21 NH PSC DE 81-312

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

Investigation Into The Supply And Demand for Electricity, For Public Service Company of New Hampshire	)

Testimony of

PAUL L. CHERNICK

On Behalf Of

CONSERVATION LAW FOUNDATION
OF NEW ENGLAND, INC.,
NEW HAMPSHIRE ENERGY COALITION,
and UNION OF CONCERNED SCIENTISTS

October 8, 1982

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

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 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 honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

During my graduate education, I was the teaching assistant for courses in systems analysis. I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case. 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. My work considered the effects on conservation and the effects of conservation in all of these areas, including the cost, extent, effectiveness, and rate treatment of utility conservation programs.

In my current position, I have advised 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 twenty times on utility issues before such agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities 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 conservation programs.

Q. Do you have a track record of accurate predictions in capacity planning?

A. Several of my criticisms of utility projections have been confirmed by subsequent events or by the utilities themselves. In the late 1970's, I pointed out numerous errors in New England utility load forecasts, and predicted that growth rates would be lower than the utilities expected. Many of my criticisms have been incorporated in subsequent forecasts, and load growth has almost universally been lower than the utility forecast.

For example, in my testimony in MDPU 19494, Phase II, filed April 1, 1979, I described a large number of errors in PSNH's 1978 forecast most of which would exaggerate growth rates. The 1978 forecast projected a peak of 1394 mw in 1980/81 and 2341 mw in 1987/88. Since the 1980/81 peak was actually 1203 mw, and since PSNH's 1981 forecast predicted 1562 mw in 1987/88, reality has confirmed my criticisms and PSNH has implicitly accepted them.

My analyses of other utility forecasts, including Boston Edison, Northeast Utilities, the NEPOOL forecasts, and various smaller utilities, have been similarly confirmed by the low load growth over the past few years, and by repeated downward revisions in utility forecasts.

My projections of nuclear power costs have been more recent, and have yet to be fully confirmed.

However, as time goes by, utility projections have tended to confirm my analyses. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion. With techniques similar to those used in this testimony, I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was cancelled) stood at $4.0 billion.

In MDPU 20055, PSNH projected in-service dates for Seabrook of about 4/83 and 2/85, at a total cost of $2.8 billion. I predicted in-service dates of 10/85 and 10/87, with a cost around $5.3-$5.8 billion on PSNH's schedule or $7.8 billion on a realistic schedule. PSNH has moved its in-service date estimates substantially towards my projections, and increased its cost estimates to a lesser extent.

In that same testimony, I criticized PSNH's failure to recognize interim replacements, its error in ignoring real escalation in O & M, and its wildly unrealistic estimate of an 80% mature capacity factor (even the Massachusetts utilities seeking to purchase Seabrook shares were more realistic about capacity facotrs). I suggested interim replacements of $9.48/kw-yr., annual O & M increases of $1.5 million/ unit (both in 1977 $) and 60% capacity factors. PSNH now includes capital additions, escalates real O & M at about 1% (about $0.1 million per unit annually), and projects a mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though the O & M escalation and capacity factor projections are still very optimistic. While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-81 confirms the patterns of large capital additions, rapid O&M escalation, and low capacity factors. The 60% capacity factor figure, in particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison).

Critiquing and improving on utility load forecasts and nuclear power cost projections has not been very difficult over the last few years. Many other analysts have also noticed that various of these utility projections were inconsistent with reality. While other utilities have made some concessions to experience, PSNH's estimates for Seabrook costs continue to be exceedingly optimistic, and hence it is still quite easy for any competent reviewer to improve on them.

Q. What is the subject matter of your testimony in this case?

A. My clients asked me to develop a conservation program design which would be appropriate for PSNH to implement. I have also estimated the price at which conservation would be cost-effective for PSNH ratepayers, and have estimated the potential impact of a conservation program on electricity consumption.

Q. What do you conclude from your examination of these issues?

A. I conclude that completing and operating Seabrook will cost around 6.5¢/kwh for Unit 1 and 9.8¢/kwh for Unit 2 in 1983 dollars. Including marginal losses and transmission and distribution costs at the secondary level, these costs are about 8.2¢/kwh and 11.9¢/kwh, respectively.

Based on current retail rates,PSNH can pay considerable amounts for conservation without exceeding the cost of Unit 2: at least 2¢/kwh for each customer class, and over 5¢/kwh for some classes. Conservation incentives of this magnitude should produce enough conservation to displace 25% to 50% of PSNH's sales.

I believe that effective, efficient conservation programs can be designed which will result in broad participation and extensive conservation at reasonable prices, and without requiring direct utility or Commission control of detailed program design. I describe one such program in Section II.

Therefore, I conclude that a major PSNH conservation program is preferable to completion of Seabrook 2.

II. CONSERVATION PROGRAM DESIGN

A. Objectives in Designing the Conservation Program

Q. In the design of a conservation program, what objectives would you emphasize?

A. While the objectives of a utility conservation program can be stated in many ways, I think that the most important principles can be subsumed under three headings. First the program should be efficient: it should not waste social resources by encouraging customers to take actions which cost more than they are worth, or to do things in a more expensive manner than necessary. Second, the program should be inclusive: as many customers and as many conservation techniques as possible should be eligible for the program. Third, the program should be economical: as much of the savings as possible should be retained for the customers as a whole, rather than being spent to encourage participation. As is true for most public policy issues, these objectives are not completely consistent, and may at times conflict.

Q. How can a conservation program be made efficient?

A. Participating customers should be paid for the amount of conservation they provide to the utility. Some programs pay a fixed amount for a particular type of conservation activity (e.g., $100 for insulating an attic to R-38 or more), regardless of how much the activity can be expected to save for particular customers (for the attic example, savings vary with the size of the house, the old insulation level, the new insulation level, and the heating degree-days at the customer's location). Other programs pay a fixed portion of the cost of conservation, so customers have less incentive to find the least expensive way to do the job; for example, the Federal conservation tax credits have this flaw. But if a customer is paid for the number of kwh's his conservation is expected to save, he can pick the conservation levels and techniques which make the most economic sense in his particular situation.

Q. Why is it important for a conservation program to be inclusive?

A. Many programs are explicitly limited to certain customer classes and certain conservation measures, such as residential ceiling insulation in owner-occupied homes. They may be further constrained to require specific materials and implementation methods, such as utility-provided and utility-installed water heater blankets. Finally, some programs are implicitly limited to certain sub-groups within a class, such as customers who can obtain bank financing for insulation, or those who can understand and complete an application for the program.

All of these restrictions limit the impact of the program. The ideal conservation program would be open to any customer who can save the utility money by conserving, regardless of who the customer is, what sort of measures are applied, or how the work is done.

There are two basic reasons for attempting to include all kinds of conservation and all kinds of customers in the conservation program. The first reason is efficiency: unless all customers and measures are covered by the conservation program, the conservation produced will not include all of the best opportunities. The second reason is equity: while all customers will benefit from the conservation program, the greatest savings will accrue to participants, and it is not fair to arbitrarily exclude some customers from those benefits.

Different conservation implementation mechanisms will be useful for different types of customers. In order to include the full range of customers, it will generally be necessary to offer a variety of mechanisms. Some of these mechanisms can certainly be direct utility programs which provide specific measures to targeted customers by specific methods, but designing and administering targeted programs for every type of conservation by every group of customers would be an awesome task.

Q. How can a conservation program meet the objective of economical operation?

A. There are two aspects of program design which may be helpful in this regard. First, to the extent possible, incentives should be set at the minimum level necessary to encourage participation. Second, incentives should be structured to allow and even to encourage the use of leveraged resources, such as tax credits, volunteer labor, and municipal financing.

Q. How have you incorporated these objectives into your proposed conservation program design?

A. There are basically two frameworks in which the objectives can be pursued. The first is top-down, detailed regulation, with the utility (and the regulator) designing numerous specific conservation programs, addressed to every identifiable end-use of electricity and to every conceivable type of customer. The second is a bottom-up, decentralized approach, with most of the initiative and decisions left to the conservers. I believe the decentralized framework is more appropriate for PSNH and for New Hampshire in general. Therefore, I have tried to keep the following principles in mind throughout the design process:

1. <u>Mimic a free market</u>. Since the retail delivery of electricity is a regulated

natural monopoly, free-market competition between electricity and conservation does not currently exist. The conservation program should operate to restore a free market situation, with diversity and competition.

2. Rely on Yankee ingenuity. A quarter of a million customers will come up with more ways to save electricity, and cheaper ways, than PSNH ever could.

3. Keep the program open. The program should accomodate a wide (and changing) variety of participants, end-uses, techniques, funding mechanisms, etc.

B. <u>Structure of the Program</u>

Q. What basic structure would you suggest for a conservation program?

A. The five fundamental aspects of the program would be to establish

1. the price (in cents per kwh) to be paid for conservation;
2. the criteria for eligibility as a provider of conservation energy;
3. a list of eligible measures, with the annual energy savinqs and useful life attributable to each;
4. actual payment for each measure, on both an annual basis and on a lump-sum basis; and
5. administrative procedures, includind an audit system, mechanisms for adding providers and measures to the eligibilty lists, and payment procedures.

Q. Please describe your recommendation for setting the price for conservation.

A. The first step is to set some ceiling on the price to be offered. This ceiling would be the difference between the savings due to conservation (the marginal cost of electricity) and the revenue lost due to conservation (the marginal price charged to the customer). This difference is the savings to non-participants due to the conservation program, and is also the shortfall between existing customer incentive to conserve and the total value of conservation. One interesting point is that the ceiling on conservation payments would be greatest for customers whose marginal price is currently furtherest below the marginal cost of service, and thus already being subsidized most heavily by the existing rate structure. This effect can be reduced by bringing marginal prices into better agreement with marginal costs, especially for those classes with very low tailblock rates.

Q. Is the marginal price for each customer the tail block of the applicable rate?

A. No. The tail block is the marginal price only for customers whose consumption reaches into that last block. For small customers, the price that they face at the margin is the price in the last block in which they consume: this is the rate they will pay for using one more kwh, or save by conserving one more kwh. The marginal price is both the customer's inherent incentive to conserve energy, and the amount of revenue lost to the utility due to conservation.

Q. Should all customers be offered the ceiling price for conservation?

A. Not initially. If the ceiling price were paid for conservation, the customers who did not participate would receive no net benefit from the program. To the extent that conservation can be encouraged for less than the ceiling price, nonparticipants stand to benefit from the program. Also, lower prices for conservation may encourage development of the most cost-effective conservation methods and programs.

Q. How can the price to be offered for conservation be set, to extract the greatest result at the least cost?

A. Some form of bidding procedure would seem to be appropriate for setting the level of the incentive. Several approaches might be taken: I will describe the structure which I believe will produce the most satisfactory results.

For practical purposes, the bidding will be constrained by an annual (or semi-annual) financial budget which is previously incorporated in PSNH's rates. To determine how the budget will be spent, the utility must invite bids from potential providers, stated in cents per kwh for specific kwh amounts of conservation. The bids to be accepted will be those with the lowest prices, which add up to the conservation budget. The price of the most expensive bid accepted establishes the market clearing price.

Q. What price should be paid to the successful bidders?

A. There are two basic ways of setting the rates to be paid to each bidder. One approach is to pay all successful bidders the market clearing price, so that all bidders receive the same price. This approach is advantageous in that it does not penalize bidders for submitting very low bids. There is no incentive for providers to ask for higher prices than they would really require to provide the service;

if successful, they all receive the market clearing price, regardless of their individual bids. The operation of truly competitive markets produce much the same effect: all producers receive the same price, regardless of their costs, so the most efficient producers receive the greatest profits. Thus, producers have the maximum incentive to lower their own costs (or in this case, their bids).

The second approach is to pay all successful bidders only the price of their bids. This will produce the lowest cost for non-participating customers, for any given set of bids, but will encourage providers to raise their bids above the minimum they would accept: the promise of a higher price will balance the chance of being unsuccessful in bidding. Thus, the overall cost actually may be higher under this approach, depending upon how the providers react.

Q. Which approach would you suggest?

A. The first approach provides better economic incentives to the bidders and more closely approximates the operation of a competitive free market. Since only one price is paid for conservation, it is also the simplest approach to administer, and in some ways the fairest. Hence, paying all successful bidders the market-clearing price appears to be preferable.

Q. Should unsucessful bidders be allowed to participate in the program?

A. I think not. Some portion of the budget could be reserved to allow unsuccessful bidders, or potential providers who did not submit bids, to participate, perhaps at a rate lower than the market-clearing price. However, this provision would complicate the process and dilute the incentives for lowest-cost bids. Instead, I would suggest that the bidding be repeated at frequent intervals, such as semi-annually, so that unsuccessful bidders and new potential providers can respond to the pricing and efficiency standards of the successful bidders, and attempt to emulate their techniques. Indeed, this is the way in which free markets operate.

Q. Why is it appropriate to set prices through a bidding system?

A. The alternatives to a bidding system include direct utility control of the program, and the offering of a fixed price for conservation. Direct utility control would sacrifice the advantages of decentralized decision-making. Offering a fixed price for conservation, rather than working within a budget, makes financial planning more difficult. If the fixed price is too low, the budget will not be spent and conservation will proceed more slowly than necessary. If the fixed price is too high, the budget will be over-subscribed, and either the utility will have to make up the difference, or bidders will have to be culled, by a lottery or on a first-come-first-serve basis, or purchases reduced on a proportional basis. Some unnecessarily expensive conservation would be purchased in the case of over-subscription.

Q. Please describe your recommendation for eligibility criteria.

A. I do not believe that many criteria are necessary. The most important consideration is the number of providers with which the utility can deal; 250,000 customers are just too many to work with individually in the very open format I described. I would therefore recommend a minimum bid size of 20 mwh/yr. Large customers, mostly in the GV and TR rates, will be eligible individually, but the small general service and residential customers will have to operate as groups, represented by a single provider or agent.

Such providers could include governmental entities (municipalities, school districts, state agencies), traditional service organizations (e.g., Rotary, Boy Scouts), advocacy organizations (e.g., community action agencies, elderly groups, minority organizations, labor unions), business organizations (e.g., Chambers of Commerce; local associations of grocers, dry cleaners, etc.), and environmental groups (e.g., Audubon Society, local conservation groups). The Commission may also wish to include profit-making companies among the eligible providers; examples would include firms currently active in such areas as insulation, plumbing (solar water heating, waste heat recovery), HVAC (heat exchangers, heat pumps), appliance sales and repair, and wood stove installation. If these firms are not eligible for direct participation, many of them will function as contractors for eligible providers.

To increase the probability that providers will be able to deliver the amount of conservation promised, there should be some demonstration that the provider has access to a sufficient number of consumers for whom the proposed conservation measure (or measures) is applicable. This is no problem for large customers (who need no other participants). Providers representing small customers might offer a list of participants, a membership count for the organization, the number of households served in other activities, or any other indication that the provider has the necessary contacts to deliver the proposed conservation. This requirement should not be construed to exclude potential providers, but only to keep the size of their proposals realistic.

Q. What conservation measures should be eligible?

A. Any conservation measure should be eligible, if the electricity savings from the measure are reasonably predictable, at least in the aggregate. The conservation effect should not be entirely dependent on customer behavior, although the effect of any measure will vary with use.

The utility should prepare an initial list of eligible measures, for which the energy savings and useful life can be readily estimated. There should also be a mechanism for providers to suggest additional measures, with estimates of their effectiveness and longevity. Once the utility has confirmed or corrected those estimates, the new measure should be added to the standard list (unless it is essentially unique to one provider, such as a change in an unusual industrial process).

Q. Can you list some of the measures which should be included?

A. Yes. For residential customers, some general examples would be:

1. installation of switches on refrigerator anti-sweat heaters;
2. installation of switches on dishwasher drying elements; and
3. replacement of incandescent lamps with fluorescent and other high-efficiency lamps.

For customers with electric space heating, additional measures would include:

1. ceiling insulation;
2. heat pumps replacing resistance heating;
3. window insulation;
4. automatic setback thermostats;
5. wood stoves; and
6. air-heating solar panels.

For customers with electric water heating, eligible measures should include:

1. flow restrictors;
2. water heater insulation;
3. pipe insulation;
4. water-heating heat pumps;

5. solar water heating;

6. grey water heat recovery; and

7. tempering tanks.

Many of the preceding measures would be relevant for commercial, industrial, and government customers. Additional measures for these consumers would include

1. installing switches and occupancy sensors on lighting;

2. removing a fraction of existing overhead lamps;

3. replacing existing lamps and ballasts with more efficient units;

4. refrigeration waste heat recovery (which improves refrigeration efficiency and displaces electric water heating);

5. cooking heat recovery for water or space heating;

6. motor efficiency replacements and improvements, including speed and voltage controls; and

7. outdoor lighting improvements, including relamping and installing timers to reduce late-night consumption.

Q. How should the annual energy savings be determined?

A. In most cases, the savings estimates should be calculated from heat-flow equations, hours of use, and similar physical considerations. Bench tests of equipment (such as refrigeration heat recovery) may be necessary in some cases, where standard values have not yet been established. As a last resort for measures which are hard to model, such as some solar collectors, the performance of an initial set of actual installations can be monitored.

Q. Is it feasible and appropriate for the annual energy savings for each participating customer be determined exactly?

A. It is not feasible for many measures. The energy savings from insulating a building depends on the thermostat setting and the microclimate around the building. The savings from water heater insulation is a function of the hot water temperature and the temperature of the room in which it is placed. Efficiency improvements in many kinds of appliances and equipment (e.g., lighting, dishwashers, flow restrictors) depend on how much they are used. It is not practical to monitor all these factors individually, either before or after the conservation measure is put in place.

It _is_ feasible to reflect many individual variations, however. Examples would include insulation level before conservation, the level after conservation, the area insulated (in square feet, for example), whether a water heater is in a heated or unheated space, and the number of heating degree days by town or region (see IR CLF 3-4 for a map of heating degree-days).

