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COMMISSION TREATMENT OF OVERCAPACITY IN THE ELECTRIC POWER INDUSTRY

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EXECUTIVE SUMMARY

Many regulated U.S. electric utilities today have generating capacity well in excess of that needed to meet annual peak loads and assure reliability. In this report, the principal options open to state utility regulators for dealing with overcapacity are set out and examined.

A difficulty for regulators is that there is no hard and fast rule on how much capacity a utility needs. Ideally, capacity would be added until the cost of any more capacity outweighs the benefits of improved reliability. In practice, however, these benefits are difficult to quantify. As a result, most utilities and state utility commissions select a measure of proper reliability level, usually reserve margin or capacity margin, as an indicator of the appropriate amount of capacity. Conventional wisdom is that a 20 percent reserve margin is appropriate for the typical U.S. utility, but adequate reliability may be achieved at a higher or lower level of reserves depending on the circumstances and practices of the utility.

In 1982, the reserve margin for the U.S. as a whole (calculated from the aggregate of U.S. summer non-coincident peaks and the U.S. aggregate installed capacity) reached an all-time high of 57 percent. Not counting installed capacity unavailable for generation during the peak, the 1982 reserve margin still was at an all-time high value of 39 percent. High levels of reserve exist in all reliability regions throughout the nation, except for the California-Southern Nevada area. Higher than normal reserve levels are expected to exist in most regions over the next ten years--though this depends both on electric demand growth rates and on whether current utility construction plans are carried out.

Overcapacity is essentially a mismatch between the supply of generation capacity and the demand for generation capacity. If a utility requests full rate base treatment of all generating capacity and the commission finds that not all of it is useful, two sets of options for treating this overcapacity are available to regulators. One set involves controlling the supply of capacity permitted in utility rates. Unneeded capacity can be fully excluded from rate base, partially excluded, or fully included. If it is assumed that the demand for electricity and the demand growth rate are beyond the control of the utility and the commission, then these supply options are the only ones available. A second set of options is based on the assumption that utility and commission policies do have a substantial effect on the level of demand. Then, it may be possible to include all capacity in rate base and to stimulate demand sufficiently to utilize much of that capacity.

A commission may want to adopt a policy combining a supply option that limits the amount of capacity in rate base and a demand option designed to increase electricity sales. But, for purposes of examining the effects of these options separately, it is assumed here that supply options leave demand unaffected and that demand options can be attempted independently of the rate base treatment of the extra capacity.

Three effects that are important to regulators are examined for each option. First is the effect on the price of electricity faced by the customer. Ideally, the option selected by the commission would result in a price equal to the minimum cost of supplying electricity with the appropriate level of reliability. Negative effects on the economy are eliminated if the price is the correct, or economically efficient, price.

Second, the fairness with which the financial burden of extra capacity is allocated among various customer groups is examined. Specifically, the fairness, or equity, among customer classes and the equity between present and future generations of customers are of concern.

Third, the effects of each option on the financial stability of the company are examined. These effects include the effect on investors and their ability to earn an appropriate return on their investment, the effect on the utility's cost of capital, and the effect on the reliability of service to customers where an option results in such poor cash flow that certain ordinary operating and maintenance activities may be curtailed.

Several other important regulatory concerns that may apply to all options are not explicitly taken into account in the option-by-option examination. These include the cause of overcapacity and in particular whether it resulted from an oil-backout program, the fuel cost savings resulting from the newest capacity, the effects of an option on energy conservation and on the state's economy, and the proper allocation of risks and rewards between a utility's customers and its investors. However, these concerns may be taken into account by regulators as they choose among options.

In order to illustrate the options and to obtain a quantitative assessment of the price and financial effects of the options, a hypothetical typical utility is derived, which has generation, capacity, and financial characteristics based on recent average data for all U.S. class A and B electric utilities.

The principal options considered and their effects are summarized in table ES-1. The first column of the table lists the options with abbreviated names, and the second column gives a brief description of each option. The right-hand side of the table gives a summary rating of the three effects of each option, with +2 being the most desirable effect under each criterion and -2 being least desirable.

Of the supply options, one would expect that full exclusion of excess capacity would have the worst effect on the financial stability of the company. In fact, this is the case where the newest, most expensive capacity is denied rate base treatment. In the typical utility example, this option results in default on payments to creditors. But, if the new plant is used for base load power and all the excess capacity is associated with the older plants that are last in the loading order (and hence are never used in an overcapacity situation), then the company's resulting financial position is very strong. However, in this case the rates faced

TABLE ES-1

PRINCIPAL REGULATORY OPTIONS FOR TREATING OVERCAPACITY AND THEIR RATINGS AGAINST THREE CRITERIA

Option	Description	Ratings Against Three Criteria: Effect on Customers; Correct Price; Economic Efficiency	Interclass and Intergenerational Equity	Financial Stability; Reliability of Service
SUPPLY OPTIONS				
Full Exclusion				
New Plant	newest unit excluded from rate base	+2	+2	-2
Least Efficient	least efficient units excluded from rate base	-1	-1	+2
Average Plant	excess capacity excluded at average cost of capacity	+1	0	+1
Partial Exclusion				
50% of New Plant	half the newest unit excluded from rate base	+1	0	-1
2:1 Cov. Ratio	rates are set so that interest coverage ratio equals 2	-1	-1	0
Graduated	amount of exclusion tied to severity of overcapacity	-1	-1	+1
Equity Only	return on only equity portion of plant excluded	+1	0	-1
Constant Revenues	revenue requirement is unchanged	+2	0	-2
Imputed Sales	revenues spread over kWhs for full capacity use	+2	0	-1
Carrying Costs	part of excess capacity carrying costs are excluded	N.A	N.A.	N.A
Full Recovery				
Traditional	all capacity included in rate base in traditional manner	-2	-2	+2
Phase-in	capacity phased into rate base with full recovery of value	-1	0	+1
Trending	new capacity included with mortage-type depreciation	-1	+2	+1
DEMAND OPTIONS				
Bulk Power Sales	extra capacity used for sales to other utilities	+1	0	+1
Price Reduction				
Flat Reduction	all rates for all customer classes are reduced	+1	+2	-1
Time-of-Use	off-peak, industrial rates are reduced	+1	+1	+1
Marketing	create marketing office & strategy; advertise	+1	0	+1

Source: Text of the report.

Legend: substantial, negative effect = -2; moderate, negative effect = -1; little or no effect = 0; moderate, positive effect = +1, substantial, positive effect = +2.

N.A. = the ratings were not applied to this option--the ratings would depend on the amount of the excluded carrying cost.

by customers are almost as high as if no capacity were excluded from rate base at all. An alternative is to exclude excess capacity at the average cost of the system's capacity. This produces price and financial effects intermediate to those of the first two options. Hence, even with full capacity exclusion a broad range of effects is attainable.

Furthermore, the effects on price and financial stability depend importantly on commission treatment of expenses associated with excluded capacity. The newest unit--or that portion of the newest unit's capacity which exceeds reserve requirements--may be excluded from rate base, but the utility will probably use the unit regardless. In this case, variations in regulatory treatment of depreciation, fuel costs (and fuel cost savings), other operating and maintenance expenses, and property taxes permit a regulator who so desires to tailor the effects to the circumstances of the utility. It is important to note that the ratings in table ES-1 may change as the treatment of these expenses changes.

Instead of full exclusion of overcapacity from rate base, regulators may opt for exclusion of only a portion of the excess plant. This may be desirable in order to apportion the cost burden between ratepayers and stockholders in a particular way, either to reflect the degree of management responsibility for the excess, to achieve more precisely the desired price and financial effects, or for some other reason. A variety of partial exclusion approaches is, of course, possible; some of the more logical ones are listed in the table and include the following: excluding a fraction (such as half) of the excess capacity; excluding just enough capacity so that the company's interest coverage ratio does not go below two; varying the fraction of excess capacity excluded in a graduated manner so that the greater the reserve margin, the greater the fraction excluded; excluding from rates all the return on the equity associated with excess capacity while allowing return on associated debt; and including just enough excess new plant in rate base so that the increase in return balances the fuel cost savings, leaving the revenue requirement unchanged.

Clearly, the effects of such options on customers and on the company depend on the circumstances of the utility. In the typical utility example examined here, holding the revenue requirement constant has the best price effect among the options mentioned and the worst financial effect. Because the utility in this example does not have an extremely high reserve margin, the option of graduated exclusion is the most financially favorable of the partial exclusion options.

Two other partial exclusion options deserve special mention because they do not exclude a fraction of excess plant from the rate base and yet do not provide for full utility cost recovery. One is the imputed sales approach. Here it is assumed that the utility will realize a volume of kilowatt-hours sales and a level of kilowatt demand sufficient to use all the installed capacity, with proper allowance for reserves. These imputed sales are more than the sales actually expected. All capacity is included in rate base, but the resulting revenue requirement is spread over the imputed sales volume, yielding lower prices. Applying these lower prices to the actual kilowatt-hours expected to be sold results in a revenue shortfall, which is here considered equivalent to a partial exclusion of capacity. This option results in an economically efficient price with a less severe effect on company finances than full exclusion of new capacity. It also permits automatic increases in revenue as sales improve without the need for periodic rate hearings to determine how much excluded capacity should be admitted to rate base.

