#28

Conn. DPUC #27 PC notes 83-07-15

STATE OF CONNECTICUT DOCKET NO. 83-07-15

DEPARTMENT OF PUBLIC UTILITY CONTROL

RE: APPLICATION OF CONNECTICUT LIGHT AND POWER

FOR AN INCREASE IN ITS

RATES AND REVENUES

October 3, 1983

TESTIMONY OF

PAUL L. CHERNICK

On Behalf of:

ALLOY FOUNDRY

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

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

Table of Contents

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF ALLOY FOUNDRY

1 INTRODUCTION AND QUALIFICATIONS

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

A : My name is Paul L. Chernick. I am 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 honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the effects of rate design and cost allocations on conservation, efficiency, and equity.

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-five 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, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, 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. I have testified approximately eight times on rate design and cost allocation issues.

Q : Have you authored any publications on rate design or cost allocation issues?

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

Q : What is the subject of your testimony?

A : I have been asked to review the propriety of CL&P's proposed rate design tor the Large General Service class, in Rate 35 and the proposed new Rate 37. I will not be discussing the allocation of costs between among classes, or the general level of rates.

2 CL&P's PROPOSED DEMAND CHARGES FOR RATES 35 AND 37 ARE EXCESSIVE

Q : How does CL&P distribute the proposed rate increase between the various rate elements in the Large General Service rates?

A : CL&P places the entire increase in the customer and demand charges, and actually decreases the energy charges. This is highly inappropriate.

Q : Please explain why CL&P's proposed rate design for Rate 35 is inappropriate.

A : There are several problems with the proposed rate design for Rate 35; the same concerns also apply to Rate 37, which is nearly identical except for the time-of-use energy charges. First, CL&P proposes very high demand charges, which are inequitable and unrelated to cost causation. These charges include large amounts of energy-related costs, which should not be assessed on the basis of peak demand. Appropriate embedded cost classifications, including the generation cost assignments previously requested by the Commission, would indicate much lower demand charges.

Second, these are essentially anti-conservation rate designs, which encourage greater use of electrical energy. Increased energy use is not desirable, as it is likely to have very expensive consequences in the years to come. CL&P's promotion of industrial electricity consumption runs counter to the policies of the State of Connecticut and of the DPUC, and is inconsistent with CL&P's own pursuit of some very expensive sources of energy supply, including NU`s generation expansion plans.

Third, CL&P's proposed rate design has no reasonable basis or support. The low energy charges (and hence high demand charges) are based on current marginal running costs. Much higher energy charges would be suggested by any marginal cost analysis which reflected the concerns about future energy supply previously expressed by the Legislature, by this Commission, and by NU. Rate 35 customers are being told that energy consumption only costs about 5 cents/kwh while NU spends up to twice this much for power from Millstone 3 and other sources.

Fourth,the low energy charges result in very high demand charges, which are not well related to important cost causes and which may cause industrial customers to respond with extremely wasteful measures to reduce those charges. This customer response may require expensive equipment and operations changes, increase energy usage, produce little or no saving (or even an increase) in the cost of bulk power supply equipment, and have minimal effect on the costs of local service equipment.

Fifth, the proposal is decidedly inequitable. At a time when residential, commercial, and street-lighting customers are being offered large rewards for reducing their energy use, CL&P suggests substantial reductions in the meager incentives currently available to the industrial class. As other customers are assisted in shielding themselves from the effects of future energy cost increases, industrial customers are being encouraged to make themselves more vulnerable.

Sixth, and finally, it appears that CL&P's reasons for proposing this unfortunate redesign for Rate 35 have nothing to do with equity or efficiency, and a negative relationship to conservation. If CL&P's real concern is revenue stability, it can be dealt with through revenue adjustment or revenue stabilization measures, rather than through the distortion of rate design.

I will describe each of these problems in more detail below.

3 EMBEDDED COST CONSIDERATIONS

Q : You have explained why CL&P's proposed rate design for Large General Service is incompatible with conservation objectives. Can this rate design be justified on equity grounds by any reasonable embedded cost approach?

A : No. To the extent that embedded costs are used in rate design, the apportionment of costs between rate elements should reflect the causation of those costs. Properly performed, embedded cost allocations represent a concern with equity; arbitrarily performed embedded analyses accomplish no legitimate rate design purpose.

Q : What principles should be applied in dividing the embedded costs assigned to Rate 35 into demand and energy charges?

A : Some of the relevant principles can be stated as:

1. The demand cost associated with generation is the cost of gas turbines (or other inexpensive peaking capacity) providing the required or actual system generation reliability over the period of the demand measure.

2. The indirect costs imposed by large expensive energy-cost-reducing generation with long lead times,

such as CWIP in rate base, excess capacity, or CL&P's Millstone 3 phase-in proposal, should be changed to energy.

3. Transmission lines and substations which exist due to the large size or remote location of energy-serving generation are themselves energy-serving.

4. Additional capacity (e.g., in transformers and underground lines) which is required to avoid overheating, equipment deterioration, or excessive energy losses over load cycles of several hours (or even days or years) is energy-related.

These principles can be stated in alternative terms, with more-or-less equivalent implications. The concepts related to generation and transmission are explained in greater detail in an article I co-authored, "An Improved Methodology for Making Capacity/Energy Allocations for Generation and Transmission Plant". This paper, which won an Institute for Public Utilities Award, is reproduced as Appendix B to my testimony.

Q : Have you calculated what share of the costs allocated to the Large General Service class may fairly be allocated to the demand and customer charges?

A : Yes. I started with the costs associated with generation plant. The capacity cost method of classification presented in Appendix B of Dr. Overcast's testimony (where it is ~~inexplicably~~ called functionalization) appears to be quite similar to my own methodology, presented in Appendix B to this testimony. Both methods treat only the gas-turbine equivalent of each unit as demand-related. Dr. Overcast objects to using this method on the grounds that gas turbines can not operate as base-load plants. Even if Dr. Overcast's factual assertion is correct, it is irrelevant. The only reason for needing plants which can operate for long hours is that there are large off-peak loads; that is, large energy use. If all electric requirements were for short-hours on-peak service (e.g., the one-hour loads on which demand charges are set), then gas turbines would be more than adequate.

Tables 2 and 3 repeat the classification of generation plant presented in Tables 1 and 3 of Dr. Overcast's Appendix B, with one important improvement. Table 2 calculates the cost of the amount of capacity required to replace a kW of each generating unit. These ratios vary with the size and outage rates of the various technologies, as explained in Table 4 and in Appendix B.

In Table 3, I compute the demand-related fraction of production costs as 17%. It would probably be appropriate to classify additional generation costs as energy-related, to reflect the fact that excess capacity is primarily an energy-related problem. I have not calculated the magnitude of this effect.

Q : How would you classify the Millstone 3 phase-in fund?

A : Millstone 3 is being built almost exclusively for fuel-displacement. Its reliability contribution for short-duration loads could be replaced by a smaller group of gas turbines, on which construction would not yet have started, and which would not require any special ratemaking treatment. Thus, Millstone 3 costs in this rate case are entirely energy-related.

Millstone 3 is already imposing a burden on all customers, due to its effect on increasing the imbedded cost of debt and on increasing the cost of equity. The considerable influence of Millstone 3 on investor confidence and NU's cost of capital is discussed by Dr. Olson. Like the direct costs of Millstone 3, these indirect costs are accepted to reduce final costs, and are thus energy-related; unfortunately, their primary impact on the cost-of-service study is to increase indicated demand costs. I have not attempted to measure and reassign these costs to energy, so the demand charge I derive will be over stated.

Q : What would be the optimal approach for determining the portion of CL&P's transmission system that is related to serving generation, as opposed to the portion that is required to serve load?

A : The most precise solution would involve designing a transmission system to interconnect the minimum-cost reliability-serving generation alternative to the load centers. The cost of this theoretical "minimum" transmission system would be considered reliability related. The difference between the actual cost of the transmission network and the cost of the minimum system would be energy related. In the case of CL&P, a minimum system would consist of gas turbines dispersed through the service territory with transmission lines to move power into the distribution system and to interconnect generation and load centers for reliability purposes.

Q : Please explain how the actual CL&P transmission network differs from the minimum system described above and why it is more expensive?

A : A number of factors can be identified. Much of CL&P's generation is concentrated in several large stations remote from load centers. If generation were dispersed through the service area (as in the minimum system), the long, expensive transmission lines out to Connecticut Yankee and Millstone would not be required (and transmission losses would be smaller). CL&P accepts this increase in transmission costs as part of the tradeoff for the lower operating costs at the nuclear plants. As discussed above, CL&P's decision to build these nuclear units rather than combustion turbines is energy, rather than reliability related.

CL&P's transmission system is also more expensive because it is designed to allow for large transfers of energy with neighboring utilities. NU is a major member of NEPOOL and it is involved in a variety of energy transactions both through NEPOOL and in separate arrangements. Tie lines with other utilities are generally energy related unless they displace a utility's need for generating capacity. For NU and most NEPOOL members, economy power transactions dominate all others; these transactions are related to minimization of energy cost, rather than reliability. In addition, excess generation capacity (which I did not remove from the demand-related portion of generation) reduces the reliability need for interconnections.

CL&P also must reinforce its transmission system to accomodate a wide range of energy flows through the NU, CONVEX, and NEPOOL systems, to allow economy dispatch regardless of the location of loads and the outages of major generators. Outages of a few nuclear units or major oil units may shift flows dramatically, and the transmission system must be able to accomodate the flow of power from the most efficient remaining generators to wherever the loads are.

Finally, CL&P's transmission system is designed to minimize energy losses and to function over extended hours of high loadings. If the system were designed only to meet peak demands, a less costly system would be necessary; in some cases lines or circuits would not be required, voltage levels could be lower, and less or smaller transformers would be needed. The specific effect of load factor on underground transmission lines and transformers will be discussed below.

Thus, much of the cost of CL&P's transmission system is related to energy rather than reliability.

Q : Can the theoretical solution of designing a minimum transmission system be approximated by dividing the existing CL&P transmission system into demand-related and energy-related components?

A : Yes. This can be accomplished in two steps: separating the load-related portion of the transmission system from the portion required to serve the remote generation (and similar energy-related issues, such as tie lines and economy dispatch), and identifying the share of the load-related investment which is required for peak demand, as opposed to high load factors. The first step is facilitated by the configuration of the CL&P network, which allows a fairly straight-forward identification of specific transmission lines that are energy related.

CL&P's transmission system can be thought of as consisting of (1) 345kV lines which serve to interconnect with other systems, to connect remote major generating facilities (mostly Millstone) to the grid, and to reinforce the local transmission system against the variety of flow caused by economy dispatch and by the various combinations of major generator outages, and (2) lower voltage lines which connect together the load centers. Hence, I have treated all 345 kV lines as generation-serving, and thus energy related, and all other lines as load serving.

From the 1981 CL&P and HELCO FERC Form 1's, 345kV lines represented $69,811,588 of the $196,746,497 invested in transmission lines, or 35.5%. Thus, I estimate that only 64.5% of the transmission investment is load serving and potentially allocable to demand charges.

Q : How well does this classification scheme described in the previous response approximate the theoretical minimum transmission network?

A : On balance, I believe it is a reasonable approximation, but probably biased toward overstating ~~load~~ demand-related costs. On the one hand, the portion of the transmission network I have classified as load related appears to provide access to all substations which connect with subtransmission and distribution. All the 345 kV lines which I treat as energy-related are paralleled by load-related lines of lower voltage. On the other hand, some of the lower-voltage capacity is only required to move power between the large or remote generating units. In a minimum system with dispersed generation, some of these lines would either be unnecessary or would be smaller in scope. Also, the newer 345 KV lines are probably less depreciated than the lower-voltage lines, so a larger share of depreciation than of plant should be treated as load-related; with the data available, I can not incorporate this level of detail. Thus, I conclude that this is a modest step towards an equitable embedded treatment of transmission plant.

Q : Are there other portions of the transmission and generation system which are not attributable to peak demand?

A : Yes. The size and number of underground conductors and of transformers is determined by thermal loading considerations, by the effect of overloads on insulation life, and by energy loss considerations. These engineering constraints are considered in Appendix D for transformers, underground transmission, and underground distribution. By comparing the capability of equipment at typical duty cycles and at a hypothetical peak-demand-only cycle, I estimated that about 50% of line transformer capacity is due to energy, and about 55% of more heavily loaded substation transformer capacity is energy-related. Similarly, 39% of underground transmission capacity and 35% of underground primary cable capacity appear to be required by thermal (that is, energy) considerations.

