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THE COMMONWEALTH OF MASSACHUSETTS

BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

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| RE: WESTERN MASSACHUSETTS ELECTRIC COMPANY PROPOSED INCREASE IN RATES | DOCKET 86-280 |

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF

THE EXECUTIVE OFFICE OF ENERGY RESOURCES

March 9, 1987

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# TESTIMONY OF PAUL CHERNICK

## 1 INTRODUCTION AND QUALIFICATIONS

Q: **Mr. Chernick, would you state your name, occupation and business address?**

A: My name is Paul L. Chernick. I am President of PLC, Inc., 10 Post Office Square, Suite 955, Boston, Massachusetts.

### 1.1 Qualifications

Q: **Mr. Chernick, would you please briefly summarize your professional education and experience?**

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options.

I left the Massachusetts Attorney General to join the professional staff of Analysis and Inference, Inc., in May 1981. In that capacity, I continued to work on a variety of electric utility issues, including rate design, cost allocations, ratemaking, and supply planning. My clients included utilities, public advocates, large customers, and regulators.

In August 1986, I founded PLC, Inc. In my current position, I have continued to advise a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

Q: **Mr. Chernick, have you testified previously in utility proceedings?**

A: Yes. I have testified approximately fifty times on utility issues before various agencies including the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Vermont Public Service Board, the Pennsylvania Public Utilities Commission, the New Mexico Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: **Have you testified previously before this Commission?**

A: Yes. I have filed testimony in approximately 20 proceedings before this Commission.

Q: **Have you testified before this Commission on conservation, rate design, and cost allocations?**

A: Yes. Dockets in which I testified on retail rate design include MDPU 19845, MDPU 200, MDPU 243, and MDPU 558. In addition, I have testified on rate design for QFs in MDPU 535, and in both phases of MDPU 84-276; on cost allocations in MDPU 85-121; on conservation program cost-effectiveness in MDPU 20055, MDPU 558, and MDPU 1627; and on conservation cost recovery in MDPU 472.

Q: **Have you testified before this Commission on issues of electric utility power supply planning and utility cost recovery for power supply investments?**

A: Yes. I testified on power supply planning decisions in MDPU 19494 (both Phase I and Phase II), MDPU 20055, MDPU 20248, MDPU 84-49/50, MDPU 84-145, MDPU 84-152, MDPU 1627 and MDPU 85-270; and on cost recovery in MDPU 84-25 and MDPU 85-270.

Q: **Have you authored any publications on utility ratemaking issues?**

A: Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, <u>Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions</u>. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. Other papers I have published on utility ratemaking and conservation include:

- "Revenue Stability Target Ratemaking",
- "Opening the Utility Market to Conservation: A Competitive Approach",

- "Power Plant Phase-In Methodologies: Alternatives to Rate Shock", and
- "Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with Ann L. Bachman).

These and additional publications are listed in my resume.

## 1.2 The Purpose and Structure of this Testimony

Q: **What is the purpose of your testimony?**

A: My testimony will respond to a number of rate design issues raised by Western Massachusetts Electric (WMECO),[1] the Commission, and other parties in this and other recent cases. Specifically, I will:

1. explain the errors in WMECO's argument that retail rate design should be based on short-run marginal cost (SRMC),

2. discuss appropriate bases for retail electric rate design,

3. explore the relative importance of demand charges and energy charges,

4. describe an appropriate relationship between rate design and economic development concerns, and

5. show how real-time pricing goals can be integrated with long-run marginal cost (LRMC) considerations in rate design.

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1. The positions taken by WMECO are dictated by its parent holding company, Northeast Utilities (NU), so my comments will frequently refer to NU's policies and arguments, rather than WMECO's.

My testimony will not discuss the details of WMECO's rate design, or propose specific alternative rate structures.

Q: **What approach does WMECO advocate for the design of retail electric rates?**

A: WMECO's approach, as laid out in the report by Mr. Ruff of Putnam, Hayes, and Bartlett (PHB), consists of a simplistic adherence to short-run marginal cost (SRMC) as a pricing guide. Mr. Ruff advocates pricing all power at the cost incurred today of producing an additional kWh today,[2] with no consideration of the cost of providing service in the longer term, such as power plant construction and O&M costs, and power purchase contracts. Essentially, Mr. Ruff argues for using only current fuel prices in calculating marginal costs, and hence tail block energy rates.[3]

Since these short-run rates will generally recover only a portion of the cost of providing service, they would promote additional usage of electrical energy. Mr. Ruff proposes that loads be allowed to grow under these promotional rates until a capacity emergency develops,

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2. Mr. Ruff indicates a preference for shifting the time periods to hours or minutes, if possible.

3. It is not clear whether Mr. Ruff would include in these short run costs the demand charges associated with purchases contracted on a monthly, weekly, or even daily basis.

and that rates then be raised as much as necessary to force sales back down to levels which produce tolerable reliability.[4] These higher "market-clearing" prices will generate revenues in excess of marginal fuel costs. In Mr. Ruff's scheme, if all works as intended, the utility will have planned a new plant to come on line (reducing short-run marginal costs and relaxing the capacity constraint), so that the overall cost of the new plant will equal the price at which demand will fully utilize the new level of capacity. If demand is too high, price would be raised until the capacity shortage is reduced to a tolerable level; if demand is "too low", prices would be lowered until capacity was just barely sufficient to meet loads.

Thus, the NU/PHB proposal is equivalent to a perpetual game of chicken between the utility and the customers: give the customers low rates, encourage them to use electricity profligately, jack up the rates when supplies get tight, hope that load growth slows enough to avoid disaster, and hope that new units come on line at about the right time.

Q: **How is your testimony structured?**

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4. His examples show rates doubling in one year and quadrupling in two years to meet this requirement: see page A-12.

A: Section 2 discusses the limitations and simplifications frequently encountered in normative economic models.

Section 3 considers whether the appropriate measure of marginal cost for use in retail electric rate design is a short-run measure or a long-run measure. Specifically, I present a number of reasons for preferring long-run measures to short-run measures, place rate design issues in their appropriate context of utility supply planning and ratemaking, and describe a set of errors in the PHB analysis. Section 3 also considers some issues in the determination for long-run marginal costs.

Section 4 applies the PHB/NU approach to short-run marginal costing, to estimate current short-run marginal costs for electricity in New England.

Section 5 deals with several other rate design issues related to the SRMC/LRMC choice. First, it compares demand charges and energy charges in terms of two standards: their effectiveness in encouraging efficient behavior on the part of ratepayers, and their effects on the industrial economy of the WMECO service territory.

Section 5 then discusses the design of efficient rates to promote economic development and employment. Finally, Section 5 considers methods for incorporating spot pricing of electricity in a regulatory structure which includes embedded-cost revenue requirement constraints, embedded-cost allocations between classes, and long-run marginal cost design within classes.

## 2 General Considerations in Economic Modeling

Q: **Is it realistic to expect economic models to capture all the relevant features of a complex market, such as that for electric power?**

A: Unfortunately, that would not be a realistic expectation. Economists, by the very nature of their profession, find it very difficult to model the world as it actually exists. They attempt to develop mathematical models which predict human behavior, and which prescribe how critical decision-makers (e.g., corporate management, legislators, and regulators) should act to shape that behavior in desired ways.

However, human behavior can not be modeled with any great specificity and accuracy. If people can fairly be said to be governed by rules at all, those rules are far too complex to model. In addition, human behavior is subject to more external influences than can be incorporated in any feasible model.

To further complicate realistic modeling, economists frequently have only very limited familiarity with the markets whose behavior they attempt to model or prescribe. Therefore, it is common for economists to simplify the world they model, and to introduce many restrictive assumptions.

Q: **What is the effect of this tendency to oversimplify?**

A: The effect depends, among other things, on the type of model under consideration. In positive (empirical) studies (e.g., regression analyses to determine price elasticities), the discrepancies caused by the restrictions (among others) can be measured as unexplained variation. The accuracy of predictions based on the model can also be determined, potentially allowing analysts to test the model against the real world. To the extent that the factors causing variation or errors can be identified, quantified, and added to the model specification, the explanatory power of the model can be improved. Positive economists thus have a clear incentive to improve the accuracy of their models.

In normative models (e.g., pricing prescriptions), there is generally no simple test of modeling accuracy. The models are largely (and sometimes entirely) deductive, drawn from first principles and assumptions, rather than inductive attempts to explain observed phenomena. Indeed, the models often involve concepts (such as net social welfare, the marginal utility of money, or marginal costs) which are difficult or impossible to observe.[5] The process of constructing the model

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5. The short-run marginal cost of producing and delivering electric power is relatively simple to measure, and the regulated nature of the business ensures that most of the

provides no direct test of its accuracy: normative equations produce no $R^2$ statistics. It may be difficult to identify situations in which the policies recommended by the model have been applied, and even more difficult to determine how the end results differed due to the policy.

Normative economists are therefore less likely than positive economists to include complications in their models, because they are not forced to confront them, and because it is frequently harder to perform a multivariate optimization than a multivariate regression.

Q: **What kinds of simplifying assumptions are frequently made in normative pricing models?**

A: Normative models for pricing policy frequently make such assumptions as:

1. Consumers have perfect information about future prices and supply curves, or at least the same information as do producers.

2. Consumers' expectations about future prices are not affected by current prices.

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requisite data is available. For most enterprises, such as the corner drug store, SRMC is much harder to define, and whatever data would be relevant is not publicly available.

3. Markets are perfectly competitive, which requires, inter alia, that consumers have no preferences as between producers.

4. Demand for a given product at a given time is independent of most complicating factors, such as prices for (or consumption of) the same product at other times.

5. Producers have perfect information about future demand curves, or at least perfect information up to the effects of a random perturbation term.

6. Producers' information about future demand is not affected by current or past demand.

There are certainly limits to the usefulness of the results of this type of simplified analysis. It is therefore important to determine whether the simplifications are reasonably accurate for the specific application proposed.

Q: **Are simplified economic models ever useful for policy analysis?**

A: Yes, in at least two ways. First, the simple model may be adequate for some situations, in which the simplifications are relatively unimportant. Second, even in applications for which the simplifications matter, the simple model may offer some important suggestions.

These points can be illustrated with the classic academic example of "spherical chickens."[6] The assumption that chickens are spherical may be perfectly reasonable for a supermarket which is estimating how many frozen birds will fit in a truck. For a processor who needs to know how fast carcasses will roll down a ramp on the processing line, the spherical approximation may provide a (possibly useful) upper limit. For a biologist studying the effects of heat loss on the size of birds in different climates, a spherical bird may provide some insights on the relationship between size and cold tolerance, but never enough detail to explain the geographical limits on particular species. But for anyone interested in understanding flight or incubation, a "spherical chicken" model would be virtually useless.

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6. At MIT, "Consider a spherical chicken" is a standard shorthand for a counter-factual assumption necessary to make a complex analysis tractable.

## 3 Marginal Cost: Short Run vs. Long Run

Q: **What issues will you address in your examination of marginal costing for electric utility rate design?**

A: I will start by discussing why it is necessary to choose between SRMC and LRMC, and the tradeoffs inherent in that choice. I will then explain why LRMC are generally the correct measure for the design of retail electric rates. In the third part of this Section, I will discuss some of the realities of the electric utility business, which differentiate it from other markets and necessitate LRMC pricing. I will then describe some of the errors in the NU/PHB analysis.

The fifth part provides a reality check, by examining whether the reliable and economical operation of the NU and New England power supply systems will be better achieved by the rate designs implied by the pricing approaches advocated by NU or by those I have supported. I then discuss situations in which NU's approach <u>is</u> appropriate. The seventh section addresses some issues in the estimation of LRMC.

Q: **Do you have any introductory comments on the distinctions between SRMC and LRMC approaches?**

A: Yes. In the course of explaining why LRMC are to be preferred to SRMC in retail electric rate design, I will frequently criticize the assumptions and analyses of PHB. As noted in the previous Section, errors like those of PHB are common in this field. I certainly engaged in large amounts of oversimplification in writing my thesis, which dealt with the generalization to other goods of the time-of-use pricing concepts which had been developed for electricity. Like most of the authors I quoted in my thesis, I ignored most of the real complications of electric power supply planning.

Since my purposes were to extract general lessons from the literature, and to reconcile apparently contradictory approaches, I had a little better excuse for ignoring the messy details than did most authors on this subject. The basic reason for the oversimplifications in my thesis is much less commendable, I fear: like most of the authorities I cited, I limited my review to the realm of academic theory. I accepted the assumptions and conventions which had been handed down to me by other authors, often without realizing that I had made any assumptions. At the time, I knew very little about the actual practice of utility load forecasting, power supply planning, customer response patterns, conservation decision-making, or cost recovery ratemaking. Therefore, many of the conclusions in my thesis are as correct and as flawed (at least with respect to their applicability to electric utilities) as are those in the economic literature on electric utility pricing and those in the PHB analysis.

### 3.1 Inherent Conflicts Between Short- and Long-Run Objectives

Q: **Is either SRMC or LRMC clearly preferable for all electric rate design purposes?**

A: No. This is a practical decision, rather than some grand issue of principle or theory. If rates have primarily short-run effects, they should be based on SRMC: if rates have primarily long-run effects, they should be based on the cost of supplying load in the longer term.

Electric rates affect both long-run and short-run decisions and actions by customers, and customer responses affect both short-run and long-run actions by utilities. For example, residential customers must daily decide whether to use their gas oven or their microwave, and whether to leave the porch light on in the evening. Both of those decisions directly increase the utility's short-run costs, but the decisions themselves are swiftly reversible. On the other hand, every day some customers select long-lived appliances and decide how much insulation to build into new homes.[7]

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7. Some consumer decisions may depend as much on prices over the last few years as prices today.

These decisions will affect utility loads and costs for decades to come. Similar variations exist in the choices made by customers in other classes.

Viewed from the other end of the meter, utilities can not determine from system load levels whether the end uses constituting that load are short-term or long-term, price elastic or inelastic, fast or slow to respond to price changes.[8] Regardless of the origin of the load, every additional kWh demanded requires the utility to burn more fuel, buy more power, and/or sell less power at wholesale, all resulting in almost immediate costs.[9] Each additional kWh of sales also changes the utility's expectation of future load, either through an intuitive process (high loads and high load growth breed expectations of further high loads and high growth) or through a more formal influence on the starting point and calibration of utility load models. The added demand may thus trigger such utility decisions as signing a new contract to purchase power, canceling a

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8. Utilities should be able to infer some of this information from past experience, the class mix of load, and end-use surveys, but such inferences are, in practice, subject to considerable uncertainty and controversy.

9. Depending on the fuel source, fuel use may require payments within a few days, or may not require additional expenditures for months. The cost of lost wholesale sales will depend on whether the lost sales would have been made on an hourly, daily, weekly, monthly, annual, or multi-year basis: the cost of additional load therefore varies with the utility's expectation of the load's duration.

margins established by NEPOOL for its members' planning purposes.