Another option for commissions is to take the view that there is no excess capacity, only premature capacity completed before the demand for it materializes. The treatment then may be to exclude all or a portion of the carrying costs from the time of completion to the time of need. A related option for commissions is to scrutinize construction delays and associated higher carrying cost for evidence of footdragging on plant completion while waiting for demand to catch up with supply. The extra carrying costs, if they can be identified, may be excluded from ratepayer reimbursment. (Because the effects of this option depend so heavily on the amount and time period of exclusion, rating this option is not possible.)

Also, among the supply options, a commission may choose to include all completed capacity fully in rate base. This decision may be based on the limited amount of overcapacity, the short time period anticipated before the capacity is needed, lack of management culpability, or some other reason. Still, there are several ways to provide for full utility cost recovery--three of which are listed in table ES-1. These are the traditional rate base treatment of capacity, some form of phase-in treatment, and rate trending. Rate trending spreads the recovery of costs evenly over the life of the plant, as opposed to the traditional approach, which recovers the most revenue in the early years. Such early recovery is particularly undesirable in an overcapacity situation because customers who need the new plant the least pay the most for it. Rate trending has a positive effect on intergenerational equity, as well as keeping the company financially sound.

Phase-in approaches depart from the traditional approach over the first few years only, then resume the usual revenue collection pattern. Phase-in, here, is not the gradual addition of plant to rate base (treated as partial exclusion), but a plan of full cost recovery through increasing revenues, with the net present value of the phase-in revenue stream equal to that under the traditional approach. As such, phase-in has a positive effect on the company's financial stability while avoiding some of the negative equity effects associated with a sudden, large increase in rates. However, later rates are higher than those under the traditional approach.

A major disadvantage of a sudden, large increase in rates is that it may drastically reduce the volume of sales so that the expected revenue requirement is not realized. Instead of raising rates to cover the costs of excess supply, regulators might consider options for stimulating demand--such as lowering rates. Among the demand options that merit consideration are promoting bulk power sales, price reductions, and marketing.

Bulk power sales are possible, however, only if there are imbalances in the system, that is, if one utility is short on capacity while another has overcapacity, or if one utility can produce and deliver electricity to another at a lower cost than the latter can produce power from its own equipment.

Also, the utilities must be interconnected. There are three major transmission networks in the United States: in the east, in the west, and in Texas. The three networks are not currently interconnected, but the regions and utilities within each one are intertied with connections of varying strength. There are currently some 57 interregional connections, with another 20 planned for the period 1983-1992. It is apparent that sufficient interconnections exist to make it feasible to sell the output from extra capacity to other utilities if the other conditions are met. The variation in production costs within each transmission network suggests that there is a great deal of room for bargaining, so that there should be no difficulty in agreeing on a price, assuming there is a need for electricity.

However, as mentioned, at this time all reliability council regions have more than enough capacity, except the California-Southern Nevada subregion. Therefore, bulk power sales within the western transmission network ought to be possible and, in fact, are being pursued. Sales within a region to a neighboring utility may be possible also at the present time.

More interregional bulk power sales to alleviate the overcapacity problem may be possible over the next ten years. However, if current construction plans are carried out and demand growth rates are moderate, in 1992 all the regions will have adequate, or more than adequate, generating reserves without purchases from other regions. Only if such plans are curtailed would significant interregional power transfers seem likely.

A problem for commissions with interregional exchanges is that most of the decisions on interconnections and on construction curtailments for utilities in other regions are outside of direct state control and may be difficult to foster. All things considered, an interregional market for the output of current excess plant, while desirable, is speculative and, at this point, should not be relied on by state commissions as a principal solution to the overcapacity problem except in special cases.

The main way to stimulate demand in the jurisdictional market is with price reductions. Table ES-1 lists two of the dozen price reduction options examined. These options are various combinations of reductions for all customers and reductions for industrials only; options with new capacity additions allowed and not allowed; options with rate reductions of 5 percent, ten percent, and others; and options with flat rate decreases and decreases in components of a time-of-use industrial tariff.

In addition, the options are examined not only for the typical utility but also for a larger utility to test sensitivity of the results to utility size. There are no significant differences in the results for the two utility sizes.

Two distinct pricing options are the flat rate reduction for all customers and the use of strategic time-of-use pricing to stimulate industrial demand. Both have a positive effect on economic efficiency in that prices are being lowered in response to an oversupply. Both have a positive intergenerational equity effect. The case of price reductions for all customers is preferred in terms of interclass equity. However, the time-of-use strategy for industrial customers results in better financial performance for the company over a period of years than a policy of no price reductions. This is not so with the flat reduction for all customers.

Increased effort at marketing electricity in the utility's service area is an option that rates well with regard to price and financial effects--assuming the beneficial effects of such marketing outweigh the costs of the program.

Overcapacity may be a problem for the next ten years or more, but it is not too early for utilities and commissions to consider ways to avoid such a problem in the future. One way is for utilities to reduce reliance on load forecasts, which drive most construction plans. Instead, utilities could aim toward flexibility in responding to an uncertain future load.

Flexibility in supply can be obtained by constructing smaller, modular units of base load capacity that can be built relatively quickly and by using more cogeneration and small power production for peaking needs. The additional unit cost of the smaller units can be viewed as an insurance premium against the possible waste associated with long-range forecasting and capacity planning. Improved coordination in capacity planning with neighboring utilities and improved interconnection within and among regions would increase supply flexibility also.

Flexibility in demand is also achievable through seasonal and time-of-day pricing, load management devices, and interruptible rates. These tools permit the utility to plan capacity additions more conservatively because if supply proves inadequate the means of controlling demand are available.

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Foreword

The bylaws of The National Regulatory Research Institute state that among the purposes of the Institute are:

> ...to carry out research and related activities directed to the needs of state regulatory commissioners, to assist the state commissions with developing innovative solutions to state regulatory problems, and to address regulatory issues of national concern.

This report helps meet those purposes, since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with electric utility regulation.

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Director
September 26, 1984

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CHAPTER 1

THE OVERCAPACITY PROBLEM

In 1984, many regulated U.S. electric utilities face capacity-related problems, particularly that of having generating capacity well in excess of that needed to meet annual peak loads and assure reliability. In this report, the options open to regulators for dealing with this overcapacity are set out and examined.

The Nature of the Problem

Because several related issues are facing state commissions at the time of this writing, it is important to note what our study does and does not attempt to do. There are several serious problems related to overcapacity that are outside the scope of this present report. One is plant abandonment, where a utility cancels a plant under construction for overcapacity or financial reasons and where a state commission must decide how to treat the costs of the abandoned plant. A special case of plant abandonment involves large units that are substantially completed. In this case, commission decisions may mean the difference between utility survival and bankruptcy, and such decisions, of course, pose a special problem in cost allocation for commissions--a problem we do not attempt to treat here. Still further afield from the focus of this particular study is how commissions can or must deal with the courts, receivers, and new owners in the event of bankruptcy or receivership.

Another problem not explicitly treated here is so-called "rate shock," a sudden large increase in rates caused by the addition of a large generating facility to rate base. If, in the opinion of the commission, the addition does not result in overcapacity, the rate shock problem is outside this study. However, some of the options covered here for treating overcapacity may also be useful for the rate shock problem. These problems are, of course, related in that it is more difficult for a commission to permit a utility to add a plant to rate base that would not only result in overcapacity, but in rate shock as well. The solutions, however, are distinct. For example, some utilities have argued that including the cost of construction work in progress (CWIP) in rate base is a solution to the rate shock problem. Be that as it may, it would not address the overcapacity problem if the plant additions resulted in an unacceptably high level of reserves. In this report, the CWIP versus no-CWIP issue is treated neutrally, that is, commission options for treating overcapacity are discussed for commissions that allow CWIP and for those that do not.

Still another problem is the degree of utility responsibility for the overcapacity situation. Overcapacity may have resulted from mismanagement, imprudent judgement, industry-wide miscalculation, government policy, economic circumstances, bad luck, or some combination of these reasons. How to determine the prudence of management is an important question, but one that would take us on an extended tangent here. The prudence question is related to, but separable from, the overcapacity question. An NRRI report on the prudence question was developed in parallel with this overcapacity report, and the two reports are being published at about the same time. However, in chapter 4, we discuss the factors that may affect a commission's choice among the options, and one such factor is the degree of utility management responsibility for the particular utility's overcapacity situation.

This report on overcapacity deals with the options available to commissions for treating existing excess electric generating plant. It does not deal directly with options for treating plant under construction that may become excess capacity when in service; however, the companion report on the prudence of management treats this plant abandonment issue extensively. Also, this report does not deal explicitly with gas utility overcapacity or electric transmission and distribution overcapacity, although in principle the options available to commissions are the same.

Commissions face the overcapacity question in two ways. In one, generating plant currently in rate base is in excess of needs due, for example, to a decline in sales. More likely, an overcapacity situation that was intended to be short term has become long term because the growth in sales is slower than expected. On the other hand, capacity currently in rate base may be adequate or nearly adequate, but a new plant coming on line may not be needed at present. Commission treatment here may differ from that in the first case. In principle, treatment of overcapacity in these two cases could be the same regardless of the context. In practice, commissions are often reluctant to exclude from rate base capacity that was once approved as used and useful. For example, in the case of excess natural gas distribution capacity during the gas curtailments of the mid-1970s, some commissions had a capacity factor adjustment clause to recover from served customers the carrying cost of capacity unused by curtailed customers. An important aspect of this policy was commission expectation that the situation would be short lived. New and unneeded capacity entering the rate base is another story.

