# CRIEPI REPORT

# Application of Incentive Regulations to the Electricity Supply Industry

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# Application of Incentive Regulations to the Electricity Supply Industry

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## Abstract

Historically, the tool traditionally used by utility regulators to restrain electricity rates has been cost-plus (rate-of-return) regulation. Experience shows that cost-plus regulation does not necessarily induce efficiency improvements in utility operations. In order to improve efficiency in non-competitive markets, incentive mechanisms have been designed to replace traditional cost-plus regulation. It can now be said that cost-plus regulation has become outmoded, as economic forces are gradually pushing electric utility industries toward increased competition.

In the US, many types of incentive regulations have been developed. In general, US-style incentive regulation can be described as consisting of a cost-plus regulation-based framework, with incentive schemes applied supplementarily to certain utility functions. The effect on performance improvement is therefore regarded as marginal.

Recent experience with Performance-Based Regulation (PBR) in California suggests that stronger incentives to improve efficiency are created by: 1) making rates independent of costs; 2) lengthening the time between general rate reviews; and 3) sharing cost savings between customers and shareholders.

Price-cap regulation, which is applied to UK utilities, is also structured to separate rates from costs and to lengthen the regulatory lag. In theory, this mechanism gives the utility incentive to aggressively reduce costs, because it knows beforehand that it will permanently retain a share of the savings between general rate cases.

In practice, however, price cap regulation tends to produce the same effects as rate-of-return regulation, because of regulatory intervention to restrict high profits to certain "appropriate" levels in or even before scheduled reviews. To avoid ever-expanding regulatory intervention, it is necessary to insulate regulators from public pressures to pursue a variety of social goals. By combining an automatic adjustment mechanism such as pass-through or earnings sharings with prohibition of regulatory intervention, the relatively stable, less bureaucratic regulatory structure that price-cap regulation provides in theory can be realized in practice. California's PBR mechanism is based on this idea.

CONTENTS.................................................................................................................................................page

## PREFACE

Deregulatory reform of the electricity supply industry is a world-wide phenomenon. A number of forms of deregulation have emerged.

In the US to date, there has been limited competition in the electric utility industry. Competitive restructuring is at an early stage. Therefore, incentive regulation is being introduced in a transitional phase to a competitive market structure, to improve the economic performance of utilities in markets where market-based price competition is not significant.

In the UK, a pool system has been used to introduce vigorous competition in both generation and supply. Even in the most ambitious reform model, other functions such as transmission and distribution continue to be regulated as natural monopolies. A part of supply function also continues to be regulated during the transitional stage to full competition. In the UK, price-cap regulation has been applied to these remaining monopolistic functions.

This paper deals with the status and problems of incentive regulations applied to the electric utility industry in the UK and the US. Chapter One outlines the theoretical foundation of regulation. Chapter Two deals with the problems of standard cost-plus regulation in a partially deregulated electricity industry. With Chapters One and Two providing the basis for inquiry, Chapters Three and Four investigate the application of incentive regulations to the electric utility industries of the UK and the US.

# 1 Some Theoretical Foundations of Regulation

## 1.1 Objectives and Justification of Regulation

We have outlined earlier that typical features in the electricity industries such as the requirement of line-bound transportation together with the economic non-storability of electricity which call for a minimum of central control of the system lead to naturally monopolistic functions (transmission, system control (dispatch, balancing, pool) distribution) side-by-side with electricity generation and supply which can be opened to competition.

So far, we have been concerned with the question of which functions and markets in the electricity industry should be opened to competition and should thus not be regulated. The underlying paradigm is that in general control and auditing of an industry with the aim of optimal efficiency is best achieved by the workings of competition. Only in those areas where control by competition fails (because a natural monopoly situation has evolved) should some other form of control of utility operations prevail. We have established that in essence only the functions of transmission, system control and distribution (excluding metering and connection activities), i.e. the central transportation tasks should be considered to be subjected to such monitoring.

Next, we have to ask why non-competitive monitoring of transmission, distribution and the system control function may be necessary and to what extent some official "auditor" should interfere. The necessity for regulation arises, because a utility not faced by competition may exploit the situation of non-availability of substitution alternatives for customers. The natural monopolist will take into account his own cost situation together with demand conditions when setting output prices or quantities. Typically, he will charge a price above marginal cost (the efficient price level) and will thus earn an economic rent (undeserved profit beyond compensation for the cost of capital). Consequently, at these excessive prices, fewer of the services in question will be demanded than would be efficient from a social perspective. Thus, regulation must aim at ensuring that economically efficient prices are being charged to achieve an efficient allocation of scarce resources in the economy, at the same time preventing the occurrence of economic rents with their undeserved redistribution of assets (money) from buyers of the services to monopolist utilities.

When discussing regulation, it is important to stress at this point that regulation requires monitoring of utilities that evolve as the sole suppliers because of cost subadditivity conditions. It is not necessary to regulate access of new utilities. If conditions of natural monopoly truly prevail, incumbents can ensure that they remain sole suppliers by (price) strategic measures (Faulhaber [1975]). Should entry be limited where natural monopoly conditions do not (or no longer) prevail, this will only help to maintain a monopolistic position with the subsequent danger of abuse.

We then have to determine a situation to serve as reference for the structuring of regulation. Taken that competition exerts control most efficiently we may consider competition as such a reference standard. Conceptually the workings of competition are quite easy to understand through the "structure-conduct-performance" paradigm (Scherer [1970]). Prices along with other aspects such as supply quantities and qualities are indicators of performance in a market. They will be determined by the conduct or behavior of suppliers and consumers. Conduct again will strongly depend on the structure in the industry. In a competitive sector the structure is particularly characterized by the existence of a large number of suppliers, in a natural monopoly only one supplier prevails. When we want to achieve allocative efficiency (without undeserved redistribution) we are mainly concerned with the performance in the industry. It will come clear in subsequent sections that not all regulatory regimes effectively target the performance. Regulation may then lead to suboptimal results (situation where welfare is increased compared to a situation without regulation but which are inferior to situations of optimal regulation).

Last, we have to establish how regulation is to be executed technically. Conceptually, regulation means that state authorities limit utilities in their use of one or several strategic parameters such as price, quality, quantity, investment (e.g. capital intensity, plant type), procurement (e.g. fuels) etc. Under many regimes a regulation of prices, i.e. a regulation of the performance has evolved. Whereas traditional regulatory regimes such as rate of return (ROR) regulation largely ignore the conduct of utilities in a run-up to the price/tariff setting, incentive regulation (such as price cap regulation) explicitly takes into account strategic behavior of utilities within the regulatory framework.

## 1.2    Optimal Regulatory Regime

In a world of perfect information efficiency would best be achieved by directly regulating utility manager's conduct e.g. by demanding them to act in the best of social interest by charging quasi-optimal (Ramsey) prices (Baumol and Bradford [1970], Ramsey [1927]). In practice this will not be a realistic option due to information asymmetries. These arise since utility managers have better or more detailed information at hand than regulators. In particular, regulators do not know the optimal decisions that utility managers should take due to lack of information (Baron and Myerson [1982]). Even if optimal decisions can be found by regulators it will be difficult to monitor whether respective actions have really been taken by utility mangers. Utility Managers or utilities in general can rather be expected to follow their own targets. In particular, they can be expected to behave in a way as to maximize their profits within the regulatory framework and to manipulate information on which regulatory decisions are based in their own interest where possible.

A strategy for the regulator would then establish an incentive scheme which lets utilities' choose targets compatible with welfare goals within the entire economy. One such welfare concept is that of producer and consumer surplus. Consumer surplus in the absence of price discrimination between customer groups arises because customers are charged a uniform price that equals the willingness to pay of the customer at the margin (i.e. with the lowest willingness to pay among all consumers since the willingness to pay per unit is decreasing in quantity). The sum of the differences of individual customers' willingness to pay and the actual strike price equals the consumer surplus. Social and utilities' aims will then be matching if utilities are being paid a transfer by the amount of achieved consumer surplus thus giving them a monetary incentive to maximize the sum of consumer and producer[1] surplus. This transfer would however mean a redistribution of assets from consumers to utilities.[2] To correct for this, the utility could be obliged to retransfer some amount. To keep up incentives this retransfer should be a fixed payment. To correct for redistribution in the welfare optimal situation completely the retransfer

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[1]    We do not need to consider producer surplus explicitly as producers are claimants of this surplus anyway.

[2]    The redistributional effect would give the same revenues to utilities as in a situation where they could perfeclty price discriminate with the difference that under perfect price discrimination each consumer would pay according to his willingness to pay, whereas under the transfer scheme the amount of the transfer that is levied on consumers depends on the financing of the transfer.

should be equal to the consumer surplus in the welfare optimal situation.[3]

The practical application of this optimal regulatory regime has several shortcomings, though. In particular, there are limitations to evaluating achieved and optimal consumer surplus. This would require the estimation of a demand function in the entire range of consumers using econometric practices (the application of econometric instruments as means of determining the extent of financial transfers can be questioned in itself). Demand conditions will be subject to change so that reference points in time for estimations would have to be set. The problem of estimating the optimal consumer surplus as basis for the fixed transfer could be overcome by opening transmission/distribution franchise contracts for tendering (in a particular area). The utility that agrees on the highest retransferal to society/consumers would then gain the transmission/distribution license (Loeb and Magat [1979]). Usually regulators are not allowed to decide on transfers in order not to give them too much power over an industry.

The concept of the optimal regulatory regime will not be pursued any further for practical considerations but certain important elements of an optimal regulatory regime have been identified with implications for developing (second-) best regulatory regimes:

— - the optimal situation is reached by giving monetary incentives to utilities,

— - the pricing policy of utilities is not influenced by the regulator, in fact none of the major strategic variables of the utility are being regulated,

— - the main objective of the regulator is to ensure an acceptable (re)distribution of the benefits from reaching a welfare optimal solution (in the optimal case consumers obtain full consumer surplus, producers obtain full producer surplus).

### 1.3 Natural Incentive Mechanisms

It has been shown above how monetary incentives can induce utilities to behave in a way compatible with social objectives. After having shown that incentive schemes are required to improve on the welfare contribution of the (regulated segment of the) electricity industry, we next look at what incentive mechanisms are present to a differing extent no matter which regulatory regime prevails.

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3     Although utilities would not improve financially compared to the status quo situation (no transfers either way) incentives would arise as utilities would incur losses if they did not achieve optimal supply quantities/prices.

Basic incentive mechanisms arise from the fact that regulatory decisions (e.g. limiting prices or fixing price structures) are based on information about firm's cost structure, demand conditions and the economic environment as a whole available to the regulator at the time of the regulatory decisions. The regulator will not be able to adjust his regulatory parameters in reaction to some change in the base conditions immediately; regulation is said to be lagged.

Monetary incentives from regulatory lag arise since it allows utilities to obtain intermediate profits. Under any regulatory regime regulatory decisions are based on forecast data about utilities, particularly their cost performance and demand developments. Once regulatory conditions have been set, utilities are free to adjust their strategic parameters in order to increase profits. Intermediate profits particularly arise when productivity can be increased/cost can be lowered compared to levels forecasted for regulatory decisions. Utilities can keep residual incomes that arise from productivity improvements not expected by regulatory authorities (Joskow and Schmalensee [1986]).

Intermediate profits can be achieved as long as the regulatory parameters and framework are held constant. Once a regulatory review occurs, regulatory parameters and framework are adjusted to conditions then prevalent. Regulatory reviews thus decrease some of the incentives stemming from the regulatory lag. A utility e.g. that rationalizes severely early in its life initially achieves high intermediate profits, but reduces its potential for further cost reductions and will be faced by tight regulatory conditions thus diminishing the potential of further intermediate profits considerably.[4]

Under any regulatory regime incentives exist to lower cost after a regulatory review partly by reducing service quality (reconnection after supply failure, voltage stability, meter accuracy etc.). To counteract this adverse effect another incentive scheme can be imposed: utilities can be confronted by a penalty scheme that lists fines for not fulfilling certain service standards. These are usually included in licenses to make them enforceable legally.

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4    Here we have a major difference to competitive markets, where prices are set by the market and not by regulators, so that it is always beneficial to achieve cost reductions as early as possible.

## 2 Problems of Standard Cost-Plus Regulation in a Partially Deregulated Electricity Industry

### 2.1 Description of Cost-Plus Regulation

### (1) General Approach of Cost-Plus Regulation

The standard regulatory regime applied in most countries is that of rate-of-return (ROR) or cost-of-service regulation (Laffont and Tirole [1993]). This regulatory approach is best described by the expression of cost-plus regulation. Under this regime utilities are allowed to levy the cost of service onto their customers (cost element in the electricity tariff). Furthermore, utilities are granted an "appropriate" or "fair" return on their capital invested which can also be rolled over to customers in the sales process (plus element in the electricity tariff). Tariff setting effectively takes place through averaging of forecasted cost data. Under this approach "profits" or rather an "appropriate" return on capital invested are the target of regulation, although the parameter being regulated is the electricity price/tariff.

### (2) Justification

We will in turn analyze the justification of the cost and rate-of-return component in regulated electricity tariffs. When considering cost-reflectiveness of electricity tariffs, we take as given the result that optimal allocation of resources is best achieved by basing prices/tariffs on marginal cost (MC).[5] This suggests that prices/tariffs should be related to cost, more appropriately to MC in some way. The general idea then is to levy cost as a whole onto customers with a detailed allocation to customer groups/time-zones according to MC information. The main shortcoming of this approach, as will become clearer in the following discussion, though, is that it is assuming that cost incurred reflect full productive efficiency. Whether such productive efficiency will prevail is highly questionable. Rather, the mechanism of cost roll-over can be seen as "cost-immunization" eliminating incentives for any effort for productivity improvements.

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5    We will not go into detail with problems of load-specific pricing and the issue of allocating capacity costs to customer groups (either directly or through time-zoning) as measures of ensuring total cost coverage in the presence of large fixed cost (i.e. MC=0 for these cost components at least in the short run) and decreasing MC as result of economies of scale and scope (for certain firm sizes).

The other main element of cost-plus based prices is that of the "appropriate" return on the capital invested, which functions as a compensation for claims by utilities on the ground that assets invested in the electricity business are not available for alternative uses. Only when utilities are granted such a "fair" return will they continue to operate in the electricity supply industry (so called viability or participation constraint) (Tirole [1988], Coles and Malcomson [1989]). If the allowed return is not sufficient to cover the cost of capital, firms will refrain from replacement and extension investment. They will simply continue to operate those plants/lines for which investment cost have been sunk previously thus endangering service safety in the long run (Grout [1994]).

## 2.2      General Problems of Cost-Plus Regulation

### (1)      Overview of General Problems of Cost-Plus Regulation

When discussing the merit of incentive regulation it is important to identify problems emerging under non-incentive based regulatory regimes such as cost-plus regulation. In this context three important aspects are subject to extensive discussion:

−      the question of observed capital intensity compared the optimal capital intensity from a social perspective (investment problem),

−      the question of the efficacy of prudency reviews,

−      the intensity of "natural incentive mechanisms" under cost-plus regulation together with potential asymmetries in tariff adjustment, possibly resulting in multiple recovery of depreciation.

### (2)      Investment Problem

One major criticism goes back to Averch and Johnson (Averch and Johnson [1962], Vickers and Yarrow [1989]), who conclude that cost-plus type regulation will lead to excessive employment of capital. Their criticism does not point at the process of assessing cost of service but rather targets the mechanism underlying the determination of the "appropriate" return. If the return is defined by a "fair" rate and a rate base, utilities will be induced to increase their rate base, namely their capital investment, whenever the allowed rate of return exceeds the cost of capital. Allowed rate and market rate of return

(= cost of capital) will almost always divert, simply because of the explained inability of regulators to react to changes in the environment immediately. Some evidence points towards a bias of regulators towards favorable allowed rates (from utilities' perspective) due to supply safety considerations. The existence of incentives for excessive capital intensity has lead to investment regulation in many countries (e.g. Germany, USA). Any new investment has to be authorized by regulatory authorities. Because of potential dangers of under-investment paired with information asymmetries in favor of utilities, regulars cannot be expected to rigorously limit new investments, though.

When we move on to a dynamic setting the investment problem could lose in severity. On the one hand, the long run tendency for excessive capital investment remains, on the other hand, the opportunity for intermediate profits due to regulatory lag may counterbalance the investment bias towards a more efficient capital intensity. The reason for such counterbalance is that lagged regulation induces incentives for cost reduction and thus also savings in capital cost. This argument is not a strong one, though, since investments usually have a gestation period of between 5 and 10 years, while the regulatory lag usually has a duration of between one and three years thus weakening the counterbalancing effect (Baumol and Klevorick [1970], Bailey and Coleman [1971]).

### (3) Prudency Review Problem/Dynamic Inefficiency Problem

Prudency reviews have been established in order to assess the cost basis of utilities applying for tariff increases. Several variations of such reviews are in place in different countries. The underlying principle in US regulation focuses on the capital structure of utilities in that facilities employed in the electricity business and for which depreciation is to be charged to customers has to be "used and useful" In the German process of tariff authorization particular weight is put on the efficiency of the operational process by only allowing cost that would be incurred under "rational operations management" (*rationelle Betriebsführung*). In any case it remains questionable whether informational asymmetries will allow any regulator to detect inefficiencies thus defined. For this reason yardstick orientated approaches have been employed in practice, identifying the cheapest supplier for a particular type of service region structure. Suppliers with higher costs are then required to justify costs exceeding the reference level on the grounds of remaining structural differences. Any unexplainable costs will be disallowed. In such a process tariffs are usually determined as the outcome of a bargaining procedure.