In the short term, NEPOOL uses a less stochastic standard: reliability is judged to be inadequate if the level of demonstrated capability, minus the sum of scheduled outages and an allowance for unscheduled outages, is less than projected load plus required operating reserves. The allowance for unscheduled outages is set equal to the average level of unscheduled outages in the preceding years. In some weeks, the capacity situation will be much more critical than indicated by this analysis, due to high loads and/or higher unscheduled outages. However, power will often (but not always) be available from other pools at the time of NEPOOL's greatest need, so capacity shortfalls do not necessarily lead to customer disconnections. Considering these offsetting factors, NEPOOL has accepted the capacity calculation described above as a reasonable measure of the adequacy of capability for short-run planning purposes. This standard is set forth in NEPOOL Operating Procedure #5.

Q: **What is NEPOOL's projection for its capacity situation in 1987?**

A: NEPOOL projects that it will be short on capacity in 12 weeks of this year, if Seabrook is in commercial contract to sell power, starting procurement and construction of a new power plant, or increasing the price paid to qualifying facilities.

Thus, any utility tariff will have both short-run and long-run effects on consumption, and any consumption will have both long-run and short-run cost effects. Unfortunately, any one utility rate can not be designed to provide optimal signals for both short-run and long-run decisions, any more than a power plant can be simultaneously designed for low capital cost, low fuel cost, high efficiency, low operating cost, small unit size, short construction schedule, high reliability, and rapid response to load changes. Simultaneous optimization of multiple objectives is simply not possible, so compromises are necessary.

Q: **Does the PHB study recognize this inherent conflict?**

A: Yes. Pages 39-43 of the PHB report discuss the wide variety of decisions made by consumers on the basis of prices,[10] and acknowledge the conflicting objectives of rate design. However, since this discussion (and the "economic theory" cited in the discussion) assume completely un realistic behavior on the part of consumers and the utility, the PHB report reaches a

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10. The PHB report does not distinguish clearly between rate design and rate level effects.

simple, easy, and incorrect conclusion that pricing should reflect only short-run cost considerations.

Q: **How should the necessary tradeoffs between long-run and short-run considerations be made?**

A: Rate design should balance SRMC and LRMC in a manner which reflects the relative importance of each type of cost, and the relative influence of the rates on each type of cost. In an energy emergency, such as the oil crises of the 1970s, SRMC considerations will be particularly important: when the utility is nearing a decision to make a major plant investment, the LRMC considerations should be given much greater weight. Rates which are applicable to new electric heating loads may have little effect on this year's loads, since the affected buildings will still be under construction, but they will have important long-term implications, and should be closely tied to long-term cost considerations. At the other extreme, a single-year special discount or surcharge for specific large industrial loads may have very little effect on long-run planning and long-run costs.[11]

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11. This effect will only be small if the utility is able and willing to exclude the effect of the special rate from its supply planning. Such exclusion may not always be possible. For example, if the customer can switch to a regular rate after a special discount contract is terminated, and continues to use additional equipment added due to the discount, the discount effect will have long-term implications.

### 3.2 The Necessity of Long-Run Pricing

Q: **Under current conditions, are short-run or long-run cost considerations more important for retail rate design in New England?**

A: Long-run costs are more important for most rate design decisions.

Q: **What considerations make long-run costs more important than short-run costs for current retail rate design in New England?**

A: There are five such considerations:

1. Today's rate designs have a greater effect on future loads than on current loads.
2. Today's loads determine utility supply-planning decisions.
3. Electric utility systems react slowly to changing pricing and cost conditions, requiring that pricing lead expected cost change.
4. Rapid changes in electric rates are disruptive.
5. New England utilities are facing major supply planning decisions over the next few years, which

will have significant cost effects for the rest of the century.

### 3.2.1 Today's Prices Determine Future Loads

Q: **How do you know that current prices affect future load levels?**

A: Empirical time-series studies of consumer demand for electricity uniformly find major lags in the response to price changes.[12] Typically, 10% to 20% of the effect of a price change may be experienced in the year in which the change occurs: the remainder of the effect is spread over a decade or more.

This lagged elasticity effect is observed for residential, commercial, and industrial customers.

Q: **Why do current prices affect future load levels?**

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12. Some simplistic studies, especially those carried out by utilities, do not test for any demand lag, and therefore do not identify it. NU's forecasting models have failed to fully reflect this important relationship, especially for industrial sales. This is an error I pointed out to NU with respect to its 1978 and 1980 forecasts: see my testimony in EFSC 78-17, in EFSC 80-17, and in MDPU 19494, Phase II. NU's current forecast accepts some of these realities: long-run elasticities are included for residential and commercial sales (but curiously not for industrial), although the long-run elasticities are still very low.

A: There are several reasons for this effect. The most important is that major conservation, consumption, and fuel-choice decisions are not usually made quickly. Such decisions as insulating a house, upgrading HVAC controller efficiency, and replacing an electric heating system with a gas system, all require time for problem identification, analysis, contractor bidding, financing, and implementation.

Major energy-use investments are not likely to start until customers have experienced new rates for a period long enough to convince them that the rates are likely to persist. Consumers must be convinced of the stability (or trend) of the underlying costs, the allocation of those costs between classes, and the design of rates within each class, before they make large investments to respond to those rates. Industrial customers will not react much to higher rates, if they believe that the DPU is about to capitulate to their demands for lower "economic development" rates. Commercial customers may not invest in energy conservation, if they perceive that the DPU is in the process of redesigning rates so as to collect most revenues from demand charges.[13] Residential customers

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13. Even if very sophisticated consumers have some ability to forecast future utility cost trends, they can not expect to forecast future rate designs.

may require some time to understand how a new rate design affects the costs of increased consumption.

While almost any end-use is susceptible to efficiency improvements at almost any time, many decisions to consume, conserve, or switch fuels are most easily and economically made at the time that equipment is replaced or renovated. Refrigerators, HVAC equipment, lighting systems, buildings, and industrial motors all have natural life cycles. Customers are understandably reluctant to replace or rebuild fairly new equipment simply to save energy: the same improvements may be much easier when the equipment wears out or when some other type of overhaul or remodeling is desired for other reasons.

Even energy use changes which involve little or no capital investment may require some adaptation period. Householders and employees may require some time to change habits, to find comfortable temperature setbacks and lighting levels, and so on.

Thus, it is hardly surprising that empirical studies find that all classes of consumers require significant periods of time to adapt to price changes.

Q: **Does PHB agree that consumer responses to price changes are slow?**

A: Yes. This point is acknowledged at page 43.

Q: **How does the PHB report deal with this lag in response?**

A: PHB chooses to ignore the lagged price elasticity effect, and instead treats consumers as if they reacted to rate design and rate level changes before the changes occur, rather than well after the fact. Dr. Ruff goes so far as to suggest that consumers should be treated as if they forecasted electricity prices, even if they do not do so (page 6).[14]

Q: **Do you have other evidence to support your assertion that current prices dominate most consumer decisions which have major effects on future loads?**

A: Yes, I have four other kinds of evidence. First, in determining the cost-effectiveness of conservation and fuel-switching investments, analysts generally use current prices, rather than a forecast of rates into the future. This has been my experience in reviewing engineers', contractors', and vendors' evaluations and proposals for such investments as conservation and cogeneration equipment. NU also states very clearly that it uses only current rates in evaluating

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14. The same passage also describes the fact that consumers act on the basis of current rates as "an arguable proposition, at best". Since PHB presents not a scintilla of evidence to argue with the proposition, and since NU uses only current rates and assumes its customers do so as well (IR EOER-72), there is no real argument. Consumers simply do not respond to prices in the way Dr. Ruff thinks they should.

conservation investments, and assumes that its customers do the same:

> [W]hen informing customers of their cost savings attributable to conservation, the current rate for that customer is applied for the calculation. MASS Save and CONN Save . . . also utilize the current rate of fuel cost when the customer does not provide that information. When the customer provides the information, it is assumed they too use their current rates. (IR EOER-72)

Second, it is abundantly clear that consumers' energy-use investments and habits have not even caught up to today's prices. Large amounts of very economical conservation has not yet been achieved, even where the adjustment is as simple as buying more efficient light bulbs. While Dr. Ruff purports to worry that LRMC pricing will cause excessive conservation (page 28), the exact opposite has occurred under current energy rates, which Dr. Ruff considers too high.

Third, Dr. Ruff acknowledges that consumers can not accurately forecast price changes due to rate design or regulation. (See the discussion of gas pricing on page 43, note 19 of the PHB report.) Recall that the PHB rate design scheme requires that rate design change radically and rapidly, with marginal energy rates increasing (perhaps by a factor of 4 or 5 times) in periods of tight capacity,[15] followed by an even sharper

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15. As will be demonstrated in Section 4, it may be impossible to fully offset these increases with reductions in demand and customer charges, requiring an

decrease in energy rates once new capacity enters service. Since ratepayers can not be expected to foresee these changes (even if they could accurately project total utility revenue requirements), the PHB proposal would produce more resentment and despair than conservation and efficiency.

Fourth, even large customers have shown little ability to forecast utility total costs (let alone rate design). For example, many industrial electricity consumers supported the construction of nuclear power plants in New England, long after it became clear to independent observers that the plants would increase rates. Even with regard to these multi-billion dollar investments, few ratepayers appear to have done anything to project costs, other than to accept what they heard from the utilities and read in the newspapers.[16]

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abrupt switch from rates with high customer and demand charges and declining energy blocks, to rates with only energy charges, and those strongly inverted.

16. In one particularly egregious example, a manager of a large paper manufacturing plant wrote to the Attorney General's office in 1980, soliciting our support for Seabrook 1 and 2 (then officially scheduled for operation in 1983 and 1985, respectively), because he was concerned that the high fuel adjustment charges in 1980 would result in the closure of his plant. Even if there were any reasonable hope that Seabrook would have been cheaper that current fuel costs (which there was not), the timing of the plant made it irrelevant to the paper company's problems.

### 3.2.2 Today's Loads Determine Utility Supply Actions

Q: **How do utility supply planning decisions depend on current loads?**

A: In a world of perfect forecasting models, current loads would only affect long-run utility forecasts to the extent that they would incorporate the inertia inherent in the lagged responses discussed above. If current loads were high due to the kinds of intentionally promotional rate designs NU proposes, NU's forecasting models would include the load reductions which would occur in the future when the higher load growth precipitated a capacity shortage, and (under NU's proposal) the promotional rate design would finally be replaced by a conservation-oriented rate design. Thus, if the DPU anticipated a capacity crisis in 1994, it would project a rate increase in 1994, which would reduce the expectation for capacity required in that year.[17]

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17. Of course, the rate increase would have to be enormous in order to reverse the excessive and uneconomical consumption encouraged by years of low energy rates. I would hope that the DPU would be more realistic than NU, and phase the increase in over several years, rather than doubling or tripling tail-block prices in 1994 to force down consumption.

Unfortunately, we do not live in a world of perfect forecasting models. NU's model (which is better than average in the industry) does not even consistently reflect the existing knowledge about the effect of average rates on consumption: for example, NU assumes that long-run elasticities are very close to short-run elasticities for residential and commercial customers, and identical to short-run elasticities for industrial customers. NU's long-run forecast (and so far as I know, every other utility load forecast) completely ignores the effect of rate design on demand. Thus, no mechanism currently exists for reflecting future rate design changes in utility planning.

Since we can not incorporate future rate design changes in load forecasting and capacity planning, load forecasts in the real world are based on the rate designs which influence the available data: those are current and recent rate designs, not future ones. The current level of loads affects the utility's expectation of future load, and recent rates of load growth affect expectations of future load growth.

Current rate design may affect the forecast very formally and directly. For example, NU's model must be calibrated, so that the observed data produce the current load and recent load growth. To the extent that some of the current load and recent increases result from changes in rate design, future loads will be over-estimated for periods in which rate design objectives would reverse.[18] The added demand due to promotional rates may thus trigger such utility decisions as signing a new contract to purchase power, canceling a contract to sell power, starting procurement and construction of a new power plant, or increasing the price paid to qualifying facilities.

Important utility power supply decisions generally have lengthy lead times. Thus, NU will have to make decisions regarding the mid- to late-1990, in the next few years, based on load data available now and in the near future. The higher tail-block rates which NU advocates for the capacity crisis it plans for the mid-1990s will not appear in the data NU and the DPU will have to use in evaluating the construction, power purchase, and power sale decisions which will determine NU's power supply situation for the late 1990's.

### 3.2.3 Appropriate Market Periods

Q: **On page 12 of his report to NU, Dr. Ruff discusses the concept of "market period", the time scale on which pricing, production, and consumption decisions**

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18. Recall that NU argues for steep increases in marginal tail-block rates, once promotional rates cause a capacity crisis.

**are effectively made. In light of your preceding discussion, what is an appropriate market period for retail electric rate design?**

A: There is no simple answer to that question, because of the complexities of utility planning and consumer responses. However, it is clear that today's rate design will have significant effects on consumption patterns in the next several years. Those consumption patterns may have disproportionate effects on the utility supply planning decisions in that period, since the recent rate designs will influence load growth and the expectations of future load growth. Thus, the "market period", in which "buyers and sellers can learn about and react to changing conditions" (Ex. C-JR-6 page 12, note 9), is on the order of ten years. In normal utility practice, the costs of decisions made in that period, such as to start plant construction, or to sign wholesale power agreements, will determine revenue requirements and cost recovery far into the future. Those deferred costs are incurred when the plant is ordered or the contract is signed, and they therefore must be included in the market period, to properly match costs to the consumer and utility decisions which produce them.

Q: **What market period does Dr. Ruff propose for retail electric sales?**

A: Dr. Ruff does not specify the market period he considers appropriate, but from his discussion it is clear that he supports a market period no longer than one year, and preferably much shorter.

Q: **Has WMECO proposed to change retail rate design to the extent advocated by Dr. Ruff?**

A: No. WMECO's rate design proposals in this case are dominated by continuity considerations, and do not move far towards implementing Dr. Ruff's proposed pricing approaches.

Q: **What is the implication of WMECO's behavior in this case for the appropriate market period?**

A: Clearly, WMECO recognizes that electric rate designs should not be changed very rapidly. Retail electric supply is not a spot market activity, as Dr. Ruff implies,[19] and WMECO is not willing to treat it as such. Changing retail rates dramatically, rapidly, or repeatedly reduces their effectiveness, and imposes large costs on the customers and the utility. Dr. Ruff's proposal depends on the ability and willingness of the utility and the DPU to increase and decrease

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19. See Ex. C-JR-6, page 27. Even where efficient spot markets exist, government often finds it necessary to add incentive to reflect long-term cost considerations, as in the proposed oil import fees, Synthetic Fuels Corporation price guarantees, and in the numerous tax credits and other mechanisms to encourage renewable energy development.

marginal energy charges dramatically and instantaneously, to force demand to match supply. Since such changes in rate design are impractical, they will not occur, and it would be most improvident to base current rate design on the assumption that they would occur.

Therefore, the market period must be tied to the period of time for which rate design should is to be stabilized: this implies a market period on the order of a decade, rather than a year.

### 3.2.4 Supply Planning Considerations

Q: **How does New England's current power supply situation affect the relative importance of SRMC and LRMC in rate design?**

A: Short-term running costs are quite low, due to the depressed short-run market price of oil. Fuels are abundant. Short-run operating costs are thus of limited concern.