Defining Excess Capacity

Commissions, by law, must include "used and useful" capacity in the rate base and exclude both unused capacity and capacity that is not useful, so-called excess capacity. Typically, the legislature and the courts allow commissions a good deal of discretion in determining what represents excess capacity. Most commissions have avoided hard-and-fast rules on how much generating capacity an electric utility needs. Clearly, as a minimum it needs at least as much as that required to meet its peak demand of the last 12 months--assuming, of course, that purchased power is undesirable for cost or reliability reasons.

A utility, however, almost always needs more than that required in the previous year for several reasons. Demand in the current year will probably be greater. With the exception of 1982, U.S. electric sales and peak loads have increased every year--before 1973 at a rate of about seven percent each year, doubling every ten years. Since 1973, of course, sales growth has been much less. Also, peak demand is subject to variation because of severe weather, economic activity, and the statistical fluctuations to be expected from any group of voluntary customers. More importantly, on the supply side, a utility needs capacity in excess of expected demand in case some capacity is unavailable. This unavailability may be due to a unit outage, derating of a unit, maintenance, NRC-ordered derating in the case of a nuclear unit, or low water conditions in the case of a hydroelectric unit. In short, generating capability is less than installed generating capacity.

Consider recent national data on capacity, capability, and peak load shown in table 1-1. The first four columns of table 1-1 provide some information on the difference between installed capacity and summer peak capability. The first column lists all the years, for which data are available, during which the national non-coincident summer peak load exceeded the national non-coincident winter peak load. A national seasonal non-coincident peak load is the sum of the seasonal peak loads of all U.S. utilities, where these individual peak loads occur at various times during the season. The second column contains the sum of the installed generating capacities of all U.S. utilities: investor-owned, cooperatives, and governmental utilities. The third column contains the sum of the (presumably non-coincident) generating capacities of all utilities at the times of their summer peaks, and the fourth column expresses this total capability as a percentage of installed capacity.

Summer capability as a percent of installed capacity declined from 98 percent in 1964 to 89 percent in 1982. One must be careful in drawing conclusions from this statistic about the capability (as a percent of capacity) for individual utilities. Many utilities have winter peak loads greater than summer peak loads, so that planned summer maintenance results in reduced capability during the national peak season, summer. This tends to lower the national percentage reported here. However, the trend over the last two decades has been for summer air conditioning loads to convert more and more utilities from winter-peaking to summer-peaking systems.

TABLE 1-1

TOTAL U.S. ELECTRIC INDUSTRY INSTALLED GENERATING CAPACITY, SUMMER CAPABILITY, NON-COINCIDENT SUMMER PEAK, AND RESERVES FOR YEARS WHEN SUMMER PEAK LOAD EXCEEDED WINTER PEAK LOAD[a]

(1) Year	(2) Installed Capacity (GW)	(3) Capability At Time Of Summer Peak Load[b] (GW)	(4) Capability As A Percent Of Installed Capacity	(5) Non-coincident Summer Peak Load (GW)	(6) Reserve Margin[c] Based on Installed Capacity (%)	(7) Reserve Margin[c] Based On Capability (%)
1982[d]	650	578	89	415	57	39
1981	635	572	90	428	48	34
1980	614	559	91	427	44	30
1979[e]	598	545	91	398	50	37
1978[e]	579	546	94	408	42	34
1977	560	516	92	396	41	30
1976	531	499	94	371	43	35
1975	508	479	94	357	42	34
1974	476	444	93	349	36	27
1973	440	416	95	344	28	21
1972	399	382	96	319	25	20
1971	369	353	96	292	26	21
1970	341	327	96	275	24	19
1969	313	300	96	258	21	16
1968	291	279	96	238	22	17
1967	269	258	96	213	26	21
1966	248	241	97	203	22	19
1965	236	229	97	186	27	23
1964	222	217	98	175	27	24

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry 1982 (Washington: EEI, 1983), pp. 8 and 14.

[a] The data available for installed generating capacity apply to all 50 states, but the data for capability and non-coincident summer peak load apply only to the contiguous 48 states excluding Alaska and Hawaii. In 1982, the installed capacity in Alaska and Hawaii was less than one-half percent of the U.S. total. Assuming this proportion is valid for prior years, the percentages reported here are correct to two significant figures as shown. (However, rounding could change the reported figure; e.g., a reserve margin based on installed capacity of 29.60% is reported here as 30%; if Alaska and Hawaii were included, the correct figure would be about 29.47%, which would be then reported as 29%.)

[b] Capability represents the maximum kilowatt output with all power sources available and with hydraulic equipment under actual water conditions. It must, therefore, provide the necessary allowance for maintenance, emergency outages, and system operating requirements. This rating is more indicative of the actual generating ability of existing power stations than the familiar name-plate rating reported as installed capacity.

[c] Reserve margin = ((Capacity ÷ Peak Load)-1) x 100%. See text for discussion of what these reserve margin data do and do not represent.

[d] Except for installed capacity, 1982 data are preliminary.

[e] Except for installed capacity, all data series shown here have a discontinuity between 1978 and 1979 because EEI switched data sources.

Also, the non-coincident summer peak load (reported in the fifth column of table 1-1) as a percentage of the non-coincident winter peak load (not reported) increased from 102 percent in 1964 to 117 percent in 1973, and declined to 111% in 1982. The overall net increase in summer loads over winter loads suggests that, absent other factors, summer capability as a percent of installed capacity ought to have increased from 1964 to 1982. Instead, it decreased.

The decline in summer capability may have been due initially to reduced maintenance on derated older units, once used for peaking, as oil and gas burning peaking units came into common use in the mid-1960s. Since the mid-1970s, the use of peaking turbines has declined, and old units are once again retained for peaking purposes. A large population of older units could also account for the decline in capability. As a unit ages it often cannot be operated at full nameplate capacity without extensive costly refurbishing. It may be more economical, for example, to retain an old coal unit for use at less than full capacity for meeting peak period loads than to purchase an oil-burning peaking unit for the same purpose. This is especially true if the unit is near or at the end of its depreciation life and makes little or no contribution to the value of the rate base. In such a case, the more important goal of cost minimization takes precedence, of course, over the less important goal of maintaining attractive statistics on capability as a percent of installed capacity.

Another possible, related explanation for the decline in capability is that some utilities have been able to extend the useful service lives of older units--in some cases from a projected 30-year life to 40 years or more. Capability is lowered when the utility takes an older unit off-line to rebuild it. Even though older units have poorer fuel efficiency and often higher outage rates, increasing costs of new units may make it more economical to keep a group of fully depreciated older units than to build new capacity to meet intermediate and base loads. Such higher outage rates could also account for lower utility capability as a percent of installed capacity.

The statistic most frequently used by utilities and regulatory commissions to determine whether utility generating capacity is adequate is the reserve margin. Reserve margin is the percentage by which the installed capacity exceeds the annual peak demand. Recently, many utilities have preferred to use a related statistic, capacity margin, to convey the same information.[1]

In table 1-1, the fifth column contains the U.S. non-coincident summer peak load. A statistic akin to a U.S. reserve margin can be calculated from columns 2 and 5. This statistic is listed in the sixth column. This is not a true national reserve margin, as if the U.S. were dispatched as a single system, which would be based on the coincident summer peak load and result in a higher percentage in column 6. Nor is it an average of all U.S. utilities' reserve margins, which would be based on winter loads for winter peaking utilities and result in a lower percentage in column 6. Such an average would be interesting, but the data needed to calculate it are not available. The reserve margin in column 6 conveys information about the weighted average amount of reserves for all U.S. utilities, both summer and winter peaking, at the times of their summer peaks.

This reserve margin increased from 27 percent in 1964 to 57 percent in 1982.[2] For the ten-year period 1964 through 1973, it averaged 24.8

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[1]For example, if a utility has an installed capacity of 12,000 MW and an annual peak demand of 10,000 MW, the reserve margin is the amount of reserve (2000 MW) expressed as a percentage of the peak load (10,000 MW), or 20 percent. Capacity margin is the amount of reserve (2000 MW) expressed as a percentage of installed capacity (12,000 MW), or 16.7 percent. The smaller number may be more attractive but contains no new information. To convert a capacity margin (C) to a reserve margin (R), use the equation $R = (100 \times C) \div (100 - C)$. That is, if the capacity margin is 16.7 percent, the reserve margin is $(100 \times 16.7) \div (100 - 16.7) = 20$ percent.

[2]In 1963, when the non-coincident winter peak load exceeded that for summer, the reserve margin based on installed capacity and winter peak was 31 percent. It seems likely that capacity was being installed to meet the growing summer peaks, causing a surge in reserve margin. The comparable 1962 reserve margin was 26 percent.

percent. During this same period, as mentioned, there was an overall net increase in summer loads over winter loads, which tends to lower the column 6 reserve margin figure. From 1974 though 1982, it averaged 44.8 percent. This higher average is due in part to the decline in summer loads relative to winter loads. Nevertheless, the net increase in relative summer loads from 1964 to 1982 suggests that, all other factors remaining constant, the reserve margin of column 6 ought to have declined. Clearly it did not.