As shown in Table 5, these load-factor considerations lead to the conclusions that 18% of non-generation-serving transmission (or 47% of total transmission) and 24% of distribution plant are energy-serving.

Q : To what conclusion do these calculations lead you, regarding a reasonable embedded-cost-based demand charge?

A : Table 6 displays the requested revenues by function for Rate 35 and computes the portion of each which is not energy-related. The total demand portion is apt to be over-stated, since my analysis of the CL&P transmission system was quite limited. Even so, after subtracting out the proposed customer charge revenues, only $3.80/kW remains for a demand charge. Even this figure is appropriate only for peak demands coincident with system peak. As Dr. Overcast explains in response to Q-RA-37:

> If one were to mechanistically use these values [for demand costs from a cost of service study], the great majority of customers would be charged incorrectly...typically higher coincidence factors are associated with higher load factors. The inclusion of some demand costs in the energy charge effectively requires high load factor customers to pay the higher than average demand costs which they impose on the company.

Thus, the demand charge should be lower than $3.80/kW.

4 THE CONSERVATION IMPLICATIONS OF CL&P'S RATE DESIGN

Q : Please explain why CL&P's rate design discourages conservation.

A : Table 1 presents a comparison of the revenues by element, for the current base rates, ~~for current base rates increased across the board by the proposed increase to Rate 35~~, and for CL&P's proposed rates. All three cases in Table 1 assume the simplification in block structures proposed by CL&P. It is clear from this table that CL&P has done much more than emphasize the demand and customer charges in the allocation of the revenue deficiency. With an overall base rate increase of ~~6~~10.8% for Large General Service (not including the rate effect of eliminating the fuel adjustment credit), CL&P has increased the customer charge 372%, increased the demand charge by 59%, and actually <u>decreased</u> the energy charge by ~~8~~7%. Compared to an equal percentage across-the-board rate increase, CL&P's proposal reduces energy charges by 16%.

The clear direction of these changes has been to increase the least price-sensitive rate elements and to decrease the more responsive price elements. That is also the direction of rate design changes endorsed by Dr. Overcast (p.9 of his testimony); so this outcome is not an accidental effect of the ratemaking process.

Dr. Overcast is also quite explicit in explaining the reason for shifting revenue collection away from the energy charges; he advocates this change in price structure on the ground that it will encourage greater energy use.

> Such pricing would avoid reductions in the consumption of electricity . . .[Under current conditions] pricing strategy should seek to avoid economically artificial inducements to reduce consumption. (pages 9 - 10)

Q : Is Dr. Overcast correct in his assessment that the customer and demand charges are less price sensitive than the energy charges?

A : Almost certainly. Although Dr. Overcast offers no evidence concerning the effect of the so-called "fixed" charges on customer behavior, it is likely that consumption of kwh's and the level of other billing determinants (e.g., billed kw's) react less to demand charges than to energy charges, and that customers react little (if at all) to customer charges.

It would be surprising if ratepayers <u>did</u> respond to customer charges, since there is nothing that a consumer can do to reduce customer charges other than cease to be a customer. This is rarely a feasible alternative. Ratepayers have more control over their demand charges, but this is still difficult. A single hour of equipment malfunction, or high requirement for services, can undo an entire month (or a year, at 70% ratchet level) of excruciating care in controlling loads.

This issue does not appear to have been researched extensively, but one study[1] estimated that VEPCo system peak demand was over five times as sensitive to marginal energy prices as to marginal demand charges. Individual customer peak demand may respond somewhat more to demand charges than does system peak, but it still appears that energy charges affect revenues more than demand charges do.

This proposal by CL&P would

- promote the use of electrical energy
- discourage conservation
- limit consumers' ability to control their bills

and thus appears to run counter to the policies of the DPUC~~A~~ ? and of the Connecticut legislature. ~~It is also inconsistent~~

----

1. "Econometric Estimation of Peak Electricity Demands," R.M. Spann and E.C. Beauvais, in Forecasting and Modeling Time-of-Day and Seasonal Electricity Demands, EPRI EA-578-SR, December 1977

with NU's avowed desire to promote conservation, limit its load growth, and avoid the need for new investments in major generation projects.

5 MARGINAL COST CONSIDERATIONS

Q : How should energy charges be set?

A : I would agree with Dr. Overcast that energy charges should be based on marginal cost, and should certainly not be less than marginal energy costs. However, I believe that Dr. Overcast's interpretation of marginal cost is short-sighted and limited.

Q : How did CL&P determine the size of the energy charges for Rate 35?

A : CL&P bases the energy charges on what Dr. Overcast calls "out of pocket costs", or essentially CL&P's estimates of marginal fuel costs during the rate year. The Rate 35 and 37 energy charges are very close to projected marginal fuel costs, plus associated marginal losses and revenue taxes.

Q : Are those projected costs reasonable approximations of the marginal fuel costs for the projected cost-of-service period ending June 30, 1984, or for the calendar year 1984?

A : CL&P's proposed energy rates appear to barely cover the short-run fuel costs associated with delivering an additional kWh to the customer, as demonstrated in Table 7[2]. The response to CIEC Q-47 indicates that CL&P based the energy charges on average losses, rather than marginal losses. As demonstrated in Appendix C, marginal losses in resistive loads are greater than average losses.

In addition, it appears that the marginal costs estimates are somewhat understated. Specifically, very optimistic figures appear to be used for outages at NU's nuclear plants and at the Yankee plants in which NU holds entitlements. No refueling is assumed for Connecticut Yankee or for Vermont Yankee, both of which would be expected to refuel in two out of every three years. Only one month of outage is allowed for Millstone 2, which would be expected to average one refueling per year. (This is clearly inadequate for the year ended June 1984, as Millstone 2 has already been out of service for more than one month in that year.) There are also no provisions for unscheduled or other non-fueling outages.

While it is certainly possible to hope for the outage

----

2. While CL&P proposes energy charges just about at marginal running cost, its proposed demand charge is close to twice the marginal demand cost estimated in NU's 1980 response to PURPA section 133.

performance portrayed in Appendix C to Dr. Overcast's testimony, and while a year with these characteristics may occasionally occur (particularly when the plants have major outage immediately before and after the subject year), it certainly is not typical, and should not be used for rate design purposes.

Of course, CL&P's proposed energy rates provide no contribution to covering the costs of trans~~i~~mission and distribution expansion required by higher load factors, heat buildup, etc., as described in Section 4, above.

Q : If the marginal fuel cost analysis were performed with realistic assumptions, would it provide the appropriate marginal costs for use in rate design?

A : No. CL&P's marginal cost analysis is artificially restricted to the test year. Essentially, Dr. Overcast assumes that the only costs which will be incurred due to customer energy use (and energy use decisions) in 1984 are the costs of the fuel burned in 1984; these are his "out of pocket" costs. This assumption is ~~patently~~ untrue, for two reasons. First, the choices which customers make in 1984 regarding the amount of new energy-using and energy-saving equipment to be installed, the efficiency of that equipment, the trade-off between energy-saving and load leveling investments, and the development of energy-saving operating procedures, will all affect the level of energy demand for years, and perhaps decades, to come. Second, the trends in load growth in the short term must have an important influence on expectations for long-term growth, and thus on the need to develop expensive new sources of generating capacity. Thus, more appropriate time scales for marginal cost estimation would be the lifetime of customer investment decisions, or the NU planning horizon for generation capacity.

Q : Why is it inappropriate to impose low energy charges when marginal fuel costs are low, and gradually raise those energy charges as rising fuel prices and load growth pushes up marginal running costs?

A : There are two reasons that this would not give consumers adequate price signals. First, energy use can not be turned on and off like a spigot. As noted above, customers make consumption decisions in the short term which have very long-term consequences. Most electric energy demand studies which estimate both short and long-run elasticities find that the long-term price effect is five to ten times as large as the short-term effect. Thus, a price reduction for electric energy in 1984 would be expected to have a greater effect on 1994 consumption than on 1984 consumption. CL&P's short-term pricing approach might do more to encourage consumption when prices are high than low.

Second, and perhaps more fundamentally, CL&P's approach does not reflect its own expensive efforts to reduce marginal energy costs. Current marginal running costs have been reduced by CL&P's investments in conservation, coal conversion and hydro development; future marginal fuel costs will be low because CL&P is investing billions of dollars in Millstone 3, and millions more in the Hydro Quebec interconnection. Thus, CL&P may be able to keep current marginal fuel costs low indefinitely by continually building new energy sources with low running costs, fully justified by projections of future marginal fuel prices. Customers would never be given incentives to conserve energy equalling the cost of the new energy sources, or by the future fuel costs which justify the new sources. CL&P would apparently continue to promote energy use under these circumstances, leading to a perpetual spiral of low energy charges, high growth in energy use, expensive new construction to avoid future fuel costs, and rapidly increasing revenue requirements, collected mainly through demand charges.

Q : How would you suggest estimating the marginal energy costs for rate design purposes?

A : The basic principle in rate design is that energy charges, the most price-sensitive rate element, should reflect the cost of new energy sources, over the life of consumer investment decisions, and over the NU planning horizon. One approach to estimating these costs is to project out marginal fuel costs and the cost and schedule of fuel-cost-reducing investments over the next decade or more. This is clearly a very complex process, involving some very difficult forecasting issues.

A more tractable approach to estimating marginal energy costs is to examine the costs that NU and the DPUCA considers reasonable for the purpose of backing out fuel use. It certainly seems reasonable to suggest that marginal energy costs should be consistent with the prices NU is willing to pay for marginal energy supplies. This approach allows customer conservation (as a response to the energy charge) to compete with other energy supply options on a fair footing. It also implicitly reflects the premium placed on backing out oil-fired generation due to risk aversion and to the macroeconomic, social, political and other liabilities created by excessive oil dependence.

Q : What energy sources would you use in estimating the marginal cost of energy on the NU system?

A : There are several possibilities. Perhaps the most obvious, ~~given its role in this proceeding~~, is the cost of completing and operating Millstone 3. Surely, if the cost of increased energy consumption does not exceed the cost of Millstone 3, there is no point in completing that unit. If Millstone 3 is expected to be cost-effective over its useful life, then the relevant price is the entire cost of power from Millstone 3, including sunk costs. If the unit is only cost-effective on an incremental basis, then some or all of the sunk cost should be removed from the comparison. Conversely, if Millstone 3 will more than break even for the ratepayers, the relevant price is the maximum cost of power from Millstone 3 at which co~~s~~nstruction of the plant is still cost-effective.

Similar comparisons can also be performed for

1. The cost of completing and operating Seabrook 1.
2. The cost of NU's hydro development programs.
3. The cost of the Hydro Quebec intertie, adjusted for the fact that it will reduce fuel costs by only about 20%.

Q : Have you performed any of these calculations?

A : Yes. First,I have estimated the full and incremental costs of:

1. Millstone 3 at NU's estimated cost and capacity factors,
2. Millstone 3 at NU's estimated cost with my estimate of

capacity factors,

3. Seabrook 1 at NU's estimated cost and capacity factors, and

4. Seabrook 1 at my estimated cost and capacity factors.

This analysis is laid out in Table 8 (for Millstone) and Table 9 (for Seabrook). Table 8 also calculates the maximum credit which can be applied to these costs to represent the reliability benefits of the investment. These costs are all in levelized 1984 dollars, comparable to the prices charged for energy in the rate year.

Q : Have you estimated the price NU is willing to pay for energy sources other than these nuclear units?

Yes. Other NU power supply projects are somewhat more economical than the nuclear program, but still more expensive than current oil prices. The original NU Conservation Program for the 1980's and 1990's report (January 1981) estimated that hydro capacity supplying 115,000 MWh annually could be developed for $55 million. At the 12.8% fixed charge rate used previously[3], this is equivalent to 6.1

----

3. Hydro plants have longer lives and less risk than nuclear units, so a lower carrying charge would be applicable. The 12.8% rate would include an allowance for O&M, insurance, etc.

cents/kWh.

The Hydro-Quebec interconnection is reported by Mr. Cagnetta to be expected to carry 3000 GWh annually, at a cost about 20% below oil prices, or the cost equivalent of totally displacing 600 GWh. The most recent construction cost estimate for the line that I have seen was $350 million (Wall St. Journal, March 15, 1983). At 12.8%[4], this is equivalent to 7.5 cents per kwh before particularly large transmission losses.