Short-term reliability problems are more serious. NEPOOL expects significant capacity shortages in the summer of 1987, even if Pilgrim were to return to service in April,[20] and even if average unscheduled outages this summer are about 400 MW lower than they were last summer. Without Seabrook,[21] NEPOOL reliability criteria are violated in 21 weeks of the year, with capacity shortfalls of as much as 2000 MW.[22] This analysis is contained in a series of NEPOOL

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20. Boston Edison is now hoping that Pilgrim can be operating by June, but there is no assurance even that target will be met.

21. Seabrook is unlikely to operate commercially in 1987.

22. The fact that NU or WMECO may have more installed capacity than it needs to meet NEPOOL requirements does not reduce the risk to WMECO ratepayers. A shortage of operable capacity in New England can result in blackouts in Springfield as easily as in Boston.

documents, which are Exhibits EOER-8, 9, and 10 in this proceeding.

These short-term reliability problems would justify accelerated efforts to use rate design to increase reliability. For example, WMECO could add a third "super-peak" period to its time of use rates, covering the hours of highest LOLP exposure. WMECO's current 16 hour peak period includes many hours with low probabilities of capacity distress. For very large customers, the super-peak periods could be designated in real time, so that the conservation incentives would be greatest in the hours of greatest risk. For all customers, incentives for short-term interruptible rates (e.g., controlled water heating) could be increased dramatically. Demand charges, which may actually increase peak loads, could be discontinued in favor of on-peak energy charges.

Unfortunately, it is probably already too late for rate design to have much of an effect on the loads experienced in the summer of 1987. By the time that the decision in this case is issued, WMECO's customer representatives have explained the new rates and options, metering is ordered and installed, customers have resolved the technical and institutional constraints on load shifting, and customer equipment is ordered and installed, we will be well into next year.

While the problems anticipated for 1987 may be repeated in 1988, it is generally assumed that the short-run reliability problems will be solved by the wave of cogeneration and small power producers already in development, assisted by the utility conservation programs,[23] possibly Seabrook, and finally the completion of the Hydro Quebec Phase II project. It may be very difficult to get customers to make significant investments of time, effort, and money, if the financial incentives are expected to last only a couple years. Thus, it is not clear whether rate design can have a major effect on the short-term reliability crisis. To the extent that rate design can have a significant effect, that effect would tend to be concentrated in rates (such as uncontrolled water heating) in which loads can be quickly and reliably moved out of high-exposure periods.

The situation is clearer regarding long-run capacity decisions. Some utilities are planning to add central station capacity as early as 1989. NEPOOL as a whole expects to be capacity deficient in 1994, or 1992 if Seabrook never operates. The New England Governors' Conference Report (December 1986) projects a potential

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23. Few utilities have shown any serious interest in conservation, but enough utilities, including NU, have talked about doing something that it is possible that meaningful conservation programs will be implemented in the next couple years.

deficiency of 1700 MW in 1991, without Seabrook and additional sources, and 1000 even with Seabrook.[24] Lead times on the most likely new generation sources, such as cogeneration, combined cycle and fluidized bed plants,[25] are at least a few years (including cogeneration bidding, environmental permitting, and so on), so decisions about major blocks of capacity will have to be made in the next few years. Those decisions will determine the size and composition of the next generation of New England supply sources.

NU will be deciding whether to start the process of recommissioning its retired plants and converting them to combined-cycle operation; install coal gasification equipment; participate in additional purchases from coal, nuclear, and hydro plants in Canada; increase purchases from QFs; accelerate its conservation programs; build new central-station plants; and/or make long-term sales of existing capacity. Those decisions will be made in the light of NU's load levels and rates of load growth in 1987-1990, a period for which loads will be strongly influenced by the rate designs established in this proceeding. Thus, current loads

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24. The Governors' Report projected 430 MW of load reduction due to "additional conservation and load management." By far the lowest-cost conservation is available through intelligent rate design.

25. A conventional coal plant probably could not be brought on line in New England until the late 1990s, even if a commitment were made today.

have a major influence on important long-run costs, and those costs should be fully reflected in current rates.

On the whole, long-term cost considerations are much more important than short-term considerations, for WMECO's current rate design.

### 3.3 The Realities of Utility Regulation and Planning

Q: **What realistic considerations must be incorporated in retail electric utility rate design?**

A: I have aggregated these issues into three groups: the special characteristics of the retail electric utility market, the utility planning process, and the systematic differences between LRMC and SRMC.

#### 3.3.1 Unique Characteristics of Electric Power Markets

Q: **What aspects of retail electric power markets differentiate them from other retail markets?**

A: There are several such differences:

- Electric power distribution is a monopoly service, and electric power transmission is either a monopoly or an oligopoly service.

- While cogeneration and small power production have introduced some elements of competition into electric power supply, a fairly small percentage of retail sales are subject to direct competition:

the distributor is generally the only source of power supply.[26]

- Electricity can not be stored in any significant quantity.

- Retail electricity prices can not be revised rapidly to match demand to supply.[27]

- Electricity can not be rationed effectively.

- Consumers who are willing to pay more than average for power can not effectively bid up the price to ensure their supply, especially in the short run.[28]

- Small consumers (residential and many commercial and industrial customers) have little

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26. In particular, high demand charges for backup power make cogeneration expensive.

27. Experiments are underway to relax this constraint for very large customers, for whom telemetering is cost effective.

28. Very large customers with dedicated transmission and distribution facilities could, in principle, negotiate the right to be disconnected less often, in exchange for higher rates. However, operation of the system near its limits may result in transmission- or generation-related outages which encompass the favored customer, despite WMECO's best effort to avoid disconnection. At the other extreme, large customers who are willing to accept explicitly interruptible service can receive lower rates. However, these rate and reliability categories, even where they are feasible, generally must be established months or years in advance, further limiting the ability of customers to ensure themselves of service when they most need it.

understanding of the consumption and billing effect of individual decisions (e.g., turning on a light), and are thus react more slowly to rate changes than they would if each decision were accompanied by a bill.

- In the short run, alternatives are available to replace only a small share of power sales.

- Significant reductions in electric power consumption typically require considerable time to accomplish, if they are not to cause serious dislocations.

- Shortages of electric power (e.g., supply interruptions) result in major inconveniences, significant costs, and in some cases hazards to life and property.

This situation is quite unusual. Most retail goods have many suppliers, are subject to rapid price revisions, can be rationed if necessary, are available to the customers who are most willing to pay for them, can be stored by consumers who are most concerned about continuity of supply, have ready substitutes, and are far from essential.

Contrast the situation of retail roast coffee sales with that of retail electric sales. When changing supply situations increase the cost and decrease the supply of coffee, supermarkets can immediately increase the price of the stock on their shelves, and/or restrict the quantity each customer may purchase. Customers can see the price of the coffee when they face the purchase decision, and may reject the purchase in favor of a substitute, or simply do without. Consumers who fear interruptions in coffee supply may maintain large stockpiles, or pay the higher market-clearing price at the time of a shortage. For most consumers, coffee is far from a necessity. Thus, little harm is done by the wide swings in coffee price observed in the market: everyone who <u>really</u> wants coffee can buy it.[29] This situation does not apply to shortages of electric capacity or energy, or to extreme fluctuation in their prices.

Dr. Ruff (Ex. C-JR-6, page 22, note 19) compares the pricing of electricity to the pricing of "Cape Cod real estate". Electric markets and real estate markets actually differ in many respects. There is no such thing as a shortage of vacation homes: there is simply a price at which the market clears.[30] I can determine that price precisely from newspaper listings, before I

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29. This assumes that income and wealth are fairly distributed: all pricing policies which use willingness-to-pay as a measure of a good's value make this assumption.

30. Again, I ignore here the complications that arise when income is not equally distributed, and the necessity of affordable housing becomes unavailable.

make any commitments. If I can't get a reservation at the price I expected, I can raise my offering price until a place becomes available. If Cape Cod gets too expensive, I can vacation in the Berkshires or in Maine, and I can make that decision up to the time I put down my deposit. For that matter, neither the economy nor my welfare will suffer much if I spend my vacation puttering in my garden. Furthermore, society is as indifferent regarding the outcome for vacation real estate suppliers as it is regarding the outcome for their consumers. If a developer overestimates demand, neither I nor other customers are obligated to pay for his mistakes: for every developer who goes bankrupt in a bust, a new one will enter the business in the next boom.

Obviously, retail electricity sales can not be exposed to the vagaries of markets like those for coffee and vacation houses. Electric customers can not walk into a store or open the paper, to determine the cost of each electricity-consuming action they might take: they must determine the cost of those actions by a lengthy process of trial and error. Electric customers can not switch suppliers or commodities, or otherwise react quickly when prices change. Electricity suppliers are not allowed to go out of business every time they over-estimate demand. Electricity sales are not simple, discrete events, like the decision to purchase a can of coffee off the supermarket shelf.

Consider the application of the PHB proposal to a restaurant: as long as there were empty tables, food would be priced at the cost of ingredients[31] and cooking fuel. Once the seats were filled, the restaurant would increase the price of tables, perhaps auctioning off space every five or ten minutes, so that no one who was willing to pay the market-clearing price would ever have to wait for a table. Thus, diners who were unwilling or unable to pay the new market rate would have to leave in the middle of their meals. If diners were required to order and pay for their food (or even just the first few minutes of table rental), without any assurance that they would be allowed to stay long enough to finish, or of the price they would be charged for the privilege, the restaurant would find few customers. In fact, restaurants operating in largely competitive markets, without price regulation, choose not to use SRMC pricing. Restaurants apparently use some form of LRMC, including costs which are not variable in the short run (like rent and labor), and with time-of-use differentials (e.g., lunch menus, New Year's Eve specials). They do not even vary prices from day to day to follow the demand curve: presumably, the cost in

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31. Once ingredients are purchased, they are sunk costs, and PHB might advocate giving food away.

confused customers and lost business exceeds the potential profits.

Q: **On page 45, the PHB report suggests that large increases in energy use, due to pricing electricity below the utility's cost of serving the additional load in the future, may have no important effects. Is this likely to be the case?**

A: No. Dr. Ruff suggests that the riskiness of cost projections makes the extra usage unimportant. His analysis reverses the real situation: risks add to the costs of excessive consumption, they do not decrease the costs. The costs of added load are indeed risky, utilities and ratepayers prefer to avoid risk, and thus should prefer the more predictable effects of current efficiency investments and behaviors. Risk makes long-run cost considerations <u>more</u> important for rate design, not less.

In addition, Dr. Ruff suggests that the expected value of the long-run cost of added consumption may not be very large. This is certainly a theoretical possibility, but it is hardly consistent with recent experience. Recent capacity additions (for example, Millstone 3) have been very expensive, and future additions range from the much worse (e.g., Seabrook) to the slightly better (e.g., additional power from Hydro Quebec). It is obviously much better for WMECO's customers to conserve electricity at a few cents/kWh than for WMECO to supply additional power (or forego a sale of Millstone 3 capacity) at 10 cents.

### 3.3.2 Review of Utility Planning Decisions

Q: **How do utility planning decisions differ from planning decisions in competitive markets?**

A: There are several such differences. Utilities have an obligation to serve, and may potentially be penalized (including loss of their franchises) for being unable to serve.[32] Therefore, serious shortages may pose real problems for utilities. Competitive producers prosper in shortage situations, since whatever supply they can make available fetches a premium price. Thus, utilities have an inherent bias against tight supply.

In a competitive market, each increment of additional supply decreases the price paid for all units, and any production at costs above the market clearing price immediately represents a loss to the supplier. Producers thus have considerable incentive to avoid excessive supply, collectively or individually. Utilities, however, are usually repaid fully for their investments in new supply, regardless of demand levels.[33] Utilities thus lack the incentives of

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32. As MDPU 85-271 demonstrates, utilities may be penalized for failure to serve, even before a shortage develops.

33. When utility systems are extremely inefficient (due to excess capacity or excess costs), certain costs may be

competitive suppliers to avoid excess supply situations.

Competitive suppliers always make their capacity decisions against the background of the marginal market-clearing price. Utilities generally face full cost recovery, independent of market costs. In the rare instances in which a market test is applied (as in MDPU 85-270), the test is applied on an average basis, rather than on a marginal basis. Thus, the DPU apparently would have allowed full cost recovery for Millstone 3, so long as the plant as a whole was cost-effective for WMECO, even if the last 100 MW were virtually worthless.[34]

Utilities generally recover the cost of their investments in a heavily front-loaded fashion. Capital costs are repaid long before they would have been recovered in a competitive market. Thus, utilities can and do make large investments to reduce expected costs far in the future, for which they receive compensation in the short run, well in advance of the expected costs

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disallowed. However, these penalties usually cover only excesses above a certain level, so quite large excesses may be necessary to reduce the utility's earnings to the level which would have been observed without any excess.

34. Curiously, the PHB model assumes that the Commission can and will fix electricity rates independently of WMECO's actions, and that WMECO will then act to maximize profits subject to those rates. In reality, WMECO's actual costs are the most important determinant of WMECO's total rates. Specifically, rate design issues, such as those discussed in the PHB report, are not generally allowed to affect utility profit levels.

which they avoid. Hence, unlike Dr. Ruff's simplistic examples, in which the cost of a new plant equals SRMC in the year the plant comes on line, actual utility plants are generally more expensive than SRMCs in their first year.

### 3.3.3 Long-run May Not Equal Projected Short-Run

Q: **Is Dr. Ruff correct in asserting that LRMC is simply a prediction of the future value of SRMC?**

A: No. The realities of utility planning and ratemaking may result in SRMC remaining consistently below LRMC. In his Figure A-4 (reproduced as Figure 3.1 for convenience), Dr. Ruff illustrates a situation in which a utility adds capacity in year 2, reducing SRMC below LRMC in that year. The addition is justified by the higher SRMC avoided in year 3, due to the addition in year 2. Dr. Ruff assumes that no capacity will be added in year 3, and that the average of the SRMC in year 2 and that in year 3 will equal LRMC.

However, Figure A-4 shows the SRMC in year 3, even with the capacity added in year 2, to be higher than the SRMC in year 2 without the addition. Thus, the same reasoning which justified the addition in year 2 would justify another addition in year 3, pushing SRMC back below LRMC. This process could continue indefinitely, with each year's addition justified by future avoided costs, which are then avoided and never appear as part of SRMC.[35] Figure 3.2 illustrates this pattern.

Q: **Figures 3.1 and 3.2 describe conceptual patterns of capacity additions. Have you performed a similar analysis with realistic cost relationships?**

A: Yes. Table 3.1 shows one possible relationship between SRMC, the capacity additions justified by those costs, and the LRMC associated with those additions. Column 1 represents hypothetical system load levels for the next 20 years, assuming 4% annual load growth. Column 2 is the amount of the load served by oil capacity, and Column 3 is the existing base load capacity. The short-run marginal cost in Column 4 is calculated by assuming that SRMC starts at \$.02/kWh and increases by 1 cent for each 100 MW of load served by oil capacity. Column 5 is the net present value for twenty years of the SRMC avoided by a 400 MW base-load addition,[36] minus the cost of the new unit, assumed here to be \$.20/kWh. New capacity is added to the existing baseload when the net present value of avoided SRMC is greater or equal to the

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35. Dr. Ruff avoids this embarrassing situation by assuming that capacity is lumpy because it can only be added every second year. This is not a realistic constraint: capacity is lumpy due to economies of scale, inflation, and other technical and economic considerations, which do not preclude annual additions.