Q. How would you recommend paying participants for energy saved?

A. I would recommend that participants be given the choice of receiving either:

a. an annual payment: the incentive per kwh, times estimated annual kwh savings, escalated at the CPI, for each year of the estimated life of the measure; or

b. a lump-sum payment: the incentive per kwh, times estimated annual kwh savings, times a cumulative present worth factor.

$$\frac{(1 + r)^{n} - 1}{r\ (1 + r)^{n-1}}$$

where r is the real discount rate and n is the useful life.

At a 10% real discount rate, the lump-sum payment would range from 4.17 times the initial annual payment for a short-lived measure that only lasts five years, to 10.76 times the annual payment for a long-lived measure, such as building insulation, which is assumed to last forty years.

Q. Do you have any specific recommendations regarding administrative procedures?

A. Yes. I do not believe that PSNH has shown great enthusiasm for conservation programs; it therefore seems appropriate for the program to be administered by an independent contractor. I would suggest that PSNH submit the names and qualifications of several potential contractors with experience in assessing conservation effectiveness, and that the Commission select one of these to run the program.

One advantage of this arrangement would be that PSNH could operate as a provider of conservation. Any profits earned by direct PSNH conservation efforts can be credited against the cost of service, further reducing the cost of the conservation program to non-participating customers. The Commission may prefer to allow PSNH to keep a portion of conservation profits, or otherwise offer incentives for the utility to foster conservation.

Q. Please review the operation of the program as you have proposed it.

A. Once the contractor is selected, I envision the program proceeding in the following steps:

1. Contractor issues a request for bids;
2. Potential providers submit bids, specifying target population, conservation measures, anticipated savings in kwh/year, and price per kwh;
3. Contractor selects the lowest-price bids which add up to the budget, and awards contracts;

4. Contractor conducts a pre-audit to determine that the base conditions as described in the bid are accurate;
5. Provider performs work (at least 20 mwh/yr. worth of conservation), and notifies contractor;
6. Contractor conducts a post-audit to verify that work was completed; and
7. Contractor calculates payment and instructs PSNH to pay providers.

I would recommend that the request for bids be issued every six months, to allow for frequent readjustments in the market. Parallel to this bidding procedure, the contractor would be responsible for continuously updating the list of eligible measures, including the expected kwh savings and expected lives.

Q. Would you recommend a pre-audit and post-audit of each installation?

A. Such detailed auditing would probably not be cost-effective for small customers, especially where very limited conservation is carried out at each location. For these situations, I would suggest that successful bidders submit a list of proposed conservation sites, from which the contractor can select a random set to pre-audit. Similarly, when the provider requests payment, the sites of completed work should be listed so that the contractor can complete random post-audits. The RSC program may also serve as a pre- or post-audit.

Q. Would you extend this program to include new customers and new loads?

A. I would not recommend paying customers for conservation related to new loads, where that conservation would be required by building code or general practice, or cost-justified by current electric rates. Nor would I recommend paying new customers to install more efficient electrical appliances (e.g., heat pumps) where non-electric alternatives are available; otherwise, the program may actually promote electricity use. Howevever, incremental investments, such as for lighting or refrigeration which is more efficient than average, should be eligible for conservation program incentives.

Q. Are there any precedents for conservation-purchase programs such as you have described?

A. Not in exactly this form. However, Pacific Gas and Electric purchases conservation services from municipalities, which function as providers. The Bonneville Power Administration (BPA) has an extensive conservation purchase program in which its retail utilities serve as providers. BPA pays the present value of its estimated savings (29.2¢/kwh/yr), or the total cost of the measures, whichever is lower. Energy savings are calculated from old and new insulation levels, areas covered, and local degree-days; BPA sets minimum insulation levels, but not maximum levels.

The program I have proposed is similar in many ways to those of PG&E and BPA. It is also similar to general competitive bidding systems, such as those used by utilities in purchasing coal. The coal-purchasing analogy is apt in a number of ways: several suppliers may provide coal to a utility, the price paid may vary with both the quantity and the quality of the product, and testing is required to determine compliance with contract terms.

Finally, a free-market conservation purchase program is simply the demand-side equivalent to rates for power from small producers, an area in which this Commission has been a national leader. The PURPA/LEEPA rates are paid on a kwh basis to any one who can produce power, regardless of how it is produced or how much it costs. The rates are based on PSNH's avoided costs. A conservation program should similarly pay any conserver for the amount conserved, regardless of the cost of the measure, and should be based on the cost of PSNH's alternatives. The major differences between a small power producer and a conserver is in the measurement and prediction of the energy produced or saved: power production is easier to measure, but conservation, once installed, is more predictable. It is therefore necessary to audit conservation activities, and appropriate to make lump-sum payments for them.

III. CONSERVATION PRICES AND RATEMAKING

Q. What is the maximum price PSNH can pay to encourage conservation without paying more than the price of Seabrook Unit 2?

A. I cannot calculate a specific maximum price for each rate, since PSNH could not provide a bill frequency analysis. From Table 24 and the class load factors from IR CLF-3-5, the avoidable costs associated with Unit 2 are about 11.9¢/kwh for general residential, 12.0¢/kwh for residential space and water heating, 11.8¢/kwh for rate G, 11.3¢/kwh for GV, and 10.7¢/kwh for TR. Subtracting the revenues lost due to conservation at the current rates for these classes, PSNH could pay approximately the following prices for conservation:

2.0-3.4¢/kwh for general residential,

4.5¢/kwh for uncontrolled water heating,

6.3¢/kwh for controlled water heating,

4.0¢/kwh for space heating,

4.4-5.6¢/kwh for Rate G, without demand charge, and a cent or two less with the demand charge,

at least 3.5¢/kwh for GV, and

4-4.5¢/kwh for TR.

Q. How large a first-year conservation budget would you recommend?

A. In addition to the administrative budget for the contractor (or PSNH, if no contractor is used), I would suggest a first-year budget of $5 million. This is only a little over 1% of PSNH's current revenues; at 1¢/kwh (a reasonable estimate of the market- clearing price over the first few years), $5 million will fund 500 GWH of conservation, equivalent to about 100 mw of Seabrook output. At that rate, it would be possible to produce conservation equal to 28% of Seabrook 2 (322mw) by 1986, earlier than Seabrook 2 could be available. If conservation costs less (or more) than 1¢/kwh, the amount of conservation produced by $5 million would be more (or less) than 500 GWH annually.

Q. To the extent that providers request lump-sum payment, will the conservation budget be exhausted more rapidly by these larger first-year payments than it would be if all providers request annual payments?

A. When providers opt for lump-sum payment, I would suggest that PSNH capitalize the difference between the first-year payment and the lump-sum payment, and amortize this investment over the remainder of the expected life of the conservation measure. This ratemaking treatment allows the extent of the conservation program to be independent of the payment form chosen and it better matches the benefits and costs to the non-participants.

Q. Would the capitalization of some of the conservation program costs be a burden for PSNH, given its poor financial condition?

A. I do not believe that it should pose any real problem. Capitalized conservation costs would be only a few percent of PSNH's planned annual investment in Seabrook. Unlike Seabrook, these costs would go into ratebase quite quickly, since conservation is certainly used and useful. Assuming that this Commission orders PSNH to institute a conservation program, recovery of the costs is a virtual certainty. Seabrook, on the other hand, may never be completed, it may be so expensive that portions of the investment are excluded from rate base, its performance may be so poor that some associated expenses are disallowed, and it may not survive long enough to recover the initial investment. None of these outcomes is likely for a conservation program (and some of these Seabrook events do not have real analogues in the conservation program), and even if some such problem occurred, the exposure of PSNH and its investors is much smaller.

Q. Could you provide some examples of the incentives which might be paid for some conservation measures?

A. Yes. For above-grade building insulation in electrically-heated spaces, the energy conserved is

$$7.032 \times A \times TDD \times (1/R1 - 1/R2),$$

where A = area insulated in square feet;

TDD = thousands of annual heating degree days,

R1 = original insulation level (R-value), and

R2 = new insulation level.

Therefore, adding insulation to a ceiling with R = 21 (say, 6" fiberglass plus R of 2 for the ceiling itself) in a

7500 degree-day area saves

$$2.51 - 52.74/R2 \quad kwh/ft^2/yr.$$

In this case, R2 is 21, plus the added insulation: for blown cellulose, each inch is worth about R3.6, while low-density fiberglass is about R3.1/in. Thus, blowing in 12 inches of cellulose saves about 1.69 kwh per square foot, while just 6 more inches of fiberglass would save 1.18 kwh per square foot. For a 1200 square foot ceiling, the first option would be worth about 2030 kwh annually, and the second would save 1420 kwh. If the market clearing price for conservation turns out to be 1¢/kwh*, the particant could take $20.30 or $14.20 annually for the two options; or a lump sum of $218 or $153.

A single-glazed window with storm window has an R of less than 2, so insulating a window is worth at least

$$26.4 - \frac{52.74}{R2}$$

for fixed insulation (e.g., extra glazing), and an appropriate fraction for movable insulation which is in place only part of the day. Adding two more layers of glazing (interior storms, replacement windows, etc.) raises R to about 4, savings 13.2kwh/sq. ft./yr. For a 12 sq. ft. window, at 1¢/kwh, that is worth $1.60 annually, or a lump sum of $10.70 for a ten-year life. Movable insulation of R8, in place for 75% of the heating load, would save about

---

*As this section illustrates, 1¢/kwh should produce large amounts of conservation; it is unlikely that the conservation price will have to rise much above this level for some time.

15.8kwh/sq. ft./yr.) or 190 kwh for a 12 sq. ft. window, worth $12.83 for a 10-year life. The lump-sum payment would probably cover the entire materials cost for many installations.

Water heaters are typically kept at 120°F or more, averaging at least 50°F higher than typical heated space and at least 60°F higher than an unheated basement. This is equivalent to 18000-22000 heating degree-days per year; the R6 insulation generally installed in water heaters is clearly inadequate. A typical 52 gallon water heater has a surface area of 28 square feet; the savings from insulating this water heater in a basement would be

$$722 - 4332/R2 \quad \text{kwh/yr.}$$

The typical 2-inch fiberglass water heater wrap has an R-value of 6, so it saves about 361 kwh/yr., worth $19.33 over a 7 year life at 1¢/kwh. This is considerably more than the retail cost of the wrap. Even with a 2-inch wrap, our typical water heater loses 361 kwh/yr., so much higher insulation levels are desirable.

PSNH estimates that a solar water heater reduces water heating electricity use by 50%, or 1500-2000 kwh/yr. (More precise estimates should be possible for particular designs, sizes, and orientations.) At 1¢/kwh over a 20 year life, a solar water heater would be worth a lump-sum incentive of $140-187.

The California Energy Commission (CEC) has extensively studied and assessed conservation options. For example, CEC (1982a, b) estimates that replacing a 40w fluorescent light tube with an equivalent - lumen high-efficiency 35w tube saves at least 130 kwh annually over a 3 year life, worth over $3.50 at 1¢/kwh. The high-efficiency tubes only cost about $1.00 more than standard tubes. Similarly, CEC estimates that a high-efficiency fluorescent ballast (for two 40w tubes) saves at least 200 kwh annually, with a 20-year life, worth about $19.50 at 1¢/kwh. The efficient ballast is no more than about $3.00 more expensive than a regular ballast.

CEC estimates that about half of commercial electricity use is by fluorescent lights. If that is true for PSNH, over 300 GWH annually are used for lighting. Replacing a pair of 40w tubes and a 14w ballast with 35w tubes and a 5w ballast would save 20% of the energy used. If that (or a similar) change is possible for 70% of the commercial lighting load, over 40 GWH would be saved annually.

Q. How would this program affect rates?

A. The cost of administering the program, and the actual conservation purchase payments, would have to be added to rates, either as expenses or as rate-base items. In addition, reduced sales will require that fixed costs be spread over fewer billing units. All these factors will tend to increase rates.

On the other hand, the conservation program would immediately reduce fuel costs, by backing out the most expensive generators and by reducing losses. It will also reduce T&D expenditures in the near future. Finally, if the program replaces or defers Seabrook 2, it will reduce the financial stress on PSNH, lower the cost of common equity and of new debt, and reduce the amount of expensive new debt required in the capital structure. Whether these savings will completely cover the costs of the program in the short-run is not clear, and depends in part on the behavior of oil prices and the financial markets.

It is clear that the program can be considerably less expensive than continued construction of Seabrook 2. Thus, even if rates are somewhat higher over the next few years due to the conservation program, customers would still be better off over the next decade, for having avoided the "rate shock" as Unit 2 was completed, or as a larger investment was written off. Most customers would probably participate in the conservation program, and will benefit from lower kwh consumption, as well as lower ¢/kwh rates.

Q. How would this conservation program affect PSNH's financial status?

A. That depends on the ratemaking allowed by the Commission. The direct effects of the program on PSNH are (1) that PSNH spends money on conservation and (2) that PSNH's sales will decrease. The expenditures need not be a burden to PSNH, especially if the Commission allows PSNH to include projected expenditures (including capitalized conservation payments) in rates, perhaps with a reconciliation procedure in subsequent rate cases. Periodic (e.g., quarterly) conservation expenditure adjustments are also possible, but probably not necessary.

The decrease in sales is also tractable. The Commission may allow rates to be based on lower projected sales; unfortunately, as I explain in Appendix B, this procedure still leaves PSNH with an incentive to delay or reduce the conservation program. A second alternative would be to institute a periodic rate adjustment process to reflect actual sales, which could correct for weather-related variations, as well as conservation. This sort of "revenue adjustment mechanism" has been instituted by the California PUC for its major electric utilities and requested by Niagra Mohawk. A third solution to revenue variability is what I call "Revenue Stability Target Ratemaking" or RSTR, in which rates are set to collect slightly more than allowed revenues and the difference is refunded to consumers in various ways, such as by funding conservation programs. A more complete description of RSTR is included as Appendix B.

Thus, the potential negative effects of the conservation program on PSNH's earnings can be eliminated relatively easily. The remaining effects are all positive: a higher percentage of earnings in current revenues, as opposed to AFUDC; reduced financing requirements; increased security of earnings; and, if PSNH functions as a provider, perhaps some incentives for promoting conservation.

IV. POTENTIAL EFFECTIVENESS OF A CONSERVATION PROGRAM

Q. How much conservation do you believe can be achieved through a conservation program such as you have described?

A. It is difficult to determine an exact figure, but an approximation can be derived from studies of the price elasticity of electric demand.

Q. How is price elasticity relevant to estimating the effectiveness of a conservation program?

A. Paying customers to conserve should influence their decisions in much the same way that an increase in marginal electric price would. If electricity for my water heater costs me 6¢/kwh, and I am offered 1¢/kwh to wrap it with insulation, my savings from doing so (or the price I pay for not doing so) are 7¢/kwh. Except for the income effect (rate increases make me poorer, conservation programs make me richer) the program should give me the same incentive to conserve that I would get from a 1¢/kwh price increase on my tail-block kwh's.

Q. How can the effects of increases in marginal prices be estimated?

A. Several researchers have used statistical methods to measure customers' response to marginal price and have found that this response is significant. These studies have estimated the elasticity of electric demand with respect to the marginal price of electricity by comparing electric use in areas with different marginal electric prices (cross-sectionally), by comparing electric use in one area as price changed over time (in a time series), or by combining cross-sectional and time-series data. A price elasticity is the percentage change in sales which is caused by a 1% increase in price. Thus, an elasticity near zero implies little price response, while an elasticity with a large absolute value implies considerable price response. Negative elasticities imply that increased prices decrease sales, which is the expected result.

Customers do not react instantaneously to a price increase. It takes time to change habits, insulate, replace appliances and so on. Therefore, short-run price elasticities (measured within a few months or a year of a price change) will be much smaller than elasticities which measure price effects in the long-run (ten or fifteen years).

Q. How large are these elasticities?

A. Long run marginal price elasticities for electricity are generally reported to be on the order of -1.0 for residential use, and higher for commercial and industrial use. For example, Taylor, Blattenberger, and Verleger (1977) developed two sets of elasticity models. The flow-adjustment models indicated that the marginal-charge elasticity is significant and is about -0.8 if a logarithmic equation is used, to about -5 if a linear model is assumed. For the appliance stock models, the intra-marginal charge coefficients in the intensity equations average 26% of the marginal charge coefficients. The appliance saturation equations are of very poor statistical quality, but even so the marginal price is generally more important than the intra-marginal charge. Combining the intensity and saturation equations, the authors develop marginal price elasticities for the appliance stock models of -0.46 to -0.90, with an average of -0.59. The appliance stock models are more ambitious than the flow-adjustment models and exhibit greater statistical problems, but they they support the general result.

Other studies have simply estimated elasticities for marginal price, without attempting to include average price or fixed charges.

Houthakker, Verleger, and Sheehan (1974) derived long-run marginal-price elasticity estimates of -1.0, -1.2, and -0.45, depending on the approximation of marginal price which was used. Houthakker (1978) later used a different definition of marginal price to derive elasticities for the country, the Northeast, New England, and Massachusetts; the long-run marginal elasticities ranged from -1.423 for the United States to -0.673 for the Northeast, with -0.756 for Massachusetts. Halvorsen (1975, 1976) estimated the coefficient of marginal price in several different ways, resulting in elasticities of -0.974 to -1.21 for residential use, -0.916 to -1.208 for commercial use, and -1.242 to -1.404 for national industrial use (excluding location effects) all at a high level of significance (a result of -0.562 for commercial elasticity was less significant and was eliminated by the use of dummy variables for two states).

Short-run elasticities are generally around -0.05 to -0.25.

Q. Which elasticity is relevant for estimating conservation program effectiveness?

A. The short-run elasticity captures primarily behavioral effects (lower thermostat settings, turning off lights, etc.), while the long-run elasticity measures change both in behavior and in capital stocks (the number, size, features, and efficiency of appliances, equipment, and buildings). There is some overlap, since some customers happen to buy a new major appliance (or increase efficiency of existing equipment) right after a price increase, putting some capital changes in the short-run elasticity. On the other hand, not all new behaviors which result from a price increase (lower water temperature, fuller wash loads, minimizing door openings, etc.) are learned within the first year, so some additional behavioral changes are caught in the long-run elasticity. Overall, the best approximation is that short-run elasticity is the effect of behavior, and the difference between short- and long-run elasticity is the result of adding and improving equipment.

