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November 1, 1994

Ms. Mary Cottrell  
Secretary, Department of Public Utilities  
100 Cambridge Street  
Boston, Ma.

Re: DPU 94-158; Investigation into Incentive Regulation

Dear Secretary Cottrell;

Enclosed for filing in the above captioned case are the Initial Comments of Boston Edison Company. We look forward to participating in the Department's investigation into the adoption of an incentive regulation structure.

Sincerely,

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EXECUTIVE SUMMARY OF THE INITIAL COMMENTS OF BOSTON  
EDISON COMPANY CONCERNING INCENTIVE REGULATION

November 1, 1994

Boston Edison Company believes an investigation into incentive regulation is very timely because of the competitive changes that are overtaking the electric industry. The task before the Department is to design incentive policy measures that will enable a transition to this more competitive future. We believe that effort for the electric industry should be based on the following set of principles:

Improvements in the regulation of generation and power supply should be a key focus of the Department's efforts.

An incentive regulation structure that ties generation cost recovery to the wholesale market price will ensure greater customer benefits than will other forms of administratively determined incentive regulation, such as price caps and performance incentives.

Customers will benefit from broad-based forms of incentive regulation in the transmission and distribution sectors which target price, customer service and reliability.

Any incentive based structure must uphold past regulatory cost recovery commitments and permit utilities to maintain financial integrity.

Customers will benefit from the inclusion of environmental values in wholesale market price determinations.

Based on these principles, Boston Edison has prepared a suggested approach to incentive regulation centered on the wholesale market that we believe is worthy of discussion and further development. We believe it should advance the interests of customers and utilities, and promises to provide the right signals to utilities during the transition to a competitive future. We recognize that changes to current NEPOOL policies, Department regulations and certain statutory provisions would be necessary to fully implement this proposal, as would be the support of many parties.

The Company's suggested approach to incentive regulation features six key points, which are as follows:

- Utility rates would be separated into two components: generation and T & D.

- For generation, the link between cost of service and rate level would be severed; a utility's generation rate would be based on the wholesale market price for power, irrespective of the utility's cost of production. The fuel adjustment clause would no longer be used.
- T & D rates would continue to be based on cost, but would be subject to broad based performance incentives focused on price, customer service and reliability.
- To reflect the fact that generation rates would be based on market prices, generation assets would be marked down to market value; to compensate for this change and to preserve the established regulatory commitments to utilities, T& D assets would be marked up to market values, based on replacement cost.
- Environmental values would be incorporated into wholesale market prices.
- Notwithstanding the above changes, overall rate levels would not change, at least initially, and utility franchises would be preserved.

The use of a market based system of this sort would require the establishment of a reliable, definable wholesale market price, a very significant task. Moreover, it would be a change of enormous significance to utilities. While it would promote genuine improvements in efficiency, it would also wholly alter the financial and accounting basis of the industry. Movement to market based pricing for generation in today's climate of excess capacity would expose utilities to extraordinary financial losses, unless appropriate safeguards were established.

We do not purport to have solved all of the issues that would be raised by movement to a market based generation system, or even to have identified all of them. Nonetheless, we believe it would be worthwhile for the Department to pursue the development of such a structure because it promises substantial benefits. First, the proposal can achieve real efficiency benefits while maintaining the financial integrity of utilities. Second, the proposal will position utilities and the Department for the future by precluding new stranded power supply costs and facilitating further unbundling, should such a step be appropriate at some later date. Third, the proposal can be made equitable to all customers and still honors the regulatory compact by making possible the recovery of historical, prudently incurred costs. Fourth, the proposal could simplify the current regulatory process and make rate cases less frequent. Last, the changes required to

implement the proposal, while extensive and at present only dimly defined, are nonetheless not as disruptive as those associated with other market-based proposals such as retail wheeling or industry de-integration.

Full implementation of the provisions we have suggested will take a substantial amount of time and effort. During the interim we propose that broad price cap regulation of non-fuel rates should be implemented. We also propose that the acquisition of new resources by utilities be made subject to market decision rules on an expedited basis, even while the more complete application of such principles is being developed. Under this system, cost recovery for new resources would be limited to the wholesale market price, using an adjusted NEPOOL system lambda as a surrogate until a recognized market standard develops, and the current IRM process would be largely supplanted.

While the transition to such a system is unlikely to be fully developed in the present docket, given the significant issues that will need to be resolved, nonetheless we believe the Department can make a substantial contribution to progress in this direction by endorsing in this docket the general incentive principles described in these comments.

Commonwealth of Massachusetts

before the

Department of Public Utilities

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Investigation into Incentive Regulation	)	D.P.U. 94-158
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Initial Comments of Boston Edison Company

November 1, 1994

## Introduction

Boston Edison Company (BECo or the Company) is pleased to respond to the recent Notice of Inquiry and Order Seeking Comments on Incentive Regulation issued by the Department of Public Utilities (the Department). We believe an investigation into the theory and implementation of incentive regulation for electric utilities in the Commonwealth is very timely, because in our view the power supply sector of the electric utility industry will become increasingly competitive in the next few years. Implementing an appropriate incentive regulation structure in the near future could provide a smoother transition to such a competitive environment. The Company applauds this recent initiative and looks forward to further participation in the policy debate and ultimately to the development of more competitive and efficient energy markets. The Company's comments are organized into three major parts:

- I. A description of our view of the appropriate principles that should underlie the development of an alternative regulatory structure of the type the Department is contemplating;
- II. A conceptual outline of a possible alternative regulatory structure to meet these principles;
- III. Responses to the specific questions raised by the Department in its order initiating this docket.

The remainder of this document deals with each of these three parts in turn.



## I. Principles for Incentive Regulation

The first step in devising a public policy as important and as potentially controversial as an incentive regulation structure should be the development of a set of sound and consistent guiding principles. Since we believe the electric industry is moving towards a future in which the power supply sector will become increasingly competitive and market based, we think incentive regulation should focus in that area. Incentive regulation should not be a continuation of the past; it should be a preparation for the future. Based on these beliefs, we suggest that there are five basic principles which should guide the Department. They are as follows:

1. A key focus of the effort to explore alternative approaches to regulation should be the generation and wholesale power supply area
2. An incentive regulation structure that ties generation cost recovery to the wholesale market price will ensure greater customer benefits than will other forms of incentive regulation such as administratively determined price caps or targets
3. In the transmission and distribution sectors, customers will benefit from broad-based forms of incentive regulation which target price, service and reliability
4. Any incentive-based regulatory structure must permit utilities to maintain financial integrity
5. Customers will benefit from the inclusion of environmental values in wholesale market price determinations.

Each of these principles is described in more detail in the paragraphs that follow.

**Principle 1: Generation and power supply is a key area on which to focus.**

The Department's objective in exploring incentive regulatory structures is to determine if opportunities exist to benefit customers through more efficient utility operations, better cost control incentives, and lower rates. This is a broad charter, and any number of incentive structures are possible. In our view, while incentives should be applied across all aspects of utility operations, a key focus should be the generation and wholesale power area. This is so for three basic reasons.