Q : What energy charge would you recommend for Rate 35 as a result of this analysis?

A : I would recommend that the entire increase in the Large General Service rates be recovered through the energy charge. In addition, I would strongly urge the Commission to shift as much of the current demand charge revenue as feasible to the energy charges. Table 5 presents a rate design along these lines, which retains CL&P's suggested customer charge and peak/off-peak differential.

----

4. This is probably an understatement of the carrying charge, since the agreement is only for 11 years.

6 DEMAND CHARGES ARE INEFFICIENT

Q : Are demand charges such as those proposed by CL&P useful pricing tools for most electric rate design purposes?

A : No. Demand charges do not reflect well those costs related to consumption by all customers (e.g., generation, bulk transmission) or to large groups of customers (e.g., local transmission, distribution). Demand charges have five major flaws in these applications:

1. Demand charges are zero for all points in time during which demand is less than a previously established (or forecasted) demand in the billing period. For some of CL&P's customers, ratchet provisions may effectively make the billing period an entire year. As a result, demand charges provide no incentive to conserve at those times which are off the customer's peak but which are very much on the utility peak. The time when demand charges influence a customer's behavior (i.e., at the customer's peak) is not inherently a function of system or local demand, plant availability, or any other external condition which influences costs. As noted by Dr. Overcast in response to Q-RA-37, most Large General Service customers probably do not reach

their peaks coincident with NU or NEPOOL peaks. Hence, it can not be determined whether higher demand charges will shift demand away from the system's peak hour or toward it.

2. With high demand charges, it may be cheaper for customers, by load shifting, to use more energy in the utility's peak period while cutting their individual peaks. One such customer might find it advantageous to limit loads to 5 MW throughout the peak (e.g., 11 a.m. to 5 p.m. in the summer), rather than using 6 MW for the hour from noon to one p.m. and 3 MW for the rest. If other customers similarly avoid peaks at the other hours, the result is an average use of 5 MW per customer, rather than 3.5 MW, throughout the peak period, <u>due to the demand charges</u>. This shift in the demand pattern may reduce reliability, increase losses, and require additional local transmission and distribution investments.

3. Large customer expenses to reduce demand charges by shift(ing) loads may, for the reasons discussed above, result in no system savings or even an increase in costs. This is in contrast to energy charges: if customers conserve, energy utility costs decrease.

4. Customers are also not assured that even successful

load shifting will reduce their bills. Even a single hour of equipment malfunction, or an unavoidable increase in demand for the customer's product (e.g., a number of rush jobs), can undo a month of successful load leveling. Interestingly, ten such peaks in one month cost the customer less than does one such peak in each of two months.

There are also some costs incurred to serve essentially one single customer, and which increase whenever the customer's maximum service requirements increase. Demand charges are reasonably well suited to recovering these costs, as are hookup or customer charges which respond to the amount of access provided, rather than to the customer's demand.

It should also be noted that most of the costs related to peak demand are also related to the duration of the peak and even the daily loads cycle: the system reliability considerations of generation and transmission planning, the heat buildup in T&D equipment, and distribution losses.

In summary, demand charges are not very effective in promoting conservation, reducing peak demand, or reflecting costs. By radically increasing the Rate 35 demand charges, CL&P is providing less effieient pricing signals to its large customers, and is encouraging the continued wasteful use of electricity. As a large portion of the revenue requirement is allocated to the demand charges, the importance of the energy charge is diminished.

Q : Is the retention of 70% demand ratchets proper?

A : No. A customer with strong seasonal , weather-induced, or even random peaks has less incentive to control load in months between peaks under a higher ratchet. For example, a summer peaking commercial customer may have a 70 kW peak one July and anticipate a similar peak the next summer. In the meantime, the customer may never have a demand over 45 kW. This hypothetical customer's bill would not be influenced at all by demand levels, except those in the summer which establish a 49 kW (70% times 70 kW) billing demand for all the other months. Therefore, the demand charges have no influence on the customer's behavior in any month outside the summer, including the winter peak. While demand charges are not very good at encouraging conservation or load management in any case, large ratchets can only make them worse.

Reduction or elimination of ratchets will increase the number of months in which customers on Rate 35 and 37 will have an incentive for controlling their loads.

7 CONCLUSIONS

Q : Are there any other problems with CL&P's proposed rate design for the Large General Service Class?

A : Yes. There are three additional points of concern. First, the proposed demand charge for Rate 37 is even higher than that for Rate 35. Since Rate 37's time-differentiated energy charges match CL&P's cost pattern better than the Rate 35 charges do, the efficiency advantage of energy charges is increased for Rate 37, and the value of demand charges is even less. Thus, if Rate 37 is to be set above the level of Rate 35 (to reflect presumed shifts in energy use patterns), the increase should be placed in the energy charges.

Second, the extremely large increase in the demand charge results in some bills increasing much more than the average for the class. According to page 141 of Dr. Overcast's revised testimony, the overall increase for the Large General Service class is 10.8%. Table 11 computes the bill for Alloy Foundry's actual consumption for each month from July 1983 to June 1982. The new rates represent an increase of between 13% and 56%, depending on the month, and the overall bill increases about 18%. For a 4 MW customer, the proposed rates more than double the ~~combined~~ monthly demand ~~and customer~~ charges, from $3.34 to $7.69, and monthly use of about 1,144,000 kWh of the newly discounted energy is required to bring the increase in the bill down to the average.

In contrast, even if the entire increase were placed on the energy charge, no customer would experience an increase much above the class increase. The energy charge would rise only about 13.6%, and the absence of an increase in the demand or customer charge would limit the overall increase for even the highest load factor customers to about 12.5%, or less than 1.2 times the class increase.

Third, it is clear from Dr. Overcast's comments on page 8 of his testimony, that one of CL&P's principle concerns in rate design ~~has~~ is ~~nothing to do with efficiency or equity, but rather wit~~h revenue stability. CL&P's high and rising rates will tend to encourage conservation, and CL&P is attempting to reduce the amount of conservation or at least its effect on revenues.

I certainly share CL&P's concern with revenue stability; my proposal for a revenue stabilization mechanism is attached as Appendix E. Other forms of revenue adjustment mechanisms are in place or proposed in various jurisdictions, including California and New York. It is my understanding that Public Act 83-97 specifically allows for a revenue stabilization mechanism administered through the fuel adjustment charge. If CL&P is concerned about revenue stability, it should pursue one of these models for directly solving the problem. Rate design incentives are too important to manipulate for the sake of revenue stability, expecially when there are efficient alternatives.

Q : Does this conclude your testimony?

A : Yes.

Rate Element	Current Rates	CL&P Proposed Rates	Increase over Current
Customer ($1000)	$2,871	$13,549	372%
Charge ($/cust-mn)	$42.46	$200.40	
Demand ($1000)	$94,023	$149,785	59.3%
Charge ($/kw-mn)	$4.83	$7.69	
Energy <400hrs ($1000)	$348,304	$333,484	-4.3%
Charge (cts/kwh)	5.810	5.563	
>400hrs ($1000)	$33,525	$33,525	.0%
Charge (cts/kwh)	4.963	4.963	
Miscellaneous	($1,341)	($1,335)	
Total	$477,382	$529,008	10.8%

Table 1: Comparison of Existing and Proposed Rate 35

Notes : Data from Overcast Workpapers, page 20.
Current rates include fuel adjustment of 2.72 mills, from Overcast Workpapers, page 141.
Revenues include Proposed Rate 37.

Unit	Average Summer MW Rating per Unit [1]	Gas Turbine Equivalent Capacity per MW [2]	Annual Capital Cost $/kW [3]	C [4]	E [5]
Millstone Unit 1	654.0	0.735	191.74	8	92
Millstone Unit 2	864.0	0.678	229.09	6	94
Connecticut Yankee	555.0	0.762	211.47	7	93
Massachusetts Yankee	175.0	0.866	284.40	6	94
Vermont Yankee	504.0	0.776	177.89	9	91
Maine Yankee	810.0	0.693	101.20	14	86
Devon 7, 8	107.0	0.984	71.16	27	73
Montville 5, 6	245.5	0.947	61.32	31	69
Norwalk Harbor 1, 2	166.5	0.968	81.69	24	76
Middletown 3	233.0	0.950	70.08	27	73
West Springfield 3	107.3	0.984	65.18	30	70
Mount Tom	147.0	0.974	73.41	26	74
Devon 3-6	58.5	0.998	60.30	33	67
Middletown 1, 2, 4	195.5	0.960	53.02	36	64
West Springfield 1, 2	51.0	1.000	55.64	36	64
Internal Combustion Units		1.000	19.85	100	0
Hydroelectric Units		1.0	102.29	19	81
Northfield Mountain		1.1	35.55	61	39

Table 2: Revision of NU Capacity Cost Method to Incorporate Size Effect

Sources:
1) Average Rating from NU forecast, NRC reports.
2) Equivalent Capacity calculated from Table 4.
3) Annual Cost from Table 1, App. b, Overcast Testimony.
4) [2]*19.85/[3]
5) 1-[4]

UNIT	%C	ANNUAL CAPACITY UNIT COST	CAPACITY (kW)	WEIGHTED COST
Millstone Unit 1	8	$191.74	636,500	$9,763,400.80
Millstone Unit 2	6	229.09	838,200	11,521,394.28
Connecticut Yankee	7	211.47	247,100	3,657,796.59
Massachusetts Yankee	6	284.40	53,400	911,217.60
Vermont Yankee	9	177.89	55,000	880,555.50
Maine Yankee	14	101.20	107,900	1,528,727.20
Devon 7, 8	27	71.16	209,600	4,027,086.72
Montville 5, 6	31	61.32	472,900	8,989,450.68
Norwalk Harbor 1, 2	24	81.69	325,000	6,371,820.00
Middletown 3	27	70.08	230,700	4,365,213.12
West Springfield 3	30	65.18	108,300	2,117,698.20
Mount Tom	26	73.41	92,000	1,755,967.20
Devon 3-6	33	60.30	245,000	4,875,255.00
Middletown 1, 2, 4	36	53.02	570,100	10,881,612.72
West Springfield 1, 2	36	55.64	103,000	2,063,131.20
Internal Combustion Units	100	19.85	520,900	10,339,865.00
Hydroelectric Units	19	102.29	62,000	1,204,976.20
Northfield Mountain	61	35.55	988,300	21,431,779.65
TOTAL WEIGHTED COST				$106,686,947.66

$627,000,125 =

PERCENT DEMAND RELATED 17%

Table 3: Calculation of Demand Component of NU Generation Plant Costs

Sources: %C from Table 2.
All other data and calculations as per Table 3, App. B, Overcast Testimony.

Generation Type	Unit Capacity 50 MW	1150 MW
Nuclear	0.9	0.6
Fossil Steam	1.0	0.7
Hydro	1.0	1.0
Gas Turbine	1.0	---
Pumped Storage	1.1	1.1

Table 4: Ratio of Effective Load Carrying Capacity per Rated MW to Gas Turbine (ELCC/MW)

Sources: 1150 MW Nuclear derived from NEPOOL reserve margin as function of added nuclear units; NEPOOL Executive Comittee minutes 6/24/76 and 8/12/77.

Gas Turbine by definition.

All others judgementally extrapolated.

Cost Component	Trans. S/S	Trans. UG	Other Trans.	Total Trans.	Dist. S/S	Dist. UG	Line Trans.	Other Dist.	Total Dist.
Plant in Service	57963	6197	75357	139517	43665	42545	20104	62204	168518
Accum. Deprec.	16643	2360	19525	38528	16854	9254	7004	24454	57566
Rate Base Deduct.	960	136	1126	2222	801	440	333	1162	2736
Working Capital	47	5	62	114	639	930	436	1348	3353
Total Rate Base	40408	3706	54768	98881	26649	33781	13203	37936	111569
Return @ 12.62%	5099	468	6912	12479	3363	4263	1666	4788	14080
O&M	269	28	7241	7538	2613	1080	425	8573	12691
Deprec. Amort. & Disposal	1863	225	2198	4286	1418	1060	681	2387	5546
Payroll Taxes	52	1	144	196	107	43	8	415	573
Property Taxes	732	78	952	1762	599	584	276	853	2312
subtot	8015	799	17446	26261	8101	7029	3056	17016	35202
Gross Earnings Taxes	498	50	1084	1632	503	437	190	1057	2187
Income Taxes	1040	105	2153	3298	1119	992	438	2218	4768
Total	9554	954	20683	31191	9723	8458	3684	20292	42157
Load Fraction	45%	61%	100%	82%					
Non-energy Fr.	65%	65%	65%						
Demand Fraction	29%	39%	65%	53%	45%	65%	50%	100%	76%
Demand portion	2773	375	13341	16489	4375	5498	1842	20292	32007

Table 5: Computation of Demand Related T&D Plant

Notes: Cost Data from CL&P Proposed Cost of Service Study, prorated where necessary.