For a conservation program, we are interested in estimating equipment-related changes; it is very difficult to monitor behavioral conservation, or to reward it, except through rate design. Hence, the elasticity of interest is the difference between short- and long-run elasticities.

The best available marginal elasticity estimates for New Hampshire are from Houthakker (1978), who found short- and long-run residential elasticities for New England of -.185 and -1.082, for a difference of -0.897. Adjusting the New England results to remove the less-elastic Massachusetts data (elasticities of -.253 and -.788, comprising 40% of New England load), yields non-Massachusetts New England elasticities of -0.140 short-run and -1.278 long-run, for a difference of -1.138. I use the mean of these two differences, or -1.018.

I know of no studies which have estimated both short- and long- run marginal price elasticities for classes other than residential. However, Halvorsen's (1976) results imply that commercial customers are about 5% more price-responsive at the margin than residential customers, and that industrial customers are about 30% more responsive. Thus, I use values of -1.07 and -1.32 for commercial and industrial elasticities with respect to conservation incentives.

Pushing the conservation program to its limit, eventually paying the full difference between each rate and the corresponding marginal cost based on Seabrook 2, (see the beginning of §III, above), would be equivalent to raising prices about 40% for residential, 50% for G, 45 for GV, and 60% for TR. Assuming that Rate G is primarily commercial, that GV is half commercial and half industrial, and that TR is primarily industrial, the conservation program would be expected to reduce sales by about 37%; by 1991 this would total 2938 GWH, based on PSNH's 1982 forecast. This is equivalent to more than half of a Seabrook unit's average annual output.

Improved organization of conservation services, and accelerated innovation in products and delivery, will be simulated by the conservation purchase program, and may increase the effect of the program. The effectiveness may also be increased by general progress in conservation technology. On the other hand, some activities may not be influenced as effectively by the conservation program as by a rate increase. Hence, the potential maximum impact of the program is subject to some uncertainty, ranging from 25% to 50% of base-case sales.

V. DETERMINATION OF THE VALUE OF CONSERVATION TO PSNH

A. Introduction

Q. How have you estimated the value of conservation to PSNH?

A. I have used optimistic estimates of the costs of Seabrook power, including line losses and transmission and distribution costs, as the basis for calculating the value of conservation. Based upon analyses of historical performance and trends:

1. I do not expect Seabrook 1 to be on line before early 1986, or Seabrook 2 to be on line before mid-1989.
2. I expect each unit to cost over $3 billion in 1983 dollars, not including general inflation to the actual on-line date.
3. Capacity factors for the units will probably average under 56%.
4. I expect non-fuel O & M to escalate much faster than general inflation; the capital cost of the plant will also increase significantly during its lifetime.
5. Including decommissioning, insurance, fuel, and other factors listed above, power from Seabrook 2 will cost at least half a cent more, in levelized 1983 dollars. The actual prices charged to ratepayers will include inflation and will be much larger. The

sunk costs account for only about 4.3¢ for Unit 1 and 1.4¢ for Unit 2, so avoidable costs are about 10¢/kwh for Unit 2, not counting losses and T & D investments.

A detailed analysis of the avoidable costs is presented below.

B. Comparison to Seabrook

1. Construction Duration

Q. Are PSNH's current estimates for the Seabrook in-service dates reasonable?

A. No. There are at least eight reasons for believing that the Seabrook units will reach commercial operation considerably after the dates projected by PSNH:

1. PSNH's allowances for the interval between operating license issuance (OLIS) and commercial operation date (COD) is much shorter than recent experience.

2. PSNH has consistently over estimated the rate of construction progress in the past.

3. PSNH's projections are inconsistent with historic rates of construction progress on Seabrook.

4. The NRC Caseload Forecast Panel projects construction completion (roughly OLIS, not COD) for Unit 1 at 13 months later than PSNH's schedule.

5. Simple time trends on reactor construction duration indicate that the units may not be in service before the 1990's.

6. More sophisticated regression analyses are more optimistic, but still indicate that PSNH's in-service dates are optimistic.

7. PSNH's construction duration projections are inconsistent with those of other nuclear plants under construction.

8. Actual nuclear construction durations have almost always exceeded projections by substantial amounts.

Q. What is the recent experience for the start-up interval from OLIS to COD?

A. Table 1 provides this data for all units which have received operating licenses since the beginning of 1978. The shortest start-up was 8 months, and the longest was almost 19 months, with a nine-plant average of 13 months. In addition, Diablo Canyon I, which has been listed as 99% or more complete since at least late 1977, received an operating license in 1981, only to have it suspended two months later. Diablo I will probably increase the average start-up period when (and if) it finally reaches commercial operation.

Q. What is PSNH's projection for the Seabrook start-up periods?

A. PSNH currently projects a three-month start-up period for Unit I and a five-month start-up for Unit 2. These projections are completely out of line with the historical experience.

Q. To what extent has PSNH over-estimated the past rate of Seabrook construction?

A. At the end of the first quarter of 1979, PSNH estimated that Unit I was 18.85% complete, and that it would be 39.13% complete one year later, for annual progress of

Unit	Date of Issuance, First Operating License[1] (OLIS)	Commercial Operation Date[2] (COD)	Start-up Interval[3] (months)
Three Mile Island 2	2/8/78(F)	12/30/78	10.7
Hatch 2	6/13/78(F)	9/5/79	14.7
Arkansas 2	9/1/78(F)	3/26/80	18.8
Sequoyah 1	2/29/80(L)	7/1/81	16.1
North Anna 2	4/11/80(L)	12/14/80	8.1
Salem 2	4/11/80(L)	10/13/81	17.8
Farley 2	10/23/80(L)	7/30/81	9.2
McGuire 1	1/23/81(Z)	12/1/81	10.3
Sequoyah 2	6/25/81(L)	6/1/82[4]	11.2
Average			13.0

Table 1: Recent Experience in Start-up Intervals

Notes : (1) From NRC Gray Books and "Nuclear Power Plants in the U.S.", Atomic Industrial Forum, 12/31/81. Full licenses are indicated by (F), low power licenses by (L), and zero-power licenses by (Z). Excludes Diablo Canyon I, for which a low-power license was issued 9/21/81 and suspended 11/19/81.

(2) Same sources as for OLIS.

(3) All months treated as having 30 days.

(4) Telephone inquiry, TVA.

20.28%. But at the end of the first quarter of 1980, Unit I was estimated to be only 36.70% complete: the reported progress was 17.85%, or 88% of the projected rate. In fact, the reported progress was apparently greater than the actual progress, since a period of negative reported progress followed.

In March 1980, PSNH produced a new construction estimate, which projected that Unit I would be 67.7% complete by June, 1981; but reported completion in June, 1981 was only 50.8%. Over this 15-month period, reported progress was only 45.5% of projected progress. Combining the 12 months covered by the 1979 construction estimate with the 15 months covered by the 1980 estimate, and ignoring PNSH's apparent over-optimism in the March, 1980, progress report, produces an average progress-to-estimate ratio for that 27 month period of 64.5%. Stated differently, construction has taken 55% longer than PSNH expected. Corresponding average progress-to-estimate ratios for Unit 2 and the total project are 21.1% and 53.9%, respectively.

If construction of Unit I takes 55% longer than projected in June, 1981 (29 months to November 1983), the unit will be ready for an operating license 45 months later, or in

March, 1985. If construction of the total project continues at 53.9% of projected rates (thus assuming that Unit 2 speeds up as Unit 1 slows down), completion will take 85.5% longer than projected. As of June, 1981, completion of Unit 2 was projected 54 months in the future (to December, 1985): with 85.5% slippage, Unit 2 would be complete in 100 months, or October, 1989.

Adding a year for start-up produces in-service dates of March 1986 and October 1990.

Q. What are PSNH's historic rates of construction progress, and what in-service dates do those rates suggest?

A. From March, 1979 to September, 1981, reported progress on Unit 1 averaged 1.17% per month, and progress on Unit 2 averaged 0.21% per month. PSNH is projecting sustained peak monthly construction rates of approximately 2.2% for Unit 1 and 2.0% for Unit 2. Additionally, PSNH predicted that the last 8% or so of construction on each unit will proceed more slowly, at about 1% per month.

If PSNH is only able to maintain a rate of progress on Unit I of 1.2% per month (still somewhat better than the historic level) through the 92% completion point, and 1% thereafter, construction will take 40 months past September, 1981, and will end about January, 1985. If the projected progress for the last 8% is as over-optimistic as the 2.2% sustained peak rate appears to be, that final phase will take 2.2 ÷ 1.2 = 83% longer, or seven more months, bringing completion to August, 1985.

If Unit 2 continues its past glacial construction rate until Unit 1 is complete in January, 1985 (at which point Unit 2 would be 17.6% complete), then accelerates to 1.2% per month until 92% complete, and reaches completion eight months later, that would stretch the Unit 2 completion date to November, 1990. If Unit I is completed later, if Unit 2 cannot speed up until Unit I is in commercial operation, or if Unit 2 requires more than 8 months for the last 8% of construction, Unit 2 would be complete even later. On the other hand, it may be possible to build Unit 2 somewhat faster than 0.21% per month: for example, progress of 0.41% per month was reported for March to December, 1979. At that faster rate, Seabrook 2 would be almost 26% complete in January, 1985, and could be finished (under the most favorable circumstances described above) by April of 1990.

Q. What was the projection of the NRC Caseload Forecast Panel?

A. Based upon a three-day visit to the Seabrook construction site in September, 1981, the Panel concluded for Unit I that "if Seabrook Stations' progress is typical of industry-wide progress, the time required to get from where the project is at present time to construction completion would be about December of 1984". This conclusion, which is reported without rebuttal in the September, 1981 Seabrook Quarterly Report, is consistent with my calculations from Seabrook's past progress and PSNH's past over-optimism.

Q. What are the simple time trends to which you referred?

A. I have extended a study originally performed by MMWEC (Bentley and Denehy, 1979) based on the average durations reported in the NRC Yellow Book (Construction Status Report: Nuclear Power Plants, NUREG 0030) for plants which loaded fuel in particular years. MMWEC used data for 1973 to 1978, with 1979 estimates; I extended the data from 1970 through 1981. The Yellow Book defines duration as the period from construction start (roughly CPIS for most plants) to fuel load date (FLD). In extending the data to 1980 and 1981, I assumed that FLD equals OLIS. MMWEC suggested a two-year credit for second units to make their durations comparable to first units: I applied this credit fully to duplicate units with the same start-of-construction, and partially for second units which started construction after the first unit.

MMWEC's time trend indicated that it would be 1993 before the average first unit loading fuel would have been started in 1976, and 1997 before the second units were expected to have 1976 construction permits. The corresponding fuel load dates from my trending of duration on fuel load date are 1991 for Unit 1 and 1996 for Unit 2. Regressing average duration against the average starting date (FLD - duration) produces only slightly more favorable results: early 1991 and late 1995.

It should be noted that these simple trends on averaged data have two disadvantages. First, they lose much of the detail, since several units are treated as a single data point. Second, extrapolating trends out into the future assumes that all factors continue to change in the same way they did in the past. While this may be as reasonable assumption as we can make about nuclear safety, regulation, and industrial structure, it is not true for the size of nuclear units. The average size of units loading fuel generally increased from 1970 (604 mw) through 1975 (944 mw), generally fell through 1979 (871 mw), and then rose dramatically again in 1980 (1007 mw) and 1981 (1160 mw). Thus, some of the apparent time trend may actually be the affect of increasing unit size. However, since plants loading fuel in 1976, 1977, 1978 all showed smaller size, but longer durations, than those fueling in 1975, size does not appear to be the dominant factor.

Q. What are the more sophisticated regression studies to which you refer?

A. The two such published studies of which I am aware are by Mooz (1978) and Komanoff (1980). The regression equation estimated by Mooz is presented in Table 2 and evaluated for Seabrook.

The Mooz study does not distinguish between first and second units, so (except for the small difference in LN) the projection is the same for the two units. Mooz's data

Variable Name	Meaning	Co-efficient	Value for Seabrook	Contribution to Construction Duration
Constant				-270.8
CPIS	date of construction permit	4.5478	76.5	347.9
SIZE	in MW	.043643	1150	50.2
BW	Babcock & Wilcox dummy	13.065	0	
LN	ln of number of LWRs built by A/E	-8.0039	1.87 (1)	-15.0
	construction duration, construction permit to operating license, in months			112.3

Table 2 : Calculation of Interval Between Construction Permit and Operating License, Seabrook Units as Predicted by Mooz (1978)

(1) Average for Seabrook units. Preceding five units are Brunswick 1 and 2, Indian Point 2 and 3, and WPPSS 1.

is composed of both first and non-first units. Of the sixty-five units in the data base, 39 are the first reactor at their site, and another four are second units which received construction permits after the first unit was in service (Peach Bottom, Millstone, Dresden, and Indian Point). Thus, the data is about 66% first units. Assuming a two-year separation between Units 1 and 2, this weighting is equivalent to Unit 1 being licensed 8 months before the projection and Unit 2 sixteen months after the projection, or March, 1985 and March, 1987, respectively.

Unfortunately, the data base for the Mooz projection included estimated dates for operating licenses for ten units. As Table 3 shows, these estimates were over-optimistic by a considerable amount. A few of these reactors may have been delayed somewhat by the accident at TMI 2, but every plant except Farley 2 which was not licensed as of March, 1979 was already three to twenty-one months behind Mooz's estimate. Since the mean date of construction permit for the units with estimated durations is 1.4 years later than the mean date for the sample, it is very likely that these under-estimates have biased the projection downwards.

Komanoff did not use time in his duration regression, but instead included "cumulative nuclear capacity", the total MW capacity with construction permits or in operation before the subject reactor received its permit. Komanoff

	Unit	Construction Permit Issued	Mooz Estimate Of Operating License	Actual Date of Operating License (1)	Months of Underestimate
1.	Diablo Canyon 1	4/68	6/77	8/81 (2)	51
2.	North Anna 1	2/71	6/77	11/77	5
3.	TMI 2	11/69	10/77	2/78	4
4.	Sequoyah 1	5/70	12/77	2/80	26
5.	Diablo Canyon 2	12/70	11/77	(3)	58+
6.	North Anna 2	2/71	6/78	4/80	22
7.	Cook 2	3/69	11/77	12/77	1
8.	Salem 2	9/68	12/78	4/80	16
9.	Sequoyah 2	5/70	8/78	6/81	34
10.	Farley 2	8/72	10/79	10/80	12

Table 3 : Underestimate of Construction Duration in Mooz (1978)

Notes : (1) First operating license

(2) Subsequently suspended

(3) Diablo Canyon 2 has not yet received a license

believes that this variable captures the impacts of heightened regulation better than a time variable would. Table 4 presents Komanoff's equation (omitting some dummies not applicable to Seabrook), and that data necessary to apply it in two variations.

Column 4 of Table 4 applies Komanoff's interpretation of the relationship between regulation and the size of the nuclear industry. This formulation implicitly assumes that the time-correlated effect will slow down, since the growth rate in the cumulative capacity variable in the data set is 52.6 times as great as the growth rate in the time variable (CPIS), but from the end of the data set to the Seabrook CPIS. If anything, the experience of the last couple of years suggests that regulatory scrutiny is accelerating, rather than slowing down. Thus, Column 5 of Table 4 reformulates the equation so that the growth rate in construction durrations does not slow down, but instead remains constant over time. This is accomplished by maintaining the ratio of cummulative capacity to CPIS found in the data set.

Komanoff suggests a second kind of variation when he notes that the 11% increase in construction duration for units with cooling towers cannot really be attributed to the towers themselves because

> cooling towers are not on the "critical path" of construction steps determining plant completion. Addition of a tower may indicate regulatory sensitivity to environmental concerns leading to additional measures to reduce nuclear hazards, adding to construction time. This conjecture is unproven, however.
>
> (Komanoff, 1981, p. 210)

Variable	Co-efficient[a]	Seabrook[b]	Contribution to Construction Duration	
Constant	.98		.98	
MW	.358	1150	12.47	
A-E experience	-.111	6	.8196	
Cumulative Nuclear Capacity	.185	114613[c] (115813)[c]	8.629[d] (8.646)[d]	
Northeast Location	1.12		1.12	
Second Unit	1.20		1.0 (1.2)	
Cooling Tower	1.11			
Total Without Cooling Tower			96.8 (116.4)	112.4[e] (134.9)
With Cooling Tower Variable	1.11		107.4 (129.2)	124.8 (149.7)

Table 4: Komanoff Nuclear Construction Duration Equation (months from CPIS to COD)

Notes :

a. Equation is multiplicative: MW, A-E, and cumulative capacity are raised to the power of their co-efficients, and the results are multiplied by the constant and applicalbe dummies.

b. Figures in parentheses are for Seabrook 2.

c. For constant time effect, Cumulative Capacity is equivalent to 256977.

d. For constant time effect, this factor is 10.019.

e. This column is total months, given constant time effect.

This description certainly seems to apply to the Seabrook units in general, and to the prolonged struggle over their cooling system in particular. If Seabrook is treated as being more like the typical plant with cooling towers than the typical plant without tower, it is appropriate to add 11% to the durations. This interpretation is applied in the last row of Table 4.

Finally, Komanoff repeats Mooz's practice of using overly optimistic COD values for some recent plants, which are listed in Table 5. In fact, Komanoff intentionally used COD's which he knew were inaccurate, in an attempt to eliminate any effect of the TMI accident form his data set: his projections explicitly exclude all effects of TIM. Omitting the Diablo Canyon units from the data set probably biased the construction duration projection for future large units downwards, even ignoring the impact of TMI. Since it is also almost certain that TMI has increased the construction duration of all the units currently under construction, and since future incidents are likely to further increase durations, Komanoff's data set is likely to produce optimistic duration projections. Depending on the variant assumed, Komanoff's results imply a COD between August, 1984 and November, 1986 for Unit 1, and between March, 1986 and December, 1988 for Unit 2.