One reason for the increase in reserve margin based on installed capacity is the decrease in capability as a percentage of installed capacity (column 4). To the extent that some installed capacity is not expected to be available at the time of the system peak load, reserves must be increased to allow for this supply-side unavailability as well as for surges in customer demand. In column 7 of table 1-1, a reserve margin based on capability, calculated from columns 3 and 5, is presented. The data show that allowing for a decrease in percentage capability does not wholly account for the increase in column 6 reserve margin; if it did, the column 7 figure would be constant over time. Instead, it increases from 24 percent in 1964 to 39 percent in 1982. It averages 20.1 percent during the 1964-1973 period and 33.3 percent for 1974-1982.

As a state commission judges the appropriate amount of generating capacity for a particular utility, it normally takes into account these factors just described nationally as well as factors specific to the individual utility. It may be helpful for a commission to develop a table like table 1-1, based on utility-specific data, showing long-term trends in percentage capability, reserve margin based on installed capacity, and reserve margin based on capability. (Of course, capacity margin would serve just as well.) Such a table provides useful background information and perspective for making a judgement about capacity needs.

Historically, most utilities and commissions used a rule of thumb that a reserve margin of 20 percent is appropriate. If peak period generating capability is typically close to installed capacity, there is little distinction between reserve margin based on installed capacity and reserve margin based on capability. If it is not, the commission must consider which reserve margin figure to use. Because the purpose of reserves is to allow both for unplanned outages (decreases in capability) at the time of the peak and for demand surges, it is appropriate to use the reserve margin based on installed capacity in most cases.[3] This provides the utility with an incentive to have installed capacity available when needed: poor maintenance practices ought not to justify overbuilding capacity.

It is important to recognize that the 20 percent reserve margin test is only a rule of thumb--although a useful one. Ideally, the amount of capacity a utility ought to have depends not on the reserve margin, but on the trade-off between system reliability and system cost. Reliability is a measure of how infrequently customers experience blackouts and brownouts. Capacity should be added, in theory, until the cost of any additional capacity exceeds the benefits of the improved reliability.[4] In practice, these benefits are very hard to quantify, and many utilities simply pick a target level of reliability. The objective then ought to be to meet this target reliability level at minimum cost. This approach results in three questions for regulators: Is the target level appropriate? Is the utility meeting its target? Is the target being met at minimum cost?

Selecting a target requires some measure of reliability, and reliability can be measured in several ways.[5] One of the simplest ways is to

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[3]In some cases reserve margin based on installed nameplate capacity is inappropriate. For example, when derated older units are used to lower costs (as discussed above) the installed capacity should be adjusted by the amount of the derating before the reserve margin is calculated.

[4]This concept has been developed by several analysts; see, for example, M. L. Telson, "The Economics of Alternate Levels of Reliability for Electric Power Generation Systems," The Bell Journal of Economics 6 (Autumn 1975):679-694.

[5]For an explanation of traditional measures of reliability and an introduction to loss-of-load probability, see "Power System Reliability Assessment: Phase I--Generation Effects," Edison Electric Institute, Washington, D. C., February 1977. For more advanced techniques, for example, using electric demand probability trees, see "Planning For Uncertainty," EPRI Journal, May 1978.

establish a target number of times that load may exceed system capability over a period of time. In terms of this measure, a typical U.S. utility target level of generation reliability is one outage in ten years. Many years ago, a study for Consolidated Edison showed a reliability level of one outage in ten years to be cost effective.[6] Utilities have accepted that level since. It is generally believed that if a typical utility maintains a 20 percent reserve margin it will, on average, experience a generation reliability level of one outage in ten years.

Several analysts contend that this level of reliability may be too high,[7] that regulated U.S. utilities tend to produce "the best service in the world" when many customers, given a choice, would endure less reliability in exchange for lower rates. The recent demand for low cost telephone handsets and the popularity of low cost, "no frills" air transportation may support this point.

Assuming the utility and the commission agree on a target level of reliability, in order to decide whether the utility is meeting its target, they must either agree on the statistical tools for analysis of outages and demands, such as loss-of-load probability, or agree on a proxy for such analysis, such as the rule-of-thumb estimate of the necessary reserve margin or capacity margin. Statistical tools for reliability analysis for utility use in system planning have been improving greatly over the last decade, but still may not have reached a level of precision where they can be introduced successfully in the rate hearing process. Reliability results from a proper matching of demand and supply. As is well known, the ability to forecast demand accurately is still limited. Tools for forecasting supply availability have limitations also. For example, if the

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[6]Reported in "The Growing Role of Reliability," Electrical World, Vol. 195, No. 10, October 1981, p. 78.

[7]See, for example, A. Kaufman, L. T. Crane, B. Daly, Are the Electric Utilities Gold Plated? A Perspective on Electric Utility Reliability (Washington: U.S. Library of Congress, Congressional Research Service, April 1979).

interconnections of a utility with other systems are modeled poorly or not at all, this may yield a higher level of reserves, for a given reliability target, than is actually needed. Also, tools for forecasting the supply availability in a system require input data concerning the outage rates of the generating units in the system. If these data are based on the historical performance of the units and if this performance has been below par (either because of historical flukes or poor management practices), the result will be a higher level of reserves than would be needed in an optimally managed system to achieve a target level of reliability. Furthermore, many of the tools focus on generation system reliability, treating transmission and distribution reliability inadequately or not at all. Yet, overall system reliability, of which generation reliability is an important part, is the key: the customer does not care if an outage is due to a generating unit outage or a failed transformer.

For simplicity and practicality in the hearing process, many commissions choose to use the reserve margin as a rule of thumb for determining whether capacity is more or less than sufficient for meeting the system's reliability needs. Indeed, many utilities still use the reserve margin rule of thumb for capacity planning.

A commission using a reserve margin proxy for reliability and, equivalently, a reserve margin test for excess capacity must decide whether the target that is set is an average over time, a floor, or a ceiling. For example, if the proper reserve margin is deemed to be 20 percent, is this to be the average of reserve margins over several years, a floor below which the utility should never fall in order to ensure a proper level of reliability, or a ceiling above which the utility should never rise in order to guard against excess capacity? This question suggests that either a reserve margin target average is appropriate or a reserve margin "window," specifying floor and ceiling targets, may be useful. For example, a commission could either establish a 20 percent average reserve margin target, or a window with a 25 percent ceiling and a 15 percent floor, or both. The appropriate level of the average and the size of the window may depend on the circumstances of the utility.

Ideally, the circumstances of each utility would be considered separately in establishing a reserve margin test of reliability. For one utility, a reliability level of one day in ten years may require a reserve margin of 23 percent while that reliability level for a neighboring utility may require reserves of only 17 percent.

Several factors determine the relationship between reliability and reserve margin. One obvious factor is the amount of available purchased power, which substitutes for installed capacity, and long-term contracts for wholesale sales, which effectively reduce the installed capacity available for retail service and increase required reserves. Another factor is system size and the number and size of generating units in the system.[8] For this reason, a utility that is part of a power pool can afford to have a lower reserve margin than a similar utility not in a pool, if each is to achieve the same target level of reliability.

Another factor is the shape of the peak load. A utility with a needle peak requires less reserves than a utility with a relatively flat peak of long duration if both are to be equal in reliability. This is because, assuming a constant probability of outage per unit time, the second utility has a higher probability of outage during the peak period. In other words, it is exposed for a longer time to the possibility of something going wrong.

The reserve margin ought to take into account the age and fuel type of the units of installed capacity, because these factors affect the level of reliability. Old units may be more likely to go down than new units. If new units are more reliable, then adding new units to a system may lower

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[8]For example, a large system with many units, no one of which accounts for more than five percent of installed capacity, can achieve a given reliability level at a relatively low reserve margin because it can easily meet peak load if its largest unit goes down. To achieve the same level of reliability, a smaller system with fewer units, one of which accounts for 20 percent of installed capacity, must have a larger reserve margin if it is to be self-sufficient.

the needed reserve margin. Nuclear plants and coal plants, especially those with pollution control equipment, may be subject to more planned maintenance, unplanned shutdowns, and unit deratings than oil and gas fired units. Nuclear units must be refueled on schedule, whereas routine maintenance of fossil plants can be done whenever the plant goes down. And the nameplate capacity of a hydroelectric facility means little when the reservoir is dry.

The relationship between reserve margin and reliability is also affected by the existence of interruptible customers, including customers with utility-controlled load management devices. Such customers purchase electricity at a lower price than regular retail customers because interruptible customers are willing to accept a lower level of reliability. Whenever demand exceeds available supply, they are the first to be curtailed. Reliability is maintained not only by planning supply reserves but also by planning demand curtailments. For a given target level of reliability for regular customers, interruptible load can be substituted for reserve margin. A utility with an interruptible load equal to 10 percent of peak load and with a 10 percent reserve margin ought to be just as reliable for regular customers as a utility with no interruptible load and a 20 percent reserve margin.

Commissions that use reserve margin as a proxy for reliability need to consider whether to account for these factors in establishing a reserve margin test for excess capacity. If all these factors are taken into account for a given system, a curve can be calculated showing the relationship between reliability level and reserve margin.