Cost Component	Total Prod.	Total Trans.	Total Dist.	General Plant	Total
Plant in Service	454911	139517	168518	18837	
Accum. Deprec.	159995	38528	57566	7348	
Rate Base +/-	-5995	-2222	-2736	-2104	
Working Capital	2277	114	3353	20884	
Total Rate Base	291198	98881	111569	30269	
Return @ 12.62%	36749	12479	14080	3820	
O&M	66591	7538	12691	22298	
Deprec., Amort. & Disposal	16681	4286	5546	2880	
Payroll Taxes	1132	196	573	533	
Property Taxes	7359	1762	2312	419	
subtot	128512	26261	35202	29949	
G. E. Taxes	7986	1632	2187	1861	
Income Taxes	24923	3298	4768	3473	
Total	161421	31191	42157	35283	
Demand Fraction	17%	53%	76%	33%	
Demand portion	27442	16531	32039	11560	87572
Net of Customer Charge					-13549
Demand Revenue					74023
Charge per kw					$3.80

Table 6: Calculation of Embedded Cost Demand Charge

Notes:
1. Costs from CL&P proposed cost of service study.
2. Demand fraction from Table 3 (production) and Table 5 (T&D). General plant classified in proportion to all other plant.
3. Assumes CL&P customer charge, sales projections.

	Losses			Marginal Losses	
	Avg Annual [1]	Peak Period [2]	Off-peak [3]	Peak Period [4]	Off-peak [5]
Transmission Lines	2.49%	3.16%	1.52%	6.52%	3.09%
Primary Substation Transformers [9]	0.54%	0.68%	0.33%	1.38%	0.66%
Primary Distribution Lines	1.64%	2.08%	1.00%	4.25%	2.03%
Total at Primary [6]	4.61%	5.82%	2.83%	11.72%	5.69%
Marginal Generation Cost [7]				4.67%	4.07%
Marginal Cost at Customer [8]				5.57%	4.54%

Table 7: Derivation of Short-Run Marginal Costs at Primary Voltage

Notes :
1) From CIEC Q-52
2) [1] x ratio of average peak period load to average annual load (2382/1879), from COSS
3) [1] x ratio of off-peak to annual load (1457/2382), ibid.
4) (1+[2])/(1-[2])-1; see App.C
5) (1+[3])/(1-[3])-1
6) 1-(product of each level's line losses)
7) From CIEC Q-46
8) [7]/((1-[6])*.95)
9) Only half of losses assumed variable.

Plant:		Millstone 3		Reliability Credit	
Cost per kw					
Construction Costs		$2,689		($226)	
		[$1,249]			
Fixed Charge Rate		12.8%		12.8%	
Cost per kw-yr					
Annual Capital Costs		$344		($29)	
		[$160]			
Non-fuel O&M		$57		($2)	
Capital Additions		$13			
Insurance		$10			
Decommissioning		$14			
Total Non-fuel		$439		($31)	
		[$254]			
Capacity Factor	PLC	55%		55%	
	NU		67%		67%
Cost per kwh (cents)					
Non-fuel		9.1	7.5	(0.6)	(0.5)
		[5.3]	[4.3]		
Fuel		1.1	1.1		
Total		10.2	8.6		
		[6.4]	[5.4]		

Table 8: Total Power Costs for Millstone 3.

Notes: Figures in brackets are remaining costs.
All costs are levelized real 1984 dollars.
Construction cost from CL&P estimate of $3.54 billion in 1986 dollars, deflated two years at 7% annually.
Remaining construction cost are from Q-CC-3.
Fuel cost is average of 1986 and 1988 estimates from CL&P Ex. EJF-2, p.6, deflated at 7% to 1984.
NU capacity factor estimate is from CL&P LFEx. 1, Att. 1, levelized for 25 years at 10%.
Reliability credits are for gas turbine, from Chernick (1982)
All other cost components from Testimony of Paul Chernick, DPUC 83-03-01.

Seabrook 1		
Source for Capital Cost and Capacity Factor	PLC	NU Scenario C
Cost per kw		
Construction Costs	$3,132 [$869]	$2,956 [$693]
Fixed Charge Rate	12.8%	12.8%
Cost per kw-yr		
Annual Capital Costs	$401 [$111]	$378 [$89]
Non-fuel O&M	$57	$57
Capital Additions	$13	$13
Insurance	$10	$10
Decommissioning	$14	$14
Total Non-fuel	$495 [$206]	$473 [$183]
Capacity Factor	55%	67%
Cost per kwh (cents)		
Non-fuel	10.3 [4.3]	8.1 [3.1]
Fuel	1.3	1.3
Total	11.6 [5.6]	9.4 [4.4]

Table 9: Total Power Costs for Seabrook Unit 1

Notes: Figures in brackets are remaining costs.
All costs in levelized 1984$.
NU estimates from CL&P LF Ex. 1, Docket 83-03-01.
See Table 8 for other sources.

Rate Element	Rate	Annual Sales [1]	Revenue ($1000)
Total Proposed Revenue [2]	---		$529,008
Customer Charge [3]	$200.40 /cust-mn.	67608	$13,549
Demand Charge [4]	$1.96 /kw-mn.	19477852	$38,267
Miscellaneous [5]	----	----	-1335
Energy Charges [6]			$478,527
Peak	7.235 cents/kWh	5994676	$433,709
Off-peak	6.635 cents/kWh	675495	$44,818

Table 10: Derivation of Marginal-Cost-Based Rate Design for Rates 35 and 37

Notes:
1. From p. 20, Overcast revised workpapers.
2. From p. 20, Overcast revised workpapers.
3. Uses CL&P's proposed rate.
4. Reduces current average rate by 59.3%, the same percentage that CL&P proposes to increase it. Greater decreases would be desirable, but for continuity considerations.
5. From p. 20, Overcast revised workpapers.
6. Revenues are difference between total and other charges. Peak and off-peak charges are set to be 6 mills apart, as per CL&P. Any reductions should be taken in the demand and customer charges, as the energy charges are already well below marginal cost.

MONTH	MWH	DEMAND	HOURS	1983 ENERGY	1983 DEMAND	1983 TOTAL	PROPOSED ENERGY	PROPOSED DEMAND	PROPOSED TOTAL	%INC
Jul-82	720	4320	167	$42,202	$15,151	$57,396	$39,253	$32,689	$72,142	25.69%
Aug-82	1276.8	4416	289	$73,804	$15,479	$89,325	$69,608	$33,417	$103,226	15.56%
Sep-82	979.2	4416	222	$57,142	$15,479	$72,664	$53,383	$33,417	$87,001	19.73%
Oct-82	1036.8	4224	245	$60,267	$14,824	$75,133	$56,524	$31,960	$88,684	18.04%
Nov-82	864	4224	205	$50,592	$14,824	$65,458	$47,103	$31,960	$79,264	21.09%
Dec-82	201.6	3744	54	$11,817	$13,187	$25,046	$10,991	$28,317	$39,508	57.74%
Jan-83	1209.6	4704	257	$70,193	$16,461	$86,696	$65,944	$35,603	$101,748	17.36%
Feb-83	1324.8	4896	271	$76,744	$17,115	$93,902	$72,225	$37,061	$109,486	16.60%
Mar-83	1612.8	4800	336	$92,056	$16,788	$108,886	$87,926	$36,332	$124,458	14.30%
Apr-83	1571.1	4800	327	$89,905	$16,788	$106,735	$85,652	$36,332	$122,185	14.47%
May-83	1272	4704	270	$73,687	$16,461	$90,190	$69,346	$35,603	$105,150	16.59%
Jun-83	1272	4704	270	$73,687	$16,461	$90,190	$69,346	$35,603	$105,150	16.59%
	13340.7	53952	2913	$772,095	$189,016	$961,621	$727,300	$408,296	$1,138,001	18.34%

Table 11: Calculation of Rate Increase for Actual Bills of Alloy Foundry.

Appendix B

An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant

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

Award Papers in Public Utility Economics and Regulation

1982

MSU Public Utilities Papers

Institute of Public Utilities
Graduate School of Business Administration
Michigan State University
East Lansing

Capacity/Energy Classifications and Allocations for Generation and Transmission Plant

Paul L. Chernick
and
Michael B. Meyer

In the current ratemaking system, every electric utility rate case necessarily covers three conceptually distinct subjects: estimation of total revenue needs and total revenue deficiency; allocation of total revenue needs and total revenue deficiency to the various customer classes (revenue allocation); and allocation of revenue needs within each customer class to various customers with differing usage patterns (rate design). As a result of many interrelated factors — such as the rapid increase in oil prices since 1973, the passage of the Public Utility Regulatory Polices Act of 1978, and the widespread recognition of the benefits of increased conservation incentives and of prices more accurately reflecting the costs of service — a major reform movement is under way in the United States to modify the way in which the electric utility industry accomplishes the revenue allocations among customers within classes, usually referred to as rate design. Initiatives to institute time-of-use pricing, marginal cost pricing, and lifeline rates are only a few examples of these suggested rate design reforms.

By comparison, although the second step in the ratemaking process, which involves revenue allocations between customer classes, is as important as the rate design step in every respect, it has so far attracted much less attention. This relative lack of attention to interclass revenue allocations exists among regulators, in the academic journal literature, in the industry's efforts and attention, and in the positions taken by would-be rate reformers. In short, the recent flurry of activity, discussion, and controversy over the rate design process has, by and large, not affected the interclass revenue allocation process.

The problem can be briefly stated. Revenue allocations are made to customer classes based upon the estimated costs of serving the classes. However, as the costs being allocated in the current ratemaking system are embedded costs,[1] and as a large percentage of these are joint costs, these allocations are essentially judgmental and cannot be rigorously justified by analytical methods. Furthermore, the present allocation methodologies were designed and adopted in a time when generation plant additions were not usually made for energy cost savings purposes, and when the $/kw costs of the different types of installed generation capacity varied over a much narrower range than do the various generation technologies currently available. Thus the present allocation methodologies require reexamination for two reasons: their lack of a rigorous analytical justification, and their nonresponsiveness to current generation planning considerations.

This paper first describes the traditional solution to the revenue allocation problem as it is widely applied in the United States today. It then recommends an improvement to the current practice, focusing upon the causes for constructing different types of generating capacity in terms of $/kw of capital cost, ¢/kwh of energy cost, and expected capacity factors. The last section offers brief concluding remarks.

The Traditional Solution

The interclass revenue allocation problem (the second of the three ratemaking steps) has traditionally been solved itself in three steps. First, costs are *functionalized* in production, transmission, subtransmission, and distribution cost categories depending upon the purpose served by the operating expense or capital expenditure. Second, these costs are *classified* as energy related, demand related, or customer related. Third, the demand portions of these costs are *allocated* by some method to the various customer classes.[2]

Functionalization can be based upon fairly clear-cut engineering considerations for most capital expenditures. With the exception of the joint cost problem, which appears for some overhead and administrative expenses, functionalization is not very controversial; it is quite uncontroversial as to the capital expenditures under consideration here, for example, for generation and transmission plant.

The steps of classification and allocation, however, are potentially quite arguable, at least as they are currently applied to generation and transmission plant capital expenditures. First, all or essentially all costs for these items are joint costs. With few exceptions, generation plant capital expenditures are usually classified as entirely demand related.[3] Second, once the generation plant capital expenditures are classified as entirely demand related, they are then allocated to the various customer classes by essentially arbitrary (but long-established) methods, such as the contribution to system coincident peak, the noncoincident peak, the average-and-excess, the weighted average of the contributions to summer and winter peaks, or the twelve monthly peaks methods.

The second step, which currently classfies all (or almost all) generation plant to demand, does not appear to be justified in view of the fact that different generating technologies (with different $/kw and ¢/kwh costs) are installed to serve different parts of the load duration curve at different load factors. In other words, a large percentage of generation plant capital costs are currently incurred to minimize total generation costs, including energy costs [Crew and Kleindorfer 1976; Wenders 1976].

The third step, which currently allocates all demand-related generation plant capital costs to peak or some intuitively derived alternate measure of peak, is not justified because it is well established that off-peak demand contributes measurably to total system reliability needs [Vardi and others 1977; compare Kahn 1971 at I:89–103].