First, competition - both existing and anticipated - is centered in the generation and power supply area. While there is discussion about performance-based (or incentive) regulation for the transmission and distribution sectors, there has been little suggestion that competition should be adopted in those sectors. Thus, to the extent that the Department is seeking a more competitive energy market or a transition to a more competitive future, it makes sense to focus on generation and power supply.

A second reason for focusing attention on generation and power supply is that the opportunity for improved regulation in this area is substantial. The interest in opening up the generation sector to competition exists not just because workable competition is possible in that sector; it is also because there is substantial investment in that sector. Approximately two-thirds of the delivered cost of electricity is represented by generation and power supply. Even more important is the exceptionally large economic impact of power supply decisions. Since generation resources are typically capital intensive and very costly, the difference between good and bad decisions in this area can be huge, dwarfing comparable decisions in other areas.

In addition, the significant difference between the embedded cost of generation and the current wholesale market price of power provides some indication that regulatory restructuring may provide benefits in this area. To illustrate, the average embedded costs of generation in Massachusetts currently total about five to six cents per kWh, with some purchased power obligations in the six to eight cent range. At the same time, the wholesale market price of power (given the current capacity excess throughout the region) averages between two and three cents per kWh. In a workably competitive wholesale market -- such as that which exists in New England -- and in the absence of a regulatory mechanism requiring compensatory payments, that differential is real: a buyer with access could, at least in the short term, acquire power off the grid at between two and three cents per kWh. While the current differential reflects the existing capacity surplus, it is unrealistic to expect that an efficient market would produce such low price levels over the long term, and at present the remaining fixed generation costs are being recovered through base rates, the existence of this differential nonetheless suggests that there should be some opportunity for improvement in this area over time.

A third reason to focus attention on the generation sector is that the historic administrative process has not distinguished itself in dealing with generation issues, and a new process based on incentives might do better. The current administrative procedures for dealing with power supply rely on the integrated resource planning process with specific rules for determination of need and the acquisition of supply-side and demand-side resources. The current procedures represent the logical evolutionary result of the "central planning, command and control" school of regulatory oversight for generation and power supply decisions. The result has been an

administrative process that has been expensive, contentious, and time consuming. In the Department's own words, the "alternative regulatory framework should provide a more efficient regulatory process for utilities, intervenors, and the Department."

Moreover, while the historic regulatory process has produced a sound electrical system with high reliability, the costs in the generation and power supply area have not been minimized. In some cases, the current process -- no matter how logical, how integrated, or how well meaning -- is not serving customers well. For example, in retrospect it can be seen that in many areas of the country over-investment in fixed cost generating assets has contributed to the current oversupply of energy and capacity in the wholesale market. The historic incentives of the administrative process overseeing generation investment decisions coupled with then-current forecasts of ever increasing fossil fuel prices led to what -- again in retrospect -- were uneconomic investments. Mandated purchases from non-utility generators measured against a yardstick of forecasted avoided costs have also been a major source of oversupply. Well intentioned policies to encourage a nascent industry and diversify fuel price risk, coupled with must-run contracts based on administratively determined prices has, again, led to decidedly uneconomic commitments.

It is clear that the current process leaves room for improvement. A properly structured incentive regulation structure in the generation and power supply area could produce better results for customers.

## **Principle 2: Generation Cost Recovery Should Be Tied To Wholesale Market Price**

An incentive regulation structure that ties generation cost recovery to the wholesale market price is likely to ensure greater customer benefits than

will other forms of administratively determined incentive regulation. This is so for two reasons: first, incentives should be aligned with the actual value of the outcomes desired, and in the case of generation and power supply the best way to judge value is by reference to the wholesale market price; and second, the transition to a competitive generation market can be made much smoother by adopting a market price standard in the interim. Of course, moving to a market based recovery system would have enormous consequences that would be felt throughout all facets of a utility's business, and mechanisms to deal with those consequences would have to be established prior to adopting such a standard. These statements are developed more fully in the paragraphs that follow.

1. The Wholesale Market Price is the Best Measure of the Value of Power.

The whole purpose of devising a new regulatory structure is to put in place new incentives which are better suited than the existing system to producing the outcomes in the utility industry that society, as represented by the regulator, wants to be achieved. While the existing cost of service based system has served customers well for decades, there are well known shortcomings in the incentives it produces. One perceived problem is that, in general, utilities are rewarded based upon the prudence of their forecasts, rather than on the actual value of the outcomes produced. Accordingly, to the extent that an incentive system focuses on the value of the outcome, it will be an improvement over the current system. In the case of generation, the regulatory structure should provide incentives to produce power whose value exceeds its cost of production.

Determining whether the actual value of power produced exceeds the actual costs of producing it, of course, requires an understanding of how to measure the value of power. In our view, the only meaningful way to

measure the value of power is by using the wholesale market price. Simply put, this is so because the wholesale market price is the price at which power can be bought or sold at any point in time -- no more or no less. The existing commitments that are today deemed a "bad deal" are so called because the power represented by the commitments could be obtained today at lower cost in the open market. Similarly, if a unit in NEPOOL were to shut down today with no notice and disappear from the dispatch order, the power formerly produced by that unit could be replaced immediately by market purchases at market prices. The wholesale power market in New England is sufficiently well developed to provide a real alternative to any particular power source, and as a result notions of value of power and power supply commitments already are based on the wholesale market price. Thus, it makes sense to use wholesale market price as the measure of value in any incentive system.

Plainly, one could design an incentive system for generation and power supply using alternative standards for measuring power supply efficiency. Targeted incentive programs, for example, seek to reward utilities for meeting or exceeding specified measures of productivity, such as heat rate or unit availability. Price cap structures give utilities an incentive to reduce cost by more than the stipulated productivity improvement allowance. Rate of return bandwidth regulation similarly creates incentives for cost reduction up to the edge of the band. But all of these alternative incentive mechanisms are inferior to use of wholesale market price. Despite the focus of such programs on appropriate targets such as unit efficiency and cost containment, none ties the revenues for power supply directly to the determinant of value. Not one is using the actual difference between the value and cost of power as an incentive. Such structures use specific objective yardsticks, but they are administratively determined proxies not based on market results, and thus

are subject to many of the same problems that an incentive structure is trying to correct.

Yardstick regulation -- a structure that uses peer group comparisons or other outside benchmarks -- attempts to do indirectly what the wholesale market price does directly. But that clearly is also second best; why use a proxy for a competitive market price when the real thing exists in the wholesale market? Any incentive regulation system that does not link revenues to wholesale market prices cannot consistently provide the right incentives and therefore drive the right outcomes.

## 2. A Smoother Transition to a Competitive Future

The utility industry is headed toward a competitive future. Based on historically competitive markets for commodities, it seems likely that the wholesale market price will be the valuation standard for electric power. Thus, adopting the wholesale market price as the standard for an incentive structure in the interim will provide a smoother transition to the world of greater utility competition. An incentive structure providing utilities with a greater financial stake in the outcome of their activities, together with a wholesale market price standard, establishes the right incentives for the interim period. Equally important, it establishes the same incentives that will be relevant in a truly competitive market and will facilitate utility orientation toward that coming market.