If such calculation is not feasible, a commission can choose an alternate approach. One approach is to pick a standard level of reserve that best corresponds to the desired reliability, such as a reserve margin of 20 percent, and consider on a case-by-case basis whether a higher or lower reserve margin is justified for each utility. This approach allows the commission to avoid direct reliability analysis such as loss-of-load probability analysis, but permits consideration of factors that justify reasonable deviations from the standard, either up or down. Another approach, which eliminates the need for any reliability analysis, is to set the standard at a level high enough to take these factors into account and avoid discussion of exceptions. A commission could fix the allowable reserve margin at (for example) 30 percent: then any capacity over 30 percent is deemed excess capacity. This approach has the advantage of simplicity and ease of application. The disadvantages are that utilities with unduly high reliability levels but less than 30 percent reserves are not identified and that a utility which believes it could justify a reserve margin above 30 percent is not permitted to do so.

It may be possible for some utilities to justify high reserve margins as a result of actions taken to minimize costs. As discussed, a high level of reserves may be attributable to maintaining a group of old, not very reliable units which can meet peak loads at a lower cost than replacing them with a new unit. Utilities with oil-fired capacity may find it more economical to install replacement capacity of another fuel type, letting the oil-fired units sit idle, than to burn oil. While the oil capacity is kept on the books, a high reserve margin would result from this cost minimizing action.

Moreover, in order to realize economies of scale in generation unit capacity costs, capacity must be added in large increments. Because of this, a reserve margin target cannot be met exactly year after year. Even if electricity demand could be forecast precisely (which it certainly cannot be), incremental capacity would still cause reserve margins to undergo sudden step-like increases followed by gradual declines as peak loads grow. These step-like increases in reserve margin can be small in some circumstances: if the utility is large enough so that no single addition causes a large step increase; if the smaller utility builds the smallest plant for which economies of scale are retained (as discussed in chapter 5); if small utilities combine in joint-ownership of a large facility; if reserve margin is allowed to decline below the target just before plant completion (using emergency purchased power, if needed at all, for a year or so may be the least cost strategy); and if the unneeded reserve can be sold to neighboring utilities. Better cooperative scheduling of capacity additions among neighboring utilities, along the lines currently attempted by the regional reliability councils, would be helpful in minimizing step increases in reserve margins. When these measures are not possible, some significant reserve margin increase must accompany a capacity addition.

Since demand cannot be forecast precisely, additional reserve margin variations occur due to variable peak demands from year to year. As shown in table 1-1, the 1982 recession and resulting decline in load (column 5) is partially responsible for the increase in reserve margin (columns 6 and 7) in that year. Because of variations in both supply and demand, the cost minimizing approach is some combination of matching construction lead times with typical timeframes for demand trends to become apparent and tolerating swings in reserve margin sufficient to capture economies of scale.

Cost minimization also can be used to justify lower reserve margins. Lower levels of reliability than those achieved historically by U.S. electric utilities may be justified, resulting in a reserve margin perhaps below 20 percent. Furthermore, cost minimizing actions, such as some form of power pooling or cooperative capacity expansion planning, may exploit geographic diversity and associated economies of scale, so that a utility can maintain current reliability levels while lowering reserve margins. In addition, because interruptible load is substitutable for reserves, it may be less costly to offer cost-based interruptible rates than to construct reserve generation capacity.

The emerging telecommunications capabilities of many electric utilities may make possible in the future the polling of customers to determine at what price level they would accept a service interruption. This is not dissimilar to the way deregulated airlines handle inadequate capacity (overbooking) by auctioning off on-the-spot rewards to passengers willing to defer travel. Such a system for electric utilities would be a major step toward linking reliability level and electricity price. Until such a system is available, it is likely that a target reserve margin proxy for adequate reliabiity will continue to be used by state commissions.

How We Got Here

As noted earlier, the current aggregate reserve margin is estimated at 39 percent, compared with 20 percent as an adequate level for reliability purposes. This substantial excess capacity has resulted in the cancellation of a number of plants under construction or planned, as well as financial difficulties for several utilities.

The current difficulties are believed to have their genesis in the oil price gyrations of the early 1970s and the consequent electricity price impacts. That is, electricity prices declined during most of the period from 1946 to 1972, reflecting the industry's declining cost curve. As a consequence, sales of electricity doubled every ten years during this period (7.1 percent annual growth). Most students of the industry expected these trends to continue over time. As a result, utility construction plans were based on this relatively rapid growth rate.

In the early 1970s, however, signs of a change were available. Electric costs were beginning to rise as a result of the internalization of external costs (pollution control) and the apparent exhaustion of economies of scale in generation. Great impetus to this change was provided in 1973, however, as oil prices increased dramatically, and with them electricity prices. The price of electricity in 1974 was 24 percent higher than the previous year; sales dropped for the first time in the post World War period; and peak demand increased by only 1 percent. This sudden shift was reinforced over the rest of the decade by continuing fuel price pressure, increasing construction costs, rising interest rates, and required pollution abatement costs.

As a consequence, the industry suffered rising costs throughout the period. Average revenue per kWh increased at an average rate of 12 percent per year from 1973 to 1982. This rate of increase was substantially above the 7 percent per year increase in the general economy, as measured by the GNP Implicit Price Deflator. The rise in electricity prices was less than the 18 percent annual average increase in the Producer Price Index for fuels and power. This would indicate that the price increases experienced by the electric power customer were less than those for other energy users. In part this differential may have resulted from the reluctance of regulators to increase electric prices. Also, fuel is only one component of electricity prices, and the other components may have increased at a lower rate. In any case, the result of the rise in the real cost of electricity, together with relatively sluggish economic growth, was a reduction in the growth rate for sales.

The volume of electric sales grew at an average rate of 2.1 percent per year, in the 1973-1982 period, while peak demand averaged 1.9 percent annually. Had electric prices increased at the same rate as other energy prices, this growth rate might have been less. In any case, construction plans were made some 10 to 15 years ago, based on demand growth estimates at much higher levels than those experienced in the 1970s. The construction of electric generating units, however, unlike the electricity they produce, cannot be "turned off" very easily once started. Capacity grew at an average of 3.4 percent per year, between 1973 and 1982. This disparity in capacity growth rates, compared with peak growth, has resulted in the current overcapacity situation.

Whether the utilities should have recognized what was happening at an earlier stage is not the subject of this study; nor is it a question that requires an answer for our specific purposes. Before attempting to lay the blame for the current situation at any doorstep, however, one should keep in mind that there was an unfortunate conjunction of events. The unforeseen decline in demand growth rates was coupled with an extension in the construction planning cycle. An illustration of the impact of events in the 1970s on a utility's capacity planning is presented in the first section of appendix A.

There is, however, the question of whether the present overcapacity situation is temporary or will last for some time into the future. To a considerable extent, the answer to this question is dependent upon the economic situation. That is, the state of the economy is a major factor in determining electric demand, although that relationship is not immutable. In fact, over the past few years it has changed dramatically. During the 1954-1958 period, the electric growth rate was, on average, three times higher than the GNP growth rate; in the 1969-1973 period it was approximately double, and by the 1979-1982 period the rate of electric increase was approximately equal to the GNP growth rate. It would thus appear that the nature of the relationship is changing, with the possibility that in the future electricity use will grow at a somewhat slower rate compared with GNP, rather than at a faster pace. Regardless of the shifting relationship, there remains a strong statistical correlation between GNP and electricity sales. In a statistical sense, 96 percent of the variations in electricity demand are the result of variations in GNP.[9] It is thus obvious that if the economy grows at a relatively rapid average annual rate, say 4 percent, over the 1983-1992 period, the demand for electricity will be much higher than if the economy were to grow at the same rate (2.1 percent) as in the previous ten years.

With this caveat about the effect of economic growth on electric demand, current planning data published by the North American Electric Reliability Council (NERC) indicate that most regions of the country will still be suffering from overcapacity in 1992.[10] Even if these data are adjusted to reflect abandonments and cancellations, reserve margins appear healthy in most regions. We can conclude, therefore, that barring substantial economic growth, the overcapacity problem will be with us for some time.

In view of this probability, we now turn to our major purpose, namely, a discussion of the regulatory options for treating overcapacity.

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[9]A. Kaufman and K. Nelson, An Assessment of the Need for New Electric Capacity (Washington: U.S. Library of Congress, Congressional Research Service, August 1983), p. 16.

[10]North American Electric Reliability Council, Electric Power Supply & Demand 1983-1992 (Princeton: NERC, 1983).

CHAPTER 2

OPTIONS FOR TREATING OVERCAPACITY ASSUMING INVARIABLE DEMAND

Where overcapacity exists, a commission has a variety of options for dealing with the situation. In this chapter and the next, these options are set out along with their advantages and disadvantages. The purpose is to develop a complete set of the more logical options, not to recommend a particular one.

The discussion here deals only with options generally available to the regulatory commission and does not explicitly deal with options usually open only to the utility, which include selling ownership of some capacity, retiring older plants, writing off unneeded capacity, delaying completion of plants under construction, and abandoning plants under construction--though these actions could follow from some of the commission actions suggested here. Here we deal only with commission responses to a utility's request for full rate base treatment of capacity that the commission judges to be in excess of reliability needs. Such responses can range from total exclusion from rate base of the capacity in question to total inclusion in rate base. The variety of rate base treatments is discussed here in chapter 2. Other responses include commission-initiated cooperative efforts with a utility to utilize existing capacity by promoting new sales. These are discussed in the next chapter.