Indeed, the traditional solution tends to conflate the problems of classification and allocation. It may be hypothesized that much of the motivation for the use (in step three) of allocation methods other than the contribution to coincident system peak method stems from a desire on the part of electric utilities to correct in some rough and intuitive fashion for the problems caused by the classification (in step two) of all generation plant capital expenditures to demand, which, in fact, appears to understate substantially the energy-related portion of these expenditures. In other words, it seems plausible that the utility industry is attempting to compensate for the under-recognition of energy-related expenses in step two by intuitive means in step three, through the use of allocation methods other than the contribution to system peak method, although no attempt is made to measure the relative size of the "mistake" and the corresponding "correction."

The Minimum-Cost Reliability Serving Method

We believe a set of classification and allocation principles may be derived which can satisfy the concerns raised above. Since cost classifications are more a matter of subjective measures of equity than of objective measures of efficiency, the derivations will not consist of the mathematical progression of equations that characterizes the development of efficient pricing structures. Rather, we will present a series of principles, joined by logical arguments and occasionally restated in the form of equations. We start with our fundamental principles:

> *Principle 1:* The reliability related portion of power supply production investments and nonfuel expenses is the minimum cost associated with providing the desired reliability level, or the actual reliability level, if that is lower. The remaining power supply production costs should be classified as energy.

This principle embodies a "reliability first" conception of system planning. When the utility builds generation capacity it first concentrates on maintaining adequate reliability; only after a reliable system is provided do the planners turn their attention to fuel cost reductions. Since both system reliability and energy costs are designed in simultaneously, the reliability first assumption refers more to a conceptual hierarchy of priorities than to a temporal sequence.[4]

We base our classification technique on the reliability first principle for two reasons. First, we believe it is historically correct. System planners have traditionally been more worried by the prospect of disconnecting customers and shedding load than by an increase in running costs. While attitudes may have changed somewhat in the 1970s, due to large increases in fuel costs, most utility systems probably embody this order of priorities. Second, Principle 1 provides us with fairly specific and tractable directions for deriving a classification scheme. While implementation of the principle is not without

complications and controversy, it is relatively easy to determine whether a classification approach is generally consistent with it. We recognize that Principle 1 is not the only contender for a fundamental principle of classification, and we present alternatives in Appendix A.

Principle 1, and other classification principles, are stated in terms of dividing power supply costs into energy-related and reliability related components. The use of reliability in lieu of the more common term demand reflects our concern that the latter has been too long associated with peak load and capacity, and that old habits of thought are hard to break. In reassessing the relationships among capacity, reliability, and load shape, it is advantageous to start with as clean a slate as possible.

The confusion between reliability serving costs and the larger class of capacity costs (or fixed or capital costs) is deeply rooted in the utility industry and often confuses analysis of a variety of issues. For example, a recent article on load management and oil-backout policies concluded that the Long Island Lighting Company (Lilco)

> can justify having higher reserves than required for reliability . . . to substitute nuclear base-loaded plants for oil base-loaded plants. As Lilco's system becomes more heavily nuclear the relationship of its fixed costs to its variable costs will change substantially. Nuclear plants have relatively high-capital costs and low-fuel costs; whereas, oil plants have relatively low-capital costs and high-fuel costs. If we assume that future rates will generally track costs, then demand-related charges will have to rise in relation to energy-related charges. Then assuming all other things being equal for the moment, rates for low-load factor customers will rise faster than rates for high-load factor customers. Since residential customers, as a class, almost always have significantly lower load factors than the industrial customer class, one result from Lilco's converting to a lower cost operating system through installing nuclear plants is likely to be relatively higher residential rates in respect to industrial rates [Koger 1980].

In other words, the implicit assumption that capital costs must be recovered from demand-related charges leads Koger to conclude that residential customers should pay for the nuclear plants that are built to reduce the industrial customers' fuel charges. Clearly, a new mode of thinking about fixed costs is required.

Another set of clear examples of the inadequacy of the prevalent allocation of all fixed costs to demand involves the treatment of fuel storage and treatment facilities. If an oil desulfurization unit, or a coal gasifier, is owned by a supplier who sells the high quality product to the utility, the cost of the treatment facility is rolled into the fuel cost and is therefore treated as an energy charge. If the uility buys its own treatment facilities, they would generally be treated as part of fixed plant and allocated to demand. In either case, the treatment facilities serve exactly the same purpose: to reduce fuel costs. All extra fixed costs incurred to reduce fuel costs are clearly energy related, regardless of whether the extra cost is located at a supplier's plant or beside the utility's generator. The same is true of the additional cost of a coal plant as compared to a less expensive gas-fired plant: The incremental investment is a fuel-saving measure and should be classified as energy serving.[5]

Principle 1 implies that the reliability related portion of a power supply system is the lowest cost system which would provide a particular level of reliability. Certainly, reliability users should not be charged for more reliability than they are actually receiving, so the reliability of the reference, low-cost system need never exceed actual levels. Where the actual reliability is greater than or equal to target reliability, the reference system should generally be designed to the target levels. This follows from the observation that excess capacity is generally the result of the long lead times of base load units (which caused accidental overcapacity starting around 1974 in many parts of the country) and of the effort to replace oil and gas-fired generators with other fuels (which will cause intentional overcapacity in the 1980s). In general, the hypothetical minimum-cost reliability serving system will consist of relatively small units with short lead times and will not consider fuel costs at all. Thus, the reference system should not incorporate overcapacity, unless unusual circumstances (such as a very abrupt drop in load) suggest that the overcapacity would have occurred even to an all-peaking system.

> *Principle 2:* För any generation unit built after 1963, the reliability related cost is generally that of an array of gas turbines with the same contribution to reliability and of the same vintage.

Gas turbines are chosen as the standard reference system because they are cheap and site independent. Under some circumstancs, other types of capacity (building conventional or pumped hydro, retaining obsolete generators, special purchase agreements) may be known to be cheaper for some amount of capacity; this will vary among systems, depending on the extent of current hydro development and purchases

and of information on past and future options. Where identified, such cheaper capacity should be used as the basis for reliability/energy classifications. The 1963 cutoff was chosen to reflect the fact that gas turbines were not widely available prior to that date, as evidenced by the fact that the Handy-Whitman price index for gas turbines originated in 1964.

We interpret "the same contribution to reliability" to mean the effective load carrying capability (ELCC) or something quite similar. ELCC [Garver 1965] is the amount of additional firm load that a generating unit allows a system to accommodate without violating its reliability constraint. Thus, if the system can carry 11,000 MW without the unit, and 11,500 MW with it, the unit's ELCC is 500 MW.

Ideally, it would be desirable to model the ELCC of each unit in the utility's actual system to reflect the effect of the utility's load curve, generation mix, and tie lines. Since the ELCC of a large marginal unit increases as the number of such units increases (the sixth 500 MW coal plant has a higher ELCC than the first), the ELCC of each unit should ideally be determined by adding the units in chronological order to the current system of pre-1964 units and peaking units. This level of detail and specificity will not always be possible; we suggest a simplified alternative below.

One might also wish to construct the reference system from the actual system on a unit-by-unit basis, accounting for plant in service, return, non-fuel O&M expense, accumulated depreciation, deferred taxes, depreciation expense, property taxes, and income taxes to develop a total cost in the rate year for each unit. There are three drawbacks to this approach. First, the calculations may be very time consuming for systems with many units and may be virtually impossible if units within a plant (possibly of very different sizes, vintages, and ELCC's) are aggregated in the available accounting data. Second, the components of the reference system must be "aged" to determine accumulated depreciation, deferred taxes, additions to capital cost, and property taxes, which requires assumptions regarding past and present tax treatments, depreciation rates, and capital additions. Third, if accumulated depreciation is reassigned from demand to energy along with the associated plant, the (low load factor) groups who paid for depreciation expense in the past will not generally receive the benefits of the accumulated depreciation they contributed; thus, the detailed accounting does not, in itself, produce as great an increase in equity as might be hoped.

In a previous application [Meyer and Chernick 1980], we simplified the modeling by assuming that all current cost components (except O&M) vary in proportion to initial construction cost, so that for unit i,

$$CGT_i = CM(BY) \times \frac{HW(COD)}{HW(BY)} \times ELCF_i \times MW_i \qquad (1)$$

where

CGT_i = cost of a gas turbine equivalent to unit i under the terms of Principle 1;

$CM(BY)$ = cost per MW of gas turbine index as of the base year;

$HW(COD)$ = Handy-Whitman gas turbine index as of the commercial operation date of unit i;

$HW(BY)$ = Handy-Whitman gas turbine index as of the base year;

$ELCF_i$ = effective load carrying factor, defined as (ELCC/MW for unit i ÷ ELCC/MW for gas turbines); and

MW_i = capacity in MW of unit i.

For nonfuel O&M expense for unit i,

$$OGT_i = OM \times ELCF(i) \times MW(i), \qquad (2)$$

where

OGT_i = O&M expense for unit i attributable to reliability; and

OM = current year nonfuel fixed O&M cost/MW for gas turbines.

> *Principle 3:* Steam units built prior to 1964 in primarily thermal systems may be regarded as entirely reliability related, unless a hydroelectric or other specific alternative was available.

Before 1964, units were not so specifically designed for peak or base load service; older units generally served as peaking plants, and the newest units provided the base load. Among today's base load plant types, before 1964 nuclear units were rare and heavily subsidized, while coal units, much less encumbered than at present by environmental regulations, were not much different in terms of initial capital cost per kw of capacity from oil-fired steam units. Before the gas turbine, the only real peaking alternative for thermal systems appears to have been the diesel, which has rarely been used on a large scale. For systems on which a reasonable series of diesel cost estimates can be developed, perhaps the method we suggest for post-1963 units can be pushed back some years. For systems with hydro capacity, the technique discussed in Principle 6 below may be helpful.

In general, the pre-1964 units will not be a large portion of the power production supply costs for three reasons. First, pre-1964 capacity is generally a small portion of total capacity. Second, the original cost of the old units was low; for example, Handy-Whitman all steam generation cost index for the North Atlantic Region in 1960 was 158 versus 505 in 1980. Third, the older units are largely depreciated; even a unit completed in 1963 would be about 50 percent depreciated for ratemaking purposes by 1980, and older units would be even more depreciated. Thus, the classification of old units will not generally be very important to the final allocations.

Exceptions may arise if old units have recently added pollution control or fuel conversion equipment, which would not have been necessary if the unit were a peaking plant for which the cost of fuel was relatively unimportant. Such equipment, especially in the case of coal conversion projects, may have a larger effect on rates than does the remaining balance of the unit and is generally 100 percent energy related.

> *Principle 4:* Where construction work in progress (CWIP) is included in the rate base, only the CWIP which would have accrued on a gas turbine of similar service date is attributable to reliability; the remainder is energy related.

One reason base load plants are so expensive is that they take a long time to build, during which period interest charges must be paid. If the interest portion of the construction cost is to be transferred to the rate payers, then the energy users, who receive most of the benefit from the plant, should also bear most of that interest cost.

Where CWIP is an extraordinary measure, permitted only for especially expensive investment, the gas turbine equivalent would have resulted in no CWIP at all, and all CWIP charges may be attributable to energy. This is particularly true when the unit for which CWIP is allowed is not required for reliability in the near future. If CWIP is allowed on all generation, then the amount of the CWIP on unit i in year Y attributable to reliability is

$$CWGT_i = GM(BY) \times \frac{HW(COD)}{HW(BY)} \times ELCF(i) \times MW(i) \times F(COD - Y) \times P, \tag{3}$$

where

$F(t)$ = the fraction of the final cost of a gas turbine which is invested t years before the COD; and

P = fraction of CWIP allowed in the rate base.

The F function is probably an S-curve, but we approximate it linearly as

$$F(t) = (L-t)/L \text{ for } L > t, 0 \text{ for } L \leqslant t, \tag{4}$$

where

L = construction time for gas turbines.

Two problems arise in applying Equation 3. First, COD is an estimate and, especially for nuclear plants, probably an underestimate. Using utility estimates of COD will frequently overestimate F. Second, again because COD is an estimate, $HW(COD)$ must be synthesized from a recent HW and an anticipated inflation rate. Neither difficulty is insurmountable and neither should obscure the basic reality: only a small portion of CWIP is attributable to reliability.