Unit	Komanoff Estimated COD	Actual COD	Differences Between Actual and Estimated Duration (months)
Salem 2	12/79	10/81	22
Sequoyah 1	2/80	7/81	17
Sequoyah 2	10/80	6/82	20
North Anna 2	12/79	3/80	3
Diablo Canyon 1	omitted	(1)	
Diablo Canyon 2	omitted	(1)	

Table 5 : Differences Between Komanoff COD Estimates and Actual Values

Notes :

(1) Neither Diablo Canyon unit has an active operating license. Commercial operation in 1982 is unlikely.

capacity grows only 15.4 times as fast as CPIS from the end of the data set to the Seabrook CPIS. If the rate of regulatory/institutional change actually stays constant over time, the effective value of "cumulative capacity" (as a time proxy) for Seabrook would be about 256977, construction would take 15% longer (112 and 134 months) and the in-service dates, would be pushed back to about October, 1985 and September, 1987 even without the "cooling tower" adjustment.

Combining the adjustments for "cooling tower" and the time variable produces duration estimates of 124 months and 149 months, and inservice dates of November, 1986 and December, 1988.

It should also be noted that none of the regression techniques (the trend line analysis, Mooz's equation, and Komanoff's equation) reflects either the Seabrook permit suspensions or PSNH's current or future financial difficulties. To the extent that Seabrook has experienced or will experience an atypical number of delays, its in-service date would be expected to be later than the projections.

Q. What are the construction duration projections for other nuclear power plants, and how do they compare to those for Seabrook?

A. Table 6 lists the reported percent complete and the scheduled in service date for each nuclear unit which is within 15 percentage points of the reported percent complete

Unit	Reported % Complete(1)	Estimated Commercial Operation (2)
Limerick 1	63	4/85
Braidwood 1	62	10/85
Palo Verde 2	61	5/84
South Texas 1	60	/84 (3) (5)
Byron 2	60	10/84
Susquehanna 2	59	5/84
Bellefonte 2	59	9/86
Watts Bar 2	58	10/84
Comanche Peak 2	52	/84 (3)
WPPSS 1	49.6	6/86(4)
Braidwood 2	48	10/86
Seabrook 1	48	2/84
Harris 1	43	9/85
Beaver Valley 2	41.6	5/86
Perry 2	40	5/88
Nine Mile Point 2	38	10/86
Millstone 3	36	5/86
Hope Creek 1	35	12/86
Hartsville A1	34	7/88 (4)

Table 6 : Projected Completion Dates, Units comparable to Seabrook 1 in Stage of Completion

Notes : (1) From Nuclear News, August, 1981. All units between 33% and 63% complete are listed.

(2) From Nuclear News, August, 1981.

(3) Month not given, June assumed for calculations.

(4) Since placed on indefinite status.

(5) Since delayed to 1987.

for Seabrook 1 as of June 30, 1981. None of these 18 units were projected to be on line as early as Seabrook 1 (two units in Texas were scheduled for some time in 1984). On average, these eighteen units were 50% complete and were projected to reach commercial operation in December, 1985. Depending on how fast construction proceeds in the near future construction Seabrook 1 is one to two months behind the average.

The same calculation can also be performed for Seabrook 2, but it is more constrained: few utilities are still making any effort to continue units less than 20% complete. Of the 17 units listed in Table 7, seven had no scheduled in-service date in June, 1981. The other ten units averaged 8.3% complete (versus 8% for Seabrook 2) with an average predicted in-service date at that time of about March, 1989. Perhaps it is inappropriate to include the three units which were less than 1% complete, all of which have since been cancelled. Updating the analysis to January of 1981 finds half the plants cancelled and three more rescheduled. The remaining five plants averaged 10.2% complete, with a June, 1988 in-service date. Seabrook 2 was several months to a year behind the average of this smaller group, at recent rates of progress.

Unit	Reported% Complete (1)	Estimated Commercial Operation (2)	Updated COD (3)	
Hope Creek 2	17.8	12/89	Canceled	
WPPSS 5	13.7	12/87	Canceled	(1/82)
Marble Hill 2	11	late 87 (4)	6/88	(8/82)
North Anna 3	8.8	/89 (5)		
Seabrook 2	8	5/86		
Harris 2	3	3/88	3/89	
Harris 3	1 (6)	3/94	Canceled	
Harris 4	1 (6)	3/92	Canceled	
Callaway 2	0.5	/90 (5)	Canceled	
Cherokee 1	18	indefinite		
Hartsville B1	17	indefinite	Canceled	(8/82)
Hartsville B2	7	indefinite	Canceled	(8/82)
Phipps Bend 2	5	indefinite	Canceled	(8/82)
Yellow Creek 2	3	indefinite		
Clinton 2	0	indefinite		
River Bend 2	0	indefinite		
Vogtle 1	18	5/85	3/87	
Vogtle 2	10	11/86	9/88	

Table 7 : Projected Completion Dates, Units Comparable to Seabrook 2 in Stage of Completion

Notes : (1) From Nuclear News, August, 1981. All units with CP and less than 20% complete are listed.

(2) Ibid.

(3) From AIF "Nuclear Power Plants in the U.S.", 12/31/8[illegible] except as noted.

(4) October assumed.

(5) June assumed.

(6) 0.5% assumed.

Q. Have the construction duration estimates of the nuclear industry as a whole generally been accurate?

A. No. Table 8 presents the estimated and actual construction durations for all the units which have reached commercial operation and for which I have been able to obtain one or more in-service-date estimates made after (or only a month or two before) the construction permit was issued. Thus, delays in obtaining construction permits (a problem which Seabrook no longer faces) are not included in these figures. For the three estimates over four years into the future, the actual duration averaged 2.14 times the projected duration. For the fourteen estimates between three and four years, the ratio averaged 2.31. For the nineteen estimates between two and three years, the average was 2.43.*

As of the March, 1981 estimate, Seabrook 1 was anticipated to be 35 months from COD, and Unit 2 was projected to be 62 months from COD. Multiplying these intervals by 2.43 and by 2.14, respectively, yields predictions of commercial operation in April, 1988 and April, 1992, if PSNH is just as over-optimistic as the builders of the thirteen units listed in Table 8. As noted above, PSNH is the most optimistic utility in the country as regards in-service dates for units at comparable stages of construction. It is possible that other utilities are generally more realistic now than tney were in the 1960's and 1970's. It is also possible that PSNH's current over optimism on its schedule exceeds the general level of over confidence both currently and historically.

---

*Sequoyah 2 would raise the last two averages to 2.61 and 2.52, respectively.

Unit	Estimate Date	Estimated COD	Estimated Time to Complete (Years)	Actual COD	Actual Time to Complete (Years)	Ratio of Actual Time to Estimated Time
Millstone 2[1]	11/70	4/74	3.42	12/75	5.08	1.49
	11/73	8/75	1.75		2.08	1.19
Pilgrim 1[2]	6/68	9/71	3.25	12/72	4.50	1.38
	1/70	9/71	1.67		2.92	1.75
Cooper[3]	7/68	4/72	3.75	7/74	6.00	1.6
	10/70	7/73	2.75		3.75	1.36
TMI 2[5]	12/69	5/74	4.42	12/78	9.00	2.04
	12/70	5/74	3.42		8.00	2.34
	12/71	5/65	3.42		7.00	2.05
	12/72	5/76	3.42		6.00	1.75
	12/73	5/77	3.42		5.00	1.46
	12/74	5/78	3.42		4.00	1.17
	12/75	5/78	2.42		3.00	1.24
	12/76	5/79	1.42		2.00	1.41
Hatch 2[3]	2/76	4/79	2.33	9/79	2.75	1.18
Crystal River 3[3]	1/75	9/76	1.67	3/77	2.17	1.26
Maine Yankee[3]	5/71	5/72	1.00	12/72	1.58	1.58
Rancho Seco[3]	8/73	10/74	1.17	4/75	1.67	1.43
Salem 1[4]	8/68	3/72	3.58	6/77	8.83	2.47
	9/69	3/72	2.5		7.75	3.10
	1/71	12/73	2.92		6.42	2.20
	1/71	12/73	2.42		5.92	2.45
	7/72	3/75	2.67		4.92	1.84
	7/73	9/75	2.17		3.92	1.81
	7/74	12/76	2.42		2.92	1.21
Salem 2[4]	8/68	3/73	4.58	10/81	13.17	2.88
	9/69	3/73	3.5		12.08	3.45
	1/71	12/74	3.92		10.75	2.73
	7/71	12/74	3.42		10.25	3.00
	7/72	3/76	3.67		9.25	2.52
	7/72	9/76	3.17		8.25	2.60
	7/74	5/79	4.83		7.25	1.50
	7/77	5/79	1.83		4.25	2.32

able 8 : Tendency of Utilities and A/E's to Underestimate Construction Time for Nuclear Power Plants

CONTINUED NEXT PAGE

TABLE 8 CONTINUED

Unit	Estimate Date	Estimated COD	Estimated Time to Complete (Years)	Actual COD	Actual Time to Complete (Years)	Ratio of Actual Time to Estimated Time
Brown's Ferry 1[6]	1/68	10/70	2.75	8/74	6.58	2.39
	1/70	10/71	1.75		4.58	2.62
	1/71	4/72	1.25		3.58	2.86
Brown's Ferry 2[6]	1/68	10/71	3.75	3/75	7.17	1.91
	1/70	4/72	2.25		5.17	2.30
	1/71	1/73	2.00		4.17	2.09
	1/72	7/73	1.50		3.17	2.11
	1/73	4/74	1.25		2.17	1.74
Brown's Ferry 3[6]	1/70	10/72	2.75	3/77	7.17	2.61
	1/71	10/73	2.75		6.17	2.24
	1/72	2/74	2.08		5.17	2.49
	1/73	10/74	1.75		4.17	2.38
	1/74	4/75	1.25		3.17	2.54
	1/75	1/76	1.00		2.17	2.17
Sequoyah 1[6]	1/71	4/74	3.25	7/81	10.50	3.23
	1/72	7/74	2.5		9.50	3.80
	1/73	4/75	2.25		8.50	3.78
	1/74	6/76	2.42		7.50	3.10
	1/75	1/77	2.00		6.50	3.25
	1/76	9/77	1.67		5.50	3.29
	1/77	5/78	1.33		4.50	3.46

Table 8 : Tendency of Utilities and A/E's to Underestimate Construction Time for Nuclear Power Plants

Notes :
1. From Information Response (IR) AG-7, Mass. D.P.U. 20279
2. From IR 33, NRC 50-471.
3. From IR AG-C-19, Mass. D.P.U. 20248 (RW Beck Data)
4. From "Construction Management Audit, Salem 1", May 1977, Theodore Barry and Associates.
5. From "Review of the TMI-2 Construction Project", Touche Ross & Co., Oct., 1978.
6. From TVA reports.

That over-confidence has been virtually universal within the U.S. nuclear industry. Of 172 U.S. units listed in the August, 1981 Nuclear News "World List of Nuclear Power Plants", all but three units have an "actual or expected" COD later than the "original schedule". The three exceptions are the Hanford-N plant and San Onofre 1, neither of which list original schedules, and Big Rock Point, for which the COD listed is incorrect.

Q. What dates are realistic for completion of construction and commercial operation at the Seabrook units?

A. Table 9 summarizes my previous calculations. This tabulation does not reflect several factors which could extend construction further, such as the erroneous data used in Mooz's and Komanoff's regressions and the effects of further Seabrook 1 delays on Unit 2. Over all, if the historic trends continue, Unit 1 may be complete in early 1985 and commercial in early 1986. There is a greater variation in the projections for Seabrook 2, but commercial operation in mid-1989 seems realistic, or perhaps a bit optimistic.

CONSTRUCTION DURATION STUDY

Method		Seabrook 1 OLIS	Seabrook 1 COD	Seabrook 2 OLIS	Seabrook 2 COD
Past PSNH Progress-to-Estimate Ratios		3/85		10/89	
Past Completion Rates for Seabrook	fast	1/85		4/90+	
	slow	8/85		11/90+	
NRC Caseload Forecast Panel		12/84		(2)	
Time Trends		/91		/95 or /96	
Mooz (2 years between units)		3/85+		3/87+	
Komanoff	-minimum		8/84+		3/86+
	-"cooling tower"		6/85		3/87
	-time correction		10/85		9/87
	-combined adjustments		11/86		12/88
Industry Consensus (3)			1-2/85		1-3/89
Industry Myopia (4)			4/88		4/92
Average of Estimates (1)		3/85	3/86	7/89	8/88
OLIS Average +12 Month Start-up			3/86		7/90

Table 9 : Summary of Construction Duration Predictions

Notes : 1. Averages omit simple time trend results

2. Not forecast

3. Not corrected for overall industry myopia, which would delay COD.

4. Not corrected for PSNH's greater optimism, which would delay COD.

2. Capital Costs

Q. Are PSNH's estimates of Seabrook capital costs consistent with historical experience?

A. No. Econometric studies, by L.J. Perl (1978) of National Economic Research Associates (NERA), by W.E. Mooz (1978) of the Rand Corporation, and by C. Komanoff (1981), all indicate that Seabrook will cost much more than PSNH claims. This conclusion is also supported by the historical tendency of architect/engineers (A/E's) and utilities to underestimate nuclear construction costs, and by the continuing increases in cost estimates for nuclear plants under construction.

Q. Please explain how the NERA study indicates that PSNH's capital cost estimates are optimistic.

A. The Perl study, which apparently was sponsored by the Atomic Industrial Forum, projects a capital cost of about $2245/kw (in 1990 dollars) for an 1150 mw first unit. The regression results indicate that second units are 23.6% less expensive than identical first units entering service in the same year. However, the 1990 cost projection appears to be based on three very doubtful assumptions:

1. 5.5% general inflation, 1977-1990;
2. 6% real escalation of nuclear costs, 1977-85; and
3. no real escalation of nuclear costs, 1985-90.

The annual rate of CPI inflation from 1977 (CPI=181.5) to PSNH's estimate for 1981 (270.7) has been running about 10.5%; PSNH projects 8.5% CPI inflation in 1982 and 8% thereafter to 1990. Also, since NERA's study indicates that real nuclear costs actually increased by 10% annually from 1960 to 1977, the inclusion of cost estimates with 6% real escalation from 1977 to 1985, and the exclusion of all escalation past that point, is unjustified by the historical record.

Removing the inflation and escalation estimates from NERA's 1990 projection produces a 1977 estimate of

$$2245 \div \left[(1.055)^{13} \times (1.06)^{8}\right] = \$702/\text{kw}$$

for a first unit and

$$702 \times .764 = \$536/\text{kw}$$

for a second unit entering service in 1977.

These figures are comparable to the extremes NERA presents for 1977 actual costs of $496 for an unusually inexpensive second unit to $902 for an unusually expensive first unit.

Nuclear input costs in the Northeast have actually increased by 36.6% from 1977 to 1981 (using January Handy-Whitman values for both years). From 1967 to 1980, the average annual increase in the CPI was 7.20%, while the Handy-Whitman averaged 7.88%, or 9.4% more. Applying this differential to PSNH's forecasts of CPI produces nuclear input inflation of 9.3% in 1982 and 8.8% thereafter. Thus, the total inflation from 1977 to 1983 is 1.366 x 1.093 x 1.088 = 1.624; multiplying 1977 dollars by 1.624 will give prices in 1983 dollars.

If the annual real growth in nuclear costs continue at the historical 10% level beyond 1977, and if the Seabrook units enter service at the times PSNH predicts, then Unit I would be expected to cost

$$702 \times 1.624 \times 1.1^{6.58} = \$2134/\text{kw in 1983 dollars}$$

and Unit 2 would cost

$$536 \times 1.624 \times 1.1^{8.83} = \$2020/\text{kw (1983 \$)}.$$

If the units actually come on line in January, 1986 and July, 1989, as seems more likely, the costs would be

$$702 \times 1.624 \times 1.1^{8.5} = \$2563/\text{kw for Unit 1, and}$$

$$536 \times 1.624 \times 1.1^{12} = \$2732/\text{kw for Unit 2,}$$

both in 1983 dollars.

Q. Does the Mooz study support similar estimates?

A. Yes. In his 1978 study prepared for DOE, Mooz derived the formula presented as Table 10. The 1976 dollars used in Mooz's study are estimated annual cash flow, deflated by the Handy-Whitman All-Steam-Generation index. This index increased at 8.31% annually between 1967 and 1980, or 15.4% faster than the CPI, and increased 45.0% from 1976 to 1981. Increasing the PSNH inflation estimates by 15.4% yields inflation of 9.8% in 1982 and 9.2% in 1983, for an

Variable Name	Meaning	Co-efficient	Value for Seabrook I [Seabrook II]	Contribution to Cost/kw
Constant				-9995.5
CPIS	date of construction permit	141.34	76.5	10812.5
SIZE	in MW	-.21943	1150	- 252.3
TOWER	cooling tower dummy	92.04	0	0
LOC 1	Northeast	128.12	1	128.12
LN	ln of # of LWR plants built by A/E	-72.422	ln (5) = 1.79 [ln (7) = 1.95]	-129.8 [-140.9]
Cost in 1976 $/kw			Seabrook I Seabrook II	1673.0 [1661.9]

Table 10 : Mooz Formula Estimate of Seabrook Construction Cost

overall inflation of 1.45 x 1.098 x 1.092 = 1.739 from 1976 to 1983, and costs of $2909/kw for Seabrook 1 and $2889/kw for Seabrook 2 in 1983 dollars.

Q. Can similar cost estimates be derived from Komanoff's work?

A. Yes. Table 11 presents the coefficients and applicable values for the three nuclear capital cost equations from Komanoff (1981). Table 12 evaluates the equations for the two Seabrook units, both with and without the "cooling tower" variable; Komanoff's comments on the cooling tower's impact on costs parallel his discussion of the schedule effect.

Taking the average costs predicted by the six methods, and adding in AFUDC by the methodology Komanoff used in estimating the equations, produces values of $2264.7/kw and $2433.3/kw in 1979 dollars for the two units. Adding in inflation from 1979 to 1981 (19.5% overall), for 1982 (9.8%, as for Mooz), and for 1983 (9.2%), converts these costs to $3245/kw and $3468/kw in 1983 dollars.