## (4)        Effects of Natural Incentive Mechanisms

"Natural incentive mechanisms" also prevail under cost-plus type regulation. Before going into further detail we have to distinguish two different practices of reviewing utility tariffs, though:

−     continuously, in most cases annually repeated review of tariffs,

−     assessment of tariffs only upon application of tariff alteration (i.e. practically tariff increases), so called passive regulation (Joskow [1974]).

As explained before, natural incentive mechanisms induce some extent of productivity improvement through the opportunity of intermediate profits, even if regulatory reviews are repeated on an annual basis. In practice, intermediate profits will mainly be a result of increases in supply quantities. This is because per unit revenues (= tariffs) are being calculated based on an *ex ante* demand forecast. If demand is estimated to be relatively low then fixed costs will be allocated to few output units (kWh). Tariffs will be set relatively high. If some utility then arrives at increasing its sales compared to previous forecasts (that formed the informational basis for tariff setting), higher revenue components will be obtained through the sales process than would be required for coverage of fixed costs.

If tariffs are only assessed in reaction to a tariff alteration application by some utility then an asymmetry in tariff adjustment beyond that of lagged regulatory reaction arises: utilities that incur increases in their exogenous or endogenous cost can be expected to apply for tariff increases. Utilities experiencing cost deflation even if these are exogenous and thus outside the utility's responsibility will conversely be reluctant to apply for tariff decreases. This implies that if the principle of cost-reflectiveness of tariffs is being followed, only those utilities will be subjected to extensive regulatory audit that receive a comparably low rate-of-return (Joskow [1974]). Utilities participate in the regulatory procedure in that they themselves determine the timing of regulatory reviews. Thus, the investment problem looses in importance under this regulatory practice since the duration of validity of tariffs can be as long as to allow utilities to gain financially from a more efficient capital intensity.

Another important problem relating to the recovery of depreciation emerges under asymmetric tariff adjustment, though. One of the functions of depreciation is to spread investment cost of some asset over its entire life-time. Since life-times cannot be forecasted exactly, these will usually be estimated allowing for some caution, i.e. they are

set below life-expectancy. Thus assets will usually be written off completely before their operation ceases. Considering a utility which only operates one asset, there is some possibility that the utility will not lower tariffs accordingly once this asset is written off completely although it is still in use. Customers then continue to pay a depreciation component in the price, i.e. they effectively pay for part of the asset twice (beyond any consideration of whether to apply current or historic cost accounting). When considering a utility with numerous assets the argument looses in force. Provided that replacement of assets takes place at regular short intervals it makes no difference for consumers whether the utility under consideration simply keeps its tariff or whether it continuously applies for tariff authorization where fully depreciated assets no longer inflate the cost position while new assets are calculated with the same amount of depreciation as old assets just written off (tariffs will remain at the same level either way). When investments occur in a cyclical manner, though, the problem of "paying depreciation twice" reemerges. This mechanism may in fact generate incentives for cyclical investments.

Opportunities for multiple coverage of depreciation can create a new investment problem. Depreciation earned beyond investment (replacement) cost represent an additional return on capital invested as they change in proportion to the capital base. This may allow the "adjusted" rate of return to exceed the cost of capital by far, thus triggering the investment mechanism outlined by Averch and Johnson.

In spite of the ratchet effect of asymmetric tariff adjustment some utilities pass on productivity improvements through tariff reductions in order to sustain some understanding with regulators. Such "self-limitations" must usually be interpreted as defensive measures though, that do not adjust tariffs to a socially optimal level.

able to charge monopoly prices.

If utilities were to carry more cost responsibility by the imposition of a regulatory incentive scheme any redeclaration of cost would be to the detriment of the profit-maximizing utility itself. Optimally, incentives in the regulated businesses should be to the same power as incentives in competitive sectors in order to fully eliminate the problem of unjustified cost reallocation.

As for the problem of allocating joint cost, refined accounting methods may be used to fully allocate incremental costs (additional cost of supplying another customer group on the assumption that supply of all other customer groups is a going concern already). Any cost beyond that can only be distributed by some accounting convention (fully distributed cost pricing). Here the so called Baumol-Willig rule (Baumol and Sidak [1994]) only provides a rough corridor for the determination of cost allocation:

–      no customer group should be allocated less than its incremental cost (price floor),

–      no customer group should be allocated more than its stand-alone cost (cost that would be incurred in the event of isolated supply of this group = price ceiling).

This wide corridor may easily serve as a justification for allocating as much cost to regulated businesses as possible. If responsibility for cost incurred in regulated activities could effectively be attributed to utilities, they themselves would have to decide on a price/tariff structure. They would do this in maximizing their returns. Attribution of allocation of advantages from joint supply would then also take place under particular consideration of demand conditions. Only in very rare cases would customers with inelastic demand be charged their stand alone cost (this rare case would in fact only arise if demand is fully inelastic), i.e. in most cases they would be attributed some of the advantages of joint supply.

This is also the type of allocation that would be imposed by a perfectly informed regulator. Under asymmetric information, however, the regulated price/tariff structure is likely to have an inefficiency bias. Thus the imposition of an incentive mechanism that lets utilities carry more cost responsibility would help to eliminate the problem of inefficient tariff/price structures in diversified utilities.

## (2)　　Inefficient Diversification

If utilities are not prevented from making strategic use of cost allocation between diversified businesses this may also give incentives to inefficient diversification. Utilities that would not be competitive in certain businesses under optimal regulatory control, may gain a competitive advantage if they can levy an excessive cost burden onto regulated customers thus decreasing cost that has to be recovered within the competitive diversified business. We can e.g. imagine a situation in which it would be economically efficient for a transmission utility to let a telecommunications company use part of the utility's grid against some charge. If cost from a competitive business could be transferred to the regulated transmission business in cost accounting it might pay for the utility to engage in telecommunications activities itself rather than renting out grid facilities even if it is of lower efficiency in telecommunications operations. Again, the problem arises because of an uneven distribution of inherent incentives between businesses (Braeutigam and Panzar [1989]).

# 3     UK Style Incentive Regulation (Price Cap Regulation)

## 3.1     Description of Price Cap Regulation

### (1)     General Approach

Price cap regulation imposes a restriction on the growth rate of prices. In particular, the growth of a weighted bundle of prices is not allowed to exceed the growth of a general price index (e.g. retail price index = RPI) reduced by the expected productivity growth rate $(X)$ in the respective industry. Thus a time path of price ceilings is imposed according to the formula $P = RPI - X$. Utilities then have the opportunity to increase their returns by increasing productivity growth beyond the expected rate $(X)$. This creates strong incentives for productivity improvements.

Target and object of regulation in this regulatory concept is the price or tariff. This approach reveals the underlying aim of consumer protection. Regulatory authorities applying price cap regulation also stress that capped prices should be interpreted as ceilings rather than fixed prices. Economically, undercutting of the price cap indicates excessively high price caps which may in some cases exceed monopoly prices.[6]

### (2)     Justification

The question arises why prices are bound to the retail price index (RPI) which does not reflect the specific development of cost faced by utilities. The reasoning is that RPI is a good approximation of the cost development for utilities without reflecting potentially inefficient operation. If electricity tariffs were bound to utilities' cost the "cost-immunization" problem would reemerge. Utilities could pass all cost down to customers and would have no incentive to evaluate cheaper procurement opportunities and to rationalize internally (Black [1993]).

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6     From a dynamic perspective it may pay for utilities to undercut price ceilings if this helps to prevent an exceptional regulatory review. Such utility behaviour is likely to be driven by profit maximisation. Like in the static setting undercutting of ceilings then points towards a inefficiency in regulation since the pricing decision will not be driven by macro-optimisation but by utility specific considerations.

RPI is to be corrected for systematic cost changes in order not to make utilities responsible for cost arising from political decisions such as the imposition of stricter environmental protection requirements. On the other hand utilities shall not be put in a position that allows them to earn excessive profits. This is prevented by determining in advance to what amount future cost reductions through productivity gains (no matter whether they are actually achieved) must passed down to customers. For this, a rate of productivity improvement (X) is set by the regulatory authority. A practical problem consists in determining this rate for each utility individually. This problem is aggravated by the fact that utilities operating efficiently already (offering lower tariff levels) have a lower potential for additional productivity improvements and should not be punished by a tariff deflation determined on the grounds of average productivity improvements.

Historically, first elements of price cap regulation could be observed in the USA in the early seventies. Before this time a cost based regulation with asymmetric adjustment of tariffs was prevalent in most states. Applications by utilities for tariff adjustment rarely occurred since input cost of electricity enterprises remained fairly stable. Utilities were keen to achieve intermediate profits by improving efficiency over longer periods. The situation changed increasingly with rising fuel prices that culminated in the oil crises. A new methodology was needed that combined the positive features of a standardized procedure (previously the "laissez faire" with few applications for tariff adjustment) with little workload for regulatory authorities. One important attempt was the indexation of fuel cost where its effect on supply cost could be passed down to customers. In the method of price cap regulation currently under discussion, the RPI-factor is viewed as an indicator of the development of all supply cost.

The UK version of price cap regulation has evolved from a consultancy paper that Stephen Littlechild, now Director General of Electricity Supply, prepared in 1983 for the regulation of British Telecom in its course of privatization (Littlechild [1983]). He compared several regimes assessing their expected performance with respect to aspects such as protection against monopoly, efficiency and innovation, burden of regulation, promotion of competition and "proceeds and prospects". Littlechild concluded that a concept named "Local Tariff Reduction" scheme, later known as price cap regulation, performed best.

## 3.2 Incentive Effects of Price Cap Regulation

### (1) Efficiency in Core Electricity Business

Incentives for efficiency improvements particularly arise under price cap regulation because firms carry full responsibility for their cost once price caps have been set. The X-factor can be viewed as an productivity improvement rate target since a utility that exactly reaches the set X level should be obtaining normal profits. Incentives arise because additional intermediate profits can be achieved if the productivity target can be exceeded.

The incentive effects of this type of regulation will mainly be determined by following factors:

- the length of the regulator's reaction delay,
- the reliability and predictability of regulatory reviews,
- the reference level for adjustments in the course of a regulatory review.

The length of the lag period determines the time during which intermediate profits can be achieved. If the timing of the regulatory review is known we speak of a periodic review. In the eyes of some regulators extraordinary adjustments of price caps (stochastic review) may be necessary when high profits arise. An extraordinary review is however highly counterproductive in that it introduces uncertainty about the period during which utilities can achieve intermediate profits in future regulatory periods. Firstly, the expectation about the lag period is reduced, additionally uncertainty about the length of the lag introduces uncertainties for risk-averse utilities. This takes away incentives that were meant to arise from price cap regulation.

In addition to the problem of adjustment timing the question of the reference level for tariff adjustments is of crucial importance. Since electricity tariffs are determined by extrapolating historic prices with (negative) cost growth rates, actual rates may differ from the forecast. Therefore, prices will have to be adjusted to a "reasonable level" in the course of review. Such a reasonable level is assessed by comparison of prices with supply

costs.[7] Thus price cap regulation approaches cost based regulation in practice, the major difference being that

– tariff adjustments are symmetric under price cap regulation,

– the regulatory lag is extended compared to cost based regulation.

Interestingly, price cap regulation effectively simulates a similar performance as under "imitative competition" where an innovator can only sustain super-normal profits for a limited period of time (i.e. the lag period) during which he is not faced by competition while the entrance of imitators at a later stage forces him to lower prices to competitive levels. Typically, such periods without imitators emerging on the market is determined by investment requirements and gestation periods - in the case of capital intensive industries usually several years (Littlechild [1992]).

## (2)    Efficiency under Diversification

As has just been developed, price cap regulation generates a performance similar to that of imitative competition and creates corresponding incentives for productivity improvements. Utilities have full cost responsibility at least until the next regulatory review. Therefore, the power of incentives is very similar in degree to incentives in competitive businesses into which utilities might diversify.[8] Under purely cost-based regulation utilities may find it worthwhile to diversify into unregulated businesses as this might give them the opportunity to allocate some of the overhead cost attributable to the competitive business to the regulated business thus inflating rates/tariffs there. With exogenously determined market prices in competitive markets (e.g. telecommunications) and tariffs determined endogenously by the method of rolling over cost to franchise customers the utilities' overall revenue position can be improved by diversification. This may give adverse incentives for diversification where it would not be efficient.

Under price-cap regulation a cap (or rather real reduction) on tariffs in the regulated segments can at least ensure that calculatory cost movements upon diversification do not

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7    The consequence of this methodology is that utilities which have achieved high productivity improvement rates in the past must expect a much tighter price level than in the previous review period. For utilities that rationally expect such an adjustment, incentives for extreme productivity improvements decrease.

8    Typical diversification businesses such as gas or telecommunications operations are of similar capital intensity as the electricity industry thus generating comparable inovator-imitator-competition incentives as under price cap regulation.

take place to the detriment of captive customers. A utility that would internally apply the same sharing rule for overhead cost as it would strategically do under cost-based regulation would simply "fool itself". A price cap that is not to be based purely on cost information can thus help to prevent price discrimination or cross-subsidization between regulated and unregulated operations. Some utilities may also reconsider their diversification strategy under this setting which resembles the performance of imitative competition also in the regulated market.

Then, any shifting of cost to regulated businesses for regulatory accounting purposes, would be to the detriment of utilities as redirected cost could not be recouped from regulated customers once price caps have been fixed. Redirection of cost might pay under any regime before reviews, but as lag periods are longer under price cap regulation the price structure will approach its efficient form within the lag period.

## 3.3 British Model: Pragmatic Approach to Price Cap Regulation

In the UK price cap regulation is applied not only in the electricity industry, but also in other "public service" industries. Before explaining the application of price cap regulation in the UK, the approach, justification and incentive effects of price cap regulation are investigated.

### 3.3.1 Areas of Application of Price Cap Regulation in the UK

### (1) Application of Price Cap Regulation in UK "Public Service" Industries

Apart from the electricity industry price cap regulation is also applied in other regulated industries in the UK, namely the gas industry (British Gas), water supply, airports (British Airport Authorities) and telecommunications (British Telecom). A regulatory framework which will also be based on the price cap approach is currently being developed for the railway industry. In all industries part of the operations remain unregulated. Some features of regulation in the named industries are summarized in the following table.

*Table 1:*    *Regulation in UK non-electricity industries*
*(see also Armstrong, Cowan, Vickers (1994), pp. 176)*

| | British Telecom | British Gas | British Airport Authorities | Water supply companies |
|---|---|---|---|---|
| **Regulatory body** | Oftel (Office of Telecom-munications) | Ofgas (Office of Gas Supply) | CAA (Civil Aviation Authorities), MMC (Monopolies and Mergers Commission) | Ofwat (Office of Water Services) |
| **Price index** | Tariff basket | Average revenue (per therm) | Average revenue (per passenger) | Tariff basket |
| **Cost passthrough** | - | All gas supply costs | 95% of extra security costs | Cost of new environmental and quality regulation |
| **Quality regulation** | Fixed compensations for delays in repairs and connections | Compensation scheme | - | Compensation scheme |
| **Regulatory lag** | Initially 5 years, now 4 years | 5 years | 5 years | 10 years, 5 years at regulator's or firm's request |
| **Next review** | 1997 | 1997 | 1998, (MMC involved in review) | 2000 (10 year lag), 1995 (5 year lag) |

## (2)    Application in the Electricity Industry[9]

In the UK electricity industry 3 businesses are identified for each of which distinct regulatory practices within a price cap regime can be observed:

—   transmission,

—   distribution,

—   supply.

The transmission business includes all transport activities of the National Grid Company. The distribution business incorporates transportation activities of regional electricity companies (RECs), metering and connections. Although all of these operations are currently carried out by RECs, considerations for competitive opening of metering and connection activities are under way. These activities would then be exempted from

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9    See for this OFFER (1993): Electricity Distribution: Price Control, Reliability and Customer Service, Birmingham

regulation. Furthermore, distribution to premises at or above 22kV, top-up and stand-by charges as well as charges associated with wheeled units (direct supply from generator to non-franchise customer) among others are excluded from regulation.

The value added activities in the supply business are quite limited (mainly administration, in particular invoicing) and regulation itself is limited to franchise customers (as of 1 April 1995 <100 kW customers). Therefore, the main cost drivers in the supply business, namely electricity procurement (subject to generation competition), transmission and distribution (subject to regulation) as well as the fossil fuel levy (to support nuclear generation) are of pass-through nature.

As a pre-requisite for operations in regulated business, utilities need to hold licenses outlining detailed conditions of operation, and quality standards in particular. Conditions for the NGC are outlined in the "Grid Code", supply and distribution companies hold "Public Electricity Supply Licenses". Distribution operations are exclusive to RECs, supply activities are licensed to RECs and generators.[10] Suppliers operating outside the franchise market (i.e. supplying customers beyond the load threshold of 100kW from April 1995) must hold a "second-tier-supply license".

Further aspects of regulation in the UK electricity industry will be summarized later after these have been considered in detail.

### 3.3.2    Technical Aspects of the Periodic Review

### (1)    Basic Price Cap Formula in the Electricity Industry

*i) Determination of the Price Index*

Although the initial price cap formula simply states a relationship between a cost indicator (RPI) and productivity improvements with (a basket of) prices/tariffs, refinements had to be made in order to eliminate adverse incentive effects arising from the simple "RPI-X" formula. These will gradually be developed below.

As indicated before, the price cap limits the average revenue per unit of electricity sold(/transmitted). The average revenue (M) is allowed to increase by an annual rate of

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[10]    Public Electricity Supply Licence, last modifications 30 March 1994, individual for each supply utility.