36. For this calculation, the SRMC is evaluated for the average MW added, which is the current load level minus 200 MW.

cost of added capacity. The new short-run marginal cost is then calculated based on the new calculation of load met with oil capacity. This pattern of adding capacity as the present value of the benefits of newly acquired capacity become positive is repeated until three additions of 400 MW have been added. [37]

Figure 3.3 portrays the results of this process, through the third capacity addition. SRMC drifts between 9 and 12 cents, and averages about 10 cents/kWh. This is well below the 20 cent LRMC of adding new capacity.

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37. For simplicity, some important complicating factors have been suppressed. The calculation is done in real dollars, the cost of power from the new plants is assumed to rise only with general inflation, and the details of the utility's strategies in starting and continuing construction at each decision point are not modeled.

### 3.4 Errors in the PHB Analysis

#### 3.4.1 Misconceptions

Q: **What misconceptions about utility power supply, planning, and ratemaking are evident in the PHB analysis?**

A: There are several areas in which the PHB report indicates a glaring lack of familiarity with utility economics and regulation, including:

1. confusion of "capacity" between reliability-serving and energy-serving additions (Ex. C-JR-6, pages 23 and 26),

2. failure to recognize that rate design is not the same as, and is essentially independent of, cost allocations between classes (Ex. C-JR-6, page 48),

3. a simplistic assumptions that low load factors increase costs, despite the high cost of building baseload capacity, perhaps indicative of a failure to understand utility cost structures (ibid.),

4. confusion of "average electricity costs" with the total cost of service (ibid.), and

5. a general misunderstanding of the nature of utility consumers.

Q: **Why is it inappropriate to use "average electricity costs" as a measure of rate design effectiveness?**

A: Rate design is, among other things, a means of achieving conservation. Like all conservation programs, rate design may increase the costs for some ratepayers, especially when those costs are measured in cents/kWh. Expecting all rate design changes to produce lower average costs is equivalent to the no-loser's test, which the Department has clearly and repeatedly rejected.

Q: **How does Dr. Ruff's report indicate that he misunderstands the nature of consumers?**

A: Dr. Ruff repeatedly describes the way in which he would like consumers to behave, rather than the way they do behave. He treats customers as "spherical chickens" for modeling purposes, assuming that they make decisions based on accurate projections of utility costs, of load growth, and of future DPU rate design rulings, and on the discount rate the utility would utilize. For example, he assumes that consumers have "reasonable knowledge of likely future events and uncertainties" (page 12) and that they have "reasonable expectations about the future" (page A-5). This oversimplification is hardly unexpected.

More surprising is Dr. Ruff's obvious annoyance with any suggestion that consumers act like real consumers, rather than like his convenient mathematical constructs. He accuses consumers who behave like real ratepayers (whom he describes as "hypothetical") of being "myopic" and "simple-minded" (page 41), and describes consumers who respond to current prices as being "fooled" (pages 28 and 42).[38]

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38. Dr. Ruff appears to imply that any action taken in response to an unregulated price is wise, and that any consumer who responds to regulated prices has been "fooled". On page 43, he asserts that "consumers in 1980 were not fooled into taking costly actions now (sic) because oil prices would be $50 per barrel in 1985", but then asserts that they were fooled into converting from oil heat to gas, which he clearly considered to have been a mistake. In case of conversion, Dr. Ruff alleges that consumers properly anticipated the high oil prices which he earlier claimed they did not anticipate (and did not occur), and blames the conversions on the regulation of gas prices, which "fooled" consumers into thinking they were protected.

### 3.4.2 Modeling Errors

Q: **How does Dr. Ruff err in setting up his model?**

A: There are several errors in the basic formulation of the model:[39]

1. The intertemporal interactions are very limited. The price in each period has only a very limited effect on consumption in later periods, and the utility's investment decisions are entirely independent of past consumption patterns.

2. Utility customers are assumed to have the same discount rate as the utility, and of society.

3. The model assumes that the DPU can optimize customers' consumption and investment decisions, just as it can optimize utility decisions, or that consumers will behave as if the DPU were optimizing their behavior.

4. The model assumes that consumers have the same information and the same expectations regarding future rate levels as does the utility and the

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39. This discussion covers both Dr. Ruff's initial report and the response to IR EOER-18.

DPU, and that they use those expectations in making investment decisions.

5. Consumers are further assumed to forecast rate designs. Specifically, customers must expect that the utility and DPU will attempt to drive up loads until a capacity crisis occurs, and will then radically shift rate designs to increase tail-block energy charges.

6. Continuity constraints are not binding in rate design.

7. In Appendix B of Ex. C-JR-6, Dr. Ruff treats the utility as a profit-maximizing supplier in a perfectly competitive environment. The utility provides only that level of supply which is profitable,[40] and the utility's behavior does not affect electricity demand or price.

8. In IR EOER-18, Dr. Ruff sets up a model with a social objective function, but in IR EOER-56, he disavows any opinion as to what social objective function the DPU should be seeking to maximize.[41]

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40. This is the type of behavior for which the DPU penalized Boston Edison in 86-271.

41. The DPU, among other things, is charged with the responsibility of ensuring that utility rate design serves the public interest, rather than the narrow self interest assumed in Appendix B to Ex. C-JR-6.

9. The model requires the DPU to estimate the shortage costs which result from any combination of load and supply.[42] Shortage costs are not well known, and even estimating the extent of shortages associate with various supply and demand situations is far from trivial.

**Q: How do these errors in the model assumptions affect the validity of Dr. Ruff's conclusions?**

A: For the most part, Dr. Ruff's conclusions are his assumptions. He assumes that consumers use future prices, rather than past prices, in their investment decisions, and therefore concludes that today's prices do not affect future consumption and need not reflect future costs.[43] He assumes that current and future utility investments are independent of current consumption, and therefore concludes than such investments are not a cost of current consumption.

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42. Note that this is not as simple as a single cent/kWh value, times an expected kWh shortfall. Shortage costs clearly vary with the feasibility of rationing, and hence with the timing, length, and predictability of shortages.

43. Dr. Ruff asserts that all demands depend on all prices in his model. By this, he apparently means that today's prices were reflected in investment decisions made two years ago, and therefore very indirectly affect the level of consumption both yesterday and tomorrow. This is a much weaker effect than the long lags observed in consumer response to current and past prices.

Since Dr. Ruff's assumptions are fundamentally incorrect, and do not reflect some of the most important considerations in utility planning and regulation, his conclusions are of little relevance in establishing retail rate design.

Q: **If Dr. Ruff's model were correct, would it have any implications for government energy policies beyond electric rate design?**

A: Yes. If the model were correct, it would have far-reaching consequences, and essentially imply that no active energy policy would ever be appropriate. Dr. Ruff notes that his conclusions would indicate that utility-sponsored conservation programs are improper: the same would be true for all conservation incentives, regardless of sponsorship. The results of the model would be at least as extreme if applied to industries more competitive than the electric utility industry.

For example, consider the implications of the model for government policy regarding oil supply and consumption. Dr. Ruff assumes that producers and consumers make all decisions (which for oil would include storage, as well as consumption and production) in the most efficient manner possible, and that regulation can not improve on these decisions. Hence, such programs as the Synthetic Fuels Corporation, the Fuel Use Act restrictions on large oil-burning facilities, the Strategic Petroleum

Reserve, and efficiency standards for oil furnaces could never have made sense, regardless of current or future oil prices or supplies. While some of these programs were poorly conceived or implemented,[44] it would be totally unreasonable to believe that all the goals would have been properly achieved by market mechanisms.

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44. For example, the Synfuels Corporation pursued very expensive technologies, even after oil price projections fell considerably.

### 3.5 The bottom line

Q: **Beyond the conceptual problems in the PHB/NU model, what are the effects of using SRMC rather than LRMC in retail rate design?**

A: One important effect of the PHB/NU approach is to permanently relegate rate design and conservation to very limited roles in power supply planning. As the PHB report notes (Ex. C-JR-6, page 18), utility supply planning must be guided by LRMC. If rate design and conservation programs are based on SRMC, and SRMC remains below LRMC, as illustrated in Figure 3.1,[45] neither the consumers nor the utility will invest in all the efficiency improvements which are less expensive than the cost of a new power plant.[46] If consumers are given very limited conservation incentives in their elastic billing determinants (e.g., tail-block energy charges), they will increase their consumption, requiring additional expensive capacity, which under the

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45. SRMC has been below LRMC for most of the last decade: the total cost of power from new utility power plant was more expensive than the running cost of existing plants.

46. Consumers will under-invest in conservation in any case, since they apply very high discount rates to that activity, compared to the discount rates regulators apply to utility decisions on their behalf. This may argue for energy rates in excess of LRMC.

PHB plan would be charged to the inelastic billing determinants (e.g., customer charges), while the elastic charges would remain low or actually decrease, encouraging more consumption and requiring another plant addition.[47] The limited pricing signals to consumers would be received only when high running costs or tight supplies are imminent: due to lag in consumer response and the utility's need to make commitments well in advance of need, the consumer response would come too late to allow the utility to avoid capacity expansion decisions. Each capacity expansion will tend to further reduce running costs, encouraging more load growth, and further unnecessary capacity additions.

In short, the PHB/NU plan would place conservation and rate design on a very unequal basis with supply expansions, and result in excessive consumption, capacity construction, and cost.

The PHB report correctly states that:

> If there is any reason to reflect future costs in current energy rates, it must be to discourage demand growth so that those future cost will be less. (page 26)

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47. The PHB approach would also require that the less elastic classes should pay the added cost of new capacity, so as to encourage yet more profligate consumption by the elastic industrial class. Thus, PHB and NU may be foreshadowing a future attempt to transfer a large portion of embedded costs to residential and small commercial customers' fixed charges.

Unfortunately, PHB and NU do not find the reduction of future costs by current price signals to be a worthy goal. Indeed, PHB worries that LRMC pricing will encourage conservation and fuel switching, thereby reducing the utility's sales (pages 45 and 46). Since both conservation and fuel-switching are generally more economical than the expansion of utility power supply,[48] the outcome which so concerns PHB is actually advantageous to ratepayers.

Q: **The PHB report (Ex. C-JR-6, page 46), also expresses concern that LRMC rate design will encourage "self-generation" before it is fully economical, and thereby increase total costs. Is this concern justified?**

A: While there is some possibility of the type of inefficiency PHB hypothesizes, it does not appear to be

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48. The case for the superiority of conservation is too clear-cut to warrant detailed repetition: large amounts of efficiency improvement are available for a few cents/kWh, or less. The economics of fuel choice also come out against electricity. The alternative consumer fuel will generally be natural gas, which is also the fuel for most of the central station power plants proposed for New England. Even a fairly efficient combined-cycle plant will have a heat rate in excess of 8,000 BTU/kWh, or less than 40% efficiency. Losses in the transmission and distribution system lower the delivered efficiency at secondary to about 32%. Gas-fired space heating and water heating systems are available with efficiencies in excess of 95%. Thus, if consumers are encouraged to choose gas over electric appliances, New England will burn less gas, avoid the capital costs of the combined cycle plants and associated transmission and distribution, and experience lower total utility bills.

very serious. "Self-generation" usually refers to a customer generating its own power using conventional utility technologies (as opposed to cogeneration) and operating independently from the grid. This process is apt to produce power at costs higher than LRMC, since self-generation lacks the economies of scale and diversity available to the utility, and thus should not be attractive to many consumers.[49] I will therefore address the more competitive cogeneration technologies, which are sometimes referred to as "self-generation" when the power is used internally, rather than sold to the utility.

Cogeneration poses a classic problem in the conflict between short-run and long-run pricing objectives. Whether the cogenerator plans to sell to the utility or displace utility sales, the utility will generally be reluctant to forego its own power supply expansion unless the cogenerator is firmly committed, under construction, or even in operation. Therefore, it may be necessary for the cogenerator to enter service earlier than economical for operational purposes, because such early operation is needed for planning purposes.

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49. High demand charges, as well as high energy charges, may encourage customers to self-generate at costs above LRMC, where the utility's average rates exceed LRMC. High embedded costs, due to past bad investments or bad luck, may make it difficult to retain customers, regardless of rate design.

If the utility is willing to accept less certainty that the cogenerator will be developed, it can increase economic operating efficiency by offering lower prices (but still above SRMC) to customers who have demonstrated the design for cost-effective cogeneration.[50] In exchange for these lower rates, the customer would be responsible for actually bringing the cogeneration unit on line when the utility needs it. This arrangement satisfies the long-run objective of including the plant in expansion plans, while delaying the date at which it operates. Similar schemes have been proposed by utilities in various states, although those proposals may have anti-trust and supply-planning flaws.

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50. This will probably mean lower total revenues, and not just a shift of revenues from energy to demand charges. In some situations, the utility should administer the program and absorb the losses in revenues which result from the reduced rates.

## 3.6 Exceptions to the Rule: Situations in Which Short-Run Pricing is Appropriate

Q: **When is SRMC pricing appropriate for an electric utility?**

A: SRMC is an appropriate guide for ratemaking when the utility does not expect current rates to have significant long-term effects. This situation would arise when the utility has no obligation to serve, as in many wholesale transactions. As discussed above, prices can also be moved toward SRMC for a retail customer on the verge of installing its own generation, if the utility can be assured that the customer can be disconnected before utility capacity would have to be added due to either rising SRMC sharply or inadequate reliability.

SRMC pricing will rarely work unless the utility can either disconnect the customer or radically raise the customer's rates when SRMC increases. The utility's control must continue for a time period approximating the planning cycle. If a high load-factor customer can be on SRMC-based rates for several years when short-run energy costs are low, and then switch back to LRMC rates when (and if) short-run energy costs rise above LRMC, the utility will have to include the customer's load in long-range planning. In this situation, SRMC pricing would simply encourage the customer to increase its load in the short run, complicating the utility's job of projecting sales at the ultimate LRMC-based rates.

SRMC pricing will also require that the utility have some unequivocal manner for determining whether the customer, and the associated load, are fully off the system. If a firm can relocate production to another location, and thus switch from SRMC rates to LRMC rates at will, the utility can not discount the load for planning purposes. The same is true if the customer goes put of business, to be replaced by a comparable customer.

Retail applications of SRMC will therefore be limited to very special industrial situations. For example, an air reduction plant[51] might be offered short-run rates, without any right to switch to LRMC rates. Such facilities are routinely started up and shut down, depending on local electricity prices. Since the market is national, production is unlikely to shift to another local facility when SRMC rises. It would also be easy for WMECO to identify and penalize any attempt to shift production to an alternative local site.

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51. These plants extract compressed gases from the atmosphere. The process is very energy-intensive, and is very flexible in terms of location of raw materials (which are everywhere) and skilled labor (which is needed in relatively small amounts).

### 3.7 Calculating Long-Run Marginal Costs

Q: **What comments do you have on the appropriate calculation of LRMC?**

A: Given the limited purposes of this testimony, it would not be appropriate for me to discuss all the aspects of LRMC computation. However, I would like to point out three areas in which the DPU's approach underestimates LRMC, and provides inadequate price signals to consumers. The first two points involve the discounting of future costs.