## 3. The significance of moving to market based rates.

While it is true that the use of wholesale market price is an appropriate underlying principle for organizing the market and would provide incentives for efficiency, at the same time it must be recognized that such a change would have an extraordinary impact on the way a utility does business. The value of the generating assets on a utility's balance sheet depend on the

existence of the complex set of regulatory rules in place now which provide for future recovery of the costs related to those assets. If the regulatory rules are changed - - as, for example, by the adoption of the principle that generation costs will be recovered through market prices - - the entire basis of accounting for utility generating assets would also change. The rules of accounting applicable to regulated entities would no longer apply. The value of such assets could decrease substantially, and their value could fluctuate with changes in market prices. As explained in a later section of this paper, under current market conditions this drop in value could be exceptionally large. Unless provisions to compensate for this value change were made, the effect on the industry could be catastrophic.

Thus, our statement that generation prices should be based on market prices should is not intended to mean that such a step should be lightly taken, will be easy to implement, or even that the consequences of such a step are fully understood today. However, while we do not have all the answers now, we do believe that it is appropriate for the Department to proceed in that direction, in order to better understand and accommodate the transition to a competitive future.

### **Principle 3: Incentives Should Be Introduced in the T & D Sectors.**

While Boston Edison believes that the first priority in the effort to investigate alternative regulatory structures should be placed on the generation and power supply sector, the Company also believes that customers can be better served if an incentive structure for transmission and distribution costs is initiated. Although no analogous standard to the market price mechanism exists or is likely to be developed, largely because it is not feasible to develop multiple sets of competing essential T & D facilities, that



need not deter the development of an alternative structure with performance standards for transmission and distribution.

The objective of appropriate transmission and distribution standards is to reward and penalize performance as much as possible in the way that a competitive market would do. To that end, broader based incentives such as price caps or indices, combined with reliability and customer service targets and rate-of-return bandwidths, are the most appropriate mechanisms. Broad measures are preferable to narrow incentive targets, such as heat rate, availability, employee levels and so forth, for three reasons. First, they are more feasible from an administrative point of view than more narrowly targeted incentives because they require less regulatory review. Second, they allow the utility the flexibility to implement creative performance improvements in a way that a narrow target may not have anticipated. Third, narrow incentives tend to create perverse counter-effects, as when efforts to meet one incentive goal sometimes increase the cost in some other sector.

Indeed, we believe that incentive regulation of this kind is already here. Boston Edison, for example, has for the last five years been operating under rate settlement agreements which provide exactly these kinds of mechanisms. Under these agreements, rates can increase during three year periods only according to a defined formula, and earnings are subject to a rate of return cap. At the same time, we are subject to performance incentives under which the Company is penalized or rewarded according to its achievement of defined safety and performance targets. Hence, we believe it is very feasible to provide such incentive regulation in transmission and distribution sector.

**Principle 4: Violation of Prior Regulatory Commitments in the Guise of Advancing "Competition" Would be Unfair and Would Threaten the Financial Integrity of Utilities.**

As discussed previously, the current wholesale market price is far lower than embedded cost, due to the excess capacity available throughout the region. Hence, it is clear that simply tying the recovery of generation and power supply costs to the wholesale market price, with no other adjustments, would result in a very substantial decrease in utility revenues. It has been estimated that an immediate move to market price, if done across the country, would result in total utility losses of between 200 and 300 billion dollars. Many utilities would be placed immediately in bankruptcy. Obviously, one cannot impose a structural change of this magnitude without compensating adjustments and preserve the financial integrity of utilities.

Under these circumstances, it is appropriate to provide for the continued recovery of prudently incurred generation investment and power supply purchases, even if the cost of those investments and purchases exceeds the current market value. Both efficiency and equity considerations support this position.

As to efficiency considerations, reducing generation prices to market levels and imposing the unrecovered costs resulting from this change on investors does not represent a real cost savings, and causes no real productive efficiency gain, but is rather simply a wealth transfer. Thus, there is no productive efficiency argument for denying recovery of these costs. That is, "competition" neither requires nor would be advanced by the imposition of these costs on shareholders. In fact, the reverse is likely true. Imposing these costs on investors could result in significant utility financial distress, with

associated costs to customers, as well as a much higher cost of capital for future utility investments.

From an equity perspective, continued recovery of current embedded costs is justified. Historically, utilities have had no choice over whether to invest in facilities needed to serve customer load. The obligation to serve translated to the obligation to make investments, which generally were large and long term. Indeed, in some situations, such as purchases from non-utility generators, the obligation to commit was literally a direct order by a state regulatory agency. Having been required to make such long term investments whether or not the utility thought such investments would make sense on a "market" basis, it would now be utterly unfair to deny recovery of the cost of such investments.

This is particularly true in light of the fact that in the past, utilities could not raise rates when marginal costs exceeded embedded costs, even though in a market setting such increases would have been justified. To impose a market limitation of recovery now would be inequitable. The bottom line is that it is unfair to induce action on one set of rules and, after the action has been obtained, to change the rules. An attempt to do so would also face well founded legal and constitutional challenges.

Thus, a well crafted incentive proposal should link generation cost recovery to the wholesale market price, but also include specific mechanisms to provide for recovery of all previously, prudently incurred generation costs and other regulatory assets.

#### **Principle 5: Incorporate Environmental Quality in Market Prices**

The Company has always supported the current regulatory policy goal of improving environmental quality. Indeed, in the future the Company

believes that environmental improvements will be enhanced by using market forces to provide incentives for environmental improvement. There should be a market recognition of "clean" kilowatt-hours and "dirty" kilowatt-hours. We do not believe that a preference for the construction and operation of low price but environmentally harmful generation is an acceptable outcome of a market based system.

We do not endorse a specific mechanism here for achieving this result. Indeed, it is likely beyond the scope of the Department's responsibility or authority to develop such a structure, and in any event it would certainly require the involvement of all participants in the current NEPOOL restructuring discussion, at a minimum. However, our general view is as follows. In order to provide a real incentive for utilities to reduce or improve environmental emissions, any market mechanism must have an actual effect on utility revenues and costs. Because "dirty" fuels tend to be less costly than "clean" fuels, dispatching only on fuel costs with no recognition of environmental effects will likely not result in the best impact on the environment. We would in effect be rewarding the producers of "dirty" kilowatt-hours because they would be dispatched first.

Any incentive mechanisms that are based upon historical emission levels likewise reward the producers of "dirty" kilowatt-hours, as the "cleaner" a generating source already is, the more difficult and expensive it is likely to be to reduce emissions. Asking everyone to cut historic emissions by X% is another reward for the producer of "dirty" kilowatt-hours.