(RPI+X)/100[11] or in other words is allowed to grow by a factor of (1+[RPI+X]/100) from a base level P, annually:

$$M_t = \left(1 + \frac{(RPI + X)}{100}\right) P_{t-1}$$

where:

M$_t$     :     the Maximum average revenue per unit in relevant year t

RPI     :     the percentage change in the Retail Price Index

X       :     the percentage change in cost reduction

P$_{t-1}$    :     the average revenue per unit in relevant year t-1

The average revenue within each consumer case derives from a combination of standing and variable charges. There is no specific control of standing charges and variable charges, the structure of standing and variable charge elements has to comply with the non-discrimination clause in licenses, though.[12]

Before considering how to augment the Price Cap Formula we will address some of the difficulties in assessing the indicator values in the basic price cap formula.

## ii) Rate of Inflation (RPI) Forecast

Whereas previously RPI had been determined using forecast values for the following year this had proved impractical as deviations of forecasted from actual values were significant. Thus, the average annual inflation rate estimated from actual inflation observed during previous July to December is now being used instead of forecast values.

## iii) Base Price

### a. Function of the Base Price as Reference Level

The RPI+/-X term applies a growth rate to a historic price level in order to determine a limit on future price levels. The price cap thus determined will only be appropriate (i.e. will not allow the utility to obtain super-normal profits) if the applied "historic" price level is "appropriate". Had price caps been set too high in the recent regulatory period,

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[11]     Here we switch to the original terminology of Offer which uses the formula P=RPI+X where -X is the annual rate of cost reductions as result of productivity improvements.

[12]     See Public Electricity Supply Licence as of 30 March 1994, Condition 4: Prohibition of cross-subsidies and of discrimination. Price discrimination could be increased by demanding high standing charges thus increasing average electricity cost for low demand customers relative to average charges to high demand customers.

then an increasing wedge between cost and price will have allowed the utility to generate super-normal profits (it is exactly from these that incentives for productivity improvements were derived).

In order not to sustain such super-normal profits, the "historic" price level will have to be adjusted in a way that does not let the utility obtain any super-normal profits in the next regulatory period initially. Utilities will then only be able to generate new intermediate profits by further productivity improvements. The question then is how to determine such an adjusted "historic" price level. This is done by making use of the methodology applied under cost plus regulation, i.e. it is assumed that the cost incurred at the end of the previous regulatory period together with a fair return on capital invested serves as an appropriate reference standards. In the following we will outline some particularities of cost reflectiveness in UK style regulation.[13] As we discuss later, such a cost reflectiveness makes the decoupling of realized costs from allowed revenues provided by price cap regulation unclear. Price cap regulation may tend to operate more like ROR regulation with a fixed regulatory lag.

*b. Assessment of Cost*

Typically, depreciation will form a major part of total cost incurred in the regulated businesses of transmission and distribution. Here, utilities are allowed to write down assets from replacement cost. In general, principles of current cost accounting are applied in accounting for regulation in the UK.

*c. Assessment of Rate of Return and Rate Base*

A "fair" return forms part of the expenses that can be levied onto customers. The two questions arise of determining a fair rate and a rate base which this "fair" rate is to be applied to.

In the determination of the rate base two practices have been employed. One is that of asset valuation according to cost accounting methods. To maintain consistency with the determination of cost, regulatory "book values" have been used as rate base. Alternatively, market valuation of assets has been employed. Here the argument is that shareholders have expected a certain return from utility operations and thus market values should be used as rate base. The problem was that floatation values of utilities have been below asset values thus considerably depleting the rate base. To overcome this, the

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13     For general aspects of cost reflectivity see considerations on cost-plus regulation.

dividend growth model has been used, instead. It also provides some market valuation by determining the net present value of future dividends on the assumption that dividends observed historically grow at a certain (constant) rate. In addition to dividends, investments have to be taken into account as they reduce dividends today but represent potential for additional future dividends. After further adjustment OFFER in its Periodic Review for the distribution business then arrives at a market value that amounts to 90% of cost accounting asset values.

Although this section is meant to be of descriptive nature two important inconsistencies in the asset valuation methodology just explained have to be pointed out. Firstly, there is an inconsistency in applying the dividend growth model in a regulated industry. The dividend growth model is based on the assumption that the assessed firm represents a growth stock. If this were the case for electric utilities this would point towards some ineffectiveness of regulation. The objective of regulation is exactly to only allow for a fair or market rate of return which should not allow dividends to grow (beyond inflation). Secondly, there is a more general objection to market based asset valuation in regulated industries. Theoretically, such a valuation is impossible due to a circularity between asset values and electricity tariffs. If asset values rise, the rate base and depreciation increase. Consequently tariffs should increase. Increased tariffs lead to higher revenues (without historic cost having changed) thus increasing profits and consequently the market value of assets etc.

The rate of return consists of two components:

- a risk free rate of return as can be approximated by the return on long term government bonds,

- a risk premium which reflects specific utility risks (also in correlation with market developments) as can be estimated on the grounds of historic (stock market) data using the capital asset pricing model (CAPM).

*d. Productivity Growth Forecast (X)*

The productivity growth forecast is practically based on the forecast of cost development. The productivity growth rate expresses the annual rate of change of cost (in real terms) between the current level of total cost and some future level of cost on the assumption of a constant output. Forecasts on future cost levels are largely based on information provided by utilities. The X factors to be determined thus evolve out of some sort of negotiation process.

## (2)   Advanced Price Cap Formula in the Electricity Industry

### i) Correction Factor

A correction factor has been introduced into the price cap formula in order to adjust for excessive average revenues (beyond the cap) from the previous year due to forecast errors other than cost reductions (since utilities are residual claimants of these). Such overcompensation is mainly a result of forecast errors in sales. In particular, the price cap is likely to be exceeded, if sales to high price customers were higher than expected, while sales to low price customers were relatively lower. In this case the overcompensation has to be repaid to consumers in the next period, practically by lowering average prices (the price cap) for the next period (and only for the next period). For this, a correction factor $K$ is added to the price cap formula.

It should be noted that this does not mean that cost reductions beyond forecasts have to be handed down to customers. The correction factor only relates to (average) revenues while cost reflecting components (i.e. the P and X elements) remain unchanged in the formula.

### ii) Disincentives for Boosting Sales

It has initially been argued by OFFER that incentives should be given to utilities in the regulated electricity businesses to maintain a high level of sales. The reasoning was that regulated sectors were monopoly businesses in which firms have incentives to lower sales quantities below efficient levels in order to increase profits by putting up prices (monopoly pricing).

By capping average revenues marginal revenues are practically also kept constant (while marginal revenue would be decreasing in quantity under unregulated monopoly conditions) while marginal costs are typically decreasing in the examined natural monopoly situations (i.e. at particular firm sizes observed in the UK). Increasing sales thus indeed allows to increase return on capital investment (provided no new investments are required). In fact Burns and Weyman-Jones (1994) estimate that RECs only incur around 70% of unit cost with each additional unit supplied. Practically utilities benefit from being able to distribute fixed cost onto more units than forecasted when setting price caps.

It was indeed observed that RECs took strong measures to boost sales, potentially beyond a level compatible with the energy efficiency aim at economy-wide level. Due to this, the price cap formula was adjusted for the distribution price review to take away some of the

incentives to increase sales. This adjustment has not been incorporated in the correction factor as the sales increase effect does not have the effect that the average revenue threshold (price cap) is exceeded. In fact, the (total) revenue increasing sales effect is only noticeable when examining total cost and revenue. The idea of adjusting the price cap formula is rather to reduce incentives for sales in the first instance. This was effectively done in the review of the distribution business by partly relating revenues not to sales but to customer numbers (i.e. average revenue per customer). Practically, this implies a move towards a total revenue rather than an average revenue cap, since customer numbers are not changing considerably over time. It should be noted that a shift towards a total revenue control does not eliminate incentives for productivity improvements. Again profits can be increased by reducing cost at the allowed level of revenue. On the other hand the regulator has to take care of emerging incentives to increase profits by reducing supply quantities at given allowed total revenue. A balance of incentives for and against sales increases shall be achieved through a mixed average/total revenue cap.

In fact it could be noticed that this change in the regulatory formula led to changes in the business strategies of RECs with some of them considerably cutting staff devoted to marketing activities.

### iii) Cost Pass Through

In some regulated industries utilities are allowed to pass through cost changes for certain cost categories even after price caps have been fixed. These adjustments shall mainly account for changes in utilities' economic environment for which utilities are not themselves responsible, such as adjustments in environmental standards. Similar provisions have not been made in the regulated transmission and distribution businesses. In the franchise supply market transmission cost (T), distribution cost (U), electricity purchase cost (E) and the fossil fuel levy (F) can be passed down to customers thus altering the price cap formula for franchise supply into (see also Figure 1):

$$RPI - X + Y$$
*with*
$$Y = T + U + E + F$$

This leaves RECs with responsibility over approximately 5% of the supply cost in the franchise market, the other cost components being monitored either through competition (generation or electricity purchase cost), or regulation in some other area (transmission and distribution). Some concern has arisen over the economic purchasing obligation for electricity (license condition no. 5) not providing enough incentives to negotiate

favorable conditions for electricity procurement cost hedged in the contract market because of the pass through nature of this cost component.[14]

*Figure 1: System of Price Cap regulation and competition in the UK electricity industry*

| | *generation* | *transmission (NGC)* | *distribution* | *supply* | | *end user price* |
|---|---|---|---|---|---|---|
| *regulation (Price Cap)* | | - transmission use of system charge<br>- connection charge<br>(RoR regul.)<br>( T ) | distribution use of system charge<br>(<20 kV grid)<br>( U ) | franchise market | F O S S I L<br>F U E L | charge to end user |
| *competition* | - pool prices<br>- contracts for differences<br>( E ) | | | non-franchise market | L E V Y<br>( F) | end user price |
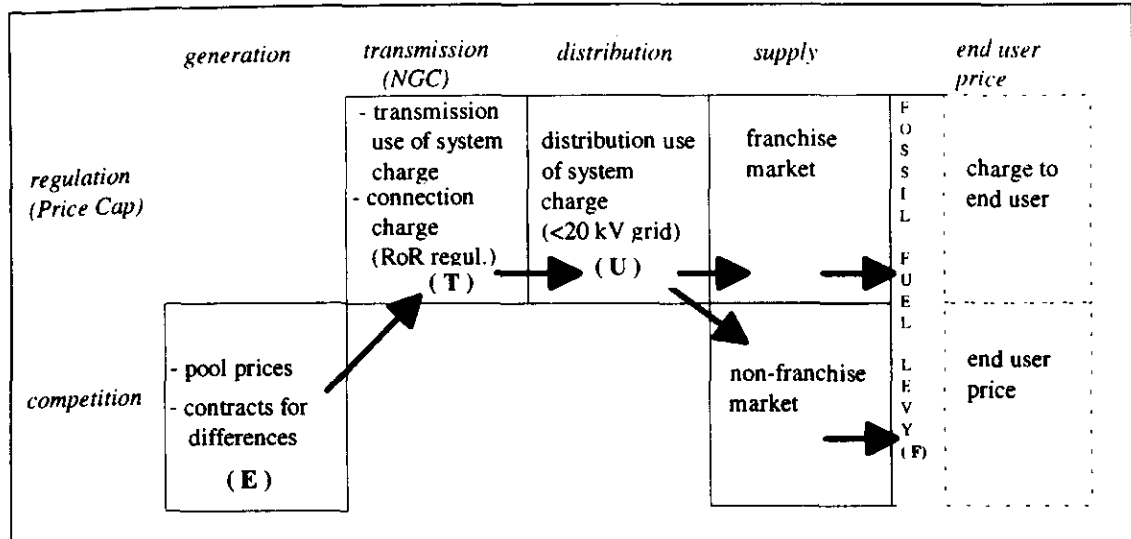
## iv) Performance Indicators

In addition to incentives derived from price cap regulation, it is viewed that incentives for certain efficiency increasing measures are not strong enough. To account for this, additional incentive mechanisms using performance indicators as outlined for US style incentive regulation can be employed. These can also be introduced into the price cap formula.

Incentives have e.g. been introduced to further reduce electricity losses in the transmission and distribution network. This has been done by letting utilities benefit from loss reductions by allowing them to increase tariffs/charges by a certain amount if a target value had been undercut.

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14 This has sparked off two consultation papers: OFFER (1992b): Review of Economic Purchasing, Birmingham, December 1992; OFFER (1993a): Review of Economic Purchasing, Birmingham, February 1993.

## (3)    Price Controls for Different Operations

### i) Overview of Price Controls in the UK Electricity Industry

The objective of the following description is to give an overview of the practical application of price cap regulation in different segments of the electricity business.

Generation costs account for the major part total cost (depending on consumer type between 54% [<100 kW customer] and 69% [<1 MW customer]). Distribution costs form the second biggest portion of cost, accounting for between 25% and 15%. Transmission cost add up to between 5% and 6% and supply cost are mainly significant for small customers only, where they contribute to 6% of total cost.

*Table 2:*        *Components in electricity supply charges to franchise customers*

| component | contribution to total supply charges |
|---|---|
| distribution charges | 23.80% |
| generation | 58.30% |
| transmission charges | 3.90% |
| fossil fuel levy | 9.30% |
| supply business margin | 4.60% |

*Source:*        *OFFER (1992), p. 11*

For RECs, supply accounts for the major part of turnover, however, most of supply services are procured from outside (i.e. they are of pass through nature). Distribution cost roughly account for 25% of total supply cost. Still RECs mainly generate their profit from their core distribution business with the supply margin being rather small in absolute terms.

*Table 3:*        *Turnover and profit in RECs main businesses (1993) in £ million*

| RECs | Distribution Turnover | Operating Profit (current cost) | Supply Turnover | Operating Profit (current cost) |
|---|---|---|---|---|
| London | 360.7 | 106.2 | 1,266.0 | 4.6 |
| SEEBOARD | 285.3 | 56.4 | 1,108.9 | 11.6 |
| Southern | 394.9 | 120.8 | 1,687.2 | 13.6 |
| South Western | 236.4 | 59.6 | 786.8 | 12.3 |
| Eastern | 428.2 | 104.5 | 1,805.3 | 27.8 |
| East Midlands | 342.9 | 116.0 | 1,325.1 | 26.4 |
| Midlands | 357.6 | 104.7 | 1,381.5 | 24.0 |
| SWALEC | 188.6 | 39.2 | 536.4 | 5.5 |
| Manweb | 248.6 | 71.4 | 797.6 | 6.0 |
| Yorkshire | 331.6 | 92.6 | 1,206.2 | 4.0 |
| Northern | 237.1 | 74.1 | 809.0 | 1.8 |
| NORWEB | 337.7 | 96.0 | 1,210.7 | 14.7 |

*Source:*        *OFFER (1993), p. 36, REC's regulatory accounts*

## ii) Distribution Price Controls

The first Distribution Price Decision has been in place for the five year period from 1 April 1990 to 31 March 1995. A proposal for revision to come into force in April 1995 (for the next 5 year period until March 2000) has been proposed in August 1994. Meanwhile, several developments have led the Director General of Electricity Supply to announce on 7 March 1995 that his proposal required further revision. In the following, the Distribution Price Control as it will be implemented provisionally from April 1995 is outlined first, and then adjustments to the underlying factor values decided in July 1995 is explained.

The price control formula can be characterized as a mixed average per unit and per customer revenue cap. It consists of three main elements:

- distribution element $(P_u)$ (historic distribution revenue),[15]

- metering element $(P_m)$ (historic metering revenue),

- loss element $(P_L)$ (with performance indicator).

$$M_{dt} = \frac{\left[1 + \frac{RPI_t + X_d}{100}\right]}{D_t} \left[(P_{ut-1} + P_{mt-1}) \cdot 0.5 \cdot \left(\frac{\sum P_{0i} D_{it}}{\sum P_{0i} D_{it-1}} + \frac{C_t}{C_{t-1}}\right) + P_{Lt-1}(AL_t - L_t)\right] - K_{dt}$$

In the case of distribution, the allowed average revenue relates to a basket of average revenue consisting of four consumer cases. Quantities $(D_i)$ entering the basket are (OFFER[1994]):[16]

| | | |
|---|---|---|
| "- LV1 | : | units sold to customers connected at LV (*low voltage*) at a higher day or peak time price; |
| - LV2 | : | units sold to customers connected at low voltage at a lower night or off-peak time price; |
| - LV3 | : | all other units sold to customers connected at LV, i.e. with uniform prices such as standard domestic tariff; |
| - HV | : | all units sold to customers connected at high voltage HV." |

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15  Note that whereas previously (see basic formula) OFFER used P to describe average revenue it now uses P to describe (total) revenue. Average revenue is now described by P/D in the formula. When calculating the basket (sum over PD) P stands for average revenue though.

16  For a worked example see CRI (ed.) (1994): The UK Electricity Industry - Charges for Electricity Services 1994/95, CIFPA, London , pp. 7.

The (historic) distribution and metering elements are indexed to demand quantities *PD* (to 50%) and customer numbers *C* (to 50%). The loss component allows RECs to increase (total) revenue by 3p for each unit of actual electricity loss (*L*) below allowed electricity losses (*AL*). In dividing the whole term by demand (*D*) all components are attributed to unit electricity charges. Multiplying the whole term with the *RPI-X* indicator determines the development of the price path. An *X* factor of -2 has been set provisionally until March 1996. The correction factor serves to correct for over-/undercompensations from previous periods due to forecast errors. The (historic) distribution, metering and loss elements have been adjusted for the next regulatory period taking into account the cost position of RECs. This calls for an additional one-off reduction of distribution price-caps by 11%, 14% or 17% depending on the REC.