Q. How does the past record of A/E cost estimates support the capital cost forecasts of the econometric models?

A. In a report prepared by Analysis and Inference for the NRC (Chernick, *et al.*, 1981), we calculated the ratio of actual to forecast costs for several nuclear power plants, and derived four equations estimating the relationship

Variable	Value for Seabrook 1 [Seabrook 2]	Coefficients for Equation 8.1	Equation 8.2	Equation 8.3
Constant		6.41	.00114	16.2
Northeast (1)	1	1.28	1.33	1.28
A-E experience	6 [7]	-.105	-.125	-.094
MW	1150	-.200	-.203	-.266
Multiple (1)	1	.903	.88	.897
Cooling Tower (1)	0 (3)	1.20	1.11	1.18
Cumulative Capacity	114613 [115814]	.577		.501
CPIS (2)	76.58		1.236	
Operating Experience (4)	765 [1113]			.067

Table 11 : Coefficients and Variable Values for Komanoff Nuclear Cost Equations

Notes :

1. Dummy variables, included if applicable, set to 1.0 if not. "Dangling" variable not shown.
2. Factor is 1.236^{CPIS}; for all other factors, the variable is raised to the power of the coefficient.
3. Or 1.0 if "Cooling Tower" designation applies.
4. In reactor-years as of the OLIS (assumed to be 6/85 and 12/88); five new reactors/year assumed, 1982 onwards.

Equation	"Cooling Tower"	Predicted Cost[1] Seabrook 1	Seabrook 2
#1	No	1245.0	1232.4
#1	Yes	1494.0	1478.9
#2	No	2791.7	2738.6
#2	Yes	3098.8	3039.8
#3	No	1288.2	1309.4
#3	Yes	1420.1	1545.1
Average		1906.3	1890.7
Real AFUDC[2]			
% increment		18.8%	28.7%
$ kw		358.4	542.6
Total with AFUDC, 1979 dollars/kw		2264.7	2433.3

Table 12 : Evaluation of Komanoff Cost Equations

Notes : (1) in 1979 dollars per kw, without real AFUDC

(2) AFUDC % $= \dfrac{1 - (1.038)^N}{N \ln (1/1.038)} - 1$, where

N = years from CPIS to COD. See Komanoff (1981, p. 244). N = 9.5 for Unit 1, 13 for Unit 2.

between real cost overruns and the length of time into the future for which the forecast is being made. The four equations are:

$$R = 1 + .204t \quad (1)$$

$$R = .598 + .300t \quad (2)$$

$$R = (1 + .147)^{t} \quad (3)$$

$$R = .844\ (1 + .195)^{t} \quad (4)$$

where R is the ratio of actual to expected costs in real dollars, and t is the expected years to completion at the time of the estimate. Table 13 evaluates these four equations for the lead times forecast by PSNH as of the 3/81 cost estimate, and for the industry consensus durations previously derived. It would not be appropriate to evaluate the equations with t equal to the most reasonable projection, since they were estimated from general industry duration projections in the 1960's and 1970's. To the extent that PSNH is more optimistic than general industry projections, PSNH's value of t is understated. On the other hand, the industry as a whole may be more realistic now then it was a decade ago, so current industry t values may be overstated somewhat for this purpose.

Averaging the results of the four equations (all of which are statistically significant at the 99.9% level), and of duration projections from PSNH and the industry, produces estimates of actual-to-forecast real cost ratios of 1.595 for

Equation Number	Source of t value	Unit Seabrook 1	Seabrook 2
1	PSNH[1]	1.566	2.055
2	PSNH	1.474	2.149
3	PSNH	1.473	2.032
4	PSNH	1.420	2.120
Average	PSNH	1.488	2.089
1	Industry[2]	1.781	2.616
2	Industry	1.747	2.974
3	Industry	1.691	2.963
4	Industry	1.670	3.460
Average	Industry	1.702	3.003
Average	Overall	1.595	2.546

Table 13 : Estimated Value of Actual-to-Forecast Real Cost of Seabrook Units, from Myopia Method

Notes : 1. t = 2.92 years to 2/84 for Unit 1;
t = 5.17 years to 5/86 for Unit 2.

2. t = 3.83 years to 1/85 for Unit 1;
t = 7.92 years to 2/89 for Unit 2.

Unit 1 and 2.546 for Unit 2. In mid-1983 dollars, PSNH's estimates of Seabrook costs are (from PSNH's response to CLF Data Request 2a, Set 2)

$$\$803008 \div (1150 \times .3556942) \div 1.08^{.58} = \$1876.9/kw$$

for Unit 1 and

$$\$532\,916 \div (1150 \times .3556942) \div 1.08^{2.83} = \$1047.6/kw$$

for Unit 2. Applying the average myopia adjustments produces estimates of $2994/kw for Unit 1 and $2667/kw for Unit 2.

Q. What Seabrook construction cost estimate do you find most reasonable?

A. Table 14 displays the results of the four methodologies I used. The average of the four estimates is about $2930/kw for Unit 1 and $2940/kw for Unit 2, both in 1983 dollars; I will use these values in my subsequent analysis. The true values may vary from these estimates by several hundred dollars per kw in either direction: normal risk averse behavior would justify basing decisions on a value of nuclear plant cost which is higher than the expectation, to reflect the economic risks, but I have not included this factor in my cost calculations.

Q. Should the full cost of Seabrook be used in designing rates for a conservation program?

A. That depends on the current assessment of the wisdom of building the plant. There are three possibilities:

1. "This Seabrook Unit has always been cost effective, and starting it was a good investment, even in retrospect."

Method	Cost per kilowatt, 1983 Dollars Seabrook 1	Seabrook 2
NERA (realistic dates)	2563	2732
Mooz	2909	2889
Komanoff (average of six methods)	3245	3486
Myopia (average of PSNH and Industry dates)	2994	2667
Average	2928	2943

Table 14 : Summary of Seabrook Cost Estimates

2. "In retrospect, starting this Seabrook unit was a bad investment, but now that it is started, finishing it is a good investment"

3. "Starting this Seabrook Unit was a bad investment and completing it would not be cost-justified.

If the first statement is true, the total cost of Seabrook power sets a lower bound on the value of conservation. If the second statement is correct, the value of conservation lies between the cost of Seabrook power based on the remaining investment, and that based on the total investment. If the third statement is true, then the remaining cost of Seabrook is an upper bound on the value of conservation.

From PSNH's response to CLF Request 2a, Set 2, PSNH expected to have spent \$1594/kw for Seabrook 1 and \$501/kw for Seabrook 2 as of the end of 1982. Including half a year's inflation at 8% annually, these values become \$1657/kw and \$521/kw in 1983 dollars. Thus, the net remaining costs of building the Seabrook units are about \$1270/kw and \$2420/kw, respectively, in 1983 dollars.

3. Capacity Factor

Q. How can the annual kilowatt-hours output of electricity from each kilowatt of Seabrook capacity be estimated?

A. The average output of a nuclear plant is less than its capacity for several reasons, including refueling, other scheduled outages, unscheduled outages, and power reductions. Predictions of annual output are generally based on estimates of capacity factors. Since PSNH's capacity factor projections are wholly unrealistic, and since PSNH appears to confuse capacity factor with availability factor, it may be helpful to consider the role of capacity factors in determining the cost of Seabrook power, before estimating those factors.

The capacity factor of a plant is the ratio of its average output to its rated capacity. In other words

$$CF = \frac{\text{Output}}{RC \times \text{hours}}$$

where CF = capacity factor, and
RC = rated capacity

In this case, it is necessary to estimate Seabrook's capacity factor, so that annual output, and hence cost per kwh, can be estimated.

On the other hand, an availability factor is the ratio of the number of hours in which some power could be produced to the total number of hours.

The difference between capacity factor and availability factor is illustrated in Figure 1. The capacity factor is the ratio of the shaded area in regions A and B to the area of the

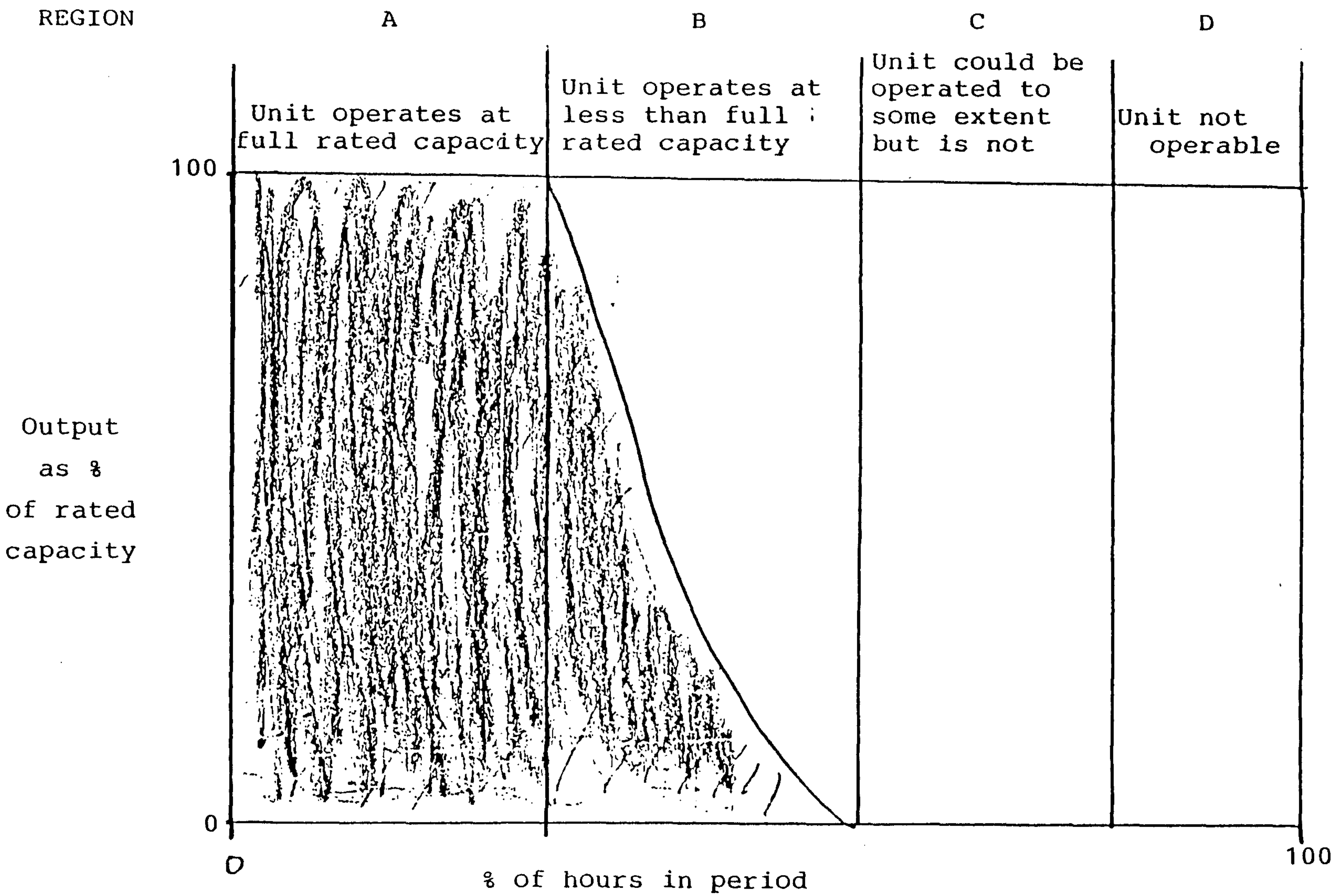

Figure 1: Diagrammatic Description of Availability Factor and Capacity Factor

rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the unshaded portion of region B, and all of region C, which are not included in the capacity factor.

Oddly enough, PSNH predicts that Seabrook's capacity factor in each year will equal its availability factor. This coincidence of factor can really only occur when the unit operates continuously at full power, (CF = AF = 1) or is continously unavailable (CF = AF = 0); the former condition rarely occurs for more than a month at a time, while the latter may persist for years. In general, capacity factor is considerably larger than availability factor, as illustrated in Table 15 for the six largest PWR's operating in December, 1978.

Q. Why is availability factor not an appropriate substitute for capacity factor in the calculation of nuclear cost?

A. The availability factor only distinguishes between hours in which some power is available and those in which no power is available. A unit is considered to be available during an hour whether it is at full power, ramping up to power after an outage, ramping down for a maintenance outage, operating

Unit	Lifetime Capacity Factor (1)	Lifetime Availability Factor (2)	Difference
Cook 1	64.4	78.2	13.8
Cook 2	64.3	77.2	12.9
Salem 1	45.8	55.3	9.5
Trojan	42.3	58.9	16.6
Zion 1	54.7	68.7	14.0
Zion 2	60.0	71.7	11.7

Table 15 : Difference Between Capacity Factor and Availability Factor

Notes: 1. NRC Gray Book, January, 1979; DER capacity

2. Ibid

at 80% power due to turbine problems, reducing output to extend core life, limited to 5% power for NRC-mandated tests, or in any other way limited or constrained, so long as <u>any power at all</u> could be generated. Thus, availability factor is not the proper quantity to multiply by rated capacity to yield output; this calculation will not work with any existing plant.

Q. What is the appropriate measure of "rated capacity" for determining historical capacity factors to be used in forecasting Seabrook power costs?

A. The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

Installed or Maximum Generator Nameplate rating (IGN or MGN).

The first two ratings are used by the NRC, and the third by FERC.

The MDC is the utility's statement of the unit's "dependable" capacity (however that is defined) at a particular time. Early in a plant's life, its MDC tends to be low until technical and regulatory constraints are relaxed, as "bugs" are worked out and systems are tested at higher and higher power levels. During this period, the MDC capacity factor will generally be larger than the capacity factor calculated on the basis of DER or IGN, which are fixed at the time the plant is designed and built. Furthermore, many plants' MDC's have never reached their DER's or IGN's.

Humboldt Bay has been retired after fourteen years without getting its MDC up to its DER; Connecticut Yankee has not done it in 14 years; nor Big Rock Point in 18 years, nor the Desden units (1, 2, or 3) in 21 years, 11 years, or 10 years; nor Lacrosse in 12 years; nor Oyster Creek 12 years. For only about one nuclear plant in five does MDC equal DER, and in only one case (Pilgrim) does the MDC exceed the DER. Therefore, capacity factors based on MDC will generally continue to be greater than those based on DER's.

The use of MDC capacity factors in forecasting Seabrook power cost would present no problem if the MDC's for the Seabrook plants were known for each year of their lives. Unfortunately, these capacities will not be known until Seabrook actually operates and its various problems and limitations appear. All that is known now are initial estimates of the DER and IGN, which I take to be 1150 mw and 1194 mw, respectively. Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and IGN capacity factors are useful for planning purposes. Using MDC capacity factors with DER ratings is as inappropriate as multiplying a kilometers/liter fuel efficiency measure by miles to try to estimate gallons of of gasoline consumed; the units are different, and in the case of MDC, unknown.

Actually, DER designations have also changed for some plants. The new, and often lower, DER's will produce different observed capacity factors than the original DER's. For example, Komanoff (1978) reports that Pilgrim's original DER was 670mw, equal to its current MDC, not the 655 mw value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1150mw expectation for Seabrook. This problem can also be avoided through the use of the MGN ratings.

Q. Have any studies been performed of the historic capacity factors for operating reactors?

A. Yes. Statistical analyses of the capacity factors of actual operating nuclear plants, all utilizing data through 1977, have been performed for the Council on Economic Priorities (CEP) (Komanoff, 1978), a Sandia Laboratories study for the NRC (Easterling, 1979), and the NERA study previously described (Perl, 1978).

The CEP study projects a levelized capacity factor for the first ten years of operation (excluding the first partial year) for Westinghouse 1150 mw reactors at 54.8% based on a statistical analysis which predicts a 46.1% capacity factor in year 1, rising to 62.3% in year 10. An alternative model found that capacity factors actually peak in year 5, at 59.1% and slowly decline to 55.2% in year 10, indicating that maturation does not continue to improve capacity factors indefinitely. However, in recognition of a perceived improvement in plants completed after 1973, Komanoff increases his 10 year levelized projection by 1.8 percentage points, over the historic trend.

The NRC study projects capacity factors on the basis of maximum generator nameplate (MGN), which appears to be 1194 mw for Seabrook. The prediction for an 1194 MW (MGN) PWR, expressed in terms of an 1150 MW DER, would be 51.6% in the second full year of operation, 55.0% in the third full year, and 58.3% thereafter. No further maturation was detected. All results for the first partial year and first full year of operation are excluded. Assuming that first year capacity factors are as good as second year capacity factors, a plant with a 30-year life would average 57.7% over its life, or 56.1% levelized at a 10% discount rate.

The NERA study presents capacity factor estimates of 63.6% for 1100 mw PWR's and 63.1% for 1200 mw plants, again excluding initial partial years of operation. These figures appear to represent levelized averages of the values generated by a regression equation, which predicts 1150 mw plant capacity factors of 54.8% in year one, rising to 66.5% in year 30. As previously noted, however, the projection of continued maturation past year 10 (or even year 5) is not supported by the historic record. The NERA projection for year 10 is 65.3% and that for year five is 63.8%.

Therefore the average life-time capacity-factor estimate for units like Seabrook would seem to lie in the range of 50% to 65%, based on the histical record. There is a great deal of variation from the average, however; the NERA and CEP studies could explain only 28% and 33% of the variation in the data, respectively, and the NRC study derives 95% prediction intervals of about 10% in years 2 to 5, 8% in years 2 to 10, and 7.3% for years 2 to 28. Roughly speaking, the NRC results predict that 19 out of every 20 nuclear units of the Seabrook size and type would have average lifetime capacity factors between 50.3% and 64.9%, with the 20th unit having a capacity factor outside that range. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.

Q. Is this similarity due to the use of idential methodologies in the studies?

A. No. While the studies all use regression analysis, the specific approaches of the three study vary. The NRC and CEP studies are limited to reactors of over 400 mw, eliminating data for Yankeee Rowe and, for the NRC study, Indian Point 1. The NERA study appears to include these smaller plants, which would tend to reduce the apparent relationship between plant size and capacity factor, since even Yankee's capacity factor has been considerably lower than the 98.0% predicted by the NERA formula for 15-year old plant of 175 mw.