The first point is that discounting of capitalized energy costs, from the projected date of operation of the next unit to be committed, back to the present time, may systematically understate costs. Consider an example in which the current and future marginal supply of power is from plants which cost 2 cents/kWh for fuel and 8 cents/kWh for all other costs, all stated in 1987 dollars. Thus, the cost of supplying additional power in any year is clearly 10 cents/kWh.

Suppose further that the plants under consideration require a firm commitment well in advance of their operation dates. For example, the utility might need to sign a firm contract with a third-party developer seven years before the plant is to enter service. Thus, the units entering service this year, or for the next six years, are no longer avoidable: the avoidable capitalized energy charge is for the potential unit seven years out, for which a contract must be signed this year.

The DPU's standard approach to pricing for future capacity, such as in the modified peaker method, is to discount the cost of capacity back to the present at the utility's allowed rate of return. At the present time, this would represent a real discount rate of about 5%.[52] Thus, the hypothetical 8 cent/kWh capacity to be added seven years hence would be discounted to about 5.7 cents, and the total calculated LRMC would be about 7.7 cents, well below the real cost of serving additional load. As long as projected costs remain constant in real terms, exactly the same calculation would be repeated every year, and LRMC-based rates would remain permanently below LRMC.[53] Thus, the discounting of future costs clearly produces understated estimates of LRMC.

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52. Roughly 10% return, minus 5% inflation.

53. Inflation would increase both the LRMC and the calculated rate proportionately. For example, at 5% inflation, the LRMC would be 16.3 cents in 1997 dollars, while the rate calculation would 12.5 cents.

Q: **What solution do you propose for understating of LRMC due to discounting?**

A: Future costs should be deflated to remove the effects of inflation, but should not be discounted to reflect the time value of money (i.e., real interest rates should be left in, and only the nominal portion of interest rates should be removed).

Q: **What is your second point regarding discounting?**

A: It is firmly established in financial theory that not all cash flows should be discounted at the same rate. Discount rates should reflect the riskiness of the cash flow, and the correlation of that cash flow with the total undiversified riskiness of the operation. For our purpose, we are interested in the correlation of costs and benefits with total utility costs, and with the general welfare of the utility and its customers. To state the rules simply in this context:

- Costs which are high when the utility and its customers are in good shape, but low when they are troubled, should be discounted more than risk-free costs.

- Costs which are low in good times, and high in bad times, should be discounted less than risk-free costs.

- Benefits which are high in good times, and low in bad times, should be discounted more than risk-free benefits.

- Benefits which are high in otherwise bad times (when they are most needed), and low in good times, should be discounted less than risk-free benefits.

For example, the costs of oil and gas power plant fuels tend to be high when other costs (e.g., gasoline, space heating fuels) are high, when total electric bills are high (since these fuels are an important part of total utility costs), and when New England is at the greatest disadvantage with respect to other regions. These costs come at the worst time for our region, and the uncertainty in these costs is not at all advantageous to us (as was widely recognized, even by utilities, until fairly recently). Thus, projected marginal costs based on the market prices of oil and gas should be discounted at a lower rate than other costs.[54]

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54. The opposite might be true for oil and gas cost projections in rate design for a Texas utility. While some other costs are still correlated with utility gas costs, the dominant effects of high gas prices on the Texas economy is positive. A Texas utility would be passing on high fuel costs to its customers at just those times when they can (on average) best afford them, and when the State is best able to assist those with trouble paying their bills.

Q: **What are the major implications of risk and discounting for retail electric rate design?**

A: The primary implication for New England utilities is that projected marginal costs based on projections of gas and oil prices should be discounted less than other costs. As a result, rate designs based on such marginal costs should have higher tail-block energy charges than would be the case if the same projected marginal costs were derived from less risky energy sources.

Q: **What is the third point you wished to make regarding the calculation of LRMC?**

A: At this point, the appropriate LRMC for WMECO is probably not the cost of a new plant NU might build. It is possible that the LRMC avoided will be an expensive purchase, but I think even this is unlikely. Given the fact that the capacity situation for New England as whole is much worse than for NU, either in terms of total capacity or in terms of fuel costs, it is likely that the greatest benefit to consumers from a reduction in retail sales would be an increase in the amount of capacity NU can sell on a long-term basis to other utilities. This sales price is quite high: Boston Edison estimates (DPU 86-253, IR #3) that its current purchase from NU will cost it about 6.4 cents this year and 8.8 cents by 1990. Higher prices are certainly possible, since Boston Edison is offering up to 13.63

cents/kWh for a twenty-year QF purchase starting in 1992 (the end of the current NU sale contract). If NU is free to sell more of its capacity (especially Millstone 3) for longer periods in a seller's market, retail rates may be substantially reduced.

## 4 An Application of Short-Run Pricing to NU's Current Situation

Q: **If the DPU were to decide to implement the PHB/NU approach to measuring marginal cost, how should it do so?**

A: If the Commission determined, despite the numerous shortcomings in the PHB model, and regardless of the dangers created by the rate design methodology NU and PHB have advocated, to rely on SRMC in setting retail electric rates, it would do so in two steps. The first step is to determine whether or not a capacity constrain applies, and the second step is to actually estimate SRMC.

Q: **Why is the first step necessary?**

A: If an excess capacity condition exists, the PHB model would set energy prices equal to the variable operating cost of the marginal unit in each hour: that is, marginal fuel costs. If the system is capacity constrained, the marginal cost must be increased until demand equals supply. Thus, the calculation of SRMC varies substantially, depending on whether or not excess capacity exists.

### 4.1 No Excess Capacity Situation Exists for WMECO Rate Design

Q: **What is the relevant system level at which to determine whether a capacity constraint exists for WMECO rate design purposes?**

A: WMECO's capacity is dispatched by NEPOOL to meet overall New England loads. If WMECO and/or NU were capacity deficient (that is, if they did not have sufficient capacity to meet their requirements to NEPOOL), the reliability of supply to WMECO's customers would not be materially affected, so long as NEPOOL had sufficient capacity. Conversely, if NU and WMECO have more capacity than they need to meet their NEPOOL obligations, but NEPOOL as a whole is short on capacity, WMECO customers are subject to blackouts.[55] Thus, we must look to NEPOOL to determine whether an excess capacity situation exists, as it applies to WMECO rate design considerations.

Q: **Is New England currently in an excess capacity situation?**

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55. Of course, transmission and distribution problems may cause customer disconnections, regardless of generation capability.

A: No. NEPOOL is projecting that its reliability constraints will be violated for much of 1987. If load growth continues -- and that would be the result of the promotional rate design strategies advocated by the PHB/NU approach -- the capacity situation in 1988 might well be worse than in 1987.

Q: **Can the PHB model be applied directly to electric rate design?**

A: No. The PHB model is deterministic in nature: it assumes that capacity and demand in any year are fixed values, and that capacity is adequate so long as it is larger than load. In fact, available capacity is highly uncertain, even in the short run, due to the variability in the number and size of generating units on forced and planned outages at any time. Thus, the definition of capacity used in the PHB model is useless for rate design purposes in a capacity-constrained situation, unless it is modified to reflect the stochastic nature of capacity, in the ways in which the adequacy of capacity is actually measured.

Q: **How can the stochastic nature of capacity be incorporated in the PHB approach?**

A: In the long term, NEPOOL measures the adequacy of capability by comparing the computed loss-of-load probability (LOLP) to a target LOLP of 1 day in 10 years. This calculation produces the required reserve margins established by NEPOOL for its members' planning purposes.

In the short term, NEPOOL uses a less stochastic standard: reliability is judged to be inadequate if the level of demonstrated capability, minus the sum of scheduled outages and an allowance for unscheduled outages, is less than projected load plus required operating reserves. The allowance for unscheduled outages is set equal to the average level of unscheduled outages in the preceding years. In some weeks, the capacity situation will be much more critical than indicated by this analysis, due to high loads and/or higher unscheduled outages. However, power will often (but not always) be available from other pools at the time of NEPOOL's greatest need, so capacity shortfalls do not necessarily lead to customer disconnections. Considering these offsetting factors, NEPOOL has accepted the capacity calculation described above as a reasonable measure of the adequacy of capability for short-run planning purposes. This standard is set forth in NEPOOL Operating Procedure #5.

Q: **What is NEPOOL's projection for its capacity situation in 1987?**

A: NEPOOL projects that it will be short on capacity in 12 weeks of this year, if Seabrook is in commercial operation by July 1, 1987. The maximum shortfall would be 955 MW.

In the more likely case that Seabrook does not reach commercial operation in 1987, NEPOOL projects shortages in 21 weeks, with shortages of up to 2093 MW. Even this analysis assumes that Pilgrim will return to service in April, while Boston Edison is aiming for a restart date during the summer, and that date could clearly slip further. If Pilgrim were out of operation all year, the shortages would rise to 28 weeks (more than half of the year) and a maximum of 2763 MW.

It is important to recognize that many of the weeks with positive margins are only very slightly positive, indicating that an unseasonably high load or an unusually large outage could cause problems at almost any time.

### 4.2 Applying the PHB Model

Q: **Given the shortfall of available capacity projected for 1987, how would the PHB model suggest setting rates?**

A: Recall that the PHB model consists of two types of pricing prescriptions:

1. If available capacity is not a binding constraint, lower rates to SRMC, to push the system towards a capacity deficiency as soon as possible.

2. If the system is capacity deficient, increase tail-block energy rates until demand falls to the level which available capacity can accommodate.

Thus, in the current capacity-constrained environment, the PHB approach would require increasing the tail-block prices enough to reduce demand to the required level.

Q: **Given the magnitude of the shortfalls projected for the next year, how much must demand be reduced?**

A: The maximum deficiency without Seabrook or Pilgrim is projected to be 2763 MW, in week 32, when the peak load is expected to be 18400 MW.[56] Loads must be reduced by

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56. This is the projected summer peak.

15% to meet NEPOOL's reliability target. Table 4.1 lists the projected peaks, projected shortfalls, and required reductions in load for three cases: NEPOOL projections with Seabrook operating in July, NEPOOL projections without Seabrook, and my modification of NEPOOL's figures for the no-Pilgrim case.

Q: **How much would 1987 tail-block rates have to increase to reduce loads by these percentages?**

A: Table 4.1 computes the required increases based on short-run marginal price elasticities of -0.1 and -0.2. Depending on the capacity case and elasticity assumed, the required increase would be on the order of 30% to 400%.

Q: **How did you select the -0.1 and -0.2 elasticities?**

A: These are typical estimates of short-run (e.g., first-year) own-price elasticities for electricity. For example, NU's estimates of its customers' short-run elasticities vary from -0.06 to -0.22, depending on the service territory and class. Several factors suggest that the effective elasticity in this case would be particularly low:

- Since the rates established in this case would be in effect for only a couple months at the time of NEPOOL's greatest hazards, a very short-run (and hence very low) elasticity is appropriate.
- Only tail blocks will be increased to meet the capacity constraint, not total rates. As a result, some customers may see their marginal prices fall, as inner blocks are reduced. Other

customers will experience higher marginal prices, but lower total bills, due to the reduction in customer charges, demand charges, and inner blocks. The elasticity of demand with respect to these marginal rate design changes must be expected to be smaller than the elasticity with respect to changes in total rates.

- Not all utilities can be expected to change their rate designs in time to encourage conservation in 1987, or even in 1988. The Massachusetts IOUs that do not have rate cases pending (representing about 30% of New England loads) could not have new rates in effect before September 1987, at the absolute earliest. The same is true of IOUs in other states. Many utilities, IOU (including NU) and public, have shown no interest in the erratic pricing suggested by the PHB model. Thus, any utilities that attempted to resolve the short-term capacity constraint through rate design would have to increase tail-block rates by much more than the average increase required for New England.

Q: **How large would the resulting tail-block prices be?**

A: They would be very high. Table 4.2 calculates the existing average tail-block rates for WMECO's major classes. An average tail-block rate is computed, averaging over pricing blocks and time periods, where required. Table 4.3 increases the test-year tail-block rate (including fuel charge) by a range of multipliers spanning the range of required increases indicated in Table 4.1. Projected fuel charges are then subtracted, to yield the base tail-block rate required by the PHB approach in the coming year.

One interesting result of these calculations is shown in the last column, which calculates the revenues left to be collected from all other billing determinants, if all kWh were priced at the tail-block price. Some rates could have no demand or customer charges, and would require some form of inverted block structure, even if the required increase were as small as 30%. If the 400% increase is necessary to clear the market, all rates would require inverted-block structures, some quite steep.

Q: **What do you conclude from your review of the effect of applying PHB's pricing approach to the situation currently facing WMECO?**

A: I reach two major conclusions. First, SRMC pricing requires higher tail-block rates in 1987/88 than does LRMC. Second, the increases required to implement PHB's pricing philosophy are so large that it is unlikely that any utility or regulator would actually follow PHB's approach in times of capacity shortages.

If WMECO had been using LRMC-based rate design over the last several years, and if the DPU had been requiring that rate designs be based on LRMC, rather than SRMC or short-run wholesale rate structures,[57] the current capacity crisis might not exist. The low, promotional tail-block rates in effect for the last several years have produced an avoidable short-run supply problem,

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57. This special pricing rule, which was applied only to Mass Electric and Eastern Edison, probably produced even more promotional rates than did SMRC.

which is now beyond the power of rate design to fix. If the Department wishes to avoid similar problems in future years, it should continue the process it announced in 85-270, of moving all tail-block energy prices toward the long-run price of delivered energy.

## 5 Miscellaneous Rate Design Issues

### 5.1 Demand Charges and Energy Charges

Q: **Through what kinds of billing determinants do NU and PHB favor collecting electric revenues?**

A: NU and PHB favor low energy charges, and hence large demand and customer charges.

Q: **What are justifications do they advance for favoring demand charges over energy charges?**

A: There are two basic justifications. First, they allege that low energy charges and high demand charges give the proper price signals. Second, they express concern about the economic effect of energy charges on industrial customers.

#### 5.1.1 Effectiveness in Controlling Load Growth

Q: **Do high demand charges give appropriate signals for rate design?**

A: No, for four distinct reasons:

1. A fairly small portion of WMECO's costs are caused by the reliability considerations which demand charges might address. This fact is reflected in the Department's use of peaking units to represent the reliability portion of generating capacity cost.

2. Much of the reliability-related costs are caused by loads outside the peak hour. NEPOOL capacity shortages have occurred at loads well below the seasonal peak.

3. Demand charges encourage consumption at, or load-shifting off of, the customer's peak, rather than WMECO, NU, or NEPOOL's peak hour. Customers' non-coincidental peaks are often very different from the WMECO, NU, or NEPOOL peak. Thus, demand charges do not necessarily reduce loads at the system's critical periods.

4. Demand charges are inherently more difficult to control than energy charges, since a malfunction or necessity which increases load for even a single hour may undo a year's worth of conservation and load shifting. This difficulty reduces the incentive for customers to reduce their loads in response to demand charges.

Q: **Does PHB agree that demand charges are not effective price signals?**

A: Yes. PHB concedes that recovering costs through demand charges, rather than energy charges, increases loads. The PHB report (Ex. C-JR-6, page 31) advocates that demand charges be reduced in tight capacity situations, so that energy charges (which do encourage conservation) can be increased.