Stock price developments have left OFFER to conclude that these settings have still been too lax. These considerations let OFFER propose in July 1995 a further one-off reduction in allowed charges by April 1996 of between 10% and 13% beyond the initial reduction decided upon for April 1995. In addition to this the X-factors are to be increased for all utilities from 2 to 3 (i.e. 3% real reduction in charges). In aggregate these reductions would in average amount to a 31% real reduction in charges within a period of 5 years (although it should be borne in mind that the April 1995 reduction is really attributable to the previous review period 1990-1995).

*Table 4:*   ***Present and Proposed Price Controls for Distribution Business***

|  | initial reduction April 1995 (%) | proposed reduction in allowed charges April 1996 (%) | proposed X-factors 1997 - 2000 (%) | aggregate reduction in allowed charges 1995 - 1997 (%) | aggregate reduction in allowed charges 1995 - 2000 (%) | average annual reduction (%) |
|---|---|---|---|---|---|---|
| Eastern | 11 | 10 | 3 | 20 | 27 | 7.9 |
| East Midlands | 11 | 13 | 3 | 23 | 29 | 8.7 |
| London | 14 | 11 | 3 | 23 | 30 | 9.3 |
| Manweb | 17 | 11 | 3 | 26 | 33 | 10.5 |
| Midlands | 14 | 11 | 3 | 23 | 30 | 9.3 |
| Northern | 17 | 13 | 3 | 28 | 34 | 11.1 |
| NORWEB | 14 | 11 | 3 | 23 | 30 | 9.3 |
| SEEBOARD | 14 | 13 | 3 | 25 | 32 | 9.9 |
| Southern | 11 | 10 | 3 | 20 | 27 | 7.9 |
| SWALEC | 17 | 11 | 3 | 26 | 33 | 10.5 |
| South Western | 14 | 11 | 3 | 23 | 30 | 9.3 |
| Yorkshire | 14 | 13 | 3 | 25 | 32 | 9.9 |
| arith. Mittel | 14 | 11.5 | 3 | 24 | 31 | 9.5 |

*Source:   OFFER (1995):Distribution Price Controls: Revised Proposals, July 1995, Birmingham.*

## iii) Supply Price Controls

The new price control for regulating the supply margin is in place for a period of 4 years until March 1998 and has been limited to the franchise supply market. In order to lower incentives to increase sales, the control has been modeled as a total revenue cap (OFFER[1992a]) consisting of three components:

— revenue per unit electricity,

— revenue per customer,

— additional individual revenue allowance per firm.

Since value adding supply activities are of minor importance compared to distribution cost, a rather simplified approach (still including correction for forecast errors) has been taken. The profit margin is allowed to match 1% on turnover (equals about 10% real return on assets). A yardstick approach by comparing data between RECs (who are the only licensed franchise suppliers) has been introduced (OFFER [1993b]).

The major argument around this price control has not arisen over the methodology but rather over which cost lie in the responsibility of RECs and thus fall under the supply price control. Passthrough of electricity purchasing cost is subjected to an economic purchasing obligation (condition 5 of the Public Electricity Supply License: „...purchase (...) electricity at the best effective price reasonably obtainable having regard to the sources available). A major controversy has arisen over this obligation as it carries the main deficiencies of a cost-plus regulation type "cost immunization". The problem would not arise if suppliers bought electricity at pool prices without hedging for pool price risks. By entering contracts for differences suppliers practically fix the purchase price for hedged quantities. Since purchase cost are of pure pass through nature suppliers are without any explicit incentives to negotiate contracts in customers' interest (low prices).[17] Some yardstick approach has been suggested by OFFER to control for economic purchasing. The first publication on this was expected by summer 1995. Pool settlement cost has been ruled a component for which RECs are to take full responsibility.

Allowed distribution revenues are computed from three components. First RECs are allowed a fixed component of 10 million Pounds which accounts for between 1% and 2% of turnover (all amounts in 1991/92 prices). The fixed payment has been increased in certain cases (by 1 million Pounds and 6 million Pounds) to take provision of generally

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17    Contracts - considered as having being economical at the time - between RECs and generators with a duration of 3 years had been in place at vesting but expired in March 1993.

unfavorable cost conditions. Further, RECs are allowed a fixed revenue per customer of 15.84 pounds and a variable revenue of 0.0924 p/kWh (all in 1991/92 prices). An X factor of -2 applies to total revenue.

A subsidiary price control RPI+F (F = fossil fuel levy) had additionally been in place for customers under 1MW until March 1993 (with escape clause, however) adding pressure for real price decreases.

### iv) Transmission Price Controls

#### a. General Stance to Transmission Regulation

In general, OFFER takes a hard stance at regulating the National Grid Company rather closely. The reasons for this are that OFFER cannot apply an additional yardstick control due to the lack of "competitors". Furthermore, technical features of the transmission business (especially capacity constraints) and subsequent potential for abuse and the ownership structure (joint ownership by RECs until December 1995) require close monitoring. The absence of competitors makes the regulator particularly dependent (regulatory capture) on information provided by NGC also with respect to advice for the development of regulation methodology.

#### b. Technical Aspects of Transmission Regulation

Price Cap type regulation applies to use of transmission system charges and for connections that existed at vesting (30 March 1990). New connections are regulated through a rate-of return approach.

The control is aimed at average transmission revenue, where the averaging relates to load on the system at maximum "Average Cold Spell" (ACS) demand in the respective year. ACS demand is defined as the average load of the three highest (half-hourly) demands which lie apart at least ten days and after correcting demand for ACS weather conditions. The price cap applies to the basket of use of system and connection charges (for "old" connections).

The values for revenue drivers in the price cap formula are determined in advance so as not to give incentives to NGC to increase transmission quantities at prevailing scale economies. This factually changes control into a total revenue cap. The methodology for the determination of the RPI factor in the price cap formula has originally been developed in the first transmission price review (July 1992) but is now applied throughout electricity

regulation: The annualized July to December inflation rate of the previous year is used in the price cap formula.

Regulatory periods for the transmission business are comparably short, with the first period with an X=0 cap lasting from 1 April 1990 to 31 March 1993 and the next period with an X=-2 cap until March 1997. Reason for this could be technical specificities of transmission which may require especially thorough review and shorter regulatory lags. There would e.g. otherwise be incentives to maintain bottlenecks in the system which could be used to justify high use of system charges on the grounds of high marginal costs (at peak times).

*c. Regulation of Transmission Charge Structure*

Although the price cap is put on revenues of system and connection charges, regulation of the charge structure is viewed as an important part of regulation, too. This is to prevent inefficient pricing (in a situation without yardstick references) and to avoid the abuse of RECs dominant position as joint owners of NGC in relation to generators with whom they practically share transmission costs (RECs 75%, generators 25%).

Control over charge structures relate to:

–   structure of use of system and connection charges

–   structure of system service and infrastructure (varying by region) charges within use of system charges

NGC successfully opposed intentions to introduce "deep connection charges" which are supposed to take account of the cost a new connection adds to the new system. This tends to be higher than connection charges determined by conventional methods, because it takes into account "externalities" e.g. through voltage distortions.

Another controversy between NGC and the regulator has arisen over spatial pricing. OFFER favored marginal cost (MC) pricing to take account for transmission distances. The old, largely undifferentiated system had led to distortions with generation being concentrated in the north while main demand lies in the south. Here again, NGC persuaded OFFER to implement its own approach called investment cost related pricing (ICRP) (National Grid Company [1994], ICRP Tariff Report [1994]). In this approach, (use of system) charges are related to capital, operating and maintenance cost of additional (new) investment in grid capacity. It does not take into account system constraints and losses

and in these respects violates principals of MC pricing. ICRP leads to larger spatial differentiation than would arise under MC pricing. This approach has been heavily criticized by grid users for lacking transparency of charges.

The following table summarizes the main technical aspects of price cap regulation in UK electricity businesses:

*Table 5:*      *Regulation in UK-electricity industries*
*(see also Armstrong, Cowan, Vickers (1994), pp. 176)*

| | Electricity transmission (NGC) | Electricity distribution (RECs) | Electricity supply (RECs) |
|---|---|---|---|
| Regulated Indicator | **revenue cap**<br><br>revenue per unit elec. (kW) where demand is set in advance<br>(also regulation of revenue structure [use of system charges/connection charges], rate of return regulation for new connections) | **mixed**<br><br>**price and revenue cap:** average revenue per unit (kWh) in tariff basket (50%); average revenue per customer (50%) | **mixed**<br><br>**price and revenue cap:** revenue per unit electricity (kWh), allowance per customer, additional individual allowance per firm |
| Regulated operations | use of system charges, connection charges | all distribution except below | supply to customers in franchise (<100kW) market |
| Unregulated (operations) | ancillary services (e.g. pumped storage) | distr. above 22kV, top-up/stand-by charges, (some others) | supply to customers in non-franchise market |
| Performance Indicator | - | incentives mechanism for loss reduction | - |
| possible opening to competition | - | metering, connections | all supply after complete competitive opening in 1998 |
| Cost passthrough | - | - | electricity purchase, transmission, distribution, fossil fuel levy |
| X-factors | X = 0 (1990-93)<br>X = -3 (1993-97) | individual for each REC<br>X = 0 to +2.5 (1991-95)<br>X = -2 (1995-1997)*<br>X = -3 (1997-2000)*<br><br>one-off reduction<br>-11 to -17 (1995)<br>-10 to -13 (1996) | X = 0 (1990-94)<br>X = -2 (1994-98) |
| Regulatory lag | initially 3 years, currently 4 years | 5 years | 4 years |
| Quality regulation | - | - | penalties for performance failures fixed in licenses |

\* proposal yet to be confirmed

the publicity (including information being available to "competitors") of such a dispute. Others state that the obligation to refer cases to the MMC if disputes cannot be settled creates a bias in favor of utilities. This could arise, if the regulator is being made accountable before the MMC.

### iii) Organization for Regulation Within Utilities

Two major functions, regulatory strategy and regulatory enforcement have been identified in the practical dealings of utilities with regulation. This division has found a replication in the organizational structure of RECs.

The function of regulatory strategy is a core business function as part of which information is collected, the current (cost and revenue) position of utilities is assessed (for internal purposes) and information is strategically provided to OFFER and other interested groups in preparation for regulatory consultation processes and decisions. Upon regulatory decisions the regulatory strategy department translates new regulatory settings into business strategies and/or advises the business strategy manager on strategy changes.

In the function of regulatory enforcement, legal aspects of regulation are being dealt with. In continuous operation this involves dealing with (major) customer complaints (soft facts), and license compliance especially compliance with price caps. It may also involve any information requirements to OFFER as outlined in licenses.

The regulatory enforcement function is in some cases subordinated to the regulatory strategy department. The regulatory strategy department is subordinated to the business strategy department (possible even identical with it) or the finance department.


### (2)      Procedural Aspects in Preparation of Periodic Review

### i) Informational Process Involving Utilities

Consultation papers are usually prepared by OFFER roughly one year in advance of regular regulatory decisions (periodic reviews). These papers outline a proposed regulatory methodology for the next review and stress any proposed changes to previous methodologies. Comments are invited by all interested groups. Consumer views are voiced through the regional Consumer Councils which are funded through OFFER. "Regulatory proposals" (decisions) are announced about 6 months before implementation. Here comments by interested groups are summarized, the chosen

methodology is described and detailed outlines of regulatory decisions including the important X-factors are presented.

A similar approach is being taken by OFFER in the preparation of extraordinary investigations, e.g. into economic purchasing of suppliers or into bidding behavior in the competitive pool market.

In general, RECs try to influence their information strategically. Most have developed detailed regulatory strategy time schedules stating which information has to be provided at what date in preparation for or in reaction to expected announcements/decisions by OFFER.

The major engagement of utilities in the regulatory process arises after OFFER has outlined its considerations in a consultation paper. By license, utilities are required to provide information, especially to let OFFER evaluate the cost and revenue position of RECs (here OFFER has to rely on information provided by utilities). In particular, the adjustment of price levels requires cost information. Utilities also make proposals how they would see the setting of price caps and where they see scope for refinements of the regulatory methodology. On the basis of the information provided, OFFER enters into consultations with individual utilities. In early stages OFFER is eager to quantify its proposals and their anticipated impact on utilities and to receive comments. This is sometimes described as a bargaining process. In final proposals OFFER will provide information in less detail, possibly as to avoid its decisions being challenged on grounds of methodological disputes. Sometimes, criticism is voiced that such negotiations do not take place in the form of public hearings as is typical of regulation in the US.

## ii) Informational Process Within Regulatory Office

Although regulatory decisions are based on cost information as provided by utilities to a large extent, yardstick approaches have played a major role, especially in the comparison of RECs which are all of comparable size. As recent experience has shown, stock market information may also be very useful to the regulator. This has even brought about the idea that regulation should ensure that shares of utilities be traded on stock markets to a considerable extent in order to allow the regulator to assess market expectations. The recent attempt of unfriendly take-over of Northern Electric by Trafalgar House e.g. has exposed the potential for super normal profits which then called for regulatory action (withdrawal of distribution price decision).

While reactive approaches have been taken recently towards issues of diversification and

cross-subsidization (these are ruled out by license condition 4) a more proactive approach can be expected from OFFER in the future. Possible fields could be the control over which parts of transmission and distribution grids are also used for telecommunications purposes and should thus allow to charge part of grid costs to telecommunications customers. The development here seems to be though, that only the transmission company will engage in telecommunications businesses while RECs fear already fierce telecommunications competition in regional markets.

Critics remark that OFFER's regulatory approach is unpredictable. Some argue that in addition to its case related consultation processes it should outline a strategic plan of objectives. Without this, stock markets are likely to react volatile to any regulatory rulings that could not be anticipated because of unclear long-term objectives. Members of OFFER stress that they cannot commit to any particular rules (other than those within one regulatory period) because of a rapidly evolving environment, the evolution having been stirred of by innovative regulation itself.

Organizational aspects of price cap regulation show that the regulatory process is not so simplified as the theory suggests. Substantial regulatory costs are imposed on both sides, i.e. the regulator and the industry to prepare for the periodic reviews as well as surveillance of compliance with license conditions by utilities.

## 3.4    British Experience: Performance under Price Cap Regulation

The performance of price cap regulation can best be assessed by examining the degrees of achievement of the main objectives of price regulation, namely

- controlling profits,

- reasonable supply conditions (prices, charges).

Discussion on these issues has recently merely been qualitative but upon entering the second regulatory period in the distribution price control some substantive quantitative data is available.

### 3.4.1    Effectiveness of Price Controls

It has often been argued that electricity prices have been inflated prior to vesting (April 1990) in order to give room for later price reductions without distorting share prices (downward). We cannot confirm this argument after intensive assessment of price data

for typical franchise customers. Pricing data (standing charge, unit price etc.) have been assessed for the England & Wales Regional Electricity Boards and the succeeding Regional Electricity Companies from 1986. Average prices have been calculated per company for several characteristic customer cases and average prices weighted by demand per company have been derived. The case of a 3,500 kWh/a customer (typical domestic customer as defined by EUROSTAT) has been selected here for further analysis, but the general picture does not significantly change if other customer cases are chosen.

In nominal terms prices (for the selected 3,500 kWh/a customer) have indeed increased steadily from 1987/88 from a level of 6.19 p/kWh up to 1992/93 to a level of 8.79 p/kWh (8.76 p/kWh including rebates) (see **Figure 2**). These price increases, however, went along with relatively high inflation (peaking at 9.5% in 1990). In real terms (1990/91 prices) prices have remained relatively unchanged at a level of 7.76 p/kWh in 1987/88 and a level of 7.85 p/kWh in 1990/91 (at vesting) and have even fallen from 8.20 p/kWh compared to 1986/87. Prices have risen after vesting in real and in nominal terms (from 7.85 p/kWh in 1990/91 to 8.79 p/kWh in 1992/93) as a result of generous initial price controls (see also this section below). Prices have further fallen even in nominal terms after 1992/93 to a level of 8.26 p/kWh in 1994/95 (including rebates). To summarize we can thus not confirm that prices have been inflated in real terms prior to privatization. Furthermore, prices have fallen in real terms compared to the pre-privatization level. In the following it will be examined what effects caused a deflation of prices.

*Figure 2: Development of average prices for 3500 kWh/a franchise customer (standard tariff) before and after vesting*
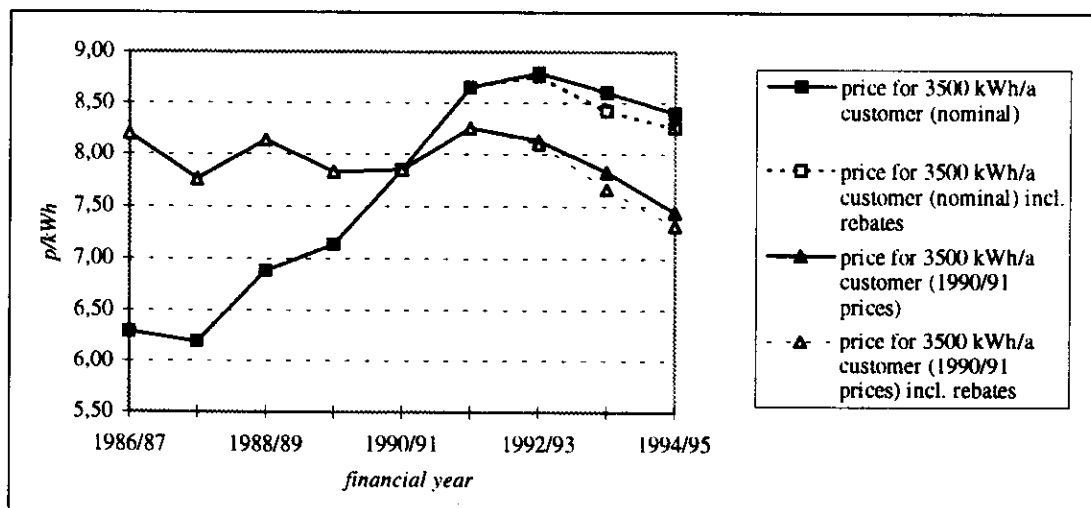


Sources of data: Electricity Association, Company accounts, DTI

Two approaches are thinkable to separate the potential influence of cost components on final customer prices, especially to isolate the impacts of cost in regulated (transmission, distribution, supply to franchise customers) and unregulated (generation, supply to non-franchise customers) businesses:

– a regressive approach by deducting the cost of electricity procurement for Public Electricity Suppliers from the price to final customers,

– a progressive approach by calculating allowed or effective charges for regulated businesses.