Some of the options to be considered have already been put into practice by commissions. Examples of such practical application are given in chapter 4. Other options suggested here have not yet been tried. Also in chapter 4, factors that may affect a commission's choice among all these options are discussed.

A Framework for Analysis

A summary of the various options is presented in table 2-1. As shown, the various options can be classified as either supply options or demand

TABLE 2-1

REGULATORY OPTIONS FOR TREATING OVERCAPACITY

A. Supply Options
   1. Fully exclude excess capacity from rate base
      (a) exclude newest plant(s)
      (b) exclude least efficient plant(s)
      (c) exclude average plant
   2. Partially exclude excess capacity
      (a) exclude some fraction of excess capacity
      (b) keep coverage ratio at 2
      (c) use a graduated excess capacity exclusion
      (d) exclude return on equity but not debt
      (e) keep revenue constant
      (f) base rates on imputed sales
      (g) exclude a portion of the carrying costs
   3. Fully include overcapacity in rate base
      (a) use traditional rate base treatment
      (b) phase in new capacity
      (c) use a trended rate base

B. Demand Options
   1. Promote bulk power sales
      (a) encourage sales to neighboring companies
      (b) encourage interregional power transfers
   2. Promote new jurisdictional sales
      (a) lower rates
      (b) encourage marketing

Source: Chapters 2 and 3 of this report.

options. Supply options are treated here, and demand options are treated in chapter 3. In each chapter, the options are applied to a hypothetical typical utility, if appropriate, to illustrate the option and to estimate its effect.

Relationship of Supply and Demand Options

Supply options are those that take electricity demand as unchangeable and adjust the supply of capacity allowed in rates. Historically, most utilities and commissions have treated demand, for kilowatt-hours of energy and kilowatts of capacity, as determined by growth in the number of customers, increasing market penetration of electrical appliances and equipment, weather, and the state of the local economy--all factors over which the utility and the commission have no control. In a rate case, new rates are usually determined by spreading the new revenue requirement over the billing units existing in a historical (sometimes future) test year. The level of new rates is assumed by many commissions to have no effect on the billing units, that is, on the demand for electricity. In other words, the price elasticity of demand for electricity is assumed to be zero. With this assumption, the main option open to utilities, which by law must serve all comers, is to adjust supply to the level of demand. This is accomplished principally by building generating plants, regardless of cost, to meet projected demand and by selling or leasing extra capacity if that demand fails to develop fully. For the commission, the choices are whether to include excess capacity costs in rates fully, partially, or not at all. This choice is based on the "used and useful" test, the prudence test, or commission judgement concerning how well the utility has supplied capacity to meet an exogenously determined demand.

Demand options take into account that utility and commission actions affect the demand for electricity. For unregulated companies, when demand falls short of supply, the response is to stimulate demand with lower prices. Automobile manufacturers offer rebates, and airlines offer discounts, super-savers, off-peak rates, and "free" trips to frequent flyers. For many regulated companies, however, when demand falls short of supply, the response is to seek a rate increase.

In principle, this could lead to a so-called "death spiral": excess capacity is included in rates, raising prices and lowering demand, which results in more excess capacity, higher rates, and so on. In the "death spiral," the process continues until demand shrinks to zero. In practice, this is most unlikely to occur for electric utilities since the price elasticity of demand is less than unity for most customers. But, a limited death spiral response is likely to occur because including excess capacity in rates will result in demand stabilizing at a reduced level, exacerbating the excess capacity problem.

The two sets of options for dealing with overcapacity, relating to supply and demand, differ in rationale but not necessarily in effect. For example, excluding from rate base that portion of capacity in excess of need would result in lower electricity prices, perhaps similar to those arrived at by lowering rates to bring supply and demand more nearly into balance. Moreover, a commission may hear several different arguments for lower rates, some based on excess supply and some based on inadequate demand, and reach a judgement that gives weight to both arguments. A commission opinion and order may provide for a partial exclusion of overcapacity from rates, based primarily on the used-and-useful test and secondarily on the desire to avoid further dampening demand.

Despite the possible similarity in effect, it is worthwhile to treat these two sets of options separately for two reasons. One is that in a rate case commissions must consider the rationale for any action and have that rationale developed on the record. Hence, it is appropriate to identify distinct lines of argument here. Second, commissions must determine the amount of any rate adjustment, and this amount will depend on the method used.

The Criteria

In order to have a somewhat consistent framework against which to compare the advantages and disadvantages of the various options, we consider each option with respect to three criteria, in addition to other factors specific to the particular option.

The first criterion is the correctness of the electricity prices resulting from the option. This criterion measures the effect on the customer--whether he is asked to pay for capacity that he does not need. It is not, however, simply a measure of how low the price is. A price below the cost of producing electricity is as bad as one above. The question is whether the price is correct. Here, a correct price is what we consider the economically efficient price. For our purposes, it is not a price simply equal to the utility's incurred costs, but a price equal to the minimum cost required to supply electricity while maintaining the appropriate level of reliability. The correct price may be considered the price that the utility would have to offer if it were competing with other electric companies for the customer's business.

In our examples, the average revenue per kilowatt-hour of generation is used as a measure of the price. (It differs from average price only by a constant factor that accounts for line losses.) In a multi-year example, price is measured by the levelized revenue per kilowatt-hour, which we define as the net present value of the revenue stream divided by total generation over all years in the example.

The second criterion is equity, or fairness, which has two aspects. One is whether the various customer classes are treated fairly with respect to one another. We could call this interclass equity. It is a measure of how much one customer class bears the cost--or enjoys the benefits--of the regulatory treatment of overcapacity compared to the other customer classes.

Another aspect of equity is whether this year's customers are treated fairly with respect to customers in the future. We call this intergenerational equity. It measures how well the capacity payments made by each generation of customers matches their use of the capacity. Here in chapter 2, interclass equity is not considered explicitly because we assume that commissions will treat the various customer classes fairly as rate base is adjusted. But, intergenerational equity is very important here. In chapter 3, interclass equity is a concern as the company promotes new sales.

The third criterion is the financial effects of the option. These include the effects on both the company and its customers. By the company, we refer to managers, creditors, and stockholders together. The financial effects include the ability to provide a return to equity owners, to pay interest to creditors, and to operate and maintain the utility in a manner that assures adequate and reliable service to customers. The adequacy and reliability of service depends on whether there is enough capacity (obviously not a factor in an overcapacity situation) and whether there is enough cash flow to operate and maintain properly the capacity that exists.

In our examples, the after-tax interest coverage ratio is used as the principal measure of the financial effects. The after-tax interest coverage ratio is the number of times that return on investment is able to cover interest. A financially sound company generally has a coverage ratio well above 2.0. A high coverage ratio contributes to a good credit rating, which allows the company to take on new debt or roll-over old debt at low interest rates. A company may be prohibited from borrowing, according to the terms of some existing debt instruments, if its coverage ratio falls below 2.0, and at any rate borrowing under this condition is expensive. A coverage ratio below 2.0 also makes the company's preferred and common stock more risky--raising these capital costs--because small percentage revenue variations then produce large percentage variations in earnings available for stockholders. A coverage ratio below 1.00 means that the utility is not able to make interest payments on its long-term debt.

The Typical Utility

The discussion of each option is presented along with an illustration of the application of the option to a hypothetical typical utility. Having such an example also allows us to examine numerically the impact of each option on the typical utility and its customers. This typical utility is a version of the IEEE Reliability Test System, modified so that the utility's generation, peak load, capacity, and certain financial ratios are equal to recent averages of these data for all 204 class A and B electric utilities.

This typical or "average" utility is described in detail in appendix A. Important summary information about this utility is presented here in tables 2-2 and 2-3.

This utility is requesting rate base inclusion of 400 MW of nuclear capacity. This would increase the generation component of rate base by 428 percent, from $268 million to $1,146 million. Total rate base would increase by 272 percent, from $514 million to $1,400 million (including associated transmission facilities). Table 2-2 shows the generation components of rate base by fuel type, including the proposed nuclear addition. The nuclear addition is large relative to existing rate base because recent nuclear plant costs are high and because much of the contribution to rate base of the older units has been reduced by depreciation.

The need for new capacity is shown in table 2-3. With a peak load of 1645 MW and a capacity of 1950 MW before adding the new unit, the utility has a reserve margin of 19 percent. Adding 400 MW of new capacity raises the reserve margin to 43 percent. How the utility came to this situation is described in the first section of appendix A.

The second and third sections of appendix A contain data on the contribution of each generating unit to rate base, the capital structure of the utility, and the other assumptions, equations, and data used to derive the results of the numerical examples presented in the remainder of this chapter.

Let us now consider the options open to a commission for treating this request for rate base inclusion of the new facility. For the remainder of this chapter, it is assumed that the annual generation of 8790 GWh and the

TABLE 2-2

RATE BASE OF THE HYPOTHETICAL UTILITY

	Generation Capacity (MW)	Rate Base Contribution ($ x million)
Generation		
Nuclear	400	878
Coal	950	179
Hydro	200	7
Oil (steam)	720	81
Oil (turbine)	80	1
Subtotal	2350	1146
Transmission		56
Distribution		194
Other		4
Total Rate Base		
before 400 MW nuclear addition[a]		514
after 400 MW nuclear addition		1400

Source: Appendix A

[a]The 400 MW addition adds $878 million to generation rate base and $8 million of transmission associated with the new facility.