> *Principle 5:* Amortization of the cost of a canceled generation project should only be assigned to reliability to the extent comparable costs would have been incurred for an equivalent gas-turbine addition planned for the same COD.

The same principles apply here as in the case of CWIP. Base load plants require extensive advance preparation which is sometimes lost when events render further development impractical or inappropriate. In the mid-1970s, falling demand and rising oil prices resulted in cancellation of several oil-fired plants on which sizable sums had already been expended. More recently, regulatory actions, budget constraints, and continued conservation have resulted in the cancellation of numerous nuclear units.

In most cases, these cancellations occurred long before a gas-turbine project with the same planned COD would have required much commitment beyond (at most) land acquisition. Since the value of the site is seldom included in the amortization, essentially no amortization would have been necessary if gas turbines had been planned instead of base load units.

> *Principle 6:* For high load factor hydroelectric facilities built prior to 1963, the reliability related portion can be determined from the cost per kw for pumped hydro storage or a low load factor conventional hydroelectric facility of the same vintage.

Just as thermal plants are built more expensively than would be necessary if they were solely designed to meet reliability needs, so are hydroelectric plants. In the case of thermal plants, additional investment (in the form of building steam plants rather than gas turbines) buys lower heat rates (in Btu/kwh) and the ability to use cheaper fuels (in ¢/Btu). In the case of hydroelectric plants, additional investment buys higher capacity factors through such devices as larger capacity storage ponds. In either case, the additional cost is incurred to reduce fuel costs and accommodate high load factor customers and therefore should be classified as energy related.

Isolating the reliability related portion of hydroelectric facility costs involves two problems not encountered in analyzing thermal systems. First, hydroelectric plants exist on a continuum of capacity factors, from base load units (which may operate at 70 percent or greater capacity factors), to peaking units (which operate at capacity factors below 20 percent), to pumped storage hydroelectric units (which contribute no net energy and are designed for varying storage cycles). It is not always obvious what type of hydroelectric plant would represent the portion of the actual plant attributable to reliability. Second, unlike gas turbines, hydroelectric capacity costs ($/kw) are highly site dependent. Thus for each utility system, the cost of an additional kw of hydroelectric capacity varies with the amount of hydroelectric capacity already installed as well as with the capacity factors of the existing system and of the additions to the system. Therefore, some technique must be devised to separate the reliability serving portion of hydroelectric capacity on a utility-specific basis. (In some regions, such as New England, in which utilities commonly own generation outside their service territories, the perspective may be broadened to the region. This ameliorates, but does not remove entirely, the problem).

The first problem may be resolved by reference to the utility's load curves. On a system which experiences sharp, short-duration peaks, very low load factor pumped storage plants might provide adequate reliability; on a system with broader peaks and relatively high off-peak loads (precluding pumping), conventional hydroelectric facilities with higher capacity factors may be needed to carry load. An approximation to the capacity factor needed to replace the hydroelectric portion of a utility system can be determined from the load factor of the portion of the load duration curve corresponding to the installed capacity. Figure 1 illustrates this approach for a utility with 30 percent of its capacity in hydroelectric units. Note that serving the top 30 percent of the load duration curve requires a capacity factor of only about 10 percent. A more rigorous approach to selecting the reliability-serving hydroelectric component would involve the application of simulation models to determine the amount of each type of hydroelectric capacity required to maintain the reliability constraint; the least expensive alternative would be the reliability serving substitute for the existing hydroelectric capacity.

The *second problem*, relating to the variability of hydroelectric capacity development costs, can be resolved in several ways, depending on the kind of capacity which is being treated as reliability serving and on the extent of specific data about the system. If pumped storage hydroelectric capacity is an appropriate substitute for existing capacity, the cost of that pumped storage capacity may be available from site-specific or from generic regional studies.[6] Similarly, the cost of developing new low load factor hydroelectric facilities, or increasing the installed capacity (while decreasing the capacity factor) at existing sites, may have been previously established.[7]

If such economic studies are not available for enough low capacity factor sites to establish an alternative reliability serving system, or if such studies have excluded the most economical sites, currently occupied by high capacity factor hydroelectric facilities, it may be possible to estimate a general regional relationship between the capacity factor of a hydroelectric development at a site and the \$/kw cost for that site. For example, an "economy of intensity" relationship, analogous to the traditional economy of scale, might be estimated as

$$\frac{\text{cost of plant 1 (\$/kw)}}{\text{cost of plant 2 (\$/kw)}} = \left[\frac{\text{capacity factor of plant 1}}{\text{capacity factor of plant 2}}\right]^m, \tag{5}$$

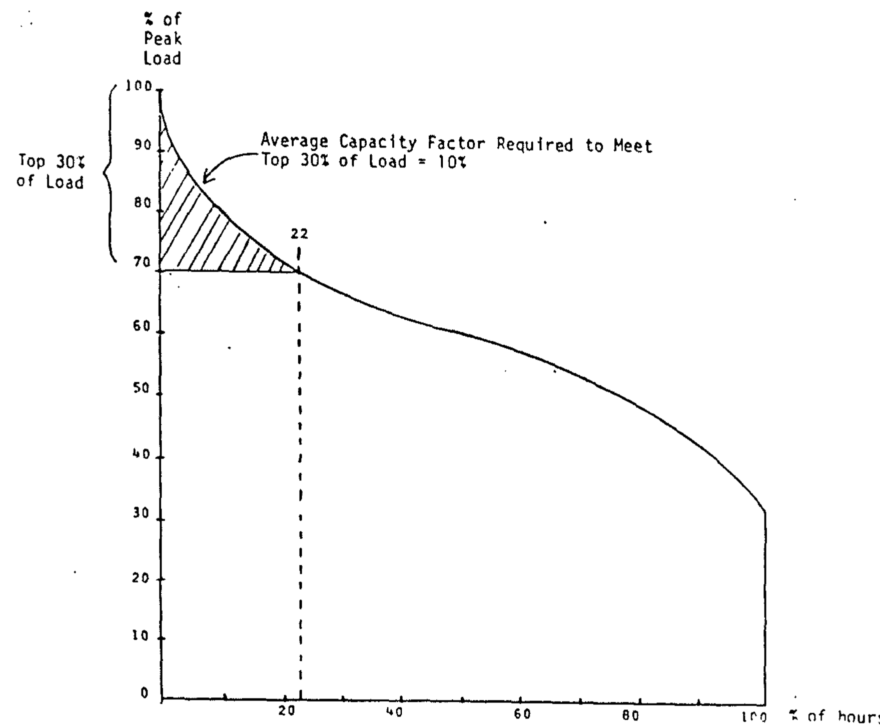


Figure 1. ***Calculation of Required Hydro Capacity Factor for Typical Load Duration Curve and 30 Percent Hydro Capacity***

where plants 1 and 2 are alternative hydroelectric developments at the same site, and m is the economy of intensity factor. Once the value of m has been determined for a representative set of hydroelectric sites, Equation (5) could then be applied to other representative sites by letting plant 2 be the existing facility (with known cost and capacity factor), assigning plant 1 the desired capacity factor for the reliability serving plant, and solving for the cost of plant 1 at the site of plant 2. Of course, alternative formulations of Equation (5) are possible. Furthermore, to the extent that they are available, detailed site-specific cost studies would be preferable to any such extrapolation.

Whether established through detailed studies or by a generalized relationship, the total low load factor, low cost hydroelectric capacity which could be developed at existing sites will generally exceed the actual installed capacity at those sites. In addition, considerable conventional and pumped hydroelectric capacity may be available at new sites. The cost of this excess of reliability serving hydroelectric capacity, beyond that which would have been required to serve the same reliability as the existing hydroelectric capacity, can be used as the reliability serving component of the pre-1964 steam capacity (assuming the excess hydroelectric capacity is less expensive than the pre-1964 steam plants) and of the post-1964 generating capacity (assuming the excess hydroelectric capacity is less expensive than the gas turbine of equivalent ELCC).

> *Principle 7:* The reliability related cost of the power supply transmission is the cost of the minimum transmission system required to interconnect the minimum-cost reliability serving generation alternative to the utility system's load centers.

For most utilities, large portions of the transmission system exist to minimize total energy costs rather than to maintain reliable service. For example, some transmission lines are required solely to connect remote base load plants to the rest of the transmission grid. These remote base load plants are, of course, largely energy serving, and the motivation for their MW size, fuel type, and remote location are connected to their energy rather than their reliability aspects. Similarly, transmission lines connecting a system's load centers must be reinforced to accommodate the large and variable power flows resulting from the existence of large units and their consequent "lumpy" dispatch patterns and outages. Further reinforcement is typically added to allow for economic dispatch of the base load generation over a variety of load levels, spatial distributions of loads, generation outages, and transmission outages. If the generation system consisted solely of small gas turbines located near load centers, fewer miles of transmission lines would be needed, and the remaining lines would have lower kva capacities. The same result would generally apply for a generation system consisting of old steam units, as these were generally located close to load centers, so long as no provision was made for economic dispatch among the system's various steam generation units.

The minimum reliability serving transmission network will thus be comprised of a set of lines connecting load centers, with some extensions to peaking hydro facilities, if any. The cost of this system can be extrapolated from the cost per kva-mile of the existing system,

disaggregated as necessary by area, voltage level, and location of line (overhead versus underground).

> *Principle 8:* The cost of tie lines between utility systems should be considered to be entirely energy serving unless they serve to replace peaking capacity. To the extent that they do replace peaking capacity, the reliability serving portion is that equivalent to minimum-cost reliability serving generation.

In keeping with the reliability first concept of Principle 1, it is appropriate to treat tie lines as entirely reliability serving if they provide ELCC more economically than peaking capacity could provide ELCC. If the tie lines cannot be entirely justified on such a basis, then the reliability serving portion can be identified from Equation (1), where unit i is a tie line or a set of tie lines to another utility.

> *Principle 9:* Reliability related costs should be allocated to customer classes on the basis of class contribution to the system's reliability needs.

An appropriate allocator for reliability related costs will have to reflect what caused the reliability related costs to be incurred. Such costs are not incurred solely to meet one annual system coincident peak, or even a few monthly peaks, but to maintain reliable service throughout the year. Such reliability measures as loss of load probability (LOLP) and loss of energy expectation (LOEE) recognize the overall reliability level at each point of the load duration curve and thus provide the basis for appropriate allocators.

Class contributions to system hourly loads are now estimated by most major utilities for their PURPA §133 filings, and hourly estimates of reliability measures, especially LOLP, are widely available from standard programs. Thus, the class share of reliability serving costs can be determined as

$$S(j) = \sum_h M(h) \times L(j,h) \div L(h), \qquad (6)$$

where

$S(j)$ = reliability allocator to class j;
$M(h)$ = reliability index, such as LOLP, in hour h;
$L(j,h)$ = load in hour h for class j; and
$L(h)$ = load in hour h for entire system.

If Equation (6) cannot be estimated, due to lack of data, then some arbitrary *ad hoc* allocator may be required. Such an allocator should reflect as much of the system load duration curve as possible, while emphasizing the relatively greater importance of the higher portions of the curve. In general, appropriate allocations will lie somewhere between those based solely on peak demand (which recognize only a few hours at the top of the load duration curve) and those based solely on energy (which recognize all hours on the load duration curve equally).

> *Principle 10:* Energy-related costs for each unit should generally be allocated to customer classes on the basis of class share of energy use (adjusted for losses) at the times of utilization of the unit.

While a reasonable argument can be made that the energy costs should be attributed equally to all periods, it appears fairer to time-differentiate both the fixed and variable components of energy costs. This procedure recognizes that the classes with high off-peak usage allow for the construction and operation of generally less expensive (on a kwh basis) base load plants, while those with heavily on-peak usage require more expensive (per kwh) peaking or intermediate units. The assignment of energy costs to periods may be based on actual or simulated data but should not be unduly sensitive to plant performance or demand patterns peculiar to the test year.

Finally, the relationship between the methodology proposed here and the "marginalist" cost allocation methodologies used by several state commissions (notably California, Montana, and Oregon) should be noted. Interclass revenue allocations based on marginalist principles are neither required nor indicated by efficient pricing theory. *Any* interclass revenue allocation methodology, whether embedded or marginalist in nature, by definition creates class revenue constraints which may require pricing away from "pure" marginal costs. In general, it is not possible to determine which interclass revenue allocation method provides a "better" second-best solution to designing rates; this is true of both embedded and marginalist revenue allocation methods. In sum, the reasons for pricing rates at marginal costs (in rate design) do not necessarily extend to interclass revenue allocations.