One way to create an effective market mechanism is to establish an absolute standard for emissions per kilowatt-hour or per million BTU, and create a system of allowances whereby "clean" producers may sell their unused allowances at negotiated prices to producers who do not meet the

standards. The alternative to buying allowances is to invest in capital equipment and switch to alternate fuels. The existence of these generic options will cause the market price of reducing emissions to be effectively determined. Such a system can only produce real benefits if the standards are based upon reasonable but absolute targets. Alternatively, the value of emissions could be established administratively.

By whatever means it is established, the "cost" of environmental impacts could be included in the dispatch price. Including the environment "cost" per kilowatt-hour the dispatch price of generating sources will shift somewhat the output levels of individual units from "dirty" units to "clean" units. It will also raise somewhat the wholesale market price. Under a cost based system of rates, such adders could increase total costs with some environmental improvement. But because fuel costs are frequently recovered via the fuel charge or some other cost based rate, a utility's profitability is largely unaffected. Under the market based proposal we have described, in which cost recovery for future generation is linked to a wholesale market price, such an environmental dispatch approach can work. The more a unit is dispatched, the more revenue a utility will receive. Thus, "clean" sources will have smaller adders than "dirty" sources, causing units to lesser environmental impact to be dispatched more. The combination of higher output levels and higher wholesale market prices will provide a tremendous incentive for utilities to reduce their emissions using market forces.

Without suggesting a specific approach, we nonetheless feel it is appropriate for the Department to acknowledge and endorse the need for incorporation of environmental values in the wholesale market price.

## II. A Conceptual Outline of a Proposed Incentive Structure

The development of a new regulatory model will not be easy. It will take time, and myriad features both large and small will need to be worked out. However, the Company offers for the Department's consideration a conceptual plan for moving forward. It features a comprehensive set of incentives for all aspects of utility operations, as well as an interim proposal which might be put in place in the period prior to the development of a final new structure.

In broad outline, the concept is as follows. Existing utility franchises would be preserved and there would be no immediate change in the level of current cost-based rates. However, rates would be separated into generation and T & D components. Most significantly, generation rates would be based not on cost of service, but rather on the wholesale market price of power. Non-generation rates would be cost based and be subject to price cap type incentive regulation. Above market generation assets would be written down in value, while the T & D portion of the business would be written up to replacement value. Environmental values would be explicitly recognized in the market price of generation.

As to the transition proposal, a key feature is to put in place wholesale market based cost recovery for any new power supply commitments, without waiting for full development of the above described market mechanisms for all generation costs, and thus eliminate in large part the current IRM process.

As noted earlier, the changes implicit in such a system would be extraordinarily large. While efficiency incentives would increase, the entire historical financial underpinning of the industry would be affected. We do not underestimate the number of issues that would need to be addressed to implement this sort of approach. However, change is coming, and all visions

of the industry's future involve significant risks and unknowns. Therefore, we believe it is appropriate now to begin to discuss the kind of incentive structure discussion outlined in this paper.

The following section of our comments begins with a description of the Company's thoughts on a possible comprehensive proposal for a new regulatory structure. Next follows a discussion of the proposed plan's compatibility with the objectives of the current regulatory process. Finally we discuss a proposed interim proposal.

#### **A Proposed Direction for Incentive Regulation**

The concept for an alternative regulatory structure consists of six key features, each of which is described briefly in the paragraphs immediately following.

1. Rates are separated into generation and T & D components.

At present, electric utilities in the Commonwealth generally collect revenues through two mechanisms: base rates and a fuel and purchased power adjustment clause. Generation and power supply costs are spread through both types of rates. Under our proposal, rates would be separated into a generation component, which would cover all aspects of power supply costs (purchased power, fuel, other O & M and capital costs related to generating plants), and a T & D component, which would cover all non-power supply costs. The fuel adjustment clause would no longer be used.

2. Generation Rates are Market-Based.

The element of this suggested approach which differs most from today's system is that a utility's revenues to cover its generation and power supply cost would be based on the wholesale market price of energy, both for existing and prospective generation resources. For each kilowatt-hour of energy produced by a utility and sold to retail customers in a given hour, the

utility would receive the market price of energy for that hour, irrespective of how the utility obtained that kilowatt-hour - no matter which generating units the utility ran that hour, or from what sources it might have bought power. The generation component of the rate is charged to customers through a market price adjustment clause that would replace the current fuel adjustment clause. Thus, a consuming customer would pay a two part rate: a cost based, T& D charge defined in the tariff, and a market based energy charge that would vary by the hour and would equal the wholesale market price of energy for that hour. (Whether individual customers would actually see the hourly charges in their bills would be a function of administrative burden and cost; for small customers, the charges could be cumulated and billed monthly.)

The determination of the wholesale market price to be used in this system obviously poses a substantial challenge at this stage of the industry's evolution. We believe that there are several criteria that should be applied in defining the market price on which rates would be based. The market price should be universally established and accepted by all who participate in the market for which it is defined. Its value must be objectively determined and readily available to all buyers and sellers. No one entity or group should be able to manipulate the outcome. It should reflect the true value of electricity over a wide range of conditions.

At present, there is no single source from which such a wholesale market price can be determined. One possible starting point in New England is the NEPOOL lambda, which represents the per kilowatt-hour cost of the last increment of power that is dispatched by the pool. This benchmark meets some of the suggested criteria. It is generally known and can be made available to all buyers and sellers. It is objectively determined by NEPOOL,



and is difficult to manipulate. It varies from moment to moment, and is frequently reported as averaged over a one hour period. Unfortunately, it fails to meet other criteria. For example, it does not include certain items such as the marginal unit start up costs. In addition, while it may serve as a somewhat reasonable proxy for the market price in times of capacity excess, it is less adequate in times of shortage, largely because it does not have a mechanism for measuring marginal cost during periods when generation resources have been exhausted and load curtailment begins. At times of shortage, when load curtailments are put in place, NEPOOL lambda remains at the running cost of the most expensive unit. However, given that the customers who are involuntarily curtailed would pay a higher price if in fact capacity to serve them were available, the real marginal cost at such times is higher - - probably much higher - - than the NEPOOL lambda.

A utility could quantify this value, for example, by securing interruptible contracts with customers specifying the price that the customer would accept to go off line. This portfolio of contracts would in effect become the marginal power supply resource of NEPOOL, and the contractual cost of interrupting the last customer could define the NEPOOL lambda in times of shortage. The result of such a structure would likely be very high marginal costs for the relatively few peak hours, with lower marginal costs at other times.

An alternative structural change to NEPOOL lambda would be to move from a system where power producers submit incremental costs to the pool, to one in which they submitted voluntary bids specifying the price at which they would supply power. This structure, currently in use in the United Kingdom and under discussion in California, would require a more extensive revision to the NEPOOL system.

It is apparent that while NEPOOL lambda has some resemblance to a wholesale market price, and for that reason may be useful as a starting point, it would need to be substantially revised in order to be used as the basis for the conceptual incentive proposal we have described.