Q: **Do WMECO's customer tend to experience their peak demand on or near the time of the system peak?**

A: No. Table 5.1 illustrates the lack of coincidence between customer peaks and the system peak, for three classes of customers, and for both summer and winter months. Line 2 shows the percentage of customers who have peak loads on the same day and hour as the system monthly peak load.[58] In half the cases, there were no customers with peak loads coincident with the system peak. In the other cases, only one customer peaked with the system. Lines 3 and 4 display the percentage of customers with peaks on the same day or in the same hour (but usually a different day) as the system peak. In most categories, less than 10% of the customers had peak loads on the same hour or day as the system peak.

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58. The customers were those metered for load research purposes.

Lines 5, 6, and 7 of Table 5.1 repeat the analysis of the first three lines, but examine the maximum peak load of each customer which occurred during on-peak hours. Since both demand and energy charges are lower in off-peak hours, some customers may shift their maximum loads out of the peak period, while still experiencing their maximum peak-period demands at the time of system peak. One would expect the results of this analysis to show greater coincidence in each category than in the first section of Table 5.1. However, the percentage of customers coincident with system peak, system peak hour, and system peak day remain quite low in all categories.

The third section of Table 5.1 displays the total of customer maximum demands, the total of customer on-peak maximum demands, and the sample customers' total contribution to system peak. In each case, the customer non-coincidental peaks are much higher than the contribution to system peak.

The last section of Table 5.1 computes half the difference between the class' non-coincident customer peaks (used for billing), and the class' contribution to system peak. Depending on the month and the class, the average customer could have reduced billing demand by 14% to 29% by shifting half its maximum demand onto the time of system peak. Thus, customers may substantially decrease their own maximum demands, and their demand charges, while increasing WMECO's peak demands and costs.

### 5.1.2 Economic Effects

Q: **What is PHB's support for the contention that energy charges may adversely affect economic development?**

A: PHB asserts that energy prices above SRMC will likely allow competition from other utilities in other states to "remove from the market some consumers" (page 45). Dr. Ruff also alleges that "high-load factor (sic) and off-peak energy users . . . are generally the industrial facilities for whom energy costs are critical factors in competitiveness and in location decisions; loss of load as such customers relocate, self-generate or take other actions could be significant" (page 48).[59]

Q: **Is there any merit to this assertion?**

A: I do not believe so. Dr. Ruff apparently believes that rate design and cost allocation are the same process,

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59. It is not clear that self-generation (by which I assume that Dr. Ruff means cogeneration) at WMECO industrial customers' facilities would be a bad thing for the economy of western Massachusetts. It would increase the reliability of power supply to those and other customers, make the customers more cost-competitive, provide increased employment in the construction and operation of the cogeneration facilities, and increase the tax base of the communities involved. The actions which some utilities, such as Atlantic Electric, are taking to encourage and even finance cogeneration by their customers, would seem to be more beneficial to WMECO's service territory than would Dr. Ruff's opposition to any reduction in WMECO energy sales.

and that using the higher energy charges from LRMC analyses in rate design will somehow shift revenue requirements from residential and commercial ratepayers to industrial ratepayers. In fact, the two processes are completely separate in Massachusett's electric utility rate regulation.

The revenue requirements for each class are normally set prior to any consideration of rate design. In the rate design process, every additional dollar collected in industrial energy rates is one less dollar collected in industrial demand (or customer) charges. For every industrial customer whose bills increase due to higher energy charges, the bills of one or more other customers decrease due to lower demand charges. It is therefore difficult to see how overall industrial development in New England will be harmed by rate design.[60]

While Dr. Ruff alleges that "high-load factor (sic) and off-peak energy users . . . are generally the industrial facilities for whom energy costs are critical factors in competitiveness and in location decisions" (page 48), he presents no evidence to support this allegation.[61]

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60. Industrial development is more likely to be impaired by uncertainty in power supply reliability. The greatest danger to industrial development under consideration in this proceeding may thus be the PHB/NU rate design philosophy of intentional capacity crisis.

61. I assume that Dr. Ruff includes demand charges in his definition of "energy costs". If not, his statement may

Considering the high historic costs of electricity, and particularly of electric energy charges, in New England, it would be surprising if there were many firms left in WMECO's service territory for whom kWh charges were a dominant determinative factor.

For firms or plants on the borderline of profitability, higher energy charges may well prove fatal, all other things being equal. But all other things would not be equal, since increased energy charges would be accompanied by decreased demand charges. Thus, increased energy charges would have little or no effect on many operations, due to the offsetting decrease in demand charges. Indeed, this shift in revenue responsibility may save as many companies as it endangers.

Q: **Is there any reason to believe that high load-factor customers are more vulnerable to competition than are low load-factor customers?**

A: No. If anything, the opposite is likely to be the case. A high load-factor industrial firm, operating three shifts, obviously has considerable demand for its product, and is able to spread its facilities cost over a large amount of output. Its electricity costs per unit of output will tend to be relatively low, since

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be true, but completely irrelevant, since demand charges are also important to many customers.

demand charges will be spread over many hours and a large portion of kWh will be at low off-peak rates. A plant producing the same product, but in a single-shift operation, clearly has lower product demand, higher facilities cost per unit output, and higher electricity costs per unit output, all other things being equal. It is this latter, low load-factor customer who is apt to be at greater risk.

The customers who bear the greatest proportional burden from demand charges are those which operate sporadically. Where such intermittent operation is due to marginal competitiveness and lack of orders, high demand charges may well prove fatal.[62]

Q: **Do you have any direct experience with these issues?**

A: Yes. In CPUCA 83-07-15, I testified on behalf of Alloy Foundry, a low load-factor industrial customer of Connecticut Light & Power which generally operates a single shift, with wide fluctuations in load, due to low and variable demand. Alloy claimed that its competitiveness was badly hurt by the high demand charges, and Alloy's management would have been much happier paying higher energy charges. Among other things, Alloy (and similar endangered operations) pay

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62. This problem is exacerbated by demand ratchets, which continue to charge the struggling firm even when it is not using power.

energy charges to the extent that they have work, while a high demand charge may be triggered by a single rush order on a single day of the month or (with NU's ratchets) anytime in the last year.

Q: **Would high load-factor and off-peak industrial customers continue to pay less per kWh than low load-factor customers, even if demand charges were entirely eliminated?**

A: Yes. All of WMECO's industrial rates have time-of-use energy differentials. Thus, some high load-factor customers could have lower rates without demand charges. Some small demand charges are likely to be appropriate indefinitely, and continuity considerations will tend to make the transition to low demand charges a rather protracted process.

## 5.2 Economic Development Rates

Q: **Are you familiar with the Commission's discussion in D.P.U. 85-270 of the potential effects of LRMC on economic development and employment in WMECO's service territory?**

A: Yes.

Q: **Does the PHB study demonstrate any relationship between LRMC and economic development?**

A: No. As I discuss above, LRMC (and low demand charges) is more likely to protect marginal firms than would PHB's SRMC (and high demand charges).[63]

Q: **If the Commission wishes to use electric rate design to encourage economic growth in WMECO's service territory, how should it do so?**

A: In encouraging economic growth, the Commission should not tamper with the incentives for customers to avoid long-run power supply costs, by carrying out less expensive efficiency improvements. Any incentives

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63. If properly applied, PHB's pricing approach would result in very low demand charges for the next couple of years. As noted in the previous section, such proper application is impractical, and no party is advocating it in this case.

should be directly addressed to the goal the Commission wishes to foster, rather than to the increased use of electricity. The Commission may legitimately desire to encourage industrial investments and industrial employment,[64] but it has no reason to encourage industries to increase their use of electricity. On the contrary, existing electricity use in New England must decline if we are to accommodate much more industrial activity.

Hence, any incentives for economic development should be designed in terms of dollars of utility bill credit per employee, or dollars of credit per dollar invested, rather than as a discount in energy or demand rate.

Massachusetts Electric takes this concept one step further, by targeting conservation investments to improve the economic viability of customers considered most at risk, or most needed by the local economy. This policy supports vulnerable businesses, while freeing up resources for new loads anywhere in the service territory. Mass Electric simply identified regions in the state which required special assistance, but WMECO

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64. The same approach could be taken to those commercial customers which represent an export opportunity, such as corporate headquarters and "back-room" computer facilities. There is no point in providing these incentives to retail stores and offices of local services, since they must locate in the region anyway in order to serve their market: incentives would simply encourage new firms to replace existing firms.

could further tie special conservation assistance to customers who agreed to increase employment.

### 5.3 Spot Pricing

**Q: Is the concept of LRMC pricing consistent with the spot pricing of retail electricity?**

A: Yes. In spot pricing, rates vary continuously, to reflect changes in short-run marginal costs (or the market-clearing price). The buyer receives new prices regularly,[65] and can decide whether to increase consumption, decrease consumption, shift loads, or alter generation patterns. This is the scheme generally used for economy sales between power pools, or between utilities which do not dispatch together. The application of this concept to retail rates is more complicated, but certainly feasible, for the few large customers whose consumption and flexibility justify the metering and communication expenses.

The primary complication in spot pricing for retail rate design is that, like any SRMC-based rate design, it gives customers the wrong signals for conservation investments, and the resulting loads give the utility the wrong signals for power supply investments. While the differences or ratios between hourly rates may be

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65. New prices may be posted every few minutes, or every hour, or a schedule of prices may be posted each evening for delivery in each hour of the next day.

shaped to reflect SMRC, the overall level of rates must reflect LRMC, or the utility will tend to build additional capacity, to meet loads which would not exist if customers were charged the cost of that capacity. Thus, it would be appropriate for WMECO to send its large customers hourly price signals, based on actual running costs or a short-run (daily or weekly forecast of those costs) and then to recover the shortfall (or return the surplus) in total energy charges compared to LRMC, in proportion to the customer's current or previous kWh consumption.[66]

A second complication arises in periods of low system reliability, such as the present. In order to properly price spot energy, WMECO would need good short-term forecasts of hourly expected average shortage costs, to add to the running costs.[67] This involves estimating the probability of customer disconnections related to generation or transmission problems; the location, advance notice, and duration of disconnections; and the cost of the shortage, given the customers involved, and the timing, advance notice, and duration of the

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66. This approach also minimizes the revenue volatility to WMECO.

67. These forecasts are not necessary for wholesale economy sales, since the sales are simply discontinued, on essentially no warning, when the seller's reliability situation becomes problematic. The same approach is not feasible for retail sales with an obligation to serve, and non-trivial costs for customer disconnections.

disconnection. Until WMECO develops a methodology for rapidly projecting these values, implementation of a retail spot-pricing scheme will provide incomplete and understated cost information.

Q: **Does this conclude your testimony?**

A: Yes.

TABLE 3.1: LRMC AND SRMC CALCULATION OF CAPACITY ADDITIONS

| | Existing Capacity | | | | | With First 400 MW Addition | | | |
|---|---|---|---|---|---|---|---|---|---|
| | L | L(Oil) | L(Base) | 1st Short-run Marginal Cost | Net Present Value of Added Capacity | L(New) | L(Oil) | 2nd Short-run Marginal Cost | Net Present Value of Added Capacity |
| | [1] | [2a] | [3] | [4a] | [5a] | [6a] | [2b] | [4b] | [5b] |
| 1986 | 3500 | 700 | 2800 | $0.09 | ($0.44) | 0 | 700 | $0.09 | ($0.83) |
| 1987 | 3620 | 820 | 2800 | $0.10 | ($0.29) | 0 | 820 | $0.10 | ($0.71) |
| 1988 | 3740 | 940 | 2800 | $0.11 | ($0.14) | 0 | 940 | $0.11 | ($0.60) |
| 1989 | 3860 | 1060 | 2800 | $0.13 | $0.01 | 400 | 660 | $0.09 | ($0.49) |
| 1990 | 3980 | 1180 | 2800 | $0.14 | $0.16 | 400 | 780 | $0.10 | ($0.34) |
| 1991 | 4100 | 1300 | 2800 | $0.15 | $0.31 | 400 | 900 | $0.11 | ($0.19) |
| 1992 | 4220 | 1420 | 2800 | $0.16 | $0.46 | 400 | 1020 | $0.12 | ($0.04) |
| 1993 | 4340 | 1540 | 2800 | $0.17 | $0.61 | 400 | 1140 | $0.13 | $0.11 |
| 1994 | 4460 | 1660 | 2800 | $0.19 | $0.76 | 400 | 1260 | $0.15 | $0.26 |
| 1995 | 4580 | 1780 | 2800 | $0.20 | $0.91 | 400 | 1380 | $0.16 | $0.41 |
| 1996 | 4700 | 1900 | 2800 | $0.21 | $1.06 | 400 | 1500 | $0.17 | $0.56 |
| 1997 | 4820 | 2020 | 2800 | $0.22 | $1.21 | 400 | 1620 | $0.18 | $0.71 |
| 1998 | 4940 | 2140 | 2800 | $0.23 | $1.36 | 400 | 1740 | $0.19 | $0.86 |
| 1999 | 5060 | 2260 | 2800 | $0.25 | $1.51 | 400 | 1860 | $0.21 | $1.01 |
| 2000 | 5180 | 2380 | 2800 | $0.26 | $1.66 | 400 | 1980 | $0.22 | $1.16 |
| 2001 | 5300 | 2500 | 2800 | $0.27 | $1.80 | 400 | 2100 | $0.23 | $1.31 |
| 2002 | 5420 | 2620 | 2800 | $0.28 | $1.95 | 400 | 2220 | $0.24 | $1.46 |
| 2003 | 5540 | 2740 | 2800 | $0.29 | $2.10 | 400 | 2340 | $0.25 | $1.61 |
| 2004 | 5660 | 2860 | 2800 | $0.31 | $2.25 | 400 | 2460 | $0.27 | $1.76 |
| 2005 | 5780 | 2980 | 2800 | $0.32 | $2.40 | 400 | 2580 | $0.28 | $1.90 |
| 2006 | 5900 | 3100 | 2800 | $0.33 | $2.55 | 400 | 2700 | $0.29 | $2.05 |

| With Second 400 MW Addition | | | | With Third 400 MW Addition | | |
|---|---|---|---|---|---|---|
| L(New) | L(Oil) | 3rd Short-run Marginal Cost | Net Present Value of Added Capacity | L(New) | L(Oil) | 4th Short-run Marginal Cost |
| [6b] | [2c] | [4c] | [5c] | [6c] | [2d] | [4d] |
| 0.00 | 700 | $0.09 | ($1.09) | 0.00 | 700 | $0.09 |
| 0.00 | 820 | $0.10 | ($1.01) | 0.00 | 820 | $0.10 |
| 0.00 | 940 | $0.11 | ($0.91) | 0.00 | 940 | $0.11 |
| 0.00 | 660 | $0.09 | ($0.81) | 0.00 | 660 | $0.09 |
| 0.00 | 780 | $0.10 | ($0.68) | 0.00 | 780 | $0.10 |
| 0.00 | 900 | $0.11 | ($0.55) | 0.00 | 900 | $0.11 |
| 0.00 | 1020 | $0.12 | ($0.42) | 0.00 | 1020 | $0.12 |
| 400.00 | 740 | $0.09 | ($0.29) | 0.00 | 740 | $0.09 |
| 400.00 | 860 | $0.11 | ($0.12) | 0.00 | 860 | $0.11 |
| 400.00 | 980 | $0.12 | $0.05 | 400.00 | 580 | $0.08 |
| 400.00 | 1100 | $0.13 | $0.23 | 400.00 | 700 | $0.09 |
| 400.00 | 1220 | $0.14 | $0.40 | 400.00 | 820 | $0.10 |
| 400.00 | 1340 | $0.15 | $0.57 | 400.00 | 940 | $0.11 |
| 400.00 | 1460 | $0.17 | $0.75 | 400.00 | 1060 | $0.13 |
| 400.00 | 1580 | $0.18 | $0.93 | 400.00 | 1180 | $0.14 |
| 400.00 | 1700 | $0.19 | $1.10 | 400.00 | 1300 | $0.15 |
| 400.00 | 1820 | $0.20 | $1.28 | 400.00 | 1420 | $0.16 |
| 400.00 | 1940 | $0.21 | $1.46 | 400.00 | 1540 | $0.17 |
| 400.00 | 2060 | $0.23 | $1.65 | 400.00 | 1660 | $0.19 |
| 400.00 | 2180 | $0.24 | $1.83 | 400.00 | 1780 | $0.20 |
| 400.00 | 2300 | $0.25 | $2.02 | 400.00 | 1900 | $0.21 |

[1] L =Load = 3000 MW * 1.04 ^ # of years.
[2a,b,c,d] L(Oil) = Load served by oil capacity.
L(Oil) = L - L(Base) - L(New).
[3] L(Base) = Existing base load = 2800 MW.
[4a,b,c,d] Short-run marginal cost = ($.02 + $.0001 * L(Oil) ) *1^year.
[5a,b,c] Net present value of Short-run marginal cost minus $.20, at 5% for 20 years. See Table 3.2.
[6a,b,c] L(New) = New Capacity. New capacity is added when present value of savings due to incremental new capacity (400 MW) over 20 years is greater or equal to $.20 (assumed cost of new capacity).