In light of this, the embedded cost revenue allocation methodology proposed here is a reasonable alternative to marginalist revenue allocation methodologies, but it cannot be said to be either more or less efficient (due to the second-best problem) than those. It is thus presented as appropriate for commissions which, for one reason or another, do not want to adopt marginalist revenue allocation methodologies but do wish to modify and improve on the traditional embedded cost revenue allocation methodologies widely in use today.

Conclusion

Because of the joint cost nature of many of the costs incurred in the production of electric power, it must be recognized that any interclass revenue allocation method is based upon judgment and not upon principles which can be rigorously derived from efficient pricing theory. However, once this is recognized, equity nevertheless demands that regulators and electric utilities do the best job possible of reflecting the various classes' responsibility for costs in rates. Given this necessity, it is submitted that the alternative interclass revenue allocation method advanced here reflects the realities of present generation planning, in which a large percentage of total generation and transmission capacity costs are incurred to serve most or all of the load duration curve and to minimize the total generation (including fuel) costs. The more traditional methods, which evolved when the capacity costs per kw of the various generation technologies existed in a narrower range, and when most or all capacity costs were in fact incurred in order to serve reliability, do not reflect those realities as well as does our method.

APPENDIX A

Alternatives to Principle I

The reliability-first principle proposed here as Principle 1 is put forth on the basis that it appears best to reflect the realities of current generation planning. However, it is certainly not the only possible basis for revenue allocations. Alternative approaches include energy-first allocation and load curve methods. This appendix briefly describes these two possible alternatives.

Energy-first allocation would allocate as an energy cost the portion of generation unit investment costs and operating and maintenance expenses which is justified on the unit's fuel-cost savings, with the remaining portion allocated to reliability. Some difficulty may arise in the definition of fuel savings; for example, if the generation alternative is an all-gas turbine system, some utility systems would find that their entire generating capacity and associated transmission investments are energy-related by that standard. The methodology may have some appeal for systems with excess capacity, mostly in oil-fired and gas-fired units, which are adding coal or nuclear capacity explicitly to reduce the use of the oil and gas units. In these cases, the energy-serving portion can be determined by comparison with the existing system. Unfortunately, variations in cost (in $/kw) in the new capacity, which is clearly intended as energy-serving, are reflected in the net classification to reliability, which does not seem appropirate.

With respect to load curve allocation methods, some interesting work has been started on allocating production costs by fitting units under the load curve, and allocating responsibility for the generation plant to the customer classes which use them [for example, Charles T. Main, Inc. 1980]. This approach is still quite incomplete: Such elementary concepts as reliability measures and ELCC have not yet been incorporated. Treatment of other issues, such as excess capacity, is still apparently done on an *ad hoc* basis without any substantial foundation. If the conceptual model can be expanded from the current deterministic form to a more reasonable probabilistic form, generalized to recognize the difference between potential contribution to energy supply (such as the capacity factor or the equivalent availability factor) and to reliability (such as ELCC), and made more rigorous, allocations based upon dispatching generators under a load curve may represent a compromise between the energy-first and the reliability-first approaches.

Notes

1. One can conceive of ratemaking systems in the future in which this would not be the case. For example, interclass revenue allocations can be performed using each class's contribution to marginal costs as the basis for allocations. Similarly, a "pure" marginal cost based rate design system would presumably omit the interclass revenue allocation step entirely and would set each class's rates based upon class marginal costs modified by Ramsey pricing, without setting class revenue constraints.
2. See NARUC [1973] at pp. 5–10 (functionalization), pp. 30–39 (classifications between energy-related and demand-related costs), and pp. 40–53 (allocation of demand-related costs).
3. See NARUC [1973] at pp. 30–35, exempting only some hydro generating capacity from the general rule that generation plant capital expenditures are demand related.
4. Applications of this principle in current utility allocation practice are uncommon, but some examples exist. Bonneville Power Administration [1981] applies simple variants of a reliability first approach for allocation of both thermal and hydro generation costs.
5. The coal plant can be thought of as a gas-fired plant with a built-in coal gasifier.
6. For example, NEPOOL has estimated that pumped storage hydroelectric capacity is available in New England for $315/kw, in 1980 dollars, up to at least 7,500 Mw [NEPOOL 1977].
7. Such studies for New England include Campbell [1977]; Acres American, Inc. [1979]; and New England River Basins Commission [1980].

References

Acres American, Inc. 1979. "Hydroelectric Power Generation Study," Phase 1, Part 1. Massachusetts Municipal Wholesale Electric Company. February.

Bonneville Power Administration, U.S. Department of Energy. 1981. "Cost of Service Analysis, Fiscal Year 1982." February.

Campbell, D. R. 1977. "Report on Potential Hydroelectric Sites in New England." New England Electric System. February.

Charles T. Main, Inc. 1980. "A Discussion of a Supply Side Time-Differentiated Accounting Cost Methodology." Prepared for Electric Utility Rate Design Study. November.

Crew, M. A., and P. R. Kleindorfer. 1976. "Variable Load Pricing in the Face of Loss of Load Probability." *Bell Journal of Economics* 7 (Spring): 207–31.

Garver, L. L. 1966. "Effective Load Carrying Capability of Generating Units." *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-85 (August):910–19.

Kahn, A. E. 1971. *The Economics of Regulation*. In 2 vols. New York: Wiley.

Koger, R. K. 1980. "The Question about Load Management: Not If, But When and How?" *Public Utilities Fortnightly*, January 31, pp. 13–20.

Meyer, M. B., and P. L. Chernick. 1980. "Joint Testimony on Behalf of East Texas Legal Services." Filed with and presented to the Texas Public Utilities Commission in *Gulf States Utilities*, PUCT Docket No. 3298. August.

National Association of Regulatory Utility Commissioners. 1973. *Public Utility Cost Allocation Manual*.

NEPOOL Planning Committee. 1977. "New England Base Load Generation Study: 1980/81 to 2000/01." February.

New England River Basins Commission. 1980. "Potential for Hydropower Development at Existing Dams in New England." January.

Vardi, J.; J. Zahavi; and B. Avi-Itzhak. 1977. "Variable Load Pricing in the Face of Loss of Load Probability." *Bell Journal of Economics* 8 (Spring):270–87.

Wenders, J. T. 1976. "Peak Load Pricing in the Electric Utility Industry." *Bell Journal of Economics* 7 (Spring):232–41.

APPENDIX C:

RELATIONSHIP OF LOSSES, INPUT, AND OUTPUT

Appendix C

As shown in Figure C for a simplified circuit:

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

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

V_o is constant, as is R_L

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

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

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

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

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

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

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

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

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

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

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

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

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

where L = losses ÷ input

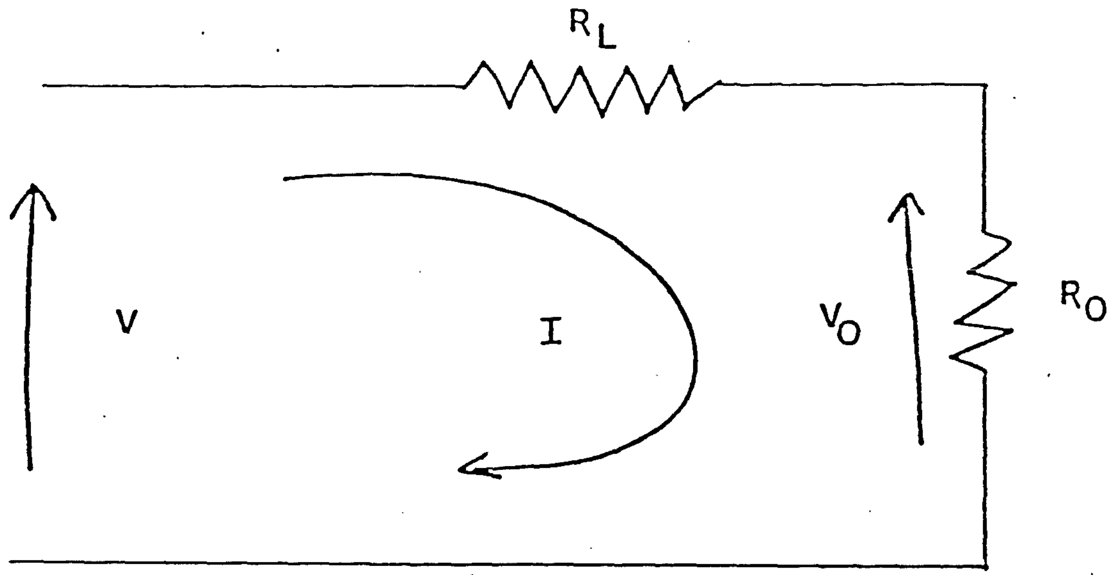


FIGURE C

Appendix D

LOAD FACTOR EFFECTS ON TRANSMISSION AND DISTRIBUTION PLANT

D.1 THE EFFECT OF LOAD FACTOR ON UNDERGROUND TRANSMISSION LINE SIZING

Table D-1 displays the extrapolation of the load factor effect to a zero load factor. The data are for 138kv 1250kcm cable in pipe, from EEI (1957), p. 10-51, a common utility installation. The ampacity at zero load factor is estimated at 1.569 times that at 100% load factor for one pipe, and 1.711 for two pipes. Transmission lines are assumed to be designed for 100% load factors. Underground transmission lines frequently have more than one circuit, in some cases four or five circuits, so averaging the two-pipe and one-pipe ratios seems reasonable. The average ratio is 1.640, indicating that only 61.0% of transmission capacity is necessary to meet peak.

D.2 EFFECTS OF OFF-PEAK LOADS ON TRANSFORMER SIZING

There are four ways in which energy use determines the sizing, and hence the cost, of transformers. The first two factors are closely related to one another: the length of the peak period and the load factor on the transformer. The third factor is the cost of the energy lost in the transformer. The fourth factor is the effect of periodic overloads on useful transformer life. Thus, the installed cost of transformers is affected by energy use during both the peak hour and other hours.

First, required transformer sizing decreases as load factor and length of the peak period decrease. Normal utility practice, which assumes high load factors and long peak periods, sizes transformers to avoid loads above the rated capacity. Typically, transformers on a radial underground system would be sized so that they are 100% loaded at peak. Transformers on the networks might be sized so as to be 120% loaded at peak under a first contingency (i.e., the failure of one of the feeders to the network). (see Fink, 1978, p. 17-4).

But lower daily load factors and shorter peak periods permit higher loadings, as illustrated in Westinghouse (1964, Ch. 5) and Fink (1978, Ch. 17). Short peaks and low off-peak currents allow the transformer to cool between peaks, so that it can tolerate a higher peak current. The limit for very short-duration load is generally stated as 200% of rated capacity (Fink, 1978, p. 17-40).

Thus, for every kva of peak load, a utility might install 1 kva of transfomer on the underground radial system. For the networks, 0.83 kva of transformer is installed per kva of first-contingency load. But in either case, only 0.5 kva of transformer would be necessary to meet the brief load (generally 30 minutes) which is the basis for most demand charges and demand allocator, were it not for the neighboring hours of high utilization and the relatively high off-peak loads on peak days. Thus, even considering only system reliability at peak, only 50% of the UG radial transformer capacity, and 60% of the network transformer capacity, can be attributed to the single-hour peak load.

Factors other than these system reliability issues may influence the sizing of transforners. Transformers may also be sized to reduce internal losses, both of energy and of peak demand. A utility would generally estimate the cost of peak demand losses per kw lost in line transformers on system peak as the sum of the annualized marginal cost per kw of peaking generation, transmission, and primary capacity. The energy loss cost per kw of peak losses is

$$\text{cents/kwh} \times 8760 \times LSF$$

where LSF is the loss factor (Fink, 1978, p. 18-103). The loss factor is itself a function of load factor (LF):

$$LSF = a \times LF + (1-a) \times LF^2.$$

The value of a is variously estimated at 0.15 to 0.30 (Op. cit.; EEI, 1957, p. 10-13).

Utilities generally estimate primary, transmission and production marginal demand costs in the \$50-\$100/kw-year. The average short-run marginal energy cost for the oil-fined systems are in the range of 4-6 cents per kwh, with higher costs occurring at higher load levels. At a 65% system load factor, LSF is .457 to .491, and the value of energy losses is 170 to 258 per kw of peak losses. Most line transformers do not experience load factors quite as high as the system load factor, but the correlation between hourly energy cost and hourly losses balances any over-statement of load factor. Thus, energy losses are more important than demand losses in decisions to upgrade line transformers for loss reduction, given typical estimates of loss costs.

