) No. 106* ("Accounting for Postretirement Benefits Other Than Pensions"): At first glance, CMP's offer to forego passthrough of 50 percent of these costs in the current rate case seems reasonable. Instead, passthrough of these costs could take place at the first annual review. Given that these costs are currently being deferred, CMP should be somewhat indifferent to the timing of the rate increases for these costs. These costs should be carefully analyzed in the follow-up proceeding.
- *Financial forecast*: The Company should develop financial and rate forecasts that compare outcomes under an ARP with those under COS regulation. Further, the Company should perform a sensitivity analysis applying the Commission-determined revenue requirements pursuant to this rate proceeding as the benchmark.
- *Treatment of large capital expenditures*: An important question is whether or not capital expenditures for both demand- and supply-side activities should constitute a passthrough cost item (assuming that the Commission performs a prudence review) to be recovered from consumers outside the price-cap formula. In theory, these expenditures should not be treated separately. (The Company could still request special passthrough treatment to be approved by the Commission under certain circumstances.) One reason for including capital expenditures in the price-cap formula is the Company's argument in another proceeding (Docket No. 92-315) that it expects to be a decreasing-cost firm in the foreseeable future. This implies that the Company expects its average cost to decline in response to

acquiring additional resources to meet increased demands on its system over the next several years. (The Company attributes this to increased competition in the wholesale power market and the current high-priced PURPA-Qualifying Facility contracts.) Therefore, by acquiring additional resources, the change in the Company's average cost should keep pace with the price change embedded in the proposed price-cap component.

Another reason for not treating capital expenditures separately is that it would help to eliminate the serious problem of COS regulation giving firms an incentive to overcapitalize (the so-called "Averch-Johnson effect"). Further, by incorporating all capital expenditures for each category of resource into the price-cap formula, the Company would have an incentive to make least-cost investment decisions.[33] This should reduce the need for the Commission to conduct retrospective prudence reviews of CMP's planning activities.

- *Treatment of fuel and purchased-power costs*: The Commission should reassess the current fuel cost adjustment (FCA) mechanism. The Commission has limited legal authority, however, to modify the FCA mechanism. In a competitive marketplace, it becomes difficult to justify any cost-plus passthrough mechanisms, including the FCA. The California study, referred to earlier, arrived at the same conclusion.

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[33] These resources include new power plants, DSM activities, and firm purchased power.

The FCA mechanism also encourages CMP to make incremental sales even when marginal cost exceeds price -- an uneconomical condition. This is because the Company discounts the fuel costs associated with incremental sales to the extent that it can quickly, and on a dollar-for-dollar basis, recover these costs from ratepayers.

Short of abolishing the FCA, which would ultimately depend on legislative action, the parties might want to consider a *quid pro quo* policy. Under such a policy, the FCA would be replaced by incorporating fuel costs in the price-cap equation and firm-purchased-power costs in a newly developed cost-sharing mechanism. The last element would provide the Company with more incentive than it currently has to restructure its existing contracts with PURPA-Qualifying Facilities. By allowing the Company to benefit more from successful renegotiations, the Company might be willing to increase its risk by recovering fuel costs within the price-cap formula.

6. IMPLEMENTATION ISSUES FOR FOLLOW-UP COLLABORATION

Since several issues pertaining to ARP, and raised in this proceeding, have not been fully addressed, a follow-up proceeding should be held. Its objective should be to have the parties in this proceeding collaborate to agree on an ARP for the Company. The Commission's Rate Case Order could provide the starting point for the collaborative process. Failing successful collaboration, a formal proceeding would be required.

The authors believe an ample record on the various "philosophical" issues exist. Consequently, further investigation of these issues will not be necessary. The rationale for this position was provided earlier in this report.

Relitigating the rate case would create costly delays in reshaping CMP's incentives. Given this reality, the follow-up proceeding would focus on implementation issues. Listed below is the authors' list of questions that could be addressed in the follow-up proceeding. Additional litigation of some of these issues may not be necessary but could be included in order to facilitate the parties' ability to arrive at a consensus:

- *Selection of a price index*: The proposed plan includes an economy-wide index, the CPI. The parties could develop other indexes, if found appropriate.
- *Creation of a profit-sharing component*: The precise design of the proposed profit-sharing component presented above should be considered. While the rate-case Order should provide a starting point for discussion, the parties should have the opportunity to modify that plan, if appropriate. For example, the precise design of the "dead band" region and the sharing ratios could be negotiated.

Further, the methodology to measure the earned return would need to be agreed upon. The same holds for how "irregular" profits should be treated and how rate adjustments would exactly be done.

- *Productivity offset*: A productivity offset would be determined. The Parties should agree on the definition of a productivity offset in terms of how it should be defined.
- *Scope of annual review*: The process by which an annual review would take place should be agreed upon. For example, routine changes, such as the price-cap and profit-sharing price adjustments, could be passed through following a thirty-day review period. Nonroutine issues, such as whether a (noncontrollable) cost should receive passthrough treatment and whether the Company's quality of service has deteriorated, would require more lengthy review in most cases.
- *FASB No. 106*: The follow-up proceeding would address three questions. First, what is the correct estimate of the total transition obligation? Second, are at least 50 percent of these costs prudent? Finally, what should the passthrough rate increase be?
- *Customer satisfaction and reliability incentives*: If the parties wish, they could propose explicit incentives designed to reward or punish (or both) CMP's actual performance relative to a prespecified "customer satisfaction" or "reliability" benchmark. The New York experience can provide guidance on the design of, and the issues surrounding, such incentives.

- *Definition of mandated costs*: The precise scope of mandated costs should be negotiated or determined.
- *Treatment of fuel and purchased-power costs*: The parties could consider the appropriate treatment, given existing legal constraints, of these costs under a price-cap plan.