TABLE 2-3

GENERATION, PEAK LOAD, CAPACITY, AND RESERVE MARGIN FOR THE HYPOTHETICAL UTILITY

Annual Generation	8790 GWh
Peak Load	1645 MW
Capacity	
before 400 MW addition	1950 MW
after 400 MW addition	2350 MW
Reserve Margin	
before 400 MW addition	19%
after 400 MW addition	43%

Source: Average of 204 class A and B electric utilities; see also appendix A.

peak load of 1645 MW is invariable. Regardless of whether the new unit is included in rate base and regardless of the resulting price of electricity, the level and pattern of sales will not change. (In chapter 3, we remove this assumption, assume the full 2350 MW is included in rate base, and consider ways to stimulate demand to utilize this capacity.) If demand is fixed, then commission options are to exclude excess capacity fully from rate base, to exclude it partially from rate base, and to include it fully in rate base. There are various ways of carrying out each option.

Fully Exclude From Rate Base

One option for a commission is to exclude excess capacity fully from rate base. This action may be based on the statutory requirement that investment be used and useful, on judicial precedent, or on commission judgement of management prudence.

Newest Capacity

Excluding plant from rate base may be accomplished by simply refusing to allow the newest capacity and associated transmission facilities into the rate base. If a commission takes this stance, it must decide how to handle the expenses associated with the plant. In the unlikely event that the utility builds the plant and does not use it, there are still plant expenses such as those associated with property taxes, insurance, and guarding the property. If the plant is truly abandoned (not just moth-balled until needed), the utility can write-off the investment under the rules summarized in the third section of appendix A. This, of course, would affect the utility's taxes, and the commission must recognize the plant's existence at least insofar as to see to the proper ratemaking treatment of the tax savings. We assume here that a new plant is not abandoned; it will be moth-balled or used.

More likely, the utility will operate the new unit because, from the utility viewpoint, the fixed costs of the unit have been incurred and are therefore sunk, the unit exists, and economic dispatch of units requires use of those with the least running cost. Then, the new unit incurs additional expenses for fuel, other operation and maintenance, and depreciation, but may produce a net savings in fuel expense, particularly in our example where nuclear generation displaces oil and coal generation. The commission must consider whether these expenses are appropriate in rates if the unit itself is excluded from rates.

Let us consider the effect of excluding the nuclear plant from the rate base of our typical utility. Excluding the plant, the new transmission facilities associated with the plant, and the associated expenses from rates is equivalent to keeping the rates that were in effect prior to the rate case because here we assume no inflation in other expenses and no change in the cost of capital. These assumptions are useful for isolating the effect of the commission's treatment of overcapacity. In effect, the commission treats the new plant as if it did not exist.

The average revenue per kilowatt-hour of generation in this case (determined from the equations in figure A-1 of appendix A) is 5.6 cents per kWh. This revenue level reflects fuel expense that includes no nuclear generation. From the customer viewpoint, this is a favorable result because the system capacity without the new unit is adequate, so no rate change is induced by the existence of unneeded capacity.

Of course, from the utility viewpoint, this is an unfavorable result. The after-tax interest coverage ratio is only 0.92. This means no return to common or preferred stockholders and the ability to pay only 92 percent of the interest due. Absent another source of cash, this ratio suggests default and possibly bankruptcy.

From the viewpoint of intergenerational equity, this commission action is favorable because it does not charge current ratepayers for capacity not currently needed.

However, the utility may operate the new unit and the commission may allow depreciation charges and fuel expenses in rates, while still disallowing rate base treatment. In this case, the revenue increase from the new depreciation charges is more than offset by fuel cost savings as nuclear fuel displaces oil and coal. Revenue per kWh drops to 4.9 cents per kWh. In principle, the coverage ratio is unchanged since revenue increases or decreases track expense charges. Actually, nuclear fuel is purchased in prior years so using nuclear fuel helps the utility's cash position, and depreciation related revenue requires no immediate, associated cash outlay, which also helps the cash flow picture. Hence, while this approach does not improve earnings and does not change the coverage ratio, it may temporarily improve cash flow sufficiently to enable a utility to meet its interest payments. At a coverage ratio of 0.92, our example utility is $5 million per year short on cash to meet interest payments. Annual depreciation expense for the new capacity is $29 million.

From the viewpoint of intergenerational equity, this approach has the disadvantage that current customers are deriving benefit ($120 million in fuel savings) from the new unit, but recovery of capital costs is to be from future customers.

The whole plant should not be excluded from rate base if a portion of the plant's capacity is needed. Rather than exclude the whole new plant, a commission would want to exclude that portion of the plant that represents excess capacity. For our typical utility with a peak of 1645 MW, the capacity required for a 20 percent reserve margin is 1974 MW. If capacity over this amount is considered excessive, then 24 MW of the new facility is needed, and 376 MW (94 percent) is not.

Suppose this 94 percent of the new facility is excluded from rate base, but the first 24 MW of capacity and all of the associated new transmission is included. The resulting revenue level depends on the treatment of fuel and depreciation expenses. Presumably, the nuclear plant would be fully used--it would make no sense and it would not be possible to run the plant at 6 percent of capacity--and the company's overall fuel expense would be reduced. The choice is between allowing a depreciation expense for the entire unit or only for the portion in rate base.

Allowing depreciation for just the portion in rate base results in the lowest revenue for the utility of any option considered: revenue per kWh is only 4.4 cents per kWh. This is because full use of the new nuclear plant reduces the fuel expense, but there is little new nuclear plant depreciation expense. The interest coverage ratio is only 0.62. Allowing the full depreciation expense for the nuclear unit raises the revenue level to 5.0 cents per kWh. In this case, the coverage ratio improves somewhat to 1.02. This is still a very low ratio, though it does permit full payment of interest obligation. The little remaining earnings must be distributed to preferred stockholders resulting in a rate of return to them of less than 1 percent, compared with the 12 percent authorized by the commission for the preferred stock component of the rate base. Of course, there is no return earned on common stock. This slight improvement in coverage ratio is slightly more advantageous to the utility than the previous approach of excluding the whole new plant.

Setting aside the level of fuel expense, which is recovered dollar for dollar, these results are similar to the results for excluding the whole plant. However, if the excess capacity portion of the new plant were significantly less than 94 percent, then under this option rates would be higher and the impact on the company would be less severe.

Least Efficient Capacity

It is not necessary to attribute the excess capacity to the new nuclear plant. Once the nuclear unit is on line, one can argue that it is used and useful and some other units are not. Perhaps the oldest plants ought to be retired if their maintenance costs are too high. Perhaps the oil plants are economically obsolete and ought to be abandoned.

If 1974 MW is required by our typical utility for peak-plus-reserve needs, an analyst could simulate economic dispatch of the company's generating units to meet a hypothetical load of 1974 MW. Then, units that come last in the loading order (with some or all peaking units excepted because of their desirable load following characteristics) could be deemed not used and useful and be excluded from rate base. These units are the last 376 MW out of the total 2350 MW capacity to be dispatched. For our typical utility, this would be the older, presumably less efficient oil-fired units. Identifying 376 MW in this way results in five oil-fired units and a portion of a sixth being excluded (see table A-5 in appendix A for details). The rate base contribution of these units is $20 million. For our typical utility, original costs for three of these units have already been fully recovered over the units' thirty-year lives, and the rate base contribution of these three units consists of the undepreciated portion of replacement equipment and parts.

Here again, the commission must consider whether expenses associated with the units should be included in rates. These include fuel costs (in the event that the units are actually used during the year), depreciation (if any), and maintenance. An important related question is whether the commission views exclusion of these plants as permanent, as if the utility had retired the plants and would write off any unrecovered investment. If so, the case for including associated expenses in rates is weaker than if the rate base exclusion is temporary. If temporary, the company then would be expected to maintain the plants so that when the peak demand grows sufficiently, the units can re-enter the rate base if they can provide power at less cost than new capacity. We assume here that depreciation of units excluded from rate base is not allowed in rates.

The effect of excluding the least efficient units from rate base is to reduce the $1400 million rate base, which includes the new capacity, by $20 million. The revenue per kWh in this case is 7.1 cents per kWh, and the interest coverage ratio is a respectable 2.46.

This revenue level is 27 percent above the pre-rate-case level. It is very close to the revenue level (7.2 cents per kWh) that would result from full rate treatment of all capacity. This is a disadvantage for utility customers who were receiving reliable service before the rate case at 5.6 cents per kWh.

The interest coverage ratio reflects a level of earnings that permits full payment of interest due, payment of all preferred dividends, and permits a return on common equity of 14.5 percent, just a little below the authorized return on equity in rate base of 15 percent.

Average Capacity

Still another way of excluding the full 376 MW of excess capacity is to exclude the average unit. That is, if 376 MW of the 2350 MW (16 percent) is excess capacity, then 16 percent of the generation portion of the rate base could be excluded. This is (from table 2-2) $183 million, or 13 percent of the total rate base.

Several states have used some version of this approach. Generally, the argument for it is that all units are used at some time during the year so that no one unit can be singled out as not used or useful. With this approach, all expenses for all units are usually recovered in rates, including depreciation, and this is assumed in our example.