However, passing for the moment the difficulties of coming up with a usable lambda, it is worth noting that the use of this type of market based cost recovery mechanism for generation would give strong efficiency incentives to utilities. As noted above, a utility's power supply revenues would be defined entirely by the market. Plainly, the utility would be motivated at all times to obtain power at the lowest possible cost, regardless of its source, because that would be the means of maximizing profits. In addition, this mechanism would shift the risk of prospective uneconomic decisions from customers to generation owners, and would position customers to benefit both from improved decision-making and improved performance.

### 3. Non-generation Rates Feature Price Caps and Targeted Incentives.

Incentive regulation of generation costs using the wholesale market price as a standard is not by itself comprehensive. For the non-generation portion of the tariff, the Company suggests a broad based approach using multi-year price caps, coupled with provisions to ensure that current service quality is maintained. Return on equity caps and floors should also be included in such an approach: caps to ensure that customers interests are protected, and floors to ensure that financial integrity of the utility is maintained.

### 4. Assets are Revalued.

As discussed earlier, any move to market-based generation cost recovery would trigger a massive write down of generation asset value -- and, absent any other arrangements, or safeguards, would not allow the Company

to maintain its financial integrity. To provide assurances of continued recovery of above-market sunk costs, we believe that a write-down of generation assets to market value should be accompanied by a write-up of transmission and distribution investment to replacement value. (Plainly, an implementation issue here would be the determination of replacement value of these assets, to make sure it would cover the generation asset write down.) This would be structured to have minimal effect on current rate levels but the asset reclassification would provide assurance of continued cost recovery.

5. Reflection of Environmental Quality

The final element of our proposal involves revision of the current Department procedures with respect to environmental improvement. The existing rules concerning monetized externalities and resource evaluation (including demand-side resources) do not produce cost effective environmental improvement and are not consistent with the market-based generation incentives earlier described. The Company has proposed a possible market mechanism to provide incentives to improve the environment and reduce emissions. The suggested environmental dispatch approach is consistent with a market based recovery for generation costs, and we suggest that a system of unit specific dispatch adders be piloted with SO<sub>2</sub> or NO<sub>x</sub> emissions.

6. Rates continue initially at current levels, and utility franchises remain.

Notwithstanding the significant changes described above such as the severance of the link to cost of service in the generation sector, it is worth noting that overall rate levels (at least at the outset) would not change. Indeed, the write up of T & D and write down of generation would be intentionally designed so that they offset each other and did not create a

change in overall rate level. However, savings to customers would accrue over time as efficiency benefits were realized.

In addition, utility franchises would continue in place, and retail customers would not be able to choose among alternate generation suppliers. However, the need or desirability of choosing an alternate supplier would obviously be largely eliminated, since customers would be paying only the market price for energy in any event, and it was only to achieve that end that anyone proposed customer choice to begin with.

\* \* \*

The proposed direction outlined above accords with all five of the principles outlined and supported earlier in the comments. It also would have substantial advantages. First, it is structured to achieve real efficiency benefits while maintaining the financial integrity of the utility. The proposal would provide efficiency benefits in the areas of generation and power supply, transmission and distribution, and environmental improvements. Second, this approach would position both utilities and the Department very well for the future. It facilitates the transition in the generation sector by assuring that no new stranded costs are possible once the plan is implemented. Further, it facilitates a transition to competitive generation markets, giving customers the benefit of market based generation but avoiding the regulatory and financial chaos that could be caused by opportunistic customers regularly changing suppliers. The plan also facilitates further unbundling in the future, should that be an appropriate thing to do.

An additional advantage of the proposal is its equity. The rates to all customers - not just those customers above a certain size - will reflect the market price of generation, and thus all customers share in the benefits of

plan. The plan also honors the regulatory compact by making possible the continued recovery of prudently incurred costs.

We acknowledge that there are many uncertainties in moving to a market based system, that the design of the plan is not yet fully sketched out, that some elements will be difficult to finalize and some will require joint action by NEPOOL participants. However, we think it is a promising area for consideration because it does have favorable features. For example, the changes called for by the proposal, significant as they are, are not as great as those involved in alternate market structures such as retail wheeling. There would be no change in jurisdictional regulatory control. The plan could be implemented largely by the Department alone without FERC involvement, since it is in essence simply a change in the state-controlled rate structure. (To the extent the transmission assets were written up as part of this proposal, it is true that FERC would be involved; however, it may also be possible for the Department to focus only on the distribution assets for the write up, and let transmission pricing proceed on the path it will otherwise take.) Similarly, there would be no need -- at least at the outset -- to change the retail franchise or obligation to serve of the utility. Finally, the plan would not require the sale or disposition of assets, and therefore would not trigger any of the issues that would accompany such sale or disposition. These advantages, taken together with the benefits they bring, argue strongly for the Department and interested parties to more fully explore the issues associated with moving toward this kind of incentive regulation structure.

#### **Compatibility of the Proposal With Other Regulatory Objectives**

Market pricing of generation plainly raises many questions. While we do not purport to deal with all of them in these comments, several significant issues are addressed below.

A key question relates to the obligation to serve. To what extent must a utility provide generation service, if the utility receives no regulatory guarantee of cost recovery but is limited to revenues based on market price? It is clear that the proposed direction we have outlined does move away from the Integrated Resource Management (IRM) process in favor of the competitive wholesale power market. However, we do not believe this would result in any degradation of reliability, nor in any elimination of a utility's obligation to serve. In addition, utilities would likely make greater use of customer-owned generation, real time pricing, and economic curtailment contracts to ensure adequate resources to deal with situations of tight supply. The obligation to serve effectively would become an obligation to deliver energy available in the wholesale market, and the utility would maintain its obligations to deliver to all customers who are willing to pay the market price.

A second concern relates to the fate of fuel diversity and price stability under a mechanism such as we describe herein. The commodity nature of the wholesale power market, and the proposal to link generation cost recovery to the wholesale market price would seem to eliminate all incentives or opportunity for a utility to provide fuel diversity or price stability -- both sometimes perceived as important regulatory objectives.

In our view, the goal of price stability need not be abandoned under a market price standard -- or ultimately in a competitive marketplace. It is certainly true that a utility today is an agent of its customers in providing and maintaining stable prices. When the generation and power supply sector becomes workably competitive, however, a "one size fits all" administratively determined product/service offering -- such as stable prices -- will not be necessary. Instead, customers preferring stability will be able to achieve it

through contract mechanisms. Other customers may not particularly care about fluctuations in the market price, or at least not care enough to pay for the privilege of price stability. Once a portion of customer's bills are linked to the spot price, utilities and other suppliers can offer tailored risk management services backed up by either physical assets such as renewables or financial assets such as gas, oil, or electricity futures. Customers will have an increased array of such services available to them at competitive, rather than regulated prices.