For reasons of data availability this study has focused on the regressive approach while a progressive calculation of distribution charges for a defined customer case has been exercised at the Centre for the Study of Regulated Industries, London (CRI). A simplified progressive calculation has also been made for this study using information on the X-factors.

In the regressive approach tariffs for defined customer groups have been calculated as described above. From these average tariffs average purchase cost of electricity by RECs for supply to franchise customers have been subtracted leaving as residual a composite of transmission, distribution and supply charges. Some caution should be exercised when interpreting results, though, since information on the development of purchase cost of electricity is not publicly available and the estimation of purchase cost was based on information about the portfolio of electricity purchases (pool related and hedged through contracts) and assumptions on a fading of the purchase obligations in the so called "coal contracts". In these contracts the burden of excessive cost of the use of domestic coal in electricity generation was passed down to franchise customers through special purchase obligations to the RECs. According to our calculations only part of the (real) reductions in final customer prices are attributable to lower purchase cost of electricity to the RECs. Part has also been due to reductions in the regulated cost components (see Figure 3),

– through the X-factors (reducing or neutral impact of transmission and supply controls, inflating impact of distribution controls)

– through quantity effects (underproportionate increase in allowed revenue relative to sales) in the price cap formula (transmission price control since 1993, supply price control since 1994),

– possibly also through undercutting allowed prices/charges.

*Figure 4: UK average distribution use of system element of typical standard domestic (3300 kWh/a) bill*
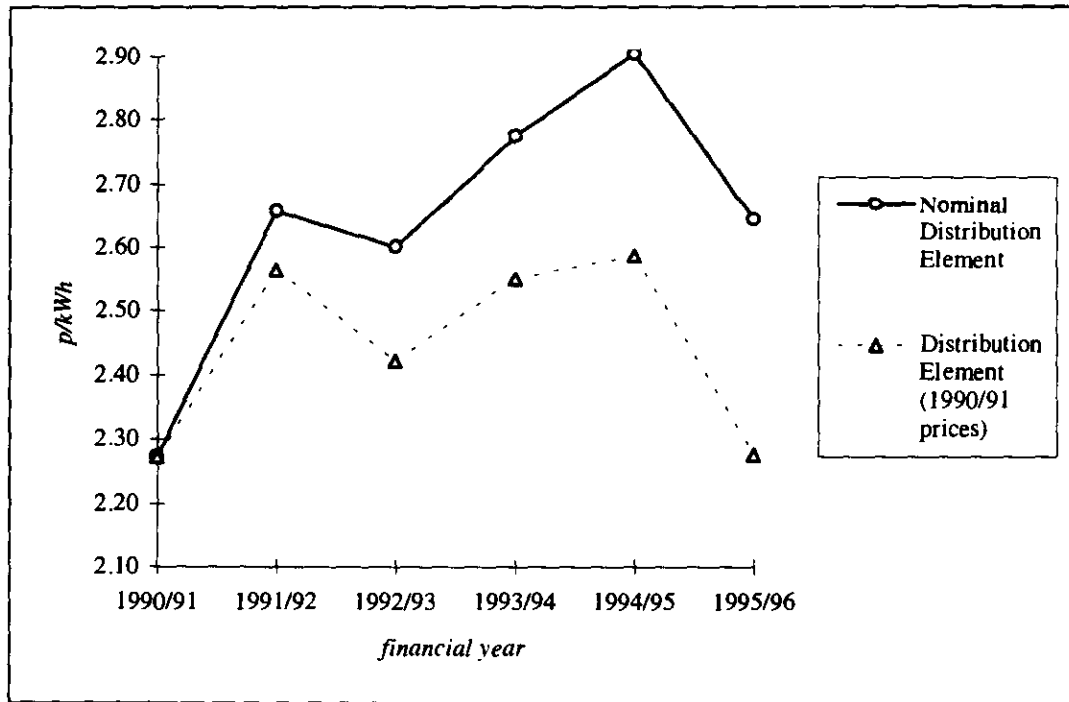


*Source: CRI, 1995*

A further approach to examine price development is to monitor **allowed charges** in the regulated businesses, here averaged over all franchise (<100 kW) customers. Regulated transmission, distribution and supply (for franchise customers) charges feed through into final prices. Average cost fractions of final prices for franchise customers are [OFFER (1994), p. 6]:

- transmission: 5%,

- distribution: 26%

- supply: 7%

Table 6 exposes how recent levels of X-factors for these businesses would feed through into regulated business' charges and final electricity prices (assuming that X-factors are employed equally for all customer groups, assuming no growth in sales and customer numbers, and eliminating any effects of changes in electricity procurement cost [pool and non-pool related] and the fossil fuel levy). The demand weighted average of distribution charge X-factors (for each year of the first regulatory period) amounts to 1.15%. Accumulated over the first regulatory period this amounts to allowed real increases of 5.89%. X-factors in the transmission and supply businesses have a downward pressure on prices, although their weight is below that of distribution controls. Thus in average

1994/05 and average overall prices are allowed to increase by 1 06%

that would apply had the new methodology been used from the start. Column (3) shows effective RPI inflation rates for each financial year. The cumulated deviation of allowed from actual inflation would have amounted to 2.89% in 1994/95 and would have peaked at 5.39% in 1992/93. The deviation of actual from potentially allowed inflation (and also the deviation of allowed charges from actual inflation) are presented graphically in Figure 5 and Figure 6.

In fact, there is a systematic bias of allowed inflation and actual inflation if the inflation rate changes over time. If e.g. inflation slows down over the years there is a systematic bias in favour of regulated utilities since allowed inflation exceeds actual inflation. For this reason the application of price cap regulation is likely to cause particular difficulties if the general economic environment is unstable with large fluctuations in the inflation rate. On the other hand properties of price cap regulation improve if the general economic environment is quite stable.

*Table 7: Development of RPI inflation rates and effective X-factors*

| financial year | regulatory RPI infl. index (annalized from July to Dec previos year)* | cumlated regulatory RPI infl. index | effective RPI infl. index in financial year | deviation of regula. from effective RPI infl. index | cumlated deviation of regula. from effective RPI infl. index | regulated busin average X-factor index | allowed annul incr. in reg. bus. prices | cumlated allowed incr. in reg. bus. prices |
|---|---|---|---|---|---|---|---|---|
| | in % | in % | in % | in % | in % | in % | in % | in % |
| | (1) | (2) | (3) | (4)=(1)-(3) | (5) | (6) | (7)=(1)+(6) | (8) |
| 1990/91 | 5.98 | 5.98 | 5.04 | 0.94 | 0.94 | 0.79 | 6.77 | 6.77 |
| 1991/92 | 5.12 | 11.09 | 2.70 | 2.41 | 3.35 | 0.79 | 5.90 | 12.67 |
| 1992/93 | 2.40 | 13.49 | 0.36 | 2.04 | 5.39 | 0.79 | 3.19 | 15.86 |
| 1993/94 | -0.14 | 13.35 | 1.35 | -1.49 | 3.90 | 0.39 | 0.25 | 16.11 |
| 1994/95 | 1.28 | 14.63 | 2.29 | -1.01 | 2.89 | 0.02 | 1.30 | 17.41 |

*effectively inflation forecasts were used in the first regulatory period of each business

*Sources of data: OFFER, DTI*

*Figure 5: Annual change in RPI inflation and allowed average change in prices (for < 100 kW) customers in UK regulated electricity businesses*
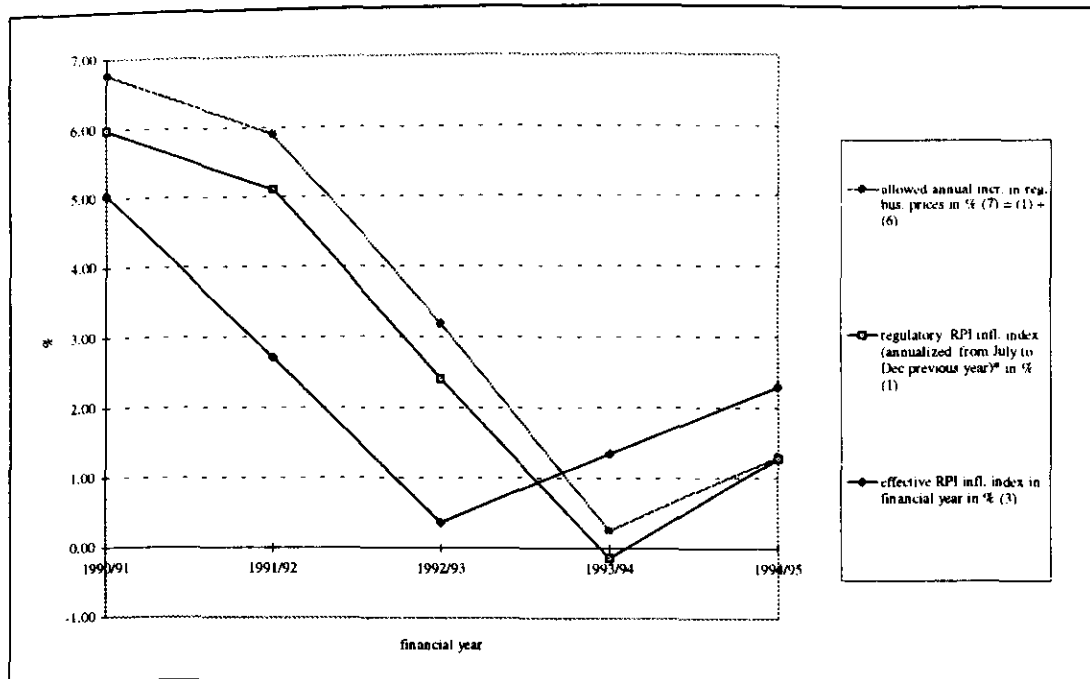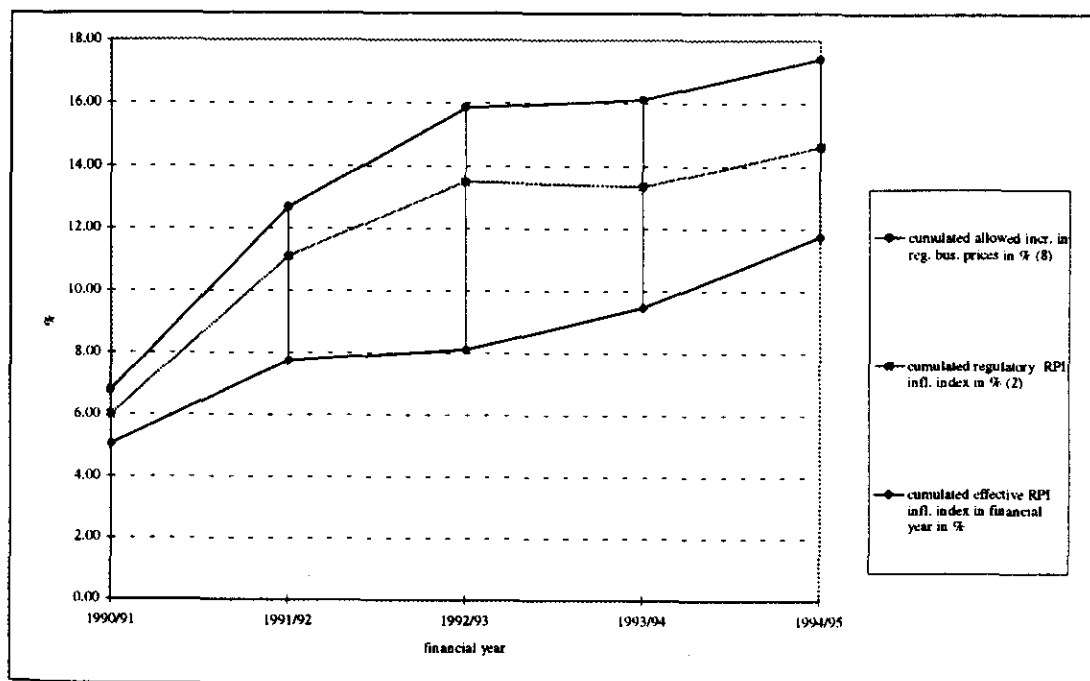
*Sources of data: OFFER, DTI*



*Figure 6: Annual change in RPI inflation and allowed average change in prices (for < 100 kW) customers in UK regulated electricity businesses*

*Sources of data: OFFER, DTI*

### 3.4.2    Effectiveness of Profit Controls

The Centre for the Study of Regulated Industries, London (CRI) regularly assesses the performance of UK regulated industries and enterprises. In a recent study it investigated the development of operating profits in UK public electricity supply (PES) companies who have their main share of turnover in the distribution business (except for Scottish and Northern Irish suppliers; see also Figure 7). In nominal terms total profits (over the 15 PES) almost doubled over the first five financial years after vesting from 1,416 £ million to 2,735 £ million (14.1% annual growth rate). In real terms (1990/91 prices) operating profits increased to 2,454 £ million (11.6% annual growth rate).

*Figure 7: Development of operating profits in UK public electricity supply companies (including Scotland and Northern Ireland)*
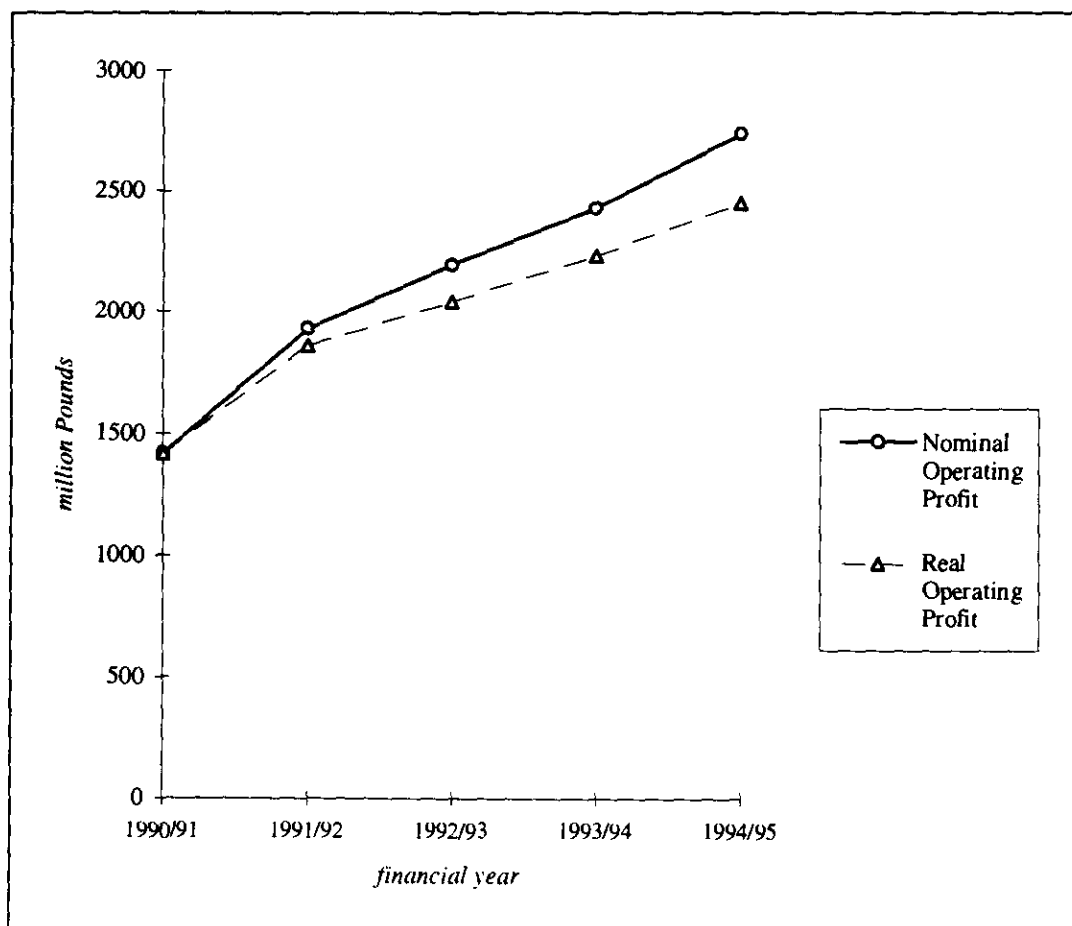


Source: CRI, 1995

An assessment of the development of share prices reveals a similar picture of the performance of regulated companies (see Table 8). The annualized growth rate of share prices (weighted with nominal capital value) exceeds 20% (starting from values at

The recent development of distribution price control shows that these preconditions for effective price cap regulation are not necessarily provided by OFFER. Combined with some cost reflectiveness in the price cap, price cap regulation may, in practice, tend to operate more like ROR regulation with a variable regulatory lag.

This can be also observed in the experience of British Telcom, which has the longest history of price cap regulation. The sharp contrast between price cap regulation in theory and in practice suggests a tendency for the application of price cap regulation to converge in effects with ROR regulation.