The NRC and NERA data include PWR's manufactured by Combustion Engineering and Babcock & Wilcox, while the CEP study uses only Westinghouse reactors' experience. In the NRC and CEP models, capacity factors are linear functions of size. In the NERA model, capacity factors are linear functions of the inverse of size, and are therefore inherently less sensitive to size differences between the largest plants (e.g., 850 mw to 1150 mw) than between the smaller plants (e.g., 200 mw to 400 mw).

Plant age is modeled discretely in the NRC study (year 2=2, year 3=3, later years = 4), as log of unit age plus one in the CEP study, and as the inverse of the CEP formula in the NERA study.

The CEP study appears to use all applicable data (90 Westinghouse unit-years), while the NRC study rejects all first year data and all of Palisades' experience, but includes other PWR's. CEP indicates that there were 127 unit-years of PWR data through 1977, of which 32 were first-year data, five more were Palisades' data, and one was omitted from the NRC's data set due to differing definitions of the COD for Trojan; the NRC's 89 unit years are otherwise consistent with CEP's count. The NERA study should have 28 more observations, for Yankee Rowe and Indian Point 1, minus one for the Trojan dispute (in which NERA sides with the NRC), yielding 154 observations. But the NERA study reports that only 125 units-years were used, without specifying which ones were deleted. In addition, the NERA study uses a dummy variable to capture some of influence of three under-achieving plants (Palisades, Indian Point 2, and Oconee 1).

As noted above, the NRC study uses MGN capacity factors, while the CEP and NERA studies use DER capacity factors.

Nonetheless, the results are strikingly similar.

Q. What capacity factor value should be used in estimating Seabrook power cost?

A. The Easterling study is fully reviewable (unlike the NERA study)and was conducted to advocate nuclear power development (unlike the CEP study), so I feel most comfortable using the levelized value of 56% from the Easterling study. Considering that none of the three studies includes the direct effects of major nuclear accidents (such as TMI 2) or the indirect effects (such as TMI 1's long operating license suspension and the major retrofitting outages experienced by other units subsequent to the TMI accident) of such accidents, 56% is probably optimistic. In fact, Easterling (1981) has updated his analysis, the same equation now predicts mature capacity factors 4 to 9 points lower.

Q. Are PSNH's capacity factor projections reasonable?

A. No. As I mentioned previously, PSNH appears to confuse the concepts of availability factor and capacity factor. PSNH's projections may be reasonable for availability factors, but they are much too high for capacity factors. This should not be very suprising, since none of PSNH's sources actually contain any capacity factor data.

As a check on the accuracy of the NRC/Easterling capacity factors, compared to PSNH's projections, I asked the CLF staff to perform the calculations presented in Tables 16 and 17. For the six PWR's over 1000 mw which had entered service by 1979, the average capacity factor as of July, 1981 was 56.3%. The capacity factor estimates which I derived from Easterling predict an average of 56.7%, while PSNH predicts an average of 66.6%. Clearly, PSNH's expectations are out of line with reality.

Predicted Capacity Factors		Calendar Years of Experience 1 [3]	2	3	4	5	6+
PSNH [1]		59	61	65	67	69	72
Easterling [2]		51.6	51.6	51.6	55	58.3	58.3
Unit Years of Experience as of 7/81	**COD**						
Salem 1	6/30/77	.50	1	1	1	.58	
Zion 1	12/31/73	(4)	1	1	1	1	3.58
Zion 2	9/17/74	.25	1	1	1	1	2.58
Cook 1	8/27/75	.33	1	1	1	1	1.58
Cook 2	7/1/78	.50	1	1	.58		
Trojan	5/20/76	.58	1	1	1	1	.58

Table 16 : Data for Comparison of Capacity Factor Predictions

Notes :

1. From PSNH response to Staff Request 32.
2. For Seabrook, as derived in text.
3. "First partial year" in Easterling terminology.
4. Negligible.

Lifetime Capacity Factors
As of July 31, 1981

Unit	Actual[1]	Easterling[3]	PSNH
Salem 1	44.8	54.8	64.3
Zion 1	56.6	58.5	68.6
Zion 2	59.9	58.3	67.7
Cook 1	61.7	57.4	66.9
Cook 2	64.4	53.4	63.1
Trojan	49.2	54.8	65.5
Average[2]	56.3	56.7	66.6

Table 17 : Comparisions of Capacity Factor Predictions

Notes :

1. DER ratings from NRC Gray Book, August, 1981.
2. Weighted by experience.
3. Includes 2.4 points for every 100 mw difference between Seabrook's 1150 mw DER and the unit's DER.

4. Carrying Charges

Q. What annual carrying charge should be applied to the cost of Seabrook?

A. I have assumed a 10% real cost of capital (including income taxes), a 2.5% property tax rate, and unit lifetime of 20 years and 30 years. The shorter lifetime is based on an analysis of the experience of smaller nuclear units, as discussed in Chernick, et al. (1981, pp. 101-109), while the longer lifetime is a more standard industry assumption. Over 20 years, the annual fixed charges for capital and depreciation would be 11.75%, and the levelized property tax would be 1.56%, for a total of 13.3%. Over thirty years, the fixed charges are 10.61% and property tax is 1.75%, for a total of 12.4%.

Table 18 displays the annual carrying cost per kwh of each Seabrook unit at 20 and 30 year lives, both for the full cost and for the remaining cost.

Q. What other costs must be added to the Seabrook carrying costs to determine the total cost of Seabrook power?

A. The other components of the costs of Seabrook which are directly assignable to that plant are:

- fuel;
- non-fuel operation and maintenance (O&M) expense;
- interim replacements (capital additions);
- insurance; and
- decommissioning.

Lifetime (years)	Cost Basis	Unit 1	Unit 2
30	Remaining[1]	3.21 ¢/kwh	6.12¢/kwh
30	Full[2]	7.40	7.44¢/kwh
20	Remaining	3.44	6.56¢/kwh
20	Full	7.94	7.98¢/kwh

Table 18 : Carrying Cost per kwh of Seabrook Power.

Notes : 1. $1270/kw and $2420/kw, respectively; all costs in 1983 dollars, 56% capacity factor

2. $2928/kw and $1243/kw.

In addition, there are some indirect, but quite real, effects of the Seabrook project on PSNH ratepayers.

5. Fuel Cost

Q. What nuclear fuel costs have you used?

A. I used PSNH's 20-year levelized estimates of 1.33¢/kwh for Seabrook 1 and 1.55¢/kwh for Seabrook 2, from PSNH's response to Staff Request 30, Set 1.

6. Non-Fuel O & M

Q. Is PSNH's estimate of Seabrook non-fuel O & M expense reasonable?

A. No. PSNH bases its O & M cost forecast on recent O & M costs for Maine Yankee, which has been an exceptionally inexpensive plant to operate. PSNH also assumes that nuclear O & M increases less than 1% annually in real terms (that is, rises only slightly faster than the inflation rate), despite very rapid historical growth rates in nuclear O & M. PSNH's historical figures for Yankee O & M (in CLF IR 2-3) apparently include costs not usually classified as plant O & M (e.g., insurance, administration, employee benefits), but they illustrate the general trend. The average annual growth rate in the O & M figures reported by PSNH for 1979-81 ranges from 36.8% to 44.5% for the various units, in a period of 12% CPI inflation. The costs nearly doubled in those two years.

Table 19 presents the 1980 O & M cost for each of the six New England nuclear units, excluding Yankee Rowe, which is much smaller than the other reactors. The table also presents the least-squares estimates of annual linear growth (in 1981 dollars) and of annual geometric growth rates, and the six-unit average of each parameter. Each unit is analyzed from its first full year of service through the latest year for which

Unit	Period Analyzed	1980 O & M ($1000)	Least - Squares Annual Growth: Linear Increase (1981$, 1000's)	Least - Squares Annual Growth: Geometric Increase
Conn. Yankee	1968-80	35155	1854	13.8%
Millstone 1	1971-80	24783	1566	9.6%
Pilgrim	1973-81	27785	2574	13.7
Vermont Yankee	1973-80	22588	1785	12.1%
Maine Yankee	1973-80	14028	980	8.9%
Millstone 2	1976-80	30164	2913	12.1%
Average		25751	1933	11.7%
		x 1.104		
1981 $		28428		
		x 1.172	x 1.172	
1983 $		33313	2265	

Table 19: Calculation of Average New England Experience, Non-Fuel Nuclear O & M Expense, Constant Dollars

I could obtain the data (1980, except 1981 for Pilgrim).

Table 20 displays the levelized O & M cost for each unit for 20 and 30 year lives, and for extrapolation of the linear and geometric average trends. Protracted geometric growth in real O & M cost would probably lead to retirement of the units around the turn of the century, as they would be prohibitively expensive to operate (unless the alternatives were even more expensive).

High costs of O & M and necessary capital additions were responsible for the retirement (formal or *de facto*) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Mass. Yankee remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's. To be on the optimistic side, I have assumed a continuation of the linear trends in New England nuclear cost escalation.

Q. Is it appropriate to include the 1979-81 period, when the TMI accident and subsequent regulatory actions affected nuclear plant operation, in the analysis of nuclear O & M trends?

A. I believe that it is. Several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Seabrook operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Miniarick and Kukielka, 1982). Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-81 period has been relatively favorable for nuclear operations.

Trend Type	Unit Life	Unit 1	Unit 2
Linear	20 years	61644	68439
Linear	30 years	65422	72217
Geometric	20 years	160458	223625
Geometric	30 years	235763	328575

Table 20: Levelized Annual Non-fuel O & M Expense (1000's of 1983 dollars), Extrapolated from New England Experience

7. Capital Additions

Q. Is PSNH's estimate of capital additions to the Seabrook units reasonable?

A. PSNH's estimate of annual capital additions (or interim replacements) is $10 million per unit, in 1981 dollars (CLF IR 2-2c). This is the first acknowledgement I have seen by any of the co-owners that the cost of nuclear units increases after the in-service date. Furthermore, PSNH's estimate appears to be of the proper order-of-magnitude, if a little low.

Based on data gathered by CLF staff for fifteen plants, totalling 159 unit-years of operation, I derived an experience-weighted average annual capital addition of $10049 per mw in 1980 dollars, or $14.9 million per Seabrook unit in 1983 dollars. The data includes all the units in New England over 300 mw, and all other plants completed by early 1973, and includes data through 1980, as available.

8. Insurance

Q. What value have you used for the cost of insuring Seabrook?

A. I have assumed that PSNH obtains the following insurance for each unit:

a. liability coverage of \$160 million, for the 1981 average premium of \$380,000;

b. property coverage of \$300 million from the commercial pool (ANI/MAERP), at the high-end premium of \$1.75 million;

c. additional property coverage of \$375 million from the self-insurance pool (NML) for the TMI 1 premium of \$1.38 million;

d. replacement power coverage of \$156 million from the self-insurance pool (NEIL) for \$1.69 million;

e. decommissioning accident coverage of one billion dollars for \$2.19 million; and

f. non-accident-initiated premature decommissioning coverage of \$250 million for \$2.42 million.

All values are 1981 dollars from Chernick, et al. (1981), except for the NEIL premium, which is from the NEIL circular of December 18, 1979. The decommissioning insurances may be from new or existing pools. These coverages have total estimated premiums of \$9.81 million in 1981 dollars, or about \$11.5 million in 1983 dollars (including just CPI inflation). While only the liability and some property coverage are currently required, failure to utilize insurance exposes the ratepayers and stockholders of PSNH to additional costs, which may be greater (on the average) than the insurance premium. Indeed, even with all the insurances listed, PSNH would still not be full covered in the event of the total and permanent loss of a Seabrook unit.

On a cents-per-kwh basis, \$11.5 million per reactor annually is \$10/kw or 0.2¢/kwh.

9. Decommissioning

Q. What allowance for decommissioning should be included in the cost of Seabrook power?

A. Chernick, et al. (1981) estimates that non-accidental decommissioning of a large reactor will cost about $250 million in 1981 dollars. This is equivalent to about $300 million in 1983 dollars (using the nuclear inflation figures from the discussion of the NERA construction cost estimate, above), or about $260/kw for Seabrook. Assuming that the decommissioning fund accumulates uniformly (in constant dollars) over the life of the plant, and that it is invested in risk-free assets (such as Treasury securities) which earn essentially zero real return, the annual contribution (in 1983 dollars) would be about $13.0 per kw-year over a 20 year life or $8.7 per kw-year over a thirty year life. These annual values are equivalent to about 0.3¢/kwh and 0.2¢/kwh, respectively.

10. <u>Total Seabrook Generation Cost</u>

Q. What is your estimate of the cost of power from Seabrook?

A. I estimate that the total cost of power will be about 11¢/kwh, levelized in 1983 dollars. Excluding sunk costs as of the end of 1982, the remaining cost is about 6.3-6.7¢/kwh for Seabrook 1, and 9.6-10.1¢/kwh for Seabrook 2. These figures are derived in Table 21.

Cost Component	Seabrook 1		Seabrook 2	
Annual Costs ($/kw year)	20-yr life	30-yr life	20-yr life	30-yr life
Capital Cost[1]	389.4 (168.9)	363.1 (157.5)	291.3 (321.9)	364.9 (300.1)
Non-fuel O & M	53.6	56.9	59.5	62.8
Interim Replacements	12.9	12.9	12.9	12.9
Insurance	10.0	10.0	10.0	10.0
Decommissioning	13.0	8.7	13.0	8.7
Total Annual Non-fuel	478.9 (258.4)	451.6 (246.0)	486.8 (417.3)	459.30 (394.50)
Cost per KWH (¢)				
Non-fuel[2]	9.76 (5.27)	9.21 (5.01)	9.92 (8.51)	9.36 (8.04)
Fuel	1.33	1.33	1.55	1.55
Total	11.09 (6.70)	10.54 (6.34)	11.47 (10.06)	10.91 (9.59)

Table 21: Calculation of Seabrook costs per kilowatt hour, 1983 $.

Notes: 1. Figures in parentheses are net of investment to end of 1982.

2. At 56% capacity factor

C. Other Costs Avoided by Conservation

1. Losses

Q. How did you estimate losses between the generation level and the customer?

A. I used the methodology in Appendix C , and PSNH's average losses at peak from the PURPA §133 filing, Schedule 502(c). As shown in Table 22, I calculated marginal losses both at peak and averaged over a constant incremental load. Typical load shapes will have marginal losses between those of the peak load and a flat load.

Sales Level	Average Variable Losses at Peak[a]	Marginal Losses at Peak[b]	Cumulative Marginal Peak Losses From: Transmission	Cumulative Marginal Peak Losses From: Primary	Variable Average Energy Losses[c]	Marginal Energy Losses[d]	Cumulative Marginal Energy Losses From Generation
	%	%	%	%	%	%	%
Secondary	1.75	3.56	21.39	10.38	1.23	1.48	14.54
Primary	3.19	6.59	17.22	6.59	2.23	4.57	11.77
Subtransmission	1.95	3.98	9.97	--	1.37	2.77	6.88
Transmission	2.80	5.76	5.76	--	1.96	4.00	4.00

Table 22: Calculation of Marginal Losses

Notes:
a. PURPA §133 filing, Schedule 502(c)
b. (1+L)/(1-L); see Appendix C; L = average losses at peak.
c. Average peak losses times .7.
d. (1+L)/(1-L), L = average energy losses

2. Transmission and Distribution

Q. How did you estimate the marginal cost of transmission and distribution investment?

A. I used PSNH's estimate from the PURPA §133 filing, Schedule 502(c). These costs are stated as $/kw of peak demand on each voltage level. In fact, a significant portion of transmission and distribution (T&D) costs are due to energy use, rather than peak demand, but this imprecision should not be very important so long as load factors do not change greatly. I updated the T&D costs to 1983 at the average of 1979-81 inflation rates (10.6% for transmission and 9.4% for distribution), for 1983 costs of $56.53/kw for transmission, $53.03/kw for primary, and $44.24/kw for secondary. Table 23 includes peak losses and adds up the costs of the various system levels for each sales voltage level.

Sales Level	Transmission Cost	Primary Cost	Secondary Cost	Total Cost
	$/kw	$/kw	$/kw	$/kw ($/kw-year)
Secondary	68.62	58.53	45.87	173.02 (30.39)
Primary	66.26	56.52	-	122.78 (21.03)
Subtransmission	62.17	-	-	62.17 (9.76)
Transmission	59.79	-	-	59.79 (9.39)

Table 23: Calculation of Marginal T&D Cost by Delivery Level

Notes: Includes losses from Table 22, lives and tax rates from PURPA §133.

3. <u>Total Marginal Costs</u>

Q. Have you calculated total marginal costs for power delivered from the Seabrook units to customers, with related T&D costs?

A. Yes. These totals are presented in Table 24.

Delivery Level	Delivered Cost of Seabrook Power[a] Unit 1	Unit 2	Delivered Cost[b] of T & D at 50% Load Factor	80% Load Factor	Total Cost[c] 50% Load Factor	80% Load Factor	Off-Peak
Secondary	7.47	11.25	.69	.69	11.94 (8.16)	11.68 (7.90)	11.25 (7.47)
Primary	7.28	10.98	.48	.30	11.46 (7.77)	11.28 (7.59)	10.98 (7.29)
Subtransmission	6.97	10.50	.22	.14	10.72 (7.19)	10.64 (7.11)	10.50 (6.97)

Table 24: Calculation of Total Marginal Costs

Notes : a. From Table 21: average of 20-yr and 30-yr net costs, with average energy losses from Table 22.

b. From Table 23.

c. Top figures are for Unit 2; bottom row is for Unit 1 (in parentheses).

BIBLOGRAPHY

1. Barry, Theodore & Associates

   Construction Management Audit of Salem Nuclear Generating Station Unit No. 1 prepared for New Jersey Department of Public Advocate and Pennsylvania Office of Consumer Advocate, May, 1977.

2. Bentley, B.W. and Denehy, R.F.

   Nuclear Plant Lead Times: An Analysis for Planners, MMWEC-PMD-001, July, 1979.