The experience in the natural gas industry following FERC Order 636 is illustrative of what may very well occur in the electric industry. There, a multitude of new product and service offerings, tailored to fit the needs and desires of customers, have developed. Indeed, even in the electric industry a number of brokers and financial houses have entered the field, and while their service offerings to date have been rather simplistic, that almost certainly will change. It is no leap of faith to envision a customer desiring price stability -- including, of course, the price stability resulting from fuel diversity -- being able to contract for such, while another customer less concerned over price fluctuations will not pay for a stabilizing contract.

A third issue relates to the extent to which the proposal herein would resolve issues related to NUG and utility purchased power contract obligations in excess of market price, which represent a significant portion of the stranded cost problem. We do not anticipate that the T & D markup we have described will provide for such NUG obligations to be discharged. This is an extremely important issue to be resolved. Above market power contracts are frequently the most significant single source of stranded costs a utility has. It may be that a combination of measures is appropriate here, such as renegotiation of NUG contracts, as well as imposition of a separate

accounting mechanism -- either an access charge or a stranded investment recovery charge -- to protect utilities from suffering revenue losses as a result of NUG contracts in a market environment.

#### **A Proposal for Interim Action**

If the Department proceeds with the exploration of the direction suggested by the Company in these comments, it is clear that resolving the relevant issue and moving to implementation of a revised incentive regulation structure would take a substantial amount of time. The question arises as to what form of incentive regulation, if any, should be put in place in the interim period. We have two suggestions.

First, we believe the Department should pursue incentives in the form of "traditional" price caps - - that is, a baseline rate that is adjusted annually for expected inflation, offset by productivity improvements, accompanied by performance targets aimed at customer service and reliability levels. We believe the feasibility of this approach is demonstrated by the fact that, as the Department is well aware, we are already operating under an incentive rate plan -- a cap on base rates through 1995, accompanied by performance incentives and penalties -- and have been doing so since 1989. The Company believes that customers have benefited from the current price cap through the increased incentive for cost control and efficiency improvement, and that this form of incentive is appropriate during the transition to competition and should be continued.

Second, while the general application of the incentive structure described herein to all elements of generation obviously would take substantial time and effort to achieve, we believe the Department should



consider breaking out one element for expedited treatment during the transition - - new resource commitments.

Because continued reliance on the IRM process could result in new stranded costs, and because in the future generation cost recovery will be determined by the wholesale market price, we believe it is not appropriate to make any new commitments under administrative, rather than market, decision rules. Therefore, as an interim measure, BECo suggests that the IRM process be set aside, that new resource commitments be made at a utility's sole discretion, but that cost recovery for any such commitments would be limited to the spot wholesale market price. This transition plan would allow time for the other elements of the comprehensive proposal to be developed, but avoid additional customer exposure to above market commitments during the interim.

Adopting wholesale market pricing even on this limited interim basis would nonetheless necessitate the quantification of an acceptable spot wholesale market price. Unfortunately, the availability of a fully acceptable spot price must await some of the NEPOOL reforms described earlier. As described earlier, the current estimate -- NEPOOL lambda -- is biased low during some periods due to the omission of startup costs and the like. These problems can be remedied, but will take time. During the transition, until better data is available, BECo suggests that it would be possible to use the NEPOOL system lambda, adjusted to compensate for its downward bias. While not a perfect solution, this would allow many of the benefits of the comprehensive proposal, and would help provide a smooth transition to a competitive future.

## Potential Department Initiatives

We do not believe the present docket necessarily provides an adequate vehicle to resolve all of the issues that would be involved in moving toward a market based system. These issues will have to be researched and analyzed in much more detail before a final decision on the direction is possible, a consensus of participants would have to be reached, and certain statutory changes would be required. However, we believe the Department can take actions in this docket to advance the process. The Department can make policy determinations at the conclusion of this docket which would form the basis of further action and agreement by utilities and others. These declarations, in our view, could include the following:

1. Endorsement of the concept of the proposed incentive system; namely, the movement to wholesale market price-based generation cost recovery for all generation, the revaluation of utility assets, and the preservation of utility franchises.
2. Support for efforts to reform NEPOOL and establish a publicly visible spot market price.
3. The adoption of broad based price cap regulation, augmented by ROE caps and floors, over the non-generation portion of a utility's costs.
4. Endorsing the inclusion of environmental costs in wholesale market price determinations.
5. Endorsing the expedited application of market pricing to new resource commitments as a transition mechanism.

### III. Responses to the Questions Posed by the Department

The Department requested in its September 20, 1994 Notice of Inquiry that participants address certain specific questions concerning incentive ratemaking structures. The Department's questions, along with Boston Edison's responses, are as follows:

**Question 1:** What authority does the Department have to facilitate the development and implementation of incentive-based programs? What changes to Department precedent and/or statutory changes, if any, would be required to facilitate the implementation of particular incentive-based programs?

**Response:** A detailed answer to this question would be lengthy and would depend on the specific provisions of the incentive plan at issue. In broad terms, however, the Department's authority is defined by the legislative enactments applicable to it. The primary source of the Department's authority over rate matters is G.L. chapter 164, section 94. That section gives the Department the authority to approve the rates of gas and electric utilities, but contains no specific standards that the Department must adhere to. We do not believe that section 94 mandates that the Department use any particular form of rate regulation. See American Hoechst Corporation v. Department of Public Utilities, 379 Mass. 408 (1980).

We believe that in establishing rates the Department is subject to essentially two requirements. First, the rate methodology must produce rates that are "just and reasonable". Second, the rate methodology must exhibit "reasoned consistency". Boston Gas Co. v. Department of Public Utilities, 324 N.E.2d 372 (1975). Taken together, we believe that these requirements allow

the Department to put in place an incentive rate making structure, provided that it is reasonable in its effect, that it allows utilities the opportunity to earn a fair return, and, with respect to costs previously incurred, that it is broadly consistent with past Department decisions and does not abrogate the "regulatory bargain" governing recovery of such costs.

Some statutes, however, do proscribe the Department's authority quite specifically. In particular, G.L. chapter 164 section 94G, the fuel clause statute, limits the Department's authority to vary the means of collection of fuel costs. The implementation of some incentive schemes - - including the one described in our comments - - would require amendment of that statute.

Whether Department regulations would need to be changed again depends on the terms of the incentive proposal. The market proposal we describe would require amendment of the Department's IRM regulations. In addition, while our proposal would perhaps not absolutely require amendment of G.L. chapter 164 section 69 et seq., the Siting Board statute, it would plainly be appropriate to do so.

**Question 2:** Would the implementation of an incentive approach give rise to any jurisdictional issues between state and federal regulators? If so, what are they and how should they be resolved?

**Response:** The extent of any state-federal conflict would depend on the terms of the proposal. For example, in the case of our market based suggestion, there could be some need for FERC concurrence, if a write up of transmission assets were to be undertaken; this concurrence might not be required if the write up were limited to distribution assets. FERC concurrence would also be needed for changes in the NEPOOL structure.

Question 3: Are there special cost recovery issues that may need to be addressed in any incentive regulatory scheme that might be adopted, as a result of increasing competition? How should they be addressed?