## LE 3.2: DERIVATION OF NET PRESENT VALUE OF ADDITIONAL CAPACITY

Cost of Capital [1]: $0.20

| | 1st Short-run Marginal Cost ---[2]--- | Marginal Cost Minus Capital Cost ----[3]----- | 1st Net Present Value of Added Capacity ---[4]--- | 2nd Short-run Marginal Cost ---[5]--- | Marginal Cost Minus Capital Cost ----[6]----- | 2nd Net Present Value of Added Capacity ---[7]--- | 3rd Short-run Marginal Cost ---[8]--- | Marginal Cost Minus Capital Cost ----[9]---- | 3rd Net Present Value of Added Capacity ---[10]--- |
|---|---|---|---|---|---|---|---|---|---|
| 1986 | $0.09 | ($0.13) | ($0.44) | $0.09 | ($0.13) | ($0.83) | $0.09 | ($0.13) | ($1.09) |
| 1987 | $0.10 | ($0.12) | ($0.29) | $0.10 | ($0.12) | ($0.71) | $0.10 | ($0.12) | ($1.01) |
| 1988 | $0.11 | ($0.11) | ($0.14) | $0.11 | ($0.11) | ($0.60) | $0.11 | ($0.11) | ($0.91) |
| 1989 | $0.13 | ($0.09) | $0.01 | $0.09 | ($0.13) | ($0.49) | $0.09 | ($0.13) | ($0.81) |
| 1990 | $0.14 | ($0.08) | $0.16 | $0.10 | ($0.12) | ($0.34) | $0.10 | ($0.12) | ($0.68) |
| 1991 | $0.15 | ($0.07) | $0.31 | $0.11 | ($0.11) | ($0.19) | $0.11 | ($0.11) | ($0.55) |
| 1992 | $0.16 | ($0.06) | $0.46 | $0.12 | ($0.10) | ($0.04) | $0.12 | ($0.10) | ($0.42) |
| 1993 | $0.17 | ($0.05) | $0.61 | $0.13 | ($0.09) | $0.11 | $0.09 | ($0.13) | ($0.29) |
| 1994 | $0.19 | ($0.03) | $0.76 | $0.15 | ($0.07) | $0.26 | $0.11 | ($0.11) | ($0.12) |
| 1995 | $0.20 | ($0.02) | $0.91 | $0.16 | ($0.06) | $0.41 | $0.12 | ($0.10) | $0.05 |
| 1996 | $0.21 | ($0.01) | $1.06 | $0.17 | ($0.05) | $0.56 | $0.13 | ($0.09) | $0.23 |
| 1997 | $0.22 | $0.00 | $1.21 | $0.18 | ($0.04) | $0.71 | $0.14 | ($0.08) | $0.40 |
| 1998 | $0.23 | $0.01 | $1.36 | $0.19 | ($0.03) | $0.86 | $0.15 | ($0.07) | $0.57 |
| 1999 | $0.25 | $0.03 | $1.51 | $0.21 | ($0.01) | $1.01 | $0.17 | ($0.05) | $0.75 |
| 2000 | $0.26 | $0.04 | $1.66 | $0.22 | ($0.00) | $1.16 | $0.18 | ($0.04) | $0.93 |
| 2001 | $0.27 | $0.05 | $1.80 | $0.23 | $0.01 | $1.31 | $0.19 | ($0.03) | $1.10 |
| 2002 | $0.28 | $0.06 | $1.95 | $0.24 | $0.02 | $1.46 | $0.20 | ($0.02) | $1.28 |
| 2003 | $0.29 | $0.07 | $2.10 | $0.25 | $0.03 | $1.61 | $0.21 | ($0.01) | $1.46 |
| 2004 | $0.31 | $0.09 | $2.25 | $0.27 | $0.05 | $1.76 | $0.23 | $0.01 | $1.65 |
| 2005 | $0.32 | $0.10 | $2.40 | $0.28 | $0.06 | $1.90 | $0.24 | $0.02 | $1.83 |
| 2006 | $0.33 | $0.11 | $2.55 | $0.29 | $0.07 | $2.05 | $0.25 | $0.03 | $2.02 |
| 2007 | $0.00 | $0.12 | $0.00 | $0.00 | $0.08 | $0.00 | $0.00 | $0.08 | $0.00 |
| 2008 | $0.00 | $0.13 | $0.00 | $0.00 | $0.09 | $0.00 | $0.00 | $0.09 | $0.00 |
| 2009 | $0.00 | $0.15 | $0.00 | $0.00 | $0.11 | $0.00 | $0.00 | $0.11 | $0.00 |
| 2010 | $0.00 | $0.16 | $0.00 | $0.00 | $0.12 | $0.00 | $0.00 | $0.12 | $0.00 |
| 2011 | $0.00 | $0.17 | $0.00 | $0.00 | $0.13 | $0.00 | $0.00 | $0.13 | $0.00 |
| 2012 | $0.00 | $0.18 | $0.00 | $0.00 | $0.14 | $0.00 | $0.00 | $0.14 | $0.00 |
| 2013 | $0.00 | $0.19 | $0.00 | $0.00 | $0.15 | $0.00 | $0.00 | $0.15 | $0.00 |
| 2014 | $0.00 | $0.21 | $0.00 | $0.00 | $0.17 | $0.00 | $0.00 | $0.17 | $0.00 |
| 2015 | $0.00 | $0.22 | $0.00 | $0.00 | $0.18 | $0.00 | $0.00 | $0.18 | $0.00 |
| 2016 | $0.00 | $0.23 | $0.00 | $0.00 | $0.19 | $0.00 | $0.00 | $0.19 | $0.00 |
| 2017 | $0.00 | $0.24 | $0.00 | $0.00 | $0.20 | $0.00 | $0.00 | $0.20 | $0.00 |
| 2018 | $0.00 | $0.25 | $0.00 | $0.00 | $0.21 | $0.00 | $0.00 | $0.21 | $0.00 |
| 2019 | $0.00 | $0.27 | $0.00 | $0.00 | $0.23 | $0.00 | $0.00 | $0.23 | $0.00 |
| 2020 | $0.00 | $0.28 | $0.00 | $0.00 | $0.24 | $0.00 | $0.00 | $0.24 | $0.00 |
| 2021 | $0.00 | $0.29 | $0.00 | $0.00 | $0.25 | $0.00 | $0.00 | $0.25 | $0.00 |
| 2022 | $0.00 | $0.30 | $0.00 | $0.00 | $0.26 | $0.00 | $0.00 | $0.26 | $0.00 |
| 2023 | $0.00 | $0.31 | $0.00 | $0.00 | $0.27 | $0.00 | $0.00 | $0.27 | $0.00 |
| 2024 | $0.00 | $0.33 | $0.00 | $0.00 | $0.29 | $0.00 | $0.00 | $0.29 | $0.00 |
| 2025 | $0.00 | $0.34 | $0.00 | $0.00 | $0.30 | $0.00 | $0.00 | $0.30 | $0.00 |

Notes:

[illegible],[5], and [8] ($.02 + $.0001 * L(Oil)) [illegible] f1^year.
[3],[6], and [9] Short-run marginal cost - 200 - capital cost of new additions.
[4],[7], and [10] Net present value of Column [3] for twenty years beginning in the present year, at a discount rate of 5%.

FIGURE 3.1

(PHB Figure A-4)

LONG-RUN MARGINAL COST: A GUIDE TO CAPACITY DECISIONS

CASE B: "LUMPY" CAPACITY ADDITIONS

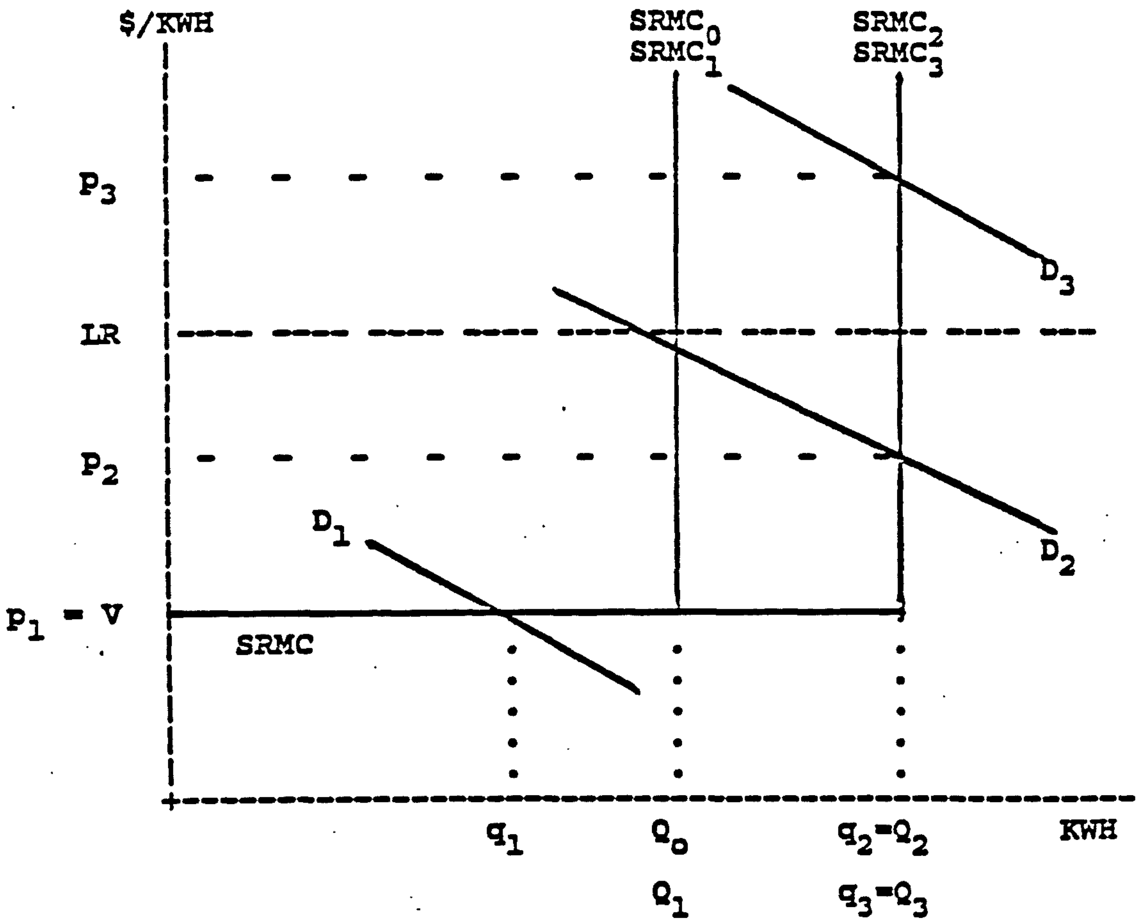
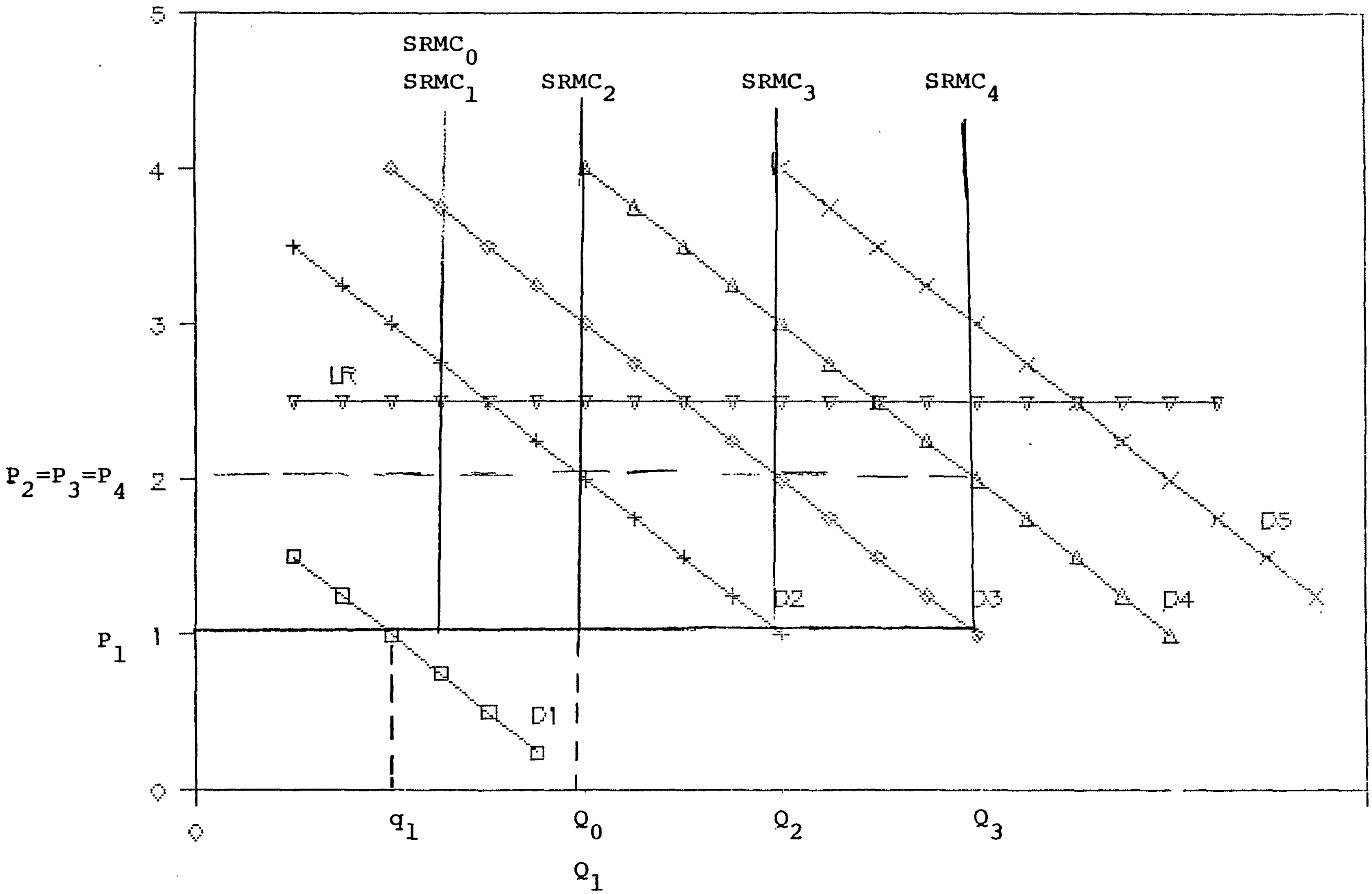