3. California Energy Commission

   Energy Conserving Measures Costs and Engineering Assumptions, Conservation Division, P400-82-032, April, 1982(a).

4. California Energy Commission

   Staff Report on Fluorescent Lamp Ballasts, Conservation Division, P400=82-036, April, 1982(b).

5. Chernick, P., Fairley, W., Meyer, M., and Scharff, L.

   Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

6. Easterling, Robert G.

   Statistical Analysis of Power Plant Capacity Factors, (Albuquerque, NM: Sandia Laboratories) 1979.

7. Easterling, Robert G.

   Statistical Analysis of Power Plant Capacity Factors Through 1979, (Albuquerque, NM: Sandia Laboratories), April, 1981.

8. Komanoff, Charles

   Nuclear Plant Performance, Update 2, (New York, NY: Komanoff Energy Associates), 1978.

9. Komanoff, Charles

Power Plant Cost Escalation, (New York, NY: Komanoff Energy Associates), 1981.

10. Mooz, W.E.

Cost Analysis of Light Water Reactor Power Plants, prepared for the Department of Energy, Rand Corporation Report R-2304-DOE, June, 1978.

11. Perl, Lewis J.

"Estimated Costs of Coal and Nuclear Generation", presented to the New York Society of Security Analysts, December 12, 1978.

APPENDIX B:

REVENUE STABILITY TARGET RATEMAKING

REVENUE STABILITY TARGET RATEMAKING

Paul L. Chernick

Analysis and Inference, Inc.

August 5, 1982

I. Introduction and Summary

Traditional utility ratemaking procedures result in orders allowing specific rate levels and rate designs. These rates are expected to allow the utility to generate the required revenue. Because this ratemaking approach does not recognize that sales are a function both of the utility's actions and of such random variables as weather, the resultant rates discourage utility conservation efforts, fail to protect the utility's revenue stream, increase required rates of return, and alternately produce overcollections and undercollections. Uncertainty is increased by the transition to new rates, such as time-of-use rate and inverted blocks.

This paper suggests an alternative ratemaking scheme, which decouples utility revenues from sales. Utility revenue streams would be stabilized, at least with respect to sales fluctuations and rate design changes: thus, the cost of capital should decrease to the ultimate benefit of the customers. Utility resistance to consumers' conservation and to efficient rate design should also decrease. The proposed approach would be readily compatible with utility financing of conservation programs; with cost indexing; with marginal cost pricing; with other innovative rate designs whose effects are not well known; and with tax relief proposals.

This paper consists of four sections, other than this introduction. Section II describes the pertinent aspects of current ratemaking, and enumerates the problems which result from current practice. Section III outlines an alternative proposal, which I call Revenue Stability Target Ratemaking (RSTR). Section IV discusses the advantages and opportunities afforded by RSTR, while Section V describes some of the possible drawbacks to this approach.

II. Current Ratemaking Procedures

In general, utility rates are set in a three-step process. First, the total revenue target, T, is set as the sum of all allowed expenses (including O & M, return, depreciation, and taxes). Second, the allowed revenues are allocated to the various customer classes to establish class revenue constraints, t_i, where

$$\sum_i t_i = T. \qquad (1)$$

Finally, for each class a set of rates (r_j) is approved, so that

$$\sum_j r_j b_{ij} = t_i \qquad (2)$$

where b_{ij} is the anticipated number of billing units in class i to which rate j is applicable. Examples of billing units would include customer-months, kwh, and kw, perhaps distinguished by subclass, block, and other special provisions (e.g., high load factor or high voltage discounts).

It is the r_j which are ultimately approved in a typical rate proceeding, and the final order grants the utility new rates, which are based upon (but not identical to) the revenue target. If the calculations have been performed properly, and if the actual billing units (b^*_{ij}) in the rate year exactly equal the b_{ij} used in equation 2 in the rate case, then

$$\sum_i \sum_j r_j b^*_{ij} = T, \qquad (3)$$

and the utility collects exactly the amount of revenue the regulatory commission expected it to collect.[1/]

In fact, actual billing units hardly ever equal anticipated billing units. Several factors contribute to this divergence, including:

- economic fluctuations, which affect the level of industrial production, of commercial activities, and of new equipment and appliance purchases, as well as the care with which energy budgets are controlled;

- actions of large customers, such as faster (or slower) completion of new facilities or housing complexes, relocation of operations, or changes in technology;

- the weather, which has major effects on heating and air conditioning usage, with smaller effects on several other energy uses;

- conservation (or consumption) caused by price changes (including the ones allowed in this case), and by conservation and fuel switching programs of governmental bodies and of the utility itself;

- the ratemaking process may be based on an historic test year, and thus may use historic values of billing units, rather than the best available projections of those values; and

-rate design changes, which may introduce billing units for which even current values are unknown (e.g., off-peak kwh, residential noncoincident demand), and which may cause significant shifts in consumption patterns (e.g., changes in use by time of day, or by block, or in load factor).

Two major problems result from the divergence of actual from anticipated billing units. First, there is no assurance that the utility will actually receive the revenues, T, which the commission has approved. In fact, it is quite unlikely that equation 3 will be exactly satisfied. Some years will produce revenues lower than T, while other years will produce revenues higher than T. The variation of actual revenues, around the level of allowed revenues, creates difficulty for the utility in budgeting, both for operations and for capital investment.[2/] More importantly, the variability in earnings[3/] is five to ten times greater than the variability in revenues. Earnings (E) are the residual after expenses, interest, and preferred dividends (which I will collectively call X) are subtracted from revenues:

$$E = \sum_i \sum_j r_j \, b^*_{ij} - X \qquad (4)$$

Earnings are typically about 10% of revenues. Income taxes are approximately equal to earnings (at least at the margin) and vary directly with them. Thus, if earnings are 10% of revenues, both earnings and income taxes would be eliminated by a 20% decrease in revenues, with expenses and other charges held constant.[4/]

While the reliability of earnings is directly important to shareholders, it is also significant for ratepayers. Earnings variability, particularly when positively correlated with changes in the general economic environment[5/], increases the required return on common equity, and hence the cost of utility service.

In addition to the direct effects on the utility and its cost of capital, the dependence of cash flow and earnings on billing units also causes utilities to engage in undesirable, but understandable, behavior. One typical utility response is to attempt to maintain or increase billing units in the short run: no matter what set of rates are approved, the utility will be better off in the short run, (i.e., while these rates are in effect) with higher sales than with lower sales. Thus, utilities are generally uninterested in rate reform, which may have large impact within a short period of time. Even if the b_{ij} values used in ratesetting are reduced (and hence the r_j are increased) to reflect the anticipated effect of a conservation program, it still is in the utility's self-interest to delay the program, and promote sales. Earnings are positively and directly related to sales, regardless of the rates granted.

The second utility response to the current ratemaking system is a preference for recovering revenues through charges on those billing units which are less responsive to customers' behavior. In this regard, the ideal billing unit is the take-or-pay contract. A close second choice is the monthly customer charge, which will always be assessed so long as the customer remains on the system. Ratcheted demand charges[6/] and the inner blocks of energy and demand schedules are also less responsive to customer consumption patterns than are normal monthly charges or the marginal energy or demand block. Unfortunately, the billing units which are most desirable for revenue stability are least desirable for efficiency purposes, particularly when marginal costs exceed average costs.

Consumer behavior is unlikely to be affected by charges which are independent of that behavior. For example, the size of the residential electric customer charge and of the inner most energy blocks (e.g., 0-50 kwh/month) are unlikely to influence consumption and conservation decisions: very few residences will be able to avoid either of these charges, and few will attempt to do so, regardless of the size of the charges. The tailblock energy charges, on the other hand, are very potent price signals, since a customer who uses one more (or less) kwh will pay (or save) the tailblock rate.[7/] But by the same token, tailblock sales are more volatile than those from the inner blocks and customer charges, and hence less desirable for revenue stability purposes.

A third rational, but undersirable, utility tactic in maintaining revenue stability is the avoidance of rate design changes. Shifting revenue responsibility from demand charges to energy charges, or instituting time-differentiated rates, may not increase the long-term instability of revenues, but may produce great uncertainty in the short term. The test-year number of billing units may be unknown (especially for new time-differentiated rates), and the response of consumers may be very hard to estimate. Thus, next year's revenues are more secure if the rate structure remains largely unchanged.

The previous discussion has established that the current ratesetting process increases the riskiness and cost of utility equity; discourages utility participation in conservation and rate re-design; and encourages sales promotion and inefficient price signals. There is certainly room for improvement in the system: the next question is whether any such improvement is administratively feasible.

III. Redesigning The Ratemaking Process to Promote Revenue Stability

Stabilizing utility revenues and eliminating the existing perverse incentives for utility management require a fundamental change in the nature of regulatory commission rate orders. Rather than approving a set of rates (r_j) which are expected to produce the allowed revenues (T), the commission must approve the revenue level itself, as well as a mechanism for maintaining those revenues with a fair degree of certainty. The rates to be charged immediately following the effective date of the order are part of that mechanism, but are not generally sufficient in themselves, as noted above.

Revenue Stability Target Ratemaking (RSTR) would establish two separate total dollar amounts: the target revenues (T) to the utility, and a larger sum, the estimated collections (C) from the customers. A set of rates (r_j) would be established so that

$$\Sigma_i \ \Sigma_j \ r_j \, b_{ij} = C \qquad (5)$$

If actual billing units equal the b_{ij}, the utility will collect C from its customers, but only T will be counted as revenues to the utility. The remainder, a buffer B (= C - T), is the customers' money held in trust by the utility. The buffer, and associated interest at market rates, may be returned to the customers in several ways, to be discussed in the next section.

If sales are below expectation ($b^* < b$), the buffer will be smaller than expected: the utility still receives T, and less money is accumulated to be returned to the customers. So long as ratio of actual to forecast billing units, b^*/b (averaged over the b_{ij} in proportion to expected revenues), is higher than T/C, the utility is guaranteed to receive its full allowed revenues, but no more than allowed revenues. Since some of the billing units (especially customer-months) may be very stable, a buffer of 5% of allowed revenues should provide substantial revenue security to the utility.

The expected buffer, B, may be apportioned to classes, rates, and billing units, in proportion to allocated revenues, or so as to bring rates closer to marginal costs or other rate design targets. Similarly, the actual buffer, B*, may be returned to the customers as a whole, or to the customer classes in proportion to their contribution to B or B*.

For many utilities, fuel costs are collected through an adjustment process which tracks costs closely and essentially guarantees full recovery. For these utilities, RSTR can be applied to just the base (non-fuel) rates, and

$$T = N + A \tag{6}$$

where N is non-fuel costs and A is actual fuel costs (collected through the fuel clause). For utilities without fuel clauses (generally those with fairly stable fuel costs), RSTR can be structured as

$$T = N + E + M\,(S^*-S) \tag{7}$$

where E is expected energy costs, M is the marginal cost of energy (over reasonable variations in sales), and S and S* are expected and actual kwh output. Thus, if sales increase, the revenue target rises to cover the associated increase in fuel expense.

IV. Some Advantages of RSTR

RSTR should directly correct several of the problems discussed in §II, above. Utility resistance to conservation programs (and rate reform) should decrease, utility earnings should stabilize (and particularly become less weather-sensitive), the cost of equity should decline, and rate redesign will have less impact on utility revenues. The buffer can also be collected so as to bring energy charges closer to marginal costs within embedded-cost revenue constraints.

The disposition of the buffer, once it has been collected, can also be helpful in various ways. The accumulated funds can be directed to financing conservation programs, with the convenient feature that available funds increase when increasing loads make conservation particularly desirable. The buffer can alternatively be distributed to local governments to offset property taxes (perhaps in proportion to sales by class and by municipality), meeting a major social concern.

The buffer can also be used to stabilize rates and to reduce the frequency of rate increase requests. Directly, RSTR would reduce the need for rate increases to compensate for falling sales. Indirectly, the accumulated funds may be used to pay for small revenue increases to the utility, without changing rates paid by customers. For example, the commission could allow an increase in property taxes to be paid from the buffer. Similarly, if the commission wishes to adjust a portion of the cost of service to follow a published price index, or to follow a utility-specific parameter (e.g., the actual seniority mix of employees, periodly adjusted for retirements and promotions), these changes in costs may be absorbed by the buffer.

The use of the revenue stability buffer to smooth out small cost fluctuations is incidental to its primary purpose of decoupling earnings from sales. Nonetheless, this use of the buffer has certain appealing aspects, compared to such alternatives as forecasting costs for rate cases, or introducing cost-of-service adjustment mechanisms similar to fuel clauses. First, the buffer system can better match the time of cost occurence with the time of revenue collection, since the buffer is collected while the cost adjustment is being calculated and adjusted. Second, this approach eliminates the need to forecast costs, and can rely on real data. Third, since collection of the buffer fund is continuous (assuming sales do not fall dramatically), the advantages of regulatory lag (careful scrutiny of the issues) can be gained without the usually disadvantages (financial penalties for the petitioner). Data collection and hearings may take (say) six months, but the day after the adjustment is approved, the utility could transfer six months of increased revenues, with accrued interest, from the buffer fund to its own accounts (or vice versa, in the event of a cost decrease). Finally, the avoidance of cost-of-service adjustment surcharges, credits, refunds, and rate adjustment simplifies the customer's bill, and increases the comprehensibility of the rate design and of the affect of consumption on the bill size.

V. The Disadvantages of RSTR

The primary disadvantage of an RSTR system is that, like any other ratemaking innovation, its implementation may conceal many other de facto changes in ratemaking treatments. Particularly if the buffer is used to offset cost changes, it is possible that costs will be double-counted (included in base rates and again in an adjustment); that increases in some costs will be collected, without offsets for decreased costs of other types (or vice versa); or that standards of regulatory review or of due process will be compromised. The last possibility seems particularly likely for jurisdictions with limited regulatory staff support and limited public-interest intervention. The small size of individual adjustments (compared to a full rate case), the competition of other matters for staff attention, and perhaps a perception of the RSTR buffer fund as "funny money", up for grabs, could result in only superficial review of the utility's proposed adjustments.

RSTR will certainly not eliminate all the difficulties currently faced by utilities or the regulatory system, but it should not create too many new ones. Any tendency in that direction can be controlled in several ways. First, all parties must come to view the buffer fund as the property of ratepayers, held in trust, until the commission finds otherwise. Frequent reports to the public on the size and disposition of the fund may be helpful in this regard. Second, the uses of the fund, whether for conservation, for tax relief, or for cost-tracking, must be carefully specified and regulated. The extent to which the commission must control the magnitude, distribution, and application of withdrawals for conservation or for tax relief will vary between jurisdictions and between utilities, but scrutiny of RSTR funds should not be substantially lower than regulatory scrutiny of other utility behavior. In general, rules for transfer of funds from the buffer to the utility's accounts, for cost-of-service adjustments, will have to be quite specific, prescribing the times at which costs will be reviewed, the types of costs which are to be included, and the method for calculating adjustments, to prevent any upward bias in the selection of costs, and to ensure that the mechanisms by which costs and offsets are measured in rate cases are not circumvented. Some commissions will find it easier and more efficient to regulate without RSTR (or with a limited version) than to construct an adequate system of RSTR review.

In addition to the general potential for abuse of RSTR, a half-dozen assorted cautions are in order. First, it must be remembered that RSTR absolutely prevents the utility from receiving revenues in excess of those allocated, but only prevents revenue short-falls by the size of the buffer: a utility which abruptly loses half its sales will still be in trouble. Second, the actual size of the buffer (B*) will vary randomly, so it cannot be counted on to fund any particular level of conservation, tax-relief, or cost-adjustment program. Third, very careful attention must be paid to the calculation of interest on the buffer, to prevent windfalls or penalties to the utility. Fourth, sales vary seasonally, and the revenue target may therefore vary between months, complicating the calculation of the actual size of the buffer. Fifth, jurisdictions which have implicitly relied on sales growth to help offset inflation must recognize that RSTR eliminates this limited source of rate relief. Sixth, it is important that any excess funds accumulated in the buffer not be used to reduce rate-base. The buffer is to be established by and for current ratepayers, and should be applied to current expenses (utility or otherwise), not to rate base items which benefit customers for decades.

As the previous discussion indicates, there is certainly some potential for abuse of a RSTR system. Properly instituted, however, RSTR should have some major advantages - lower cost of capital, greater incentives for utility conservation - which should outweigh the burdens of operation of the system.

FOOTNOTES

1/ This is a separate question from whether the utility makes its allowed rate of return, which is a function of expenses, as well as revenues.

2/ The importance of the budgeting effect is reduced for most utilities by their access to extensive short-term bank credit. However, in extreme cases, revenue variation may induce a utility to defer otherwise cost-effective maintenance, may require the issuance of securities at inopportune times, and may even require (by invoking interest coverage constraints) the issuance of less desirable securities.

3/ Earnings are the sum of dividends and retained earnings, and represent the total funds available to compensate the shareholders.

4/ In fact, some expenses (primarily fuel) vary with the b_{ij} (primarily kwh).

5/ This correlation is commonly reported as the beta coefficient.

6/ Ratcheted demand charges set the billing unit as the maximum of demand in the current month and a fraction (possibly 100%) of demand in a previous time period (often a year).

7/ The block which serves as the tailblock will vary between customers. In general, however, a higher percentage of the kwh sold in a higher-use block will be sold to customers of whom that block is the tailblock than would be true for lower-use blocks. Of course, all customers who consume in the final block of the rate schedule have that as their tailblock.