The main reason for this tendency is public pressure for regulators to intervene to pursue social goals, e.g., limiting extra-normal profits of dominant suppliers of essential services. Therefore, some alternative versions of price cap regulation have to be devised which will insulate the regulator from public pressure. This will be discussed in detail in the last section.

## 4     US-Style Incentive Regulations

US-style incentive regulation can be described as generally fitting into a cost-plus regulation-based framework, with additional incentive schemes using profit sharing, yardsticks and indexing methods.

In the profit distribution method, a utility is allowed to retain a predetermined fraction of cost savings, i.e., profits or losses. In the yardstick method, a utility is rewarded or punished based on its performance relative to that of a benchmark group of representative utilities. The indexing method is an automatic rate-adjustment mechanism based on external indexes. In this approach, a utility is allowed to automatically change its rates, based on change in a specific price index.

In each approach, a utility is given incentive to improve its efficiency through rewards and penalties based on its actual performance compared with a target.

Incentive regulation has long been practiced in the United States, in the electric utility industry, and to a greater extent in the telecommunications and natural gas industries, because these industries proceeded in regulatory changes earlier. The theory in this field is highly developed. However, for countries considering deregulatory reform what is important is not how elegant and interesting the theories are, but how well they have been applied and what are the practical lessons to be learned. Therefore, this paper will focus on the application experience of various types of incentive regulation in major regulated industries.

In this section, various approaches to incentive regulation in the US are outlined and their effectiveness in application is evaluated. Then, the status of incentive regulation programs in various states is reviewed. We focus specifically on California's performance-based rate-making (PBR), which is designed to give utilities the greatest incentive to reduce their prices through improved operating efficiencies.

## 4.1 Approaches to incentive regulation in the US

Table.6 summarizes different approaches to incentive regulation in the US.[18] As indicated, there are two main types of incentive regulation. The comprehensive approach aims at decreasing the costs of a utility as a whole, whereas the partial approach focuses on specific cost factors.

Among the approaches listed in the table, sliding scale, partial overall cost adjustment, yardstick, performance incentive, partial cost adjustment and indexing belong to the traditional type. Since they are closely linked to traditional cost-based rate-of-return regulation, their ability to increase the utility's efficiency is very limited.

Revenue sharing is a sophisticated version of the sliding scale approach, and provides a utility more incentives to improve performance. However, this mechanism is also designed to operate within the structure of traditional cost-based rate-of-return regulation, although the mechanism is relatively new one.

The multi-factor performance standards approach is relatively new, but also a variation of traditional incentive regulation. It aims at promoting the overall efficiency of a utility by measuring multiple performance parameters and integrating of the results in an index which is used to adjust ROE. This mechanism also operates within the framework of the sliding scale.

Price caps are widely applied in regulated industries in the UK, e.g., the telecommunications industry since 1984. In the US, they have been applied to the telephone industry since 1988, and are being introduced to the electric utility industry. Price cap regulation, in theory, offers strong incentives to minimize costs, since the utilities' costs are not used to determine their prices. This type of regulation is therefore different from traditional cost-based rate-of-return regulation.

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18    For an analytical framework for incentive regulations see Toskow and Schmalensee: Incentive Regulations for Electric Utilities, Yale Journal on Regulation, Vol.4. No.1. 1-49

*Table 9: Approaches to incentive regulation in the US*

| Type | Approach | Contents | Method | Regulation | Application Examples |
|---|---|---|---|---|---|
| Comprehensive Approach | Sliding scale | Automatic rate adjustment based on difference between estimated and attained RORs | Profit distribution | Fit in with traditional regulation; not appropriate in case of inflation and technical innovation | U.S.electric utilities (Mississippi and Washington, DC) |
| | Partial overall cost adjustment | Automatic rate adjustment based on difference between estimated and attained total kWh costs | Same as above | Same as above | U.S.electric utilities (Utah P&L, 83-84, also Arizona, Delaware, Massachusetts, New Jersey and New York) |
| | Yardstick | Comparison among competitors with comparable rates levels | Yardstick | Objective method but difficult to exclude differences in factors external to management and to accurately reflect differences in service | U.S.: no example. Japan: bus services (rate level is based on the mid-value between the average and the actual cost of the service area) |
| | Price cap | Regulate the upper limit of rate-increase rate | Index-link plus productivity | Objective method; problem of price fixed at the upper limit; difficult to improve efficiency of passthrough cost factors; problem of influence on investment decisions | U.S.: electric and telecom utilities (Pacific Power & Light, Central Maine power) U.K.: electric, gas, telecom and water utilities |
| | Revenue sharing | Utility retains a predefined portion of cost-savings | A number of basis points are added to utility's cost of equity to create a range within which earnings are shared with ratepayers. Earnings above the range are returned to ratepayers | Greater management flexibility and discretion in utility planning and operations; difficult to design a fair range | U.S.: electric utilities (Indiana) |
| | Multifactor performance standards | Measure multiple parameters of performance and aggregate the results in an index which is used to adjust return on equity(ROE) | A set of standards and rating systems is developed for a wide range of utility economic and physical performance. A benchmark return is developed from comparable utilities' results, and a deadband is established asymmetrically around the benchmark return based on performance rating. If the actual return is above the band, revenues are adjusted downward; otherwise, upward according to performance rating | Less likely to lead to sub-optimization; difficult to design and expensive to monitor | U.S.: electric utilities (Mississippi) |
| Partial Approach | Performance incentive | Set the deadbands for plant operation, construction, and performance, and provide incentive or penalty depending on the difference between the goal and the actual results | Profit distribution and yardstick | Potential to sacrifice performance of many costs factors in order to improve that of a specific cost factor | U.S.: electric utilities (in at least 17 states, notably California and Delaware) |
| | Partial cost adjustment | Automatic rate adjustment of the difference between the target and actual costs, mainly applicable to fuel cost, electricity purchase cost, etc. | Profit distribution | Potentially ineffective if factors external to management strongly affect the cost adjustment mechanism | U.S.: electric utilities |
| | Indexing | Linking adjustment of a specific cost to a certain index, mainly applicable to labor, materials, other controllable costs | Linking with index | Easy method for price adjustment; encourages capital-intensive production; insufficient consideration for productivity | U.S.: electric, gas, and telecom utilities |

*Source:* *Joskow, P.R.; Schmalensee, R.. (1986)*
*Yamaya, S. (1991)*

### 4.1.1    Traditional Types of incentive regulation

The mechanisms described below represent essentially first-generation tools to provide utilities with incentives to enhance their operating efficiency. In most cases, they were designed to function within the traditional structure of cost-based rate-of-return regulation. However, the changing structure of the US electric power industry has rendered many of these tools obsolete.

### (1)    Sliding Scale

The sliding-scale mechanism is typical of the first generation of mechanisms designed to reward or penalize the utility for its performance. This mechanism is appropriate in relatively static economic conditions. However, this assumption is rather restrictive. Furthermore, this mechanism assumes a cost-of-service regulation mode, where the fundamental concept of cost recovery is still intact but the rate-of-return (profit) can be subject to performance risk. Generally, sliding scale plans are based on a targeted rate-of-return (ROR) or profits.

Variations in actual operating costs relative to costs filed in a rate case can put return on invested capital at risk. Automatic adjustments to rates in response to changes in actual costs relative to forecast costs can maintain allowed cost recovery, but may put the allowed rate-of-return at risk. An automatic rate adjustment mechanism (ARAM), as applied to the Mississippi Power Company, provides for rate adjustment based on the difference between the actual rate-of-return and the allowed ROR in the rate case. This, in essence, is retroactive rate-making, and provides minimal incentive to enhance overall utility performance.

The sliding-scale structure employs a sharing mechanism whereby cost savings or overruns, i.e., profits or losses, are shared between customers and utility shareholders. The sliding scale is designed to provide an incentive to capture the financial benefits of margin performance above what was projected in the rate case.

The sliding scale mechanism allows a utility to retain a pre-determined fraction of the difference between the actual earned ROR and the rate case targeted ROR. Expressing this as a formula:

$$TROR_{t+1} = AROR_t + k(TROR_t - AROR_t)$$

where:

$TROR_{t+1}$ = rate case targeted ROR for period t+1

$AROR_t$ = actual earned ROR in period t

$k$ = customer share fraction of "excess" return, $0 < k \leq 1$

As an example, assume that: (i) the PUC (Public Utility Commission) specifies that customers retain 80% of the difference between targeted ROR and earned ROR; (ii) earned ROR equals 12%; and (iii) targeted ROR equals 9%.

Under the sliding scale mechanism, the utility will retain the 3% "excess" return until the next rate case, when rates are adjusted downwards to 9.6%, i.e., $12\% + 0.8 \times [9\% - 12\%]$.

Another formulation of this mechanism is as follows:

$$Pt = P_{t-1} + k(TROR_{t-1} - AROR_{t-1}) \times K_{t-1} / Q_{t-1}$$

where:

$P$ = kWh price in period t

$TRORt-1$ = targeted ROR in period t-1

$ARORt-1$ = actual ROR in period t-1

$K$ = rate base

$Q$ = kWh

$k$ = customer share fraction of "excess" return, $0 < k \leq 1$

The choice of the "k" factor is critical in determining the allocation between shareholders and customers of losses or profits resulting from application of the sliding scale mechanism. There are several factors that regulators consider in selecting an appropriate "k" factor.

First, the "absorptive capacity" of the utility shareholders compared to the customers to bear the financial costs associated with a negative outcome is important. For instance, if there is a significant penalty cost resulting from overall substandard utility performance, the cost might be spread over a large customer base, with relatively minimal impact on customer bills. However, the per capita impact on shareholders would be more onerous if the shareholder base is substantially smaller than the customer base.

Second, the question of equity is important. There is a question whether customers should bear the financial costs of poor utility management. If substandard utility performance

results mainly from external factors, the equitable allocation of losses should be different than if it resulted from managerial incompetence. Third, if the accuracy of a utility's forecasts of future market conditions submitted to the PUC is consistently poor, there is a question of whether customers should bear the risk. Related to this problem, issues of asymmetric risk-reward structures enter the political debate.

Fourth, a high value for "k" allocates most of the risks of "negative" outcomes as well as most of the benefits of "positive" outcomes to customers. This might skew utility behavior toward a risk-averse, middle-of-the-road operating philosophy. A major negative effect of a high "k" is that the utility is given weak incentives to operate efficiently. From the PUC's perspective, it prevents the utility from earning "excess" profits when the market environment is favorable and incurring major losses when market conditions are unfavorable.

This approach become inappropriate in times of high inflation and drastic technological innovation. When linked to automatic rate adjustment mechanisms, inflation can affect the nominal cost of inputs, effectively reducing the real ROR. On the other hand, technological innovation automatically reduces costs, and hence increases real ROR, even without efforts by utilities to improve efficiency.

Because of the rather limited scope and the performance limitations of the sliding scale mechanism, it has not been widely adopted by regulatory authorities. This mechanism has only marginal ability to provide appropriate incentives and ultimately deliver enhanced overall utility performance in a dynamic market environment.

The sliding scale approach, by itself, is of very limited -if any- value in today's increasingly competitive electric power markets in the US. Since it is linked to traditional cost-based rate-of-return regulation, its ability to enhance the fundamental economic performance and efficiency of a utility is slight. Essentially, it is a tool of limited application; and has been superseded by more effective and comprehensive programs, such as the California performance-based rate-making mechanisms.


## (2)     Partial Overall Cost Adjustment

This mechanism is also retroactive rate-making, incorporating an automatic rate adjustment based on the difference between actual supply costs and the costs allowed in a rate case. An automatic pass-through of comprehensive input costs would be simply equivalent to cost-plus pricing, and would eliminate incentives for efficiency.

The formula for the partial cost mechanism is analogous to the sliding scale:

$$P_t \quad = \quad TCOST_t + k\,(ACOST_t - TCOST_t)$$

where:

Pt $\quad$ = $\quad$ rate case kWh price (tariff) for period t+1

TCOSTt $\quad$ = $\quad$ rate case targeted cost for kWh supply in period t

ACOSTt $\quad$ = $\quad$ actual cost for kWh supply in period t

k $\quad$ = $\quad$ customer share fraction of "excess" or "negative" return, $0 < k \leqq 1$

As with the sliding scale approach, inflation can distort the apparent economic performance of the utility. Over time, between rate cases, inflation can increase the actual cost of kWh supply relative to the cost filed in the rate case, which is based on a specific assumed rate of inflation. Likewise, technological innovation can reduce the cost of kWh supply. If actual cost is less than the targeted cost due to technological innovation, the utility receives a fraction of the return, irrespective of efficiency.

A high value for "k" allocates most of the benefits of good outcomes as well as most of the risks of bad outcomes to customers. A high value for "k" also weakens the utility's incentive to control its costs, since actual cost is a major component of the price for kWh. For example, a fuel adjustment clause is an automatic rate adjustment where k=1. However, economic theory suggests that as economic (inflation) and technological uncertainties increase, the value of "k" should also increase.

Again, this mechanism is directly linked to traditional cost-of-service regulation, and hence offers only weak incentives to improve overall utility performance.

## (3)  Yardstick

In this approach, the utility's potential reward is based on its performance relative to that of a benchmark group of representative utilities. An automatic rate adjustment mechanism (ARAM) is used, employing an index of the average of the cost levels or changes for the benchmark utility group. This mechanism provides incentives to minimize costs. If a utility's costs are less than the benchmark group's average (the yardstick), it should, in theory, attain an ROR greater than the benchmark average. Likewise, if the utility's costs are greater than the yardstick average, its ROR should be lower than the average.

A major problem with yardstick regulation of cost is the heterogeneity of the cost structures of the utilities in the benchmark group. Generation, transmission, and

distribution costs differ by geographical region, by type and vintage of equipment, by customer profile, and by regulatory jurisdiction. Because of this heterogeneity, comprehensive yardstick regulation is probably neither feasible nor desirable.

It has been suggested that a possible solution to the heterogeneity problem would be to classify electric utilities into fairly homogeneous groups. The basic problem is the difficulty in defining clear, objective classification criteria. Hence, it is very probable that the classification will be arbitrary. Any utility will find that it could do significantly better if it were compared against a different benchmark group.

Basing a utility's allowed prices on the costs of other utilities in a heterogeneous group is not feasible, because it could lead to prices significantly divorced from the regulated utility's costs. This could result in excessive profits or losses. Likewise, yardstick regulation is undesirable because it is likely to distort input decisions made by the regulated utility.

This suggests that a restrictive rather than a comprehensive yardstick approach should be considered. First, it may be appropriate to use the percentage change instead of the actual costs of the benchmark utility group. Since the differences in current cost levels are the result of previous changes in cost, using percentage change might reduce the problem caused by heterogeneity.

Capturing the dynamics of cost changes over time is important for assessing comparative performance efficiencies of utilities, assuming that the initial cost comparison basis is legitimate.

Second, it might be useful to restrict the yardstick to specific cost variables. Specific yardsticks may be more appropriate for certain input price changes, such as ROR, fuel, raw materials, and input quantities.

Yardstick mechanisms offer minimal direct pricing flexibility. They remain within the traditional cost-of-service ROR model, which produces rigid, cost-based prices. The mechanism allows for little or no management flexibility concerning where, when, and to what extent costs are recovered.

Use of the yardstick may be appealing because of the relative ease with which it can be implemented. However, accurate measurement may be difficult. Moreover, this mechanism may not result in overall performance efficiency. Yardstick measures may be useful for narrowly-focused performance goals in a traditional regulatory environment.

## (4)    Revenue Sharing

The revenue-sharing mechanism is refinement of the sliding scale approach, and strengthens incentives inherent in traditional ROR regulation by providing up-front assurance that if the utility can reduce its costs relative to the latest rate case cost-of-service estimate, it will be allowed to retain a predetermined share of the savings for its shareholders. A baseline allowed return on equity (ROE) is determined, using conventional rate-making procedures, and then a range (deadband) is defined above or below the baseline ROE. If actual ROE is within this deadband, shareholders are at risk for all variations in earned returns. Incremental or decremental returns outside this deadband but within a second-tier bandwidth are shared between utility shareholders and customers, based on a predetermined ratio. If the actual ROE falls outside of the bandwidth, above or below, a new rate case may be triggered or a different sharing ratio may be implemented to reallocate reward or penalty.

An essential feature of this type of incentive is a regulatory assurance that: (i) the utility will be allowed to retain its share of any savings realized during the interval between rate cases; and (ii) in the next rate case, there will be no retroactive rate-making to recoup savings from the previous rate case period. In Southern California Edison's proposed PBR mechanism, revenue sharing is an integral part of their approach. Within the target deadband or bandwidth, shareholders would be at risk for all variations in earned returns. In a second-tier band above and below the base deadband, increments of returns would be shared equally between utility shareholders and customers. Returns outside the second tier would initiate a formal review by the CPUC (California Public Utilities Commission).

The revenue-sharing approach has been designed to ensure the maintenance of fair and reasonable rates, and is regarded one of the more sophisticated forms of incentive regulation among the traditional type mechanism. However, its drawback is that it has limited pricing flexibility, because retail rates are still determined by traditional rate-making procedures. Also, once a sharing mechanism has been established, it will tend to remain in place without frequent revision. Determination of the share fraction is the key to the equitable allocation of risks and rewards between shareholders and customers, and a potential point of contention.

## (5)    Multi-factor Performance Standards

The distinguishing characteristic of this new generic mechanism is that it measures multiple performance factors and aggregates the results in a "global" index which is used to adjust the utility's ROE. In the US there is only one example, Mississippi Power, as of 1993. It is incorporated into the sliding scale framework discussed above. Company performance is measured in seven areas: construction cost management, load factor improvement, customer satisfaction, plant availability, residential rate levels, employee accident levels, and service reliability.