FIGURE 3.2

MULTIPLE LUMPY CAPITAL ADDITIONS



# FIGURE 3.3: LRMC AND AVERAGE SRMC

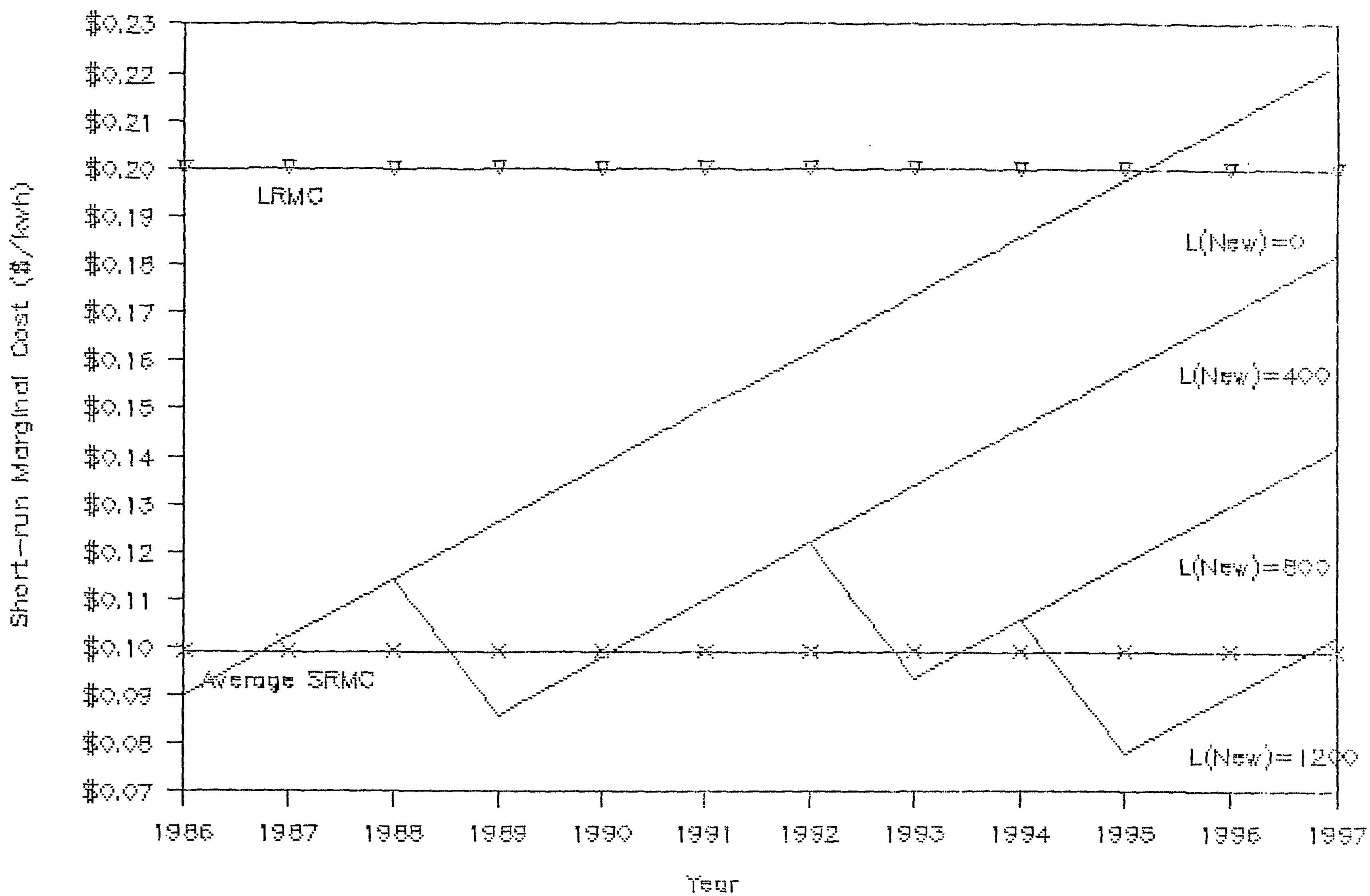


TABLE 4.1

| | | | | | | |
|---|---|---|---|---|---|---|
| 1. Case: | Seabrook in 7/1 Pilgrim in 4/1 | | No Seabrook | | No Seabrook No Pilgrim | |
| 2. Weeks negative margin: | 12 | | 21 | | 28 | |
| 3. Maximum Negative Margin: | 955 | | 2093 | | 2763 | |
| 4. Peak Load (MW): | 18400 | | 18400 | | 18400 | |
| 5. Shortfall in % [3]/[4]: | 5.2% | | 11.4% | | 15.0% | |
| 6. Elasticity: | -0.1 | -0.2 | -0.1 | -0.2 | -0.1 | -0.2 |
| 7. Price Increase Required to Eliminate Shortfall: | 70% | 31% | 235% | 93% | 409% | 126% |

Source: [1] - [5] Memo to NEPOOL Operations Committee from E. Kenneth Nielson, 12/9/86.

[6] Price elasticities are estimated based on the results of NU Studies. From the *NU Forecast of Loads and Resources*, 1986, page 107.

TABLE 4.2: AVERAGE TAIL BLOCK RATES

| Rate | Energy Tail Block | Test Year Tail Blocks: Base Rate | W/Fuel | KWH |
|---|---|---|---|---|
| R-1 | Under 800 kwh | 7.966 | 9.304 | 74.82% |
| | Over 800 kwh | 6.134 | 7.472 | 25.18% |
| | Total/Average | 7.505 | 8.843 | 100.00% |
| R-1 WH | Under 400 kwh | 7.966 | 9.304 | 6.10% |
| | Over 400 kwh | 6.134 | 7.472 | 93.90% |
| | Total/Average | 6.246 | 7.584 | 100.00% |
| R-3 | Under 800 kwh | 6.734 | 8.072 | 28.44% |
| | Over 800 kwh | 5.938 | 7.276 | 71.56% |
| | Total/Average | 6.164 | 7.502 | 100.00% |
| R-3 WH | Under 400 kwh | 6.734 | 8.072 | 1.57% |
| | Over 400 kwh | 5.938 | 7.276 | 98.43% |
| | Total/Average | 5.950 | 7.288 | 100.00% |
| G-0 | | 5.12 | 6.458 | -- |
| G-1 | | 4.942 | 6.28 | -- |
| G-2 | | 4.939 | 6.277 | -- |
| T-2 | Peak | 4.463 | 5.801 | 122.7 |
| | Off-Peak | 2.831 | 4.169 | 91.7 |
| | Total/Average | 3.765 | 5.103 | 214.4 |
| G-3 | Peak | 5.086 | 6.424 | 467.6 |
| | Off-Peak | 3.227 | 4.565 | 364.3 |
| | Total/Average | 4.272 | 5.610 | 831.9 |
| G-4 | Peak | 4.467 | 5.805 | 80.2 |
| | Off-Peak | 2.825 | 4.163 | 61.7 |
| | Total/Average | 3.753 | 5.091 | 141.9 |

Notes: [1] Schedule E-2. Total/Average weighted by Column [3].
[2] [1] plus 1.338, from Schedule E-4.1, total fuel revenue divided by total kwh.
[3] From IR AG-CJR-3, and WPE 4.2. Residential in %, GS in GWH.

E 4.3(A): LOWEST INCREASE IN TAIL BLOCK

Increase in Tail Block [8]: 31%

| Rates | KWH Sales ---[1]--- | Proposed Base Revenue ---[2]-- | Test Year Average Tail Block With Fuel (Cents/kwh) ---[3]--- | Tail Block With Fuel (Cents/kwh) ---[4]--- | Tail Block Without Fuel (Cents/kwh) ---[5]--- | Tail Block Revenues ---[6]--- | Other Revenues --[7]--- |
|---|---|---|---|---|---|---|---|
| R-1 | 581,369,687 | $57,328,061 | 8.843 | 11.543 | 10.104 | $58,741,680 | ($1,413,619) |
| R-1 WH | 199,261,032 | $17,176,457 | 7.584 | 9.900 | 8.461 | $16,858,712 | $317,745 |
| R-3 | 60,577,020 | $4,954,100 | 7.502 | 9.793 | 8.354 | $5,060,846 | ($106,746) |
| 3 WH | 295,576,870 | $21,537,362 | 7.288 | 9.514 | 8.075 | $23,868,421 | ($2,331,059) |
| G-0 | 282,535,830 | $25,224,535 | 6.458 | 8.430 | 6.991 | $19,752,338 | $5,472,197 |
| G-1 | 86,278,165 | $6,294,174 | 6.280 | 8.198 | 6.759 | $5,831,313 | $462,861 |
| G-2 | 368,679,226 | $23,529,180 | 6.277 | 8.194 | 6.755 | $24,903,615 | ($1,374,435) |
| T-2 | 327,421,475 | $19,934,833 | 5.801 | 7.572 | 6.133 | $20,082,272 | ($147,439) |
| G-3 | 823,896,255 | $47,739,578 | 5.610 | 7.323 | 5.884 | $48,478,310 | ($738,732) |
| G-4 | 141,939,392 | $7,069,733 | 5.091 | 6.646 | 5.207 | $7,390,379 | ($320,646) |

TABLE 4.3(B): HIGHEST INCREASE IN TAIL BLOCK

Increase in Tail block [8]: 409%

| Rates | KWH Sales | Proposed Base Revenue | Test Year Average Tail Block With Fuel (Cents/kwh) | Tail Block With Fuel (Cents/kwh) | Tail Block Without Fuel (Cents/kwh) | Tail Block Revenues | Other Revenues |
|---|---|---|---|---|---|---|---|
| ----- | ---[1]--- | ---[2]-- | ---[3]--- | ---[4]--- | ---[5]--- | ---[6]--- | --[7]--- |
| R-1 | 581,369,687 | $57,328,061 | 8.843 | 45.002 | 43.563 | $253,260,307 | ($195,932,246) |
| R-1 WH | 199,261,032 | $17,176,457 | 7.584 | 38.595 | 37.156 | $74,036,888 | ($56,860,431) |
| R-3 | 60,577,020 | $4,954,100 | 7.502 | 38.181 | 36.742 | $22,256,983 | ($17,302,883) |
| R-3 WH | 295,576,870 | $21,537,362 | 7.288 | 37.092 | 35.653 | $105,382,428 | ($83,845,066) |
| G-0 | 282,535,830 | $25,224,535 | 6.458 | 32.866 | 31.427 | $88,791,479 | ($63,566,944) |
| G-1 | 86,278,165 | $6,294,174 | 6.280 | 31.960 | 30.521 | $26,332,752 | ($20,038,578) |
| G-2 | 368,679,226 | $23,529,180 | 6.277 | 31.944 | 30.505 | $112,467,415 | ($88,938,235) |
| T-2 | 327,421,475 | $19,934,833 | 5.801 | 29.522 | 28.083 | $91,949,986 | ($72,015,153) |
| G-3 | 823,896,255 | $47,739,578 | 5.610 | 28.550 | 27.111 | $223,363,466 | ($175,623,888) |
| G-4 | 141,939,892 | $7,069,733 | 5.091 | 25.909 | 24.470 | $34,732,644 | ($27,662,911) |

TABLE 4.3(C): AVERAGE INCREASE IN TAIL BLOCK

Increase in Tail Block [8]: 159%

| Rates | KWH Sales | Proposed Base Revenue | Test Year Average Tail Block With Fuel (Cents/kwh) | Tail Block With Fuel (Cents/kwh) | Tail Block Without Fuel (Cents/kwh) | Tail Block Revenues | Other Revenues |
|---|---|---|---|---|---|---|---|
| ----- | ---[1]--- | ---[2]-- | ---[3]--- | ---[4]--- | ---[5]--- | ---[6]--- | --[7]--- |
| R-1 | 581,369,687 | $57,328,061 | 8.843 | 22.886 | 21.447 | $124,686,488 | ($67,358,427) |
| R-1 WH | 199,261,032 | $17,176,457 | 7.584 | 19.628 | 18.189 | $36,242,994 | ($19,066,537) |
| R-3 | 60,577,020 | $4,954,100 | 7.502 | 19.417 | 17.978 | $10,890,601 | ($5,936,501) |
| R-3 WH | 295,576,870 | $21,537,362 | 7.288 | 18.864 | 17.425 | $51,502,924 | ($29,965,562) |
| G-0 | 282,535,830 | $25,224,535 | 6.458 | 16.714 | 15.275 | $43,157,669 | ($17,933,134) |
| G-1 | 86,278,165 | $6,294,174 | 6.280 | 16.253 | 14.814 | $12,781,616 | ($6,487,442) |
| G-2 | 368,679,226 | $23,529,180 | 6.277 | 16.246 | 14.807 | $54,589,091 | ($31,059,911) |
| T-2 | 327,421,475 | $19,934,833 | 5.801 | 15.014 | 13.575 | $44,446,533 | ($24,511,700) |
| G-3 | 823,896,255 | $47,739,578 | 5.610 | 14.519 | 13.080 | $107,767,069 | ($60,027,491) |
| G-4 | 141,939,892 | $7,069,733 | 5.091 | 13.176 | 11.737 | $16,659,827 | ($9,590,094) |

for Tables 4.3(A), (B), and (C):

[1] Kwh Sales, from Workpaper WPE 4.3.
[2] Proposed Base Revenue, Workpaper WPE 4.3.
[3] From Table 4.2.
[4] Column [3] * Column [8].
[5] Column [4] - 1.439 cents, from WPE 4.2.2.
[6] Column [5] * Column [1].
[7] Column [2] - Column [6].
[8] Lowest, highest, and average increase in tail block from Table 4.1, line #7.

ith b

axim
De

s: [1] - [8], and [10] From Data Response EOER 4, January 16, 1987.

[2] For Large Industry in July 1985, the only customer coincident with system peak reported an on-peak demand of 0 kwh.

[9] Column 8 minus the sum of the differences between the maximum demand and the maximum on-peak demand for all customers with maximum demand off-peak.

[11] ( ([8] - [10])/[10] )/2.

[12] ( ([9] - [10])/[10] )/2.