Appendix C

As shown in Figure C-1 for a simplified circuit:

$$\text{Losses} = I^2R_L = \left(V_o^2 / R_o^2\right) R_L$$

$$\text{Output to customers} = I^2R_o = V_o^2 / R_o$$

V_o is constant, as is R_L

$$\text{input} = \text{output} + \text{losses} = I^2\left(R_o + R_L\right)$$

$$= V_o^2 \left(R_o + R_L\right) / R_o^2$$

$$\frac{d\ (\text{input})}{d\ (R_o)} = - V_o^2 / R_o^2 - 2V_o^2 R_L / R_o^3$$

$$\text{Output} = V_o^2/R_o \Rightarrow R_o = V_o^2/\text{output}$$

$$\frac{d\ R_o}{d\ \text{Output}} = - V_o^2/(\text{output})^2 = -V_o^2/\left(V_o^2/ R_o\right)^2$$

$$= - R_o^2/V_o^2$$

$$\frac{d\ \text{Input}}{d\ \text{Output}} = \frac{d\ \text{input}}{d\ R_o} \times \frac{d\ R_o}{d\ \text{output}}$$

$$= \left(- V_o^2/R_o^2 - 2\ V_o^2 R_L/R_o^3\right) \times \left(- R_o^2/V_o^2\right)$$

$$= 1 + 2 \left[\left(V_o^2/R_o^2\right) R_L\right] \left[R_o/V_o^2\right]$$

$$= 1 + 2 \times \text{losses}/\text{output}$$

$$= 1 + 2 \times \text{losses} / (\text{input} - \text{losses})$$

$$= (\text{input} + \text{losses}) / (\text{input} - \text{losses})$$

$$= (1 + L) / (1 - L)$$

where $L = \text{losses} \div \text{input}$

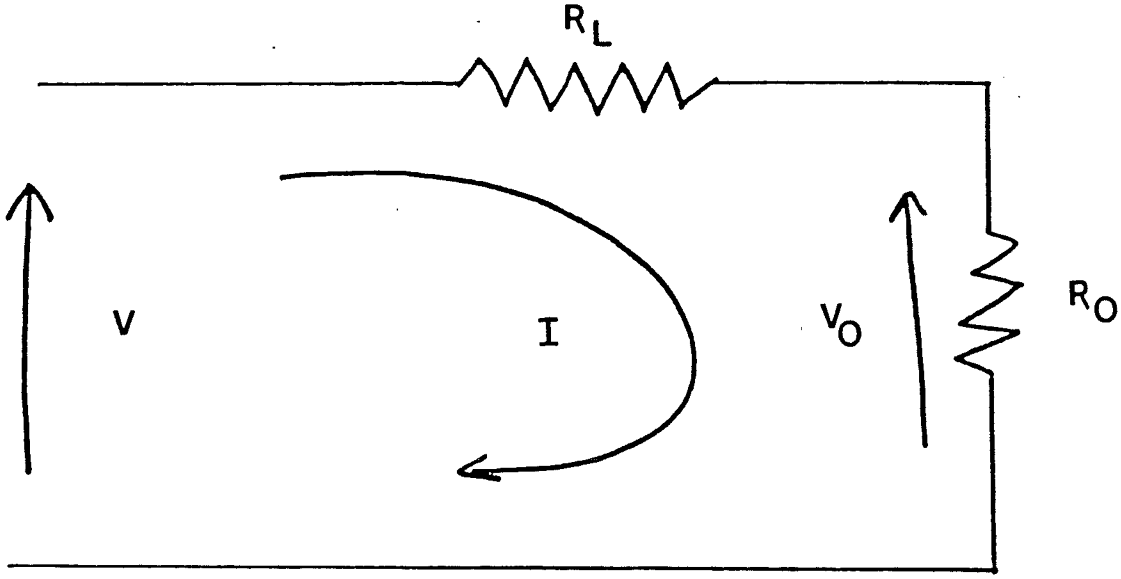

FIGURE C-1

APPENDIX C:

MARGINAL LOSS CALCULATIONS

A.D1 Suppl.

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

Investigation Into The Supply And Demand for Electricity, For Public Service Company of New Hampshire	)))))

Supplementary Testimony of

PAUL L. CHERNICK

On Behalf Of

CONSERVATION LAW FOUNDATION
OF NEW ENGLAND, INC.,
NEW HAMPSHIRE ENERGY COALITION,
and UNION OF CONCERNED SCIENTISTS

December 27, 1982

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

10 POST OFFICE SQUARE SUITE 970 ~ BOSTON, MASSACHUSETTS 02109 ~ (617) 542-0611

Q: What portions of your testimony do you wish to supplement at this time?

A: First, for the Commission's convenience, I have updated my Tables 6 and 7. Second, I have analyzed the result of trending out PSNH's cost estimate revisions, including the latest ones. Finally, I have included some comments on the relevance of Yankee plant experience to projections of Seabrook capacity factors.

Q: What is the basis for your update of Tables 6 and 7?

A: I have replaced the estimated dates of commercial operation in the original tables with the values reported in the August 1982 edition of Nuclear News, and in a few cases, with further updates. This information is presented in Tables S-1 and S-2.

Of the eighteen units, other than Seabrook 1, listed as between 33% and 63% complete in June, 1981, two are now on indefinite status. For six of the other units, the estimated commercial operation date has been pushed back by 2 to 24 months. The average projected inservice date for the 16 remaining units is February, 1986. Of the eleven units which were listed as being at least as complete as Seabrook 1, only two have estimated operation dates before Seabrook 1.

Of the 17 units, other than Seabrook 2, which were listed as less than 20% complete, seven units had no estimated completion date; of these, three have been canceled (North Anna 3 has been canceled since my testimony was filed.) Among the ten units which had estimated completion dates, six have been canceled, and the inservice datesestimated for the other four have all been revised upward by 8 to 20 months.

Unit	Reported % Complete (1)	Estimated Commercial Operation (2)
Limerick 1	63	4/85
Braidwood 1	62	10/85
Palo Verde 2	61	5/84
South Texas 1	60	/86
Byron 2	60	2/85
Susquehanna 2	59	11/84 (4)
Bellefonte 2	59	11/86 (4)
Watts Bar 2	58	6/85 (4)
Comanche Peak 2	52	1/86 (4)
WPPSS 1	49.6	indefinite
Braidwood 2	48	10/86
Seabrook 1	48	12/84 (5)
Harris 1	43	9/85
Beaver Valley 2	41.6	5/86
Perry 2	40	5/88
Nine Mile Point 2	38	10/86
Millstone 3	36	5/86
Hope Creek 1	35	12/86
Hartsville A1	34	indefinite

Table S-1 : Projected Completion Dates, Units comparable to Seabrook 1 in Stage of Completion

Notes :
(1) From Nuclear News, August, 1981. All units between 33% and 63% complete are listed.

(2) From Nuclear News, August, 1982, or as noted.

(3) Month not given, June assumed for calculations.

(4) From TVA survey, 10/26/82.

(5) 11/82 estimate.

Unit	Reported% Complete(1)	Estimated Commercial Operation(2)
Hope Creek 2	17.8	Canceled
WPPSS 5	13.7	Canceled
Marble Hill 2	11	6/88(3)
North Anna 3	8.8	Canceled(5)
Seabrook 2	8	3/87(4)
Harris 2	3	3/89
Harris 3	1	Canceled
Harris 4	1	Canceled
Callaway 2	0.5	Canceled
Cherokee 1	18	indefinite
Hartsville B1	17	Canceled
Hartsville B2	7	Canceled
Phipps Bend 2	5	Canceled
Yellow Creek 2	3	indefinite
Clinton 2	0	indefinite
River Bend 2	0	indefinite
Vogtle 1	18	3/87
Vogtle 2	10	9/88

Table S-2 : Projected Completion Dates, Units Comparable to Seabrook 2 in Stage of Completion

Notes :

(1) From Nuclear News, August, 1981. All units with CP and less than 20% complete are listed.

(2) From Nuclear News, August, 1982, or as noted.

(3) Listed as 12/87 by TVA, 10/26/82.

(4) 11/82 estimate.

(5) Wall Street Journal, 11/16/82.

Q: Have you determined what the final inservice dates and costs for Seabrook would be if PSNH continues to revise its estimated cost and schedule as it has in the past?

A: Yes. Table S-3a derives the annual percentage rate increase in the Seabrook cost estimate from various starting points to the 11/82 estimate, and to the revision announced on 12/15. For the latter, I have used a 4 month delay and $160 million increase. The annual rate of escalation of PSNH's estimate has increased quite steadily: the more recent the time period over which the trend is averaged, the higher it is. For example, the average annual percentage increase in the Seabrook cost estimate was 17.1% from 12/76 to 11/82, 19.2% from 1/79 to 11/82, and 25.8% from 4/81 to 11/82. The rates of increase are even greater if measured to 12/82.

The trends are less clear with respect to progress towards completion. Tables S-3b derives the progress ratios of each unit from each estimate to 11/82 (and to 12/82 for unit 2). The progress ratio is the reduction in months left in the construction schedule (that is, progress), divided by elapsed months. If the schedule did not change between estimates, the progress ratio would be 1.0. For various time periods ending with the 11/82 estimate, the progress ratio for Seabrook 1 ranges from 3.75% to 57.1%; that is, for each month that went by, completion drew nearer by only .375 to .571 months (11 to 17 days). To put it another way, it took 1.75 months to 2.67 months to get one month closer to completion. For Seabrook 2, the progress ratio to 11/82 ranges from 21.9% to 51.8%; a month of progress has taken as much as 4.6 months of elapsed time. The picture is much worse if we look at progress ratios for periods ending with the 12/82 estimate; these ratios go as low as 12.1%, or over 8 months of real time per month of progress.

Table S-3c extrapolates the historic trends to determine when each unit will enter service, and what the total cost estimate will be when Unit #1 enters service, assuming that PSNH continues to be as wrong as it has been in the past. Depending on the time period used for trending, Unit #1 can be expected to enter service between July 1986, and June 1988, and Unit #2 between January 1992, and October 2020. (Excluding the results from the 3/80 estimate, the latest COD for Unit 2 would be February, 1998.) These dates assume that the estimated completion dates continue to recede as they have in the past.

Given a COD for Unit #1 and assuming the continuation of a historic rate of escalation in the cost estimate, we can calculate the value of the cost estimate at the time Unit #1 enters service. Table S-3c derives such estimates for the cost trends from each of the pre-1982 estimates to the 11/82 estimate and to the 12/82 estimate. The results range from $9.4 billion to $14.9 billion. Since the rate of cost estimate escalation has been increasing, these figures may be conservative. Also, note that this method is based on escalation of combined plant cost, and is inapplicable once Unit #1 enters service or Unit #2 is canceled. If construction continues on Unit #2 past the Unit #1 COD, the total plant cost estimate can be expected to continue escalating, although perhaps at a slower rate. At the historic escalation rates, eventual cancelation of Unit #2 appears to be inevitable, so projection of its cost past the Unit #1 COD is academic.

Q: Is it appropriate to compare Yankee plant capacity factors to average nuclear power plant capacity factors?

A: Not directly. Nuclear capacity factors vary with the size, age, and type of plant. Since there is no other PWR near the size of Yankee Rowe, comparisons to other units are nearly meaningless. The remaining three units can be compared to units of their own types, size, and age. Thus, Vermont Yankee must be compared to small BWR's, Connecticut Yankee to small PWR's, and Maine Yankee to medium-size PWR's. If performance is compared by age group, such as 2-5 years, all the comparison units must have reached age 5, or the poorer performance in the early years will bring down the average.

Q: Is it appropriate to extrapolate capacity factors for the Seabrook units from Yankee plant performance?

A: Without strong evidence of a causal influence of Yankee Atomic involvement in construction oversight on plant performance, there is no reason to favor Yankee plant data over industry-wide data for four reasons. First, other than the effect on cost and construction time of architect-engineer (A/E) experience, it has never been statistically demonstrated that any party involved in building nuclear plants is able to influence the outcome. Second, Yankee Atomic's role is a curious one, as it is neither A/E, nor constructor, nor utility (except with respect to Yankee Rowe); it is not clear what sort of effect one might look for in studying Yankee influence. Third, whatever role Yankee Atomic might have had on the swift and economical completion of the Yankee units has clearly been ineffective with respect to Seabrook. Finally, the Yankee data set is very small compared to the total industry data set, and the variations due to luck and similar factors may be large.

On the whole, there does not seem to be any basis for concluding that Seabrook will perform more like the Yankee Plants than like those of Florida Power, or Commonwealth Edison.

Q: With those caveats, what is the best projection of Seabrook capacity factors from the Yankee data?

A: Using the data supplied by PSNH (CLF Request 78), I projected the size trend of capacity factors for the "commercial sized" PWRs (Connecticut and Maine Yankee) out to Seabrook's size. The results are presented in Table S-4. The Yankee PWR's display a size trend for performance quite similar to industry averages, suggesting average Seabrook capacity factors between 50% and 60%.

Q: Does this new official cost estimate affect the results of your myopia analysis, on pp. 75-78 of your testimony?

A: Yes, to some extent. From PSNH's press release of 11/30/82, the cost per kw of Unit #1, plus common and 75% of indirects, is now $2,990 per kw, and for Unit #2, plus 25% of indirects, it is $1,464/kw. The allocations of common and indirect costs appear to be unusually skewed towards Unit 1.* Converting the PSNH estimates to 1983 dollars yields

$2{,}990 \div (1.08)^{1.42} = \$2{,}680/\text{kw}$ for Unit 1, and

$1{,}464 \div (1.08)^{3.67} = \$1{,}104/\text{kw}$ for Unit 2.

The cost increase for Unit 2 announced in December ($160 million or $139/kw) brings that unit's 1983 dollar cost to

$1{,}603 \div (1.08)^{4} = \$1{,}178/\text{kw}$.

The portion of the Unit 1 estimate attributable to the extra 25% of indirects is about 18.2%, or $487/kw in 1983 dollars.

Using the zero-intercept compound growth model (Eq. 3, p.76), which I consider the most intuitively appealing of the four models, the myopia multipliers are

$1.147^{2.08} = 1.330$ for Unit 1,

$1.147^{4.33} = 1.811$ for Unit 2 on the 11/82 estimate, and

$1.147^{4.58} = 1.874$ for Unit 2 on the 12/82 estimate.

Applying these multipliers produces 1983 dollar costs of $3,564/kw for Unit 1 and $1,999 - 2,208/kw for Unit 2 under the PSNH allocation of indirects, or $2,917/kw for Unit 1 and $2,881 - 3,120/kw for Unit 2 with a 50/50 allocation of indirects. These results are consistent with my earlier projections.

---

* Compare to the 1/79 estimate, in which half of common and 57% of indirects were allocated to Unit 2.

In fact, the 11/82 estimate for total plant cost was a nominal increase of 43.8%, or 34.9% in constant dollars, with 9 months progress, or 49.0% in real terms per year of progress. This is much greater myopia than the 14.7% observed in my original data set; if it continues, Unit 1 would cost over $5,500/kw, and Unit 2 over $8,000/kw in 1983 dollars.

DATE OF ESTIMATE	12.76	3.78	1.79	3.80	4.81	11.82	12.82
MONTHS BETWEEN ESTIMATES	---	15	10	14	13	19	1
ESTIMATED COST ($M)	2015	2345	2610	3160	3560	5120	5280
INCREASE SINCE LAST ESTIMATE (%)	---	16.38	11.30	21.07	12.66	43.82	3.13
INCREASE SINCE LAST ESTIMATE (ANNUALIZED)	---	12.90	13.71	17.81	11.63	25.80	44.67
INCREASE TO 12/82 (%)	162.03	125.16	102.30	67.09	48.31	3.13	---
INCREASE TO 12/82 (ANNUAL)	17.42	18.63	19.71	20.52	26.68	44.67	---
INCREASE TO 11/82 (%)	154.09	118.34	96.17	62.03	43.82	---	---
INCREASE TO 11/82 (ANNUAL)	17.07	18.21	19.22	19.84	25.80	---	---

Table S-3a: Growth Rates in PSNH Cost Estimates for Seabrook

COMMERCIAL OPERATION DATE ESTIMATED ON:		12.76	3.78	1.79	3.80	4.81	11.82	12.82
SEABROOK UNIT #1:	DATE	11.81	12.82	4.83	4.83	2.84	12.84	12.84
	MONTHS TO GO	59	57	51	37	34	25	24
	PROGRESS (MONTHS)	---	2	6	14	3	9	1
	PROGRESS RATIO(%) TO 11/82	47.89	57.14	56.52	37.50	47.37	---	---
SEABROOK UNIT #2:	DATE	11.83	12.84	2.85	2.85	5.86	3.87	7.87
	MONTHS TO GO	83	81	73	59	61	52	55
	PROGRESS (MONTHS)	---	2	8	14	-2	9	-3
	PROGRESS RATIO(%) TO 11/82	43.66	51.79	45.65	21.88	47.37	---	---
	PROGRESS RATIO(%) TO 12/82	38.89	45.61	38.30	12.12	30.00	-300.00	---

Table S-3b: Derivation of Seabrook Progress Ratios

Notes: Progress Ratio = Difference in months-to-go
divided by months elapsed.

EXTRAPOLATING TRENDS FROM THE ESTIMATE OF:			12.76	3.78	1.79	3.80	4.81	11.82	12.82
TO 11/82:	UNIT 1	MONTHS TO GO	52	44	44	67	53	---	---
	UNIT 1	COD	3.87	7.86	7.86	6.88	4.87	---	---
	UNIT 2	MONTHS TO GO	119	100	114	238	110	---	---
	UNIT 2	COD	10.92	3.91	5.92	10.02	1.92	---	---
	PLANT COST AT UNIT #1 COD		10164	9424	9787	13993	14049	---	---
TO 12/82:	UNIT 2	MONTHS TO GO	141	121	144	454	183	---	---
	UNIT 2	COD	8.94	0.93	11.94	10.20	2.98	---	---
	PLANT COST AT UNIT #1 COD		10616	9844	10247	14895	14941	---	---

Table S-3c: Extrapolation of Seabrook Cost Estimate History

Notes: 1. 0/93 is 12/92.

2. Months-to-go is current estimate, divided by progress ratio.

Unit	MW	Capacity Factor Yrs. 2-5 (1)	Capacity Factor Yrs. 6 +
1. CN Yankee	575	79.1	78.5
2. ME Yankee	825	69.1	68.0
3. Change per	100 MW (2)	4	4.2
4. Seabrook (3)	1,150	56.1	54.3

Table S-4: Projection of Seabrook Capacity Factors from Yankee Data

Notes: 1. Year 2 is first full year.

2. (Row 1) - (Row 2) / 2.5.

3. (Row 2) + 3.25 (Row 3).