Energy use is also reflected in service life considerations. Any first-contingency loading of network transformers in excess of the transformer's rating results in a reduction of service life for each such incident. For example, a 120% first contingency loading results in a service life reduction of about 0.25%, from the values in Table 17-12 to Fink (1978), and on p. 114 of Westinghouse (1964), which approximate 120% loading for eight hours.

Since there are many hours of the year when the network is at or near full loads, first contingencies will frequently cause overloading. Thus, only a very small loss of service life is acceptable per overload.

If the only high-demand hour was the one on which the peak allocation is based, the chances of a first contingency coinciding with the peak would be small, and most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life. Thus, to the extent that transformers are sized to prolong their useful lives, energy use plays an important roles in these decisions.

Overall, it seems reasonable to classify 50% of line transformer plant investment as energy-serving. The reliability analysis suggests that 40-50% is energy serving, while the cost of losses suggests a 60-80% classification to energy. This classification probably understates the energy-related portion of line transformer investment.

Substation transformers will generally experience higher load factors than line transformers, due to load diversity and economic dispatch. In addition, substation transformers are apparently not sized in expectation of over loads, as are network transformers. Substation transformer demand losses (as assessed in general utility practice) are also lower, since they are above the primary system (and in some cases above part of the transmission system). Hence, classifiying 55% of substation plant to energy appears to be appropriate.

D.3 THE EFFECT OF LOAD FACTORS ON PRIMARY CONDUCTOR SIZING

Underground cable sizing appears to be controlled by long-term overheating considerations. High loads can be tolerated after short periods, if the cable can cool fully between loads. For example, Figure 10-28 in EEI (1957), pp. 10-31, shows typical primary cables (350 and 5000kcm, 12kv, 3 conductor, paper-insulated) reaching about 35% of their steady-state temperature in 30 minutes, and essentially 100% of steady-state temperature in 8 hours. Hence, all other things being equal, an eight-hour peak load would cause about 2.86 times (1/.35) as much cable heating as a half hour needle load at the same wattage loss rate in the same cable. Alternatively, the wattage loss rate could be 2.86 times as great in the half-hour peak, and yet cause no more heating than is experienced in the eight hour peak. Since losses are proportional to the square of the current, the half-hour peak would allow 1.69 times (= $2.86^{1/2}$) the current for the same peak temperature. Hence, only about 59.2% (1/1.69) of the cable capacity would be required to accommodate a half-hour peak.

A second method utilizes Table XXXVIII, p. 10-47 of EEI (1957), which gives the ampacities for comparable cables from #4 TO 750 kcm, at 50% to 100% load factor, and with one to twelve cables per duct bank. Extrapolating the load factor effect back to zero allows the determination of the ratio of ampacities at zero load factor and 75% load factor (a standard assumption). These calculations are presented in Table D-2. The simple average of the four ratios is 1.395. (The actual mix of primary lines varies between utility systems.) Thus, the existing cables could carry about 40% higher peak, if not for the loads in other hours.

The linear extrapolation in the second method may be quite conservative. However, averaging the two results would classify 65.4% of primary line capacity as demand related, and the remaining 34.6% as energy related.

BIBLIOGRAPHY

1. Edison Electric Institute, Underground Systems Reference Book, prepared by an Editorial Staff of EEI Transmission and Distribution Committee, EEI 55-16, New York, 1957.

2. Fink, D.G. and Beaty, H.W., eds. Standard Handbook for Electrical Engineers, (New York: McGraw-Hill, 11th ed., 1978).

3. Westinghouse Elecric Corp., Electrical Transmission and Distribution Reference Book, Fourth Edition, prepared by Central Station Engineers of Westinghouse, East Pittsburgh, 1964.

# of pipes					
	Loss Factor:	1.0	0.7	0.5	0.0
	Load Factor[a]	1.0	0.81	0.66	0.0
1	ampacity	650	701	760	1020[b]
2	ampacity	543	600	661	929[b]

Table D-1: Calculation of Demand Portion of 138kv Cables

Notes:

a. for Loss Factor = .3 (Load Factor) +.7 (Load Factor)$^{(2)}$

b. extrapolated linearly from ratings at 81% and 66% load factor.

Cable Size	Cables per Duct Bank	Ampacity Per Cable At Load Factor Of 75% (a)	50% (b)	0% (c)
#40	1	281	295	323
				(1.149) (d)
#4/0	12	83	96	122
				(1.470)
750 kcm	1	562	606	694
				(1.235)
750kcm	2	348	432	600
				(1.724)
average ratio				1.395

Table D-2 : Effect of Load Factor on Primary Cable Ampacity

Notes:
a. From Table XXXVIII, EEI (1957)

b. Extrapolated linearly from ampacities differences at 75% and 50% load factors.

c. Ratio of ampacities at 0% and 75% load factors.

Appendix E

Revenue Stability Target Ratemaking

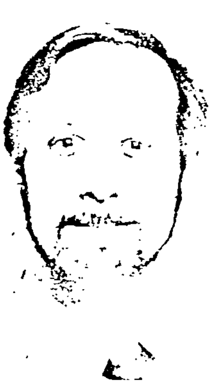
Revenue Stability Target Rate Making

By PAUL L. CHERNICK

The commonly used rate-making approaches necessarily base themselves on assumptions, vital to their success, about future levels of utility service sales. But since sales are a function of random variables beyond the control of the utility as well as actions by the utility itself, the resulting rates fail to protect the utility's revenue stream and its realized rate of return. This article proposes an alternative approach which would decouple utility revenues from sales, thus stabilizing revenue streams with respect to sales fluctuations and rate design changes. Among the benefits would be a lower cost of capital for the utility, as well as decreased utility resistance to conservation by consumers and to efficient rate design.

TRADITIONAL utility rate-making 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 rate-making 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 and inverted block rates.

This article suggests an alternative rate-making 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.



Paul L. Chernick is a research associate with Analysis and Inference, Inc., in Boston, Massachusetts, where his research and consulting work relates to various aspects of electric utility regulation, including rate design, cost allocation, load forecasting, capacity planning, and efficiency incentives. **Mr. Chernick** received an SM degree in technology and policy and an SB degree from the Massachusetts Institute of Technology. He has co-authored a report for the Nuclear Regulatory Commission on insurance for nuclear decommissioning

The article consists of four sections, other than this introduction. The first describes the pertinent aspects of current rate making, and enumerates the problems which result from current practice. The second outlines an alternative proposal, which I call revenue stability target rate making (RSTR). The third discusses the advantages and opportunities afforded by RSTR, while the fourth describes some of the possible drawbacks to this approach.

Current Rate-making 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 operations and maintenance, return, depreciation, and taxes). Second, the allowed revenues are allocated to the various customer classes to establish class revenue constraints, t_i, where

$$\sum_i t_i = T. \tag{1}$$

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

$$\sum_j r_j b_{ij} = t_i \tag{2}$$

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, kilowatt-hours, and kilowatts, perhaps distinguished by subclass, block, and other special provisions; e.g., high-load factor or high-voltage discounts.

It is the r_j which is 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 ($b^{\bullet}_{ij}$) in the rate year exactly equal the b_{ij} used in Equation 2 in the rate case, then

$$\sum_i \sum_j r_j b^{\bullet}_{ij} = T, \tag{3}$$

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 rate-making 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 kilowatt-hour, 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:

$$E = \sum_i \sum_j r_j b^{\bullet}_{ij} - X. \tag{4}$$

Earnings are typically about 10 per cent of revenues. Income taxes are approximately equal to earnings (at least at the margin) and vary directly with them. Thus, if earnings are 10 per cent of revenues, both earnings and income taxes would be eliminated by a 20 per cent 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 rate setting 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 rate-making 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.

---

[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 kilowatt-hours).

[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 per cent) of demand in a previous time period (often a year).

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 innermost energy blocks — e.g., 0-50 kilowatt-hours per 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) kilowatt-hour 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 undesirable, 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 rate-setting process increases the riskiness and cost of utility equity; discourages utility participation in conservation and rate redesign; 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.

Redesigning the Rate-making 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 rate making (RSTR or ReSToRe) 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

$$\Sigma_i \Sigma_j \, r_j \, b_{ij} = C. \tag{5}$$

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 per cent 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 (nonfuel) rates, and

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

where N is nonfuel 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 kilowatt-hour output. Thus, if sales increase, the revenue target rises to cover the associated increase in fuel expense.[8]

Some Advantages of RSTR

RSTR should directly correct several of the problems discussed in the early part of this article. Utility resistance to conservation programs (and rate reform) should

[7] The block which serves as the tailblock will vary between customers. In general, however, a higher percentage of the kilowatt-hours 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.

[8] A similar, but more limited, approach was suggested in 1979 rate design testimony by the author and Susan C. Geller on behalf of the Massachusetts attorney general (MDPU 19845). Due to the uncertainty in the time-of-use billing determinant, we suggested a form of RSTR in which *T* is the revenues which would have been collected under conventional rates at the actual billing determinants. Hence, both the utilities and the customers are protected from errors in billing determinant estimates and from the load shifting induced by the rate design change.

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 size of the actual buffer can be controlled in several ways. In a revenue-neutral approach, the size of the buffer at the time of each rate case would determine the provision for replenishing the buffer in the new rates. If the buffer were small, C would be set well above T, to continue (or even accelerate) the accumulation of a buffer. If the buffer is sufficiently large, C would be set equal to T, so that accumulation stops. And if a series of years with bad weather and good economic activity create an unnecessarily large buffer, it can be drawn down by applying the interest and a portion of the principal to the rate-year cost of service.

The basic alternative to a revenue-neutral approach is a process of continuous targeted buffer accumulation, with the surplus (when sales create one) returned to the customers or used for their benefit. For example, 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, periodically 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 occurrence 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 usual 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 adjustments simplifies the customer's bill and increases the comprehensibility of the rate design and of the affect of consumption on the bill size.[9]

The Disadvantages of RSTR

The primary disadvantage of an RSTR system is that, like any other rate-making innovation, its implementation may conceal many other de facto changes in rate-making 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,

[9]The revenue adjustment mechanisms (RAM) recently approved for Pacific Gas and Electric Company and for Southern California Edison Company and requested by Niagara Mohawk Power Corporation face several of these problems, even though they promote revenue stability, not cost indexing. They are retrospective adjustments, suffering from regulatory lag; the revenue lost in a low-sales period may well be recovered by higher rates in a high-sales period. Customers' rates must vary as the adjustments are added to their base rates and fuel charges. The complexity and confusion resulting from RAM may have contributed to the California Public Utilities Commission's decision to apply RAM only when sales deviate more than 5 per cent from the forecast; the California RAM provides protection against massive revenue shortfalls, but not against small variations in sales

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 shortfalls by the size of the buffer: A utility which abruptly loses half its sales will still be in trouble.[10] 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 an 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.

[10]This problem can be ameliorated by allowing the RSTR buffer to go negative, to be replenished in subsequent rate cases. Thus, the utility is assured of eventually receiving its allowed revenues, although its cash flow may still be problematic.

Bright Future for Coal in Europe and U. S.

Coal producers in despair over the current recession should take heart: The prospects for long-term growth in demand are as good as ever. Not only will coal displace gas and oil, its traditional source of demand growth since 1974, it will also gain a substantial fraction of the new electric generation market from nuclear. This is the conclusion of a recent National Economic Research Associates, Inc., study which compared the economics of electric generation among various fuels in both the U. S. and Western Europe. Using a detailed statistical analysis of existing power plants, the study shows that new coal-fired electricity costs are much lower than those for oil and only slightly higher than those for nuclear.

With such a small cost disadvantage over nuclear, many utilities will opt for coal for two reasons. First, nuclear power costs are highly uncertain — they tripled from 1974 to 1980 — and a small increase would easily erase its current advantage over coal. Second, a nuclear generation plant exposes a utility to large financial risks because of the high capital costs and the long lead time required for construction. Conversely, coal-fired capacity can be added quickly in small, low-cost increments.

NERA forecasts 1990 U. S. utility coal demand to be 734 million tons representing a 29 per cent increase over 1980 levels. For Western Europe, NERA forecasts 1990 utility coal demand of 336 million tons, which is 33 per cent over the 1980 amount.

Copies of the study, "The Current Economics of Electric Generation from Coal in the U. S. and Western Europe," can be obtained free of charge from Kensington Associates, Inc. (645 Madison Avenue, New York, New York, 10022).