Response: Yes. As discussed at some length in our comments, a well-crafted incentive regulation proposal for generation that is wholesale market based does require a special provision for the recovery of prudently incurred but above market generating costs. However, the recovery mechanism chosen should not undercut the principle of pricing generation at marginal cost. This is important because it insures that utilities have incentives to manage generation just like an unregulated competitor, and it insures that customers who have alternative energy choices (such as self generation) make their choice as much as possible on the basis of actual costs incurred or saved as a result of their choice. Our proposal of pricing generation at the margin while writing up T & D assets to prevent stranding of prior costs accomplishes this goal.

Question 4: What mechanisms should be adopted to ensure that customers share equitably in any overall benefits provided by an incentive-based regulatory approach?

Response: The equitable participation of customers in the benefits from an incentive proposal is a design issue of primary importance. The structure we have described in our comments accomplishes this in a number of ways. First, customers are shielded entirely from the costs of any uneconomic generation decisions, since they pay only the market price, not a utility cost.

In addition, to the extent that more vigorous wholesale competition is successful in holding down the wholesale market price, those benefits also will accrue to customers. Finally, to the extent that generating cost efficiencies or high market prices would combine to produce large profits, an aggregate ROE cap can be instituted to insure that savings above a certain level will accrue to the benefit of customers, perhaps through accelerated amortization of what would otherwise be stranded investment costs.

On the T & D side, to the extent that price caps result in greater efficiencies and lower costs, once the price cap is reset those benefits accrue 100% to customers on an ongoing basis. It is also possible to allow customers to receive benefits from a price cap regime on an ongoing basis by imputing a productivity improvement factor into the calculation of the price cap level to begin with. Finally, as with generation, to the extent that efficiency benefits are much greater than forecast, an aggregate ROE cap can serve to insure that customers will benefit under these circumstances.

**Question 5:** If incentive regulation is considered, discuss the extent to which it should be considered for overall utility operations or applied only to specific functions, such as fuel/energy procurement. What trade-offs need to be addressed when comparing the effectiveness and administrative simplicity of broad-based incentive programs? To what extent should narrowly targeted incentives be included in any new approach to ratemaking?

**Response:** As the preceding principles and our proposal make clear, we believe that broad-based incentive programs are preferred to those applied only to specific functions. In the case of generation, it is difficult to design a set of narrow, function-specific incentives that produce optimal results

because the scenarios and facts to which they must apply in real life are so varied. Narrowly defined incentives incent a specific set of actions, but such actions may not be desirable in all circumstances. For example, achievement of a specified generating unit heat rate is often used as a specific incentive target. Yet, in the case of a unit which runs infrequently, or which is near the end of its life, it may not be cost effective to make the investments necessary to achieve the target. For these reasons, an incentive program should rely on broad targets (which could be administratively determined, in the case of price caps, or market determined, as in the case of the proposal we have described), rather than narrowly defined targets.

If the Department adopts a price cap structure, it is also important to allow utilities to have pricing flexibility within the cap in order to deal with customers that have alternative energy options. Plainly, even in the absence of measures such as retail wheeling, some customers can choose alternate energy sources, such as cogeneration or a competing fuel. Where such alternatives are real and customer loss is imminent, it is clearly cost effective and in the interests of all other customers of the utility for the utility to negotiate alternate pricing arrangements with the customer at risk.

With respect to the T & D functions, the principal trade-off to be taken into account is between price and non-price attributes of service. Here a broad-based price incentive is appropriate, but the incorporation of non-price elements -- particularly service quality -- is also a necessary ingredient.

**Question 6:** Should the Department first focus its efforts on certain types of incentives? For example, would there be cause to first address opportunities to create targeted incentives in the areas of fuel procurement and purchased

power? Is there a logical sequence for implementing targeted incentives, or should a broad-based incentive program be implemented in a single step?

Response: Our answer to this question is very much influenced by our recent settlement agreements, which effectively extend price cap regulation over all non-fuel clause aspects of our business. With this as a starting point, we do not see that there is any necessary logical sequence which determines the types of cost or areas of utility operation which can be subject to incentives. With respect to incentives targeted at either fuel procurement or purchased power in particular, we believe that such targets would have to be designed very carefully to avoid the creation of uneconomic incentives.

Question 7: How could incentive schemes for compliance with market-based environmental regulations (e. g., with the acid rain provisions of Title IV of the Clean Air Act Amendments of 1990) be linked to broad-based incentives?

Response: The Department's concern that any incentive proposal deal appropriately with market-based environmental compliance activities is well placed. For all those compliance activities which fall in the generation side of the business, linking generation cost recovery to the wholesale market price does incorporate the proper incentive for environmental compliance. SO<sub>2</sub> provides a ready example. The wholesale market price at any time will reflect not just the fuel and variable O & M of the marginal power plant but also the opportunity cost of SO<sub>2</sub> emission from the marginal power plant. Thus the SO<sub>2</sub> cost will have been internalized in the wholesale market price for power. A generator, faced with this market price, must decide how to most profitably operate this facility, including what level of environmental controls for SO<sub>2</sub>.



to undertake. In maximizing the profits from generation, the owner of the generator will consider whether further control of the facility is economic, or whether purchased allowances would make more sense. Thus the wholesale price-based generation recovery sends precisely the right incentive for SO<sub>2</sub> control, provided that the wholesale market price itself includes the internalized SO<sub>2</sub> cost.

**Question 8:** What approaches would provide utilities with better financial incentives to control the cost of service to customers in monopoly and near-monopoly market segments than the incentives implicit in the current regulatory framework? How might a new approach provide better incentives?

**Response:** Boston Edison believes that its current price cap settlement provides the best template for incentive regulation of monopoly and near-monopoly market segments. In particular, we believe that the relative simplicity of the structure used in our agreements is desirable. Essentially, only three elements are necessary in such a scheme: a formula defining rate levels for a period of years (perhaps three years), a formula establishing penalties and rewards for achieving defined customer service levels, and a formula providing penalties and rewards for achieving T & D reliability targets. There is a tendency, when designing such systems, to incorporate more and more details with respect to additional targets. We believe such a tendency cuts against the benefits of using broad targets and should not be encouraged.

Question 9: For each of the approaches cited in response to Question (8) above, would such an approach achieve regulatory objectives more efficiently than existing regulations? For example, would the incentive scheme provide increased benefits to consumers by:

- a. increasing utilities' operating efficiency;
- b. lowering or stabilizing the costs of providing service;
- c. reducing regulatory burdens;
- d. ensuring and providing improved and innovative services;
- e. maintaining or enhancing utilities' financial integrity?

Response: The T & D price cap proposed by BECo would achieve regulatory objectives more efficiently than traditional cost of service regulation. The ability to "keep" operating savings for some period of time would give a significant incentive to utilities to improve operating efficiency, from which customers would benefit in subsequent periods. This increased incentive for cost control should also translate into a lower cost to serve than would otherwise have been the case. While this may not ultimately translate into a reduction from current levels, it will moderate the rate of cost growth.