A target ROE is based on the average cost of common equity for a benchmark group of utilities comparable to the utility being evaluated. The utility's performance rating is determined by assigning scores in each of the seven measurement areas and then weighting each performance factor. A matrix is constructed by plotting the utility's actual ROE, the benchmark ROE, and the utility's performance rating. This is then used to determine whether and to what extent revenues will be adjusted.

A deadband is established around the target ROE. If the actual ROE is above the deadband, utility revenues are adjusted downwards and vice versa. The magnitude of the adjustment depends on the utility's performance rating.

Establishing and maintaining a consistent, reliable performance matrix in a dynamic utility industry environment is especially difficult. Determining the relative value of the various performance factors and their contribution to overall efficiency involves subjective judgments and potential biases. The concept is comprehensive but difficult to implement.

## (6)    Performance Incentives

The structure of a performance incentive mechanism is based on defining a performance target, assessing utility performance relative to the target, and then applying appropriate rewards or penalties based on this assessment. Usually, if the utility's performance exceeds the target value, the utility is allowed to retain a pre-determined share of the savings for its shareholders. If the utility's performance is below the target value, the shareholders must absorb a pre-determined share of the incremental costs. There are many types of incentives covering performance on the supply-side, demand-side, and at the management level.

comparison of costs is introduced, there are problems with external cost benchmarks, as indicated above in the yardstick discussion.

Efficient utilization of partial cost adjustment measures is difficult. If there is only one input cost target, this can cause the utility to focus on this specific target to the detriment of overall efficiency, as discussed above. On the other hand, full price adjustment in response to cost changes may induce other forms of undesirable behavior on the part of the utility. For example, an automatic fuel adjustment clause may lead to excessive fuel use, and reduce the incentive to invest in fuel-efficient technologies. Partial cost adjustment mechanisms are likely to yield benefits only in the context of overall plans that improve overall efficiency and counteract the embedded incentive distortions.

In the case of ARAMs based on exogenous input price data, there is an incentive for the utility to reduce costs and increase its return, as in the yardstick mechanism. The obvious major problem with exogenous price indexes is that the utility's input prices may vary substantially from the index. The greater the variation, the shorter the period between rate cases. However, regulators generally prefer a long period between rate cases because a long regulatory lag tends to increase cost reduction incentives.

## (8)      Indexing

This mechanism links the ARAM mechanism with external indexes, and is mainly applied to labor, materials and other controllable costs. This mechanism is designed to provide incentives similar to regulatory lags in times when input prices are rising rapidly (Joskow and Schmalensee [1986]). In this mechanism, the utility is allowed to periodically change its overall rates based on change in a specified price index. The allowed rate changes might deviate from the utility's actual or forecast cost changes for two basic reasons.

First, changes in the external price index do not necessarily reflect changes in the utility's costs. Second, if a productivity offset is not included, the actual change in the utility's costs would probably be overstated by the index. Hence, the ARAM adjustment would allow the utility to increase its overall price above an economically efficient level. The customers would not receive the price reduction benefits of productivity improvement, at least until the next rate case, when a share of the above-normal profits earned in the prior period would be allocated to customers.

The disadvantage of this mechanism is that it may allow the utility easy price increases

and excess profits. Another disadvantage lies in the inductive nature of capital-intensive production, since its application to capital costs is usually excluded.

Traditional incentive regulation for electric utilities in the US contributes essentially to incremental enhancement of reward or penalty within the traditional regulatory structure. The first generation of incentive tools, e.g., yardstick, sliding scale, and indexed rates, were simple in design, narrow in focus, and limited in their impact on overall cost efficiency. These tools are fairly easy for regulators, utilities, and most customer groups to understand. However, the resulting efficiency improvements, as measured by utility cost (price) changes, have generally been marginal. This is not to say that the thrust of incentive regulation has been misdirected or is a sham, but rather that it is an evolutionary step in the competitive restructuring of the US electric utility industry.

Competition in the electric utility industry in the US to date has mostly been of marginal significance. The bulk of all generating capacity is either owned by utilities and financed by cost-of-service regulation or is supported by long-term contracts whose costs are passed through to customers. These market structures were not designed to function in a fully competitive wholesale market or on a fully competitive retail wheeling model. Hence, the current focus is on a transition model to facilitate restructuring to a competitive market.

A key component of this transition model is the reforming of traditional cost-of-service ROR regulation by supplementing or replacing it with incentive- or performance-based regulatory systems. In this respect, the evolution of PBR in California will be a benchmark for the rest of the industry (see below). Success of the PBR model in California would stimulate many PUCs to replace proposed incentive mechanisms with PBR structures.

## 4.1.2    Price cap regulation

This mechanism is common in the US telecommunications industry. As discussed in Section Two, price caps are regulated price ceilings for single items or a basket of services that follow a predetermined formula related to a general price index minus a fixed productivity growth rate.

The price cap is a limit on average revenues per kWh. The utility is relatively free to adjust individual tariffs, as long as the overall unit revenue does not exceed the cap.

In theory, price caps -compared with ROR regulation- promote cost efficiency, when price adjustments do not reflect changes in a utility's costs and PUC rate cases occur on schedule. Hence, price caps should provide a utility with stronger performance incentive when prices are not linked to the utility's cost factors, and PUCs do not arbitrarily change the price cap formula whenever a utility's earnings vary from a normal profit level. The price cap is considered to serve as a transition to full competition.

This approach has been very popular because it is relatively transparent and easy to use. However, there is little experience in the US electricity sector to draw on to evaluate its effectiveness. This approach has been used more widely applied to British utilities, discussed in Section Two of this chapter.

## 4.2 Status of incentive regulation in US states

This subsection examines California's regulatory environment, based on two key points: (i) California leads the US in structural reform of the electric power industry; and (ii) the progress of California's experiment is being closely monitored by other states moving toward a more competitive structure.

Incentive regulation programs in other states have not reached to the level of complexity and integration of those proposed in California. In most cases, their programs are narrowly focused, and meaningful experience has not been enough accumulated.

In California, approved and pending plans for comprehensive performance-based rate-making (PBR) have superseded the more limited incentive regulation schemes being considered in, for example, Massachusetts, New York, New Jersey, and Illinois. The incentive programs currently being considered in these states focus on specific performance attributes, such as key cost parameters relative to a benchmark index. In California, the focus is "global" i.e., the overall efficiency of utility operations.

An overview of analyses of California electric utilities' PBR mechanisms indicates that each is a fairly comprehensive, integrated structure usually incorporating multiple performance criteria, e.g., yardstick measures, price caps, and appropriate shared earnings or costs mechanisms. The basic design philosophy underlying these approaches is to improve the overall economic efficiency of the utility, as measured by key parameters such as price per kWh, quality and reliability of power and services and not to narrowly focus on specific parameters that generally characterizes incentive regulation.

Several other states are at various stages of approval and implementation of their own incentive regulation programs. In most cases, these programs are rather limited in focus compared to California's. A major factor driving design and implementation of incentive regulation is the difference in the retail price of electricity among the states. The states with the highest retail prices, such as California have the greatest incentive to reduce their prices through improved operating efficiencies.

States at advanced stages of consideration or implementation of incentive regulation programs are all monitoring the progress of PBR hearings at the CPUC. Currently, the CPUC's plan to deregulate the state's electricity market has been stalled by an intense debate over how far to extend competition (i.e., the issue of customer choice). This debate has focused on wholesale competition vs. retail competition. Wholesale competition would be limited to where utilities buy their power. This is generically referred to as the "PoolCo" structure. Retail competition would let customers contract directly with the power generator of their choice. This is generically referred to as "bilateral contracting". PG&E supports the bilateral contracting structure, while SDG&E and SCE strongly favor the PoolCo structure.

As of May 1, 1995, PG&E has continued its push for more competitive electricity markets by proposing to give rival power producers open, nondiscriminatory use of its transmission lines. PG&E has offered pricing schedules to govern sales between other generating companies and customers that use PG&E's long-distance transmission lines. PG&E provides greater wholesale transmission access than any company in the US.

PG&E is also working to establish an independent agency that would operate but not own the transmission grid. This would ensure equal access by all producers and customers to power markets without interference from the grid owner. This bold move to start bulk power competition in the western US will necessarily affect the structure of incentive regulation. No other state has proceeded as far as California along the path to competition in electricity markets.

Incentive regulation is viewed in many states as an interim phase to market competition. As indicated in the case of California, PBR is applied to bundled utility service and regarded as a transitional phase on the way to market competition. However, in a deregulated market structure such as a PoolCo or a bilateral contracting system, monopolistic functions will remain. As long as monopolistic functions -transmission, system control and distribution- exist, there is a need for the establishment of an optimal regulatory regime. In this respect, California's proposed PBR mechanism and related

## Massachusetts

Currently, the PUC is considering introducing incentive regulations. A utility's adoption of an incentive regulation program is strictly voluntary. Boston Edison has not yet submitted a proposal as of May 1995. Massachusetts Electric Company (MECO) submitted their proposal in March 1995.

MECO is proposing an incentive mechanism which would establish a link between the utility's rates and the yardstick average of all other rates charged to electricity consumers in Massachusetts. The proposal retains traditional cost-of-service regulation, but extends the period between major rate cases. Lengthening the period between major rate cases creates an incentive for the utility to minimize costs between rate cases.

Under MECO's proposal, so long as their rates remain less than the average of the rates charged by all other electric utilities in the state, MECO would be allowed, subject to certain conditions, to increase its rates by 20% of the difference between its rates and the average rate.

Actual receipt of the increased revenue is subject to: (i) a cap equal to the increase in the consumer price index (CPI) for the relevant period; and (ii) a commitment not to file for a general rate increase prior to May 1 of the next calendar year.

If MECO's rates are above the yardstick, a penalty would be imposed if MECO filed to increase its rates. The penalty would be 20% of the amount by which MECO's rates exceed the yardstick average. The penalty would take the form of an adjustment to the ROE approved in the previous rate case. Consistent with the proposed cap on rate increases, the downside risk would also be limited. The maximum negative revenue adjustment would be equivalent to a reduction of 3% in the company's allowed after-tax ROE.

## New York

The New York PUC is reviewing several proposals for incentive regulation. Currently, Consolidated Edison has implemented a simple revenue-per-customer cap and Niagara Mohawk has implemented a price cap. These programs are very simple in nature and represent a first step in experimenting with individual components that could be used in a comprehensive incentive program. Basic incentive regulation in New York is in an early stage of experimental development.

shareholders' value on improved cost performance, and not on capital additions to the rate base.

The basic elements of the Non-Generation PBR are as follows:

- a Revenue Indexing Mechanism
- a Cost of Capital Mechanism
- a Net Revenue-Sharing Mechanism
- "Z-Factors" for externalities
- a Service Quality Performance Mechanism
- a National Rate/Bill Performance Mechanism

### Structure of the Revenue Indexing Mechanism

The Revenue Indexing Mechanism will be used to determine non-generation O&M-related and capital-related rate base revenues after SCE's 1995 general rate case. This mechanism will be used until the next rate case, in 2001. The simple indexing formula incorporates a base rate productivity pledge of 1.4% per year, an allowance for general price inflation, and a specific incremental revenue per new customer.

The Revenue Indexing Mechanism formula is as follows:

$$NIBRR_t = NIBRR_{t-1} \times (1 + \Delta CPI - 1.4\%) + CGA_{t-1} \times \Delta Customers_{t-1} \times (1 + \Delta CPI - 1.4\%)$$

where:

| | | |
|---|---|---|
| NIBRR | = | non-generation indexed base rate revenue |
| t | = | years 1996-2000, successively |
| $\Delta CPI$ | = | annual rate of inflation, measured by the Consumer Price Index-All Urban |
| 1.4% | = | productivity growth factor for non-generation activities |
| CGA | = | customer growth allowance equal to $773 (1995$), reflecting the average marginal cost of adding a new customer |
| $\Delta Customers$ | = | annual change in number of SCE's retail customers |

### Structure of the Cost of Capital Trigger Mechanism

The Cost of Capital Trigger Mechanism will be used to revise the benchmark rate of return to be established in 1995. The trigger mechanism will adjust SCE's return of common equity based on changes in interest rates. The major objectives of the

mechanism are to: (i) insure that changes in interest rates by themselves do not result in returns which compensate investors inadequately; and (ii) provide safeguards for shareholders and ratepayers.

Currently, the regulatory cost of capital proceeding determines annual levels for SCE's capital structure, embedded cost of debt and preferred stock. The trigger mechanism will prohibit adjustment of revenues if changes occur in these items. Hence, cost risk is borne by the shareholders. The trigger mechanism provides SCE with the incentive to optimize its capital structure by permitting adjustment between the lower cost of debt resulting from a high equity ratio and the lower cost of maintaining reduced equity.

**Structure of the Net Revenue Sharing Mechanism**

The Net Revenue Sharing Mechanism is designed to limit shareholder gains and losses, i.e., to avoid extreme outcomes. SCE's mechanism is similar to revenue-sharing mechanisms used in the telecommunications industry, where price-cap regulation is in effect. SCE's mechanism has been structured to incorporate a balance of risk and reward in harmony with the CPUC's philosophy. In this regard, the CPUC has ruled that:

".. a regulatory mechanism which provides some self-correcting protections is more likely to be sustainable, and thus would provide more predictable and longer-run incentives to efficient utility management than would a pure price-cap model. A regulatory structure which combines the price-cap indexing approach with a sharing mechanism can provide protection to both shareholders and ratepayers from the risks that the indexing method may over- or underestimate the revenue changes which are needed to keep the utility financially healthy --but not too healthy". (CPUC Decision D.89-10-031, p.174)

SCE's Net Revenue Sharing Mechanism is based on its after-tax rate of return on rate base. To maximize the shareholder incentive to improve operating efficiency, a 1.5% bandwidth would be established above and below a benchmark return. Within this $\pm$ 1.5% bandwidth, shareholders would be at risk for all variations in earned returns. Incremental or decremental returns outside this bandwidth would be shared equally between shareholders and ratepayers. If SCE's calculated returns are = or >3.0% above/below the benchmark, a formal regulatory review could be initiated.

**Structure of "Z-Factors"**

No formula can predict the impact on utility performance of factors mostly or entirely

outside the control of the utility. The impact of these external factors must be accounted for, so as not to unduly penalize shareholders and ratepayers for negative impacts that the utility has little or no ability to mitigate or prevent.

To ensure that both shareholders and ratepayers are treated fairly when employing PBR mechanisms based on broad indexing formulae, a "Z-factor" is often incorporated in the formula. "Z-factors" are designed to allow for exceptional recovery of large unpredictable costs. The major cost uncertainties considered are:

- major changes in government-mandated fees and taxes;
- major changes in government regulations;
- significant costs associated with claims of exposure to nuclear radiation or EMF resulting from SCE's operations;
- significant accounting changes.

To screen the use of "Z-factor" adjustments, a threshold cost criterion has been proposed, i.e., the revenue/cost impact would have to exceed $\pm \$10$ million.

SCE has proposed a revenue-sharing mechanism that integrates non-generation and generation activities, which is pending CPUC approval.

**Structure of the Service Quality Performance Mechanism**

The implementation of a PBR mechanism could raise concerns about deterioration in service quality. To provide concrete assurances that service quality standards would be maintained, a service quality mechanism has been proposed, based on measures of customer satisfaction and service reliability. A survey would measure customer satisfaction, and the average annual minutes of service interruption would measure service reliability.

SCE has proposed a deadband below recent performance, with financial penalties for performance below this deadband. There would be a maximum penalty of $5 million per year for each of two performance measures. This is intended to reduce controversy and streamline application.

**Structure of the National Rate/Bill Performance Mechanism**

The average rates of SCE and other California utilities are significantly higher than other major utilities across the country. These higher rates are due, in part, to low usage per customer compared to the national average, and to the relatively high-cost mix of

The second consideration is the costs of fuel and purchased power. The potential volatility of fuel and purchased power costs creates the possibility that a national rate/bill comparison could expose SCE to penalties or rewards for events outside their control. To reduce this concern, SCE has proposed an incentive based on performance change from year to year, rather than cumulative performance.

**Evaluation of Risks of SCE's PBR Mechanism**

The overall impact of SCE's PBR Mechanism is to shift the risks of revenue shortfall and cost fluctuations from ratepayers to shareholders.

Although the Net Revenue Sharing Mechanism increases the potential gain for shareholders if costs are reduced below a target level, it also increases the potential for losses due to external events outside the control of the utility. This causes increased variability in SCE's earnings.

Increased variability of earnings is a negative for investors, who have traditionally valued the electric utility industry for its stable cash flows. However, in the rapidly evolving US electric power industry, greater ability to earn profits related to performance also implies the risk of losses due to non-competitive performance. For potential investors, this translates into a riskier profile for the utility.

The Revenue Indexing Formula also increases the variability of earnings. Since the mechanism uses a consumer price index (CPI), to the benefit of the consumer, it may not accurately reflect SCE's cost inflation for inputs, labor, etc. Moreover, SCE may not be able to attain the productivity factor specified in the formula, consequently reducing earnings potential relative to expectations.

An adjustment for customer growth can also have the effect of lowering earnings, as the actual costs of adding a new customer may vary over time and according to location. Moreover, the lengthened period between general rate cases adds to the risks of imbalances between costs and revenues.

As discussed earlier, there will be increased risk from the Cost of Capital Trigger Mechanism, because it will not adjust for changes in the cost of long-term debt, preferred stock, and capital structure. Moreover, the mechanism may not adjust adequately for changes in interest rates. The impact of only moderate increases in interest rates on returns on common equity will be substantial losses.