With a multi-year price cap, the regulatory burden of rate cases will be reduced. Service quality will be maintained and enhanced through the inclusion of appropriate non-price performance measures such as billing accuracy, response to trouble calls, outage frequency/duration and the like. Innovative services are more likely to come in the generation area, particularly new forms of risk management service and real time pricing, as discussed earlier. Financial integrity under the market based proposal we have described will be maintained principally through the stranded

investment recovery provisions, but price cap regulation and the ROE floor certainly contribute on this dimension as well.

**Question 10:** For each of the approaches cited in response to Question (8) above or for broad-based incentive regulation generally, describe how different groups of customers (i.e., residential, small commercial and industrial, large industrial, core, non-core, etc.) would be affected under incentives. Can a plan be developed so that all groups benefit? If so, how can this be done? Is it possible that some groups will benefit sooner than others, or to a different extent?

**Response:** Under a market based structure such as we have described, all groups of customers benefit. On the generation side, the prospective elimination of above market cost exposure is an across the board benefit. Similarly, the increased array of risk management alternatives will benefit all customers. On the T & D side, the operating efficiencies that result from price cap regulation will reduce cost of service generally to the benefit of all customers. In short, any well crafted proposal designed to produce productive efficiency gains will benefit all customers.

There is, of course, the possibility that the size of the benefits may vary from one group of customers to another. It is unlikely that a new incentive plan, left to operate on its own, would produce exactly the same revenue distribution as the current system. However, the Department has broad discretion to deal with rate structure issues. Continuity of rate levels (that is, avoidance of sharp changes in rates due to regulatory actions) is a principle that has long been recognized as appropriate. Hence, to the extent that a new structure dictated changed rate responsibility among customer classes, the

Department ought to have sufficient flexibility to attempt to ameliorate such changes.

**Question 11:** For each of the approaches cited in response to Question (8) above or for broad-based incentives generally, please discuss how each approach would accommodate current regulatory goals, such as:

- a. providing (i) safe, (ii) reliable, (iii) least-cost service;
- b. maintaining or improving the quality of service;
- c. supporting efficient plant operation;
- d. procuring low cost fuel/energy supplies;
- e. encouraging appropriate supply planning;
- f. supporting Demand-Side Management ("DSM");
- g. preserving low-income rates;
- h. optimizing energy use.

**Response:** Our comments address most of the issues referenced in this question, as they apply to a market based incentive system. As to DSM, customer sponsored demand side management activities could be enhanced under a market proposal, particularly if the Department were to include real-time pricing for some or all retail customers. (We note that real time pricing is on the horizon now, but is not at a stage where widespread implementation is feasible.) In that event customers would have correct and timely price signals with which to make adjustments in the time pattern or amount of their electricity usage. Insofar as utility sponsored DSM programs are concerned, the market structure described by the Company is fully compatible with the continuation of current programs. Cost recovery would

be through the distribution portion of the rate, however, not the generation portion. Existing low income rate subsidies could be treated similarly.

**Question 12.** Please discuss the extent to which the adoption of each approach cited in response to Question (8) above might require changes:

- a. to utility terms and conditions of service;
- b. in standards for quality of service;
- c. in Department rate design procedures;
- d. in Department cost-recovery procedures;
- e. in Department regulations and procedures;
- f. in (i) Federal and (ii) Massachusetts statutes.

**Response:** These issues have been addressed in earlier responses, and in our comments.

**Question 13:** How would factors outside the control of a utility's management be internalized and/or anticipated in any incentive approach? Identify any such exogenous factors affecting a utility's financial status that will likely have to be accommodated.

**Response:** The impact of factors beyond the control of utility management, particularly the impact on the financial status of the utility, would be addressed through ROE floors and ceilings that accompany the price cap. Dramatic changes in laws, regulation or price levels could well have serious financial consequences. An ROE floor provision would provide insurance against diminished financial integrity while an ROE ceiling would prevent shareholders realizing windfall gains at the expense of customers.

Question 14: Describe how incentives would affect a utility's access to capital markets.

Response: The market based incentive structure described in our comments should allow a utility to maintain financial integrity, provided that it contains adequate provisions to insure cost recovery of past prudent investments, such as the T & D asset write up that is discussed. Under that condition, a utility's access to capital markets should not be impaired or diminished. Alternate proposals which do not include the opportunity for stranded cost recovery could significantly jeopardize a utility's access to capital markets. This fact has been highlighted in recent reports by rating agencies and brokerage firm analysts that have discussed electric competition.

Question 15: Describe how incentives would interact with the accounting community's application of generally accepted accounting principals.

Response: The relevant accounting pronouncements are Statements of Financial Accounting Standards (SFAS) nos. 71 and 101. SFAS 71, Accounting for the Effects of Certain Types of Regulation, states specific criteria that a regulated company must meet in order for the statement to apply. Statement No. 71 allows certain costs to be deferred based on the regulatory promise of future recovery in rates. If future recovery is not certain, write downs may be required. A key requirement is that regulated rates must be designed to recover a company's specific costs of providing the regulated services or products. SFAS 101, Accounting for Discontinuation of Application of SFAS 71, states that one basis for not being able to use regulated accounting could be

a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation. Some changes would require write-offs of regulatory assets and non-recoverable plant investments which could seriously impair the financial integrity of most electric utilities. Incentive structures, including the one we have described, would have to be examined further with independent accountants and those responsible for accounting standards, including the FASB and SEC, in order to assure that they are structured to avoid any major write-offs.

**Question 16:** Would the use of broad-based incentive regulation present any obstacles to or opportunities for the possible need to unbundle services? How could any such obstacles be overcome?

**Response:** A market based structure, with separate but complementary incentive provisions for the generation and non-generation portions of the business, does not present any obstacles to subsequent unbundling of services. Indeed, the fact that generation would be effectively marked to the wholesale market should facilitate such an unbundling should it later be found to be desirable. Other incentive approaches which do not incorporate the generation/non-generation split will not lend themselves with any ease to subsequent unbundling.

**Question 17:** What standard of review should the Department adopt as a basis for evaluating an incentive proposal?

Response: We believe the Department should endorse and apply the five principles specified in our comments, and should judge proposals on that basis.

Question 18: Under any incentive program, and with an eye toward administrative simplicity, please explain how the utility's overall performance should be measured and reviewed by the Department.

Response: Under our proposal there is no need for the Department to review the utility's performance in generation. With respect to transmission and distribution, the non-price dimensions of the T & D incentive regulation should incorporate the Department's most important non-price concerns. With all this in place and with ROE floors and caps insulating both investors and customers from unanticipated circumstance, there is no need for measurement and review beyond what the incentive proposal requires.

Question 19: Under what circumstances would an established incentive mechanism be revisited or reset?

Response: The period for which a specific program would run without review would depend on the nature of its provisions, but in general we would expect it to be in place for a period of 2 to 4 years. In addition, we anticipate that if either a cap or a floor was reached, that would also precipitate Department review to reset the incentive proposal going forward, or perhaps to rethink some aspects of the approach if it has been found wanting.