Changing capital structure requirements can also reduce shareholder earnings. If regulations that previously allowed utilities to have significantly lower equity ratios than other industries are changed to require utilities to maintain higher equity ratios, shareholders will bear the costs. Shareholders would bear the cost difference between debt and higher cost equity. SCE estimates that for each 1% increase in equity, there would be a resulting decrease in shareholders' return on equity of 0.13%. If SCE were to align its capital structure with that of the telecommunications industry, it could require an increase in equity of up to 5%, resulting in a cost to shareholders of a decrease in return on equity of 0.65%.

**Transitional Issues**

The current uncertainty in California regarding restructuring of the electric utility industry has been reflected in SCE's phased approach to PBR mechanisms for both non-generation business activities and generation.

The separation between generation and non-generation base rate revenues will be a major consideration in the transition. SCE proposes separate PBR formulae for base rate revenues for generation and non-generation activities. As competition develops in the generation market, concern about cross-subsidy between generation and non-generation sectors will likely develop. This will probably necessitate separation of costs as well as revenues.

**(2)      Pacific Gas & Electric (PG&E)**

PG&E submitted its proposal for PBR to the CPUC (California Public Utilities Commission [1994a]). in mid-1994. PG&E has since withdrawn its proposal and is in the process of revising it. It is not likely that the revisions will significantly alter the original proposal. The basic components of PGE's PBR framework are: (i) a revenue indexing mechanism; (ii) a shared earnings mechanism; and (iii) performance incentives.

The approach proposed by PG&E to determining electric and gas base revenue requirements is very similar in structure to the SCE mechanisms. Basically, there is a link between authorized revenue and the cost of service. However, in this case, PG&E's costs are not subject to detailed review by the CPUC. PG&E must manage its costs consistently with the revenue determined by its indexing formula. The shared earnings mechanism is designed to keep their base revenue requirement in line with costs. The performance incentives are designed to motivate PG&E to operate more efficiently and productively

and maintain service quality.

It is important to note that in PG&E's initial proposal, the same formula is applied to both electric - and gas-related activities whereas with SCE's electric activities, it has specific PBR mechanisms for generation and non-generation activities.

## Structure of the Revenue Indexing Mechanism

Most of PG&E's base revenue requirement will be determined by a revenue indexing mechanism applied independently to gas and electric operations. The formula for indexing PG&E's base revenue for both gas and electric activities is as follows:

$$IBR_t = IBR_{t-1} \times (1 + i + c - p) \pm SE$$

where:

$IBR$ = indexed base revenue to be authorized (subscript t refers to year)

$i$ = recorded inflation for the 12 months ending June 30 of year t-1

$c$ = recorded customer growth for the 36 months ending June 30 of year t-1

$p$ = productivity factor

$SE$ = amount of shared earning (savings), if any

PG&E had proposed implementing its PBR mechanism in 1995; however, given the recent withdrawal of their proposal, inauguration will most likely be delayed. PG&E has proposed that the determination of base revenue in the PBR framework excludes the revenue contributions of three components: (i) funding for the Customer Energy Efficiently program; (ii) the Large Electric Manufacturing Class (LEMC); and (iii) the Diablo Canyon Nuclear Plant. It has been proposed that the CPUC continue detailed review of these components independent of the proposed PBR mechanism.

## Structure of the Shared Earnings Mechanism

The shared earnings component is designed to act as an incentive for PG&E to improve operating efficiency and productivity while maintaining its costs in line with the revenues determined by the PBR mechanism as well the components determined by the CPUC. The basic structure of PG&E's shared earnings mechanism is very similar to SCE's.

The target return measure is utility operating return on equity (ROE). The same target ROE will be used for both the gas and electric mechanisms. The shared earnings will be calculated separately for gas and electric operations. The basic elements of the sharing mechanism are summarized below:

- utility ROE within 2% above or below the target ROE will be allocated 100% to the shareholders, and will have no impact on base revenue;
- utility ROE > 2% beyond the target ROE will be allocated 50%／50% between shareholders and ratepayers. In this case, base revenue will change by ±50% of the amount of ROE beyond the target.

PG&E proposed to use ROE instead of return on rate base (ROR) for two main reasons:

- using a risk premium approach to estimate target ROR is less efficient, because embedded costs of debt and preferred stock don't move in a one-to-one correlation with the Treasury Bond market, a prime indicator of financial risk;
- ROE measures the return earned for common shareholders after the utility has met its financial responsibilities to creditors and preferred shareholders, while ROR measures the return earned for all investors, including common shareholders.

A simplified formula for shared earnings is as follows:

$$SE_t = [(PG\&E\ ROE_{t-1} - Target\ ROE_{t-1}) \times (Rate\ Base_{t-1} \times Equity\ Ratio)] \times 50\% \times Income\ Tax\ Adjustment$$

where:

$SE_t$ = shared earnings of year t

$PG\&E\ ROE_{t-1}$ = PG&E's Return on Equity of year t-1

$Target\ ROE_{t-1}$ = Target Return on Equity of year t-1

$Rate\ Base_{t-1}$ = rate base for 12 months ending June 30 of year t-1

Equity Ratio = authorized equity ratio

The target ROE is a proxy for the competitive return required by market investors.

The range of the deadband ±2% is designed to place a significant level of risk upon shareholders. The purpose is to provide a strong incentive for management to maximize efficiency and productivity. PG&E returns >5% above/below the target ROE will trigger an option, implementable either by PG&E or the CPUC, to review indexing and performance standards. This threshold should place significant risk upon shareholders, and yet not allow a significant difference between base revenue and base costs that could jeopardize PG&E's financial position.

### Structure of the Performance Incentives

PG&E proposed rewards and penalties for performance standards in three areas: (i) energy bills; (ii) customer satisfaction; and (iii) electric service reliability. The existing Customer Energy Efficiency standard will be retained as a performance incentive.

The Energy Bill performance standards have been proposed to spur PG&E to lower its residential electric and gas bills relative to the national average. PG&E has focused on customer bills rather than rates, simply because customers are more familiar with bills than rates and respond more readily to significant changes in their monthly bills.

A reference ratio comparing the 5-year moving average of revenue per residential customer in PG&E's service territory to the national average will be used as the benchmark. After the reference year, annual ratios will be compared to the benchmark. If the ratio for a given year is lower than the reference ratio, PG&E will be rewarded, and vice versa. The maximum award/penalty is $25 million, with $19 million allocated to electric and $6 million to gas.

The Customer Satisfaction performance standard will utilize an existing customer survey called Quality of Service Evaluation Plus to measure residential customers' satisfaction with electric and gas service. The 1994 survey results would serve as the benchmark. Again, performance above/below the benchmark will be subject to reward/penalty. The maximum award/penalty is $25 million, with $19 million allocated to electric and $6 million to gas.

The Electric Reliability standard has been designed to induce PG&E to maintain or improve the reliability of its service. PG&E tracks three key measures of sustained and momentary electric service outages: (i) the total number of sustained and momentary outages; (ii) the total number of customers affected by outages; and (iii) the average number of customer minutes required to restore service after a sustained outage. A 5-year moving average mechanism like that used in the Energy Bill performance standard would be employed.

### Flexible Pricing

In response to the increasing competition to supply electricity to large manufacturing customers, PG&E has proposed a pricing mechanism independent of existing tariff rates. Currently, PG&E's only tool for responding to competitive threats is a cogeneration deferral contract. This contracting process is time-consuming and potentially costly. It is

also a somewhat blunt instrument, where a precision tool is required.

PG&E has proposed to offer flexible pricing options to manufacturing customer accounts with over 2,000 kW average hourly electricity usage (approximately 17.5 million kWh per year). PG&E has proposed that standard rates for the large electric manufacturing class (LEMC) be determined by a formula which indexes rates for firm and interruptible tariffs to the Producer Price Index for Industrial Power (PPI-IP).

The standard firm service tariff would be modified to incorporate PG&E's Economic Stimulus Rate (0.4 ¢/kWh energy charge credit) plus an additional off-peak energy charge credit of 1.0¢/kWh. This would provide downward price flexibility. The objective would be to stimulate increased manufacturing capacity utilization during off-peak hours. Currently, PG&E's non-firm service rate level is competitive with energy rates in other states.

PG&E has proposed several long-term tariff options: (i) the Extended Service Option; (ii) the Cogeneration Deferral Option; (iii) the Business Retention Option; and (iv) the Business Attraction Option.

The Extended Service Option would offer a 5% discount on the applicable rate for a 10-year contract for firm and interruptible service. The Cogeneration Deferral Option would be available to customers for whom cogeneration is technically feasible and who are willing to invest in cogeneration. This would require a 10-year commitment, and increases would be based on an index weighted 40% natural gas costs and 60% appropriate capital costs.

The Business Retention Option would be offered to manufacturing customers at risk of relocating out-of-state. The starting point and rate of increase of this 10-year contract rate would be based on average industrial electricity prices in the competing state. The Business Attraction Option is designed to attract firms expected to qualify as LEMC customers, or induce an existing customer to add at least 4.38 million kWh per year. There are two contract options, for six and 10 years, with compatible rate of increase provisions.

Within the context of the overall regulatory framework, these proposed options would allow PG&E increased flexibility in pricing and administration to meet competitive challenges in its service territory.

## 4.3    Summary

In the US, incentive regulation is viewed as a transitional phase to a competitive market structure, designed to enhance the economic performance of utilities in a market where market-based price competition is not significant. Incentive regulation in the US is not intended for use in competitive markets, but rather for markets where utilities have sustained market power.

In the US to date, competition in the electric utility industry has been mostly marginal. The competitive restructuring of the electric utility industry is at only an early stage. If the structural changes such as those underway in California proceed, this could definitely reduce the significance of incentive regulation schemes.

However, even in such a relatively more competitive market structure, the application of incentive regulation to enhance the performance of an electric utility will still be needed for as long as some functions of the electricity industry remain monopolistic.

The results of the recent development of PBR in California show several important elements of effective incentive regulation. The fundamental components of PBR common to the California electric utilities mentioned above are: (i) a revenue indexing mechanism; (ii) a shared earnings mechanism; and (iii) performance incentives.

A revenue indexing mechanism ensures a strong decoupling of authorized revenues from actual costs over a long period. Traditional incentive regulation on the other hand, works within an existing ROR structure, and its effect on performance improvement is marginal.

A price cap, another type of indexing mechanism, which is applied to LEMC customers of PG&E, will have the same effects as a revenue indexing mechanism.

A shared earning mechanism provides some self-correcting protection to both shareholders and ratepayers from the risk that the indexing method (revenue indexing or price cap) may over/underestimate changes in revenue. Coupled with this shared earnings mechanism, an indexing method will provide effectively incentives to improve performance over the long run. Along with a shared earnings mechanism, "Z-factors" proposed by SCE can limit the need for regulatory intervention. Hence, passthroughs may also be considered as a means to make an indexing method function more effectively.

Strong decoupling of revenues from costs might cause the quality of a utility's service to

deteriorate. Therefore, performance incentives will be a necessary part of PBR to supplement an indexing method.

These fundamental elements of PBR could also be applied to monopolistic functions in a deregulated electric utility industry.

# 5    Conclusion

The results of UK-style incentive regulation point out the stark contrast between price cap regulation in theory and in practice.

British Telecom (BT) is a typical case. Based on the experience of price cap regulation in UK utilities, especially BT, alternative versions of price cap regulation are proposed below.

Price cap regulation has, in theory, a number of potential advantages over rate-of-return regulation. First, by breaking the link between allowed prices and actual costs, price cap regulation can enhance cost reduction incentives.

Second, by fixing the duration of the regulatory review in advance, price cap regulation can promote a predictable environment that encourages long-term planning.

Third, price cap regulation can provide significant pricing flexibility. Pricing flexibility can assist the firm in rebalancing rates. When prices reflect costs more closely, consumers receive better signals about the true costs that their consumption imposes on society. These better signals can induce consumption decisions that improve social welfare.

Increased pricing flexibility can also enable the regulated firm to respond more intelligently to competitive challenges.

Fourth, price cap regulation can reduce the administrative costs of regulation. In its pure form, price cap regulation only requires the regulator to verify that the prices set by the regulated firm each year satisfy the overall constraints. Furthermore, by setting longer time horizons for the price cap regime, the frequency of comprehensive regulatory reviews can be reduced significantly.

These advantages of price cap regulation are, at the same time, as pointed out, disadvantages in ROR regulation. However, the actual history of price cap regulation shows sharp contrasts with the theoretical advantages of price cap regulation over ROR regulation.

First, the extent to which price cap regulation severs the link between actual costs and allowed revenues is not clear. In case of BT, the productivity offset increased steadily over time, as its realized returns remained relatively high. It seems quite likely that these

increased demands would have been at least more moderate if BT's realized earnings had been mere lower. In practice, price cap regulation may tend to operate more like ROR regulation with a predetermined regulatory lag.

Second, in the case of BT, the promise of a fixed number of years before the regulatory plan would be altered was not fulfilled. The 1991 modification of the second phase of price cap regulation was implemented a year before the next review was scheduled to occur. For distribution business, the current period of present price cap regulation was reduced from five years (April 1995 to March 2000) to one year (April 1995 to March 1996), and a new price cap was proposed with a further one-off reduction which will apply from April 1996 to March 2000.

In this sense, price cap regulation resembles ROR regulation with endogenous and variable regulatory lag more than it resembles a regulatory regime in which the regulated firm can count on the absence of regulatory fine-tuning for a fixed length of time.

Third, the contrast between price cap regulation in theory and practice involves the pricing flexibility afforded the regulated firm. In the case of BT, restrictions on the ability to raise rates on individual services expanded to many services, including residential line rentals, business line rentals and installation services. The restrictions also limited BT's ability to respond aggressively to competitive pressures. On the other hand, by restricting BT's flexibility, the social goal of fostering more widespread competition was promoted. In the case of the electricity supply business, REC's ability to raise customers' prices under IMW was restricted from April 1990 to March 1993.

Companies generally have more pricing flexibility in the electricity industry than the telecommunications industry. However, there is always a possibility of regulatory intervention to restrict pricing flexibility in order to achieve social goals. It should also be pointed out that pricing flexibility is not peculiar to price cap regulation. Within the framework of ROR regulation, flexibility to set individual prices is possible.

Fourth, price cap regulation does not necessarily reduce the administrative cost of regulation, as mentioned before.

To avoid the above-mentioned pattern of ever-expanding regulatory control, there is a need to protect regulators from public pressure to pursue a variety of social goals, such as increasing competition, protection of the small residential customers, and limiting extranormal returns of dominant suppliers of essential services. Otherwise, price cap regulation may be as vulnerable as other regulatory mechanisms to outside intervention to

achieve these goals.

Some possible alternatives to the particular form of price cap regulation are described briefly below.

First, earnings sharing may be employed to limit the temptation to intervene before the expiration of a price cap plan. When such sharing is built into the regulatory mechanism, political pressures to capture realized rents in other ways (e.g., prematurely revising the term length of the regulatory regime) can be relieved. It must be noted, however, that under a move from price cap to profit sharing mechanisms marginal incentives are reduced. Under price cap regualtion redistribution of revenues to customers occurs according to set X-factors, no matter whether equivalent efficiency gains are actually achieved. Regulated utilities are full claimants in any achieved cost reductions. Under profit sharing part of the achieved efficiency gains automatically accrue to consumers thus reducing the power of incentives to regulated firms. Viehoff [1995] estimates using historic UK accounting data that under the current price cap regime a net present value of 71% of unanticipated cost savings in the first year after regulatory review eventually accrues to customers (through price cuts in the next regulatory period). If an additional 50% profit sharing mechanism was introduced, consumers would receive 86% of the unanticipated cost savings. These results suggest, that the additional redistributive effect of the additional profit sharing mechanism is relatively low. Considering that marginal incentives are reduced considerably (and keeping in mind that corporate taxation already constitutes a profit sharing mechanism) the main benefit of the additional profit sharing mechanism appears to be the credibility enhancement of the regulatory rule.

Second, passthroughs may be admitted in the price cap regime. Factors beyond the regulated firm's control, such as changes in tax laws and certain regulatory rulings, heavily influence its realized earnings. Such passthroughs can limit the need for regulatory intervention.

Third, regulatory authority to modify the terms of a price cap plan before its scheduled termination date could be explicitly restricted. By coupling automatic adjustment mechanisms such as passthroughs and earning sharings with prohibitions on regulatory intervention, the relatively stable, less bureaucratic regulatory structure that price cap regulation can provide in theory may be realized in practice.

The recent development of incentive regulations in the US shares certain similarities to the above proposal for effective price cap regulation. The fundamental components of

newly developed PBR mechanisms in the US are: (i) a revenue indexing (cap) mechanism; (ii) a shared earnings mechanism; (iii) passthroughs; and (iv) performance incentives.

A revenue indexing mechanism ensures a strong decoupling of authorized revenues from actual costs over a long period. Traditional incentive regulation on the other hand, works within an existing ROR structure, and its effect on performance improvement is marginal.

A shared earning mechanism provides some self-correcting protection to both shareholders and ratepayers from the risk that the indexing method .Coupled with this shared earnings mechanism, an indexing method will provide effectively incentives to improve performance over the long run. Along with a shared earnings mechanism, passthroughs proposed by SCE can limit the need for regulatory intervention.

Strong decoupling of revenues from costs might cause the quality of a utility's service to deteriorate. Therefore, performance incentives will be a necessary part of PBR to supplement an indexing method.

It should be noted that the UK price cap has also been structured to function as a revenue cap in recent regulatory reviews, as seen above. Performance incentives are also a necessary part of the incentive mechanism in the UK. In the UK electricity industry, service standards have been introduced, with some penalties for non-compliance with standards.

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