The effects of this approach on our typical utility are that the rate base is reduced from $1400 million to $1217 million, revenue per kWh is 6.7 cents per kWh, and the interest coverage ratio is 2.18. This approach provides enough revenue to cover interest obligations and preferred dividends fully. It also provides a return on common equity of 11 percent, compared to a commission-authorized 15 percent return on the equity portion of the rate base.

Excluding average capacity has results, as expected, that lie between the results for excluding the newest capacity and those for excluding the least efficient capacity. Rates increase by 18 percent over the rates in effect before the new capacity came on line. This is still to the disadvantage of customers who had reliable service without the new capacity, but not so disadvantageous as excluding the inefficient, generally older capacity. The effects on the company are significant without being severe.

Partially Exclude from Rate Base

A utility may want to send a signal to the utility that excess capacity is not acceptable in rate base, but may not want to exclude excess capacity fully--either because the financial impact on the company and eventually on its customers would be too severe or because the commission wants to tie the amount of rate base inclusion to the degree of management responsibility for the excess capacity. Various approaches to partial exclusion are possible.

Selected Fraction

One is for the commission to exercise its judgement about the appropriate fraction of excess capacity for inclusion, for example, 50 percent of the excess capacity may be allowed in the rate base. This judgement can be based on the results of an audit or hearing to determine the prudence of the decisions that resulted in excess capacity, based on the financial position of the utility (how much it can reasonably bear), based on the level of reserves, or based on some other factor.

The financial impact on the company will depend on whether the excess capacity is attributed to the newest unit, the average unit, or the least efficient units--as discussed in the previous section. For the purposes of example, we assume that the commission associates excess capacity with the newest unit, that no depreciation expense is allowed on excluded capacity, and that the new transmission facility is fully included in the rate base.

Suppose that the commission finds, based on a prudence study, that only 50 percent of the new unit is includable in rates. Then, revenue per kWh for the typical utility is 5.7 cents per kWh. This represents a small rate increase of less than 2 percent. This is because the increased return on half the new plant is almost offset by the fuel cost savings derived from this plant. This option is favorable to customers, but moderately unfavorable for the company. The coverage ratio in this example is 1.50--enough to allow only a 3.0 percent return on equity.

Selected Coverage Ratio

With a coverage ratio below 2.00, the company's credit rating suffers. A commission might choose to allow just enough of the new capacity into rate base to achieve a coverage ratio of 2.00. Applying this approach to the typical utility, with the same assumptions as in the previous example, yields the requirement that the rate base equal $1178 million. Hence, $222 million of the $878 million new plant (25 percent) can be excluded from rate base to achieve an interest coverage ratio of 2.00. This leads to revenue per kWh equalling 6.5 cents per kWh, a 16 percent rate increase, and return on equity equalling 10.2 percent.

Graduated Excess Capacity Exclusion

Still another approach is to relate the fraction of excess capacity excluded from rate base to the degree by which the company overestimated the need for capacity. That is, if the amount of excess capacity is small, most of it is included in rate base; but if the amount is large, most of it is excluded. For example, the dollar amount potentially excludable from rate base could be multiplied by the ratio of excess capacity to peak load. If the excess capacity is, say, ten percent of peak load, then ten percent of the excess capacity is excluded from rates, while 90 percent is allowed. But if excess capacity equals 80 percent of peak load, then 80 percent of the excess capacity costs would be excluded from rate base. In the case of our typical utility with a 43 percent reserve margin, 23 percent (376 MW of excess capacity divided by 1645 MW of peak load) of the excess capacity costs would be excluded. If these costs are again attributed to the newest unit, then rate base treatment is denied to $202 million associated with the new unit. The resulting level of revenue per kWh is 6.5 cents per kWh (a 16 percent increase), and the interest coverage ratio is 2.05, providing a 9.5 percent return on equity.

Equity Only

Another approach to excluding a portion of excess capacity from rate base is to disallow a return on the equity portion of the investment in excess capacity but to allow a return on the debt portion. The intent is to make sure that all debt can be paid, to avoid any threat of bankruptcy, and to hold bondholders harmless while directing any losses toward those who assumed a greater investment risk, the stockholders.

This approach is different in rationale from the earlier approaches but not so much different in effect. Earlier approaches that fully exclude excess capacity exclude investment funded jointly by creditors and stockholders. The "missing" return on the excluded investment is calculated at the weighted average cost of capital, as if creditors and stockholders each fail to earn a portion of their expected return. In practice, the company must, of course, pay its creditors fully before any earnings are available to stockholders. Hence, most approaches considered earlier also result in covering debt fully and deny some return to stockholders. Under the approach considered here, however, the return denied to stockholders is less because they do not have to absorb the "missing" return to creditors.

Here again the commission must decide whether excess capacity is associated with the newest unit, the average unit, or the least efficient units, and again we assume it is the newest unit for purposes of example.

The new unit costs \$878 million and is funded 50 percent by debt, 10 percent by preferred stock, and 40 percent by common equity, as explained in appendix A. Under the debt-only approach, the commission allows a 9.6 percent return on half the investment, or a return of \$42 million on \$439 million of debt associated with the new plant. But no return is allowed on stockholders' investment associated with the plant. (Of course, one could also apply this technique to a portion of the plant, especially if not all of the 400-MW plant is considered excess capacity.) In this case, all interest expense is guaranteed to be covered: the interest coverage ratio is 1.80, compared to 0.92 when all return on the new plant is denied. Earnings on rate base are sufficient to cover all obligations to preferred stockholders and a 6.6 percent return to holders of common stock.

The commission may or may not include in rates the depreciation expense on the excess capacity. If it does, revenue per kWh is 5.8 cents per kWh, a 4 percent rate increase. Compare this with a revenue level of 4.9 cents per kWh reported earlier as the result when depreciation is allowed but no return on the new plant is permitted. These results are advantageous to customers and moderately unfavorable to the company.

Constant Revenues

When a new unit begins operation, the expenses of the utility change. For example, depreciation and income taxes associated with return on equity in the new plant increase, and fuel costs usually decrease. If the fuel cost savings are substantial, total expenses can decrease. A commission might allow just enough of the new unit into rate base so that the increase in return on rate base balances the decrease in total expenses. The result intended is that the revenue requirement be unchanged.

For the typical utility, the rate level prior to the nuclear plant coming on line was 5.6 cents per kWh, which resulted from spreading the \$492 million revenue requirement over 8790 GWh. The nuclear plant results in fuel savings of $120 million annually. Hence, the commission can allow an additional $120 million of depreciation, return, and income taxes on return without raising rates. After allowing for the full depreciation expense, $278 million of new plant can be included in rate base. This is 32 percent of the new unit's cost. The resulting interest coverage ratio is 1.42, which permits a 2 percent equity return.

This approach has the advantage of holding the customer harmless. However, from the company's viewpoint nothing has changed as the result of the rate case: the same revenues are collected and are presumably dispersed by the company in the same way as they have been since the nuclear unit began full power operation.

Imputed Sales

Another approach is to grant full rate base treatment of all capacity, but calculate rates as if sales were sufficient to utilize this capacity.

Our typical utility has capacity of 2350 MW. With a 20 percent reserve margin this is sufficient capacity for a system with a peak load of 2350 MW ÷ 1.2 = 1958 MW. (This is close to the company's forecast 1984 peak of 1952 MW as shown in table A-4 of appendix A. Either figure may be used to calculated imputed sales.) Assuming the company's load factor (generation ÷ peak load ÷ 8760 hours) remains constant at 61 percent, a peak of 1958 MW implies an imputed annual generation of 10,465 GWh. This is 19 percent more than actual generation of 8790 GWh.

The full revenue requirement covering all capacity is $633 million, 23 percent above the pre-rate-case revenue requirement of $492 million. If this is spread over actual kilowatt-hours, the result is a 28 percent rate increase. However, if it is spread over the imputed kilowatt-hours, the revenue per kWh is 6.0 cents per kWh, giving a 7 percent rate increase.

This approach gives full rate base treatment of excess capacity. But if--as we assume in this chapter--demand for electricity is invariable, this approach provides for an undercollection of the revenue requirement set by the commission. At 6.0 cents per kWh of generation and with only 8790 GWh of generation, the actual revenues collected would be $527 million--a $106 million shortfall. Instead of the authorized 12 percent rate of return on rate base, the actual rate would be only 8.1 percent. Once creditors and preferred stockholders are paid, owners of common stock have earnings of 5.2 percent. The interest coverage ratio is 1.69.

Thus, with the assumption that the demand for electricity is unchangeable, this approach must be considered the equivalent of an approach that partially excludes capacity from rate base. Very likely, our hypothetical utility would consider it so. However, the spirit behind this approach may be considered the equivalent of some options considered in chapter 3, namely, to grant full rate base treatment, but to set prices at a level designed to use capacity more fully.

Carrying Costs

Another approach to partial exclusion of new plant costs is to deny full inclusion of the carrying costs of the unit prior to its entry into rate base. There are at least two approaches to doing this for a completed plant.

One is to use the traditional regulatory device of delay, usually called regulatory lag. If a new unit is completed but is not yet needed, then a commission may try to defer the rate hearing until the unit is needed. Under this approach, the commission may allow into rate base the carrying costs during construction but might not allow the carrying costs after construction and before rate base inclusion. One can argue that if the new unit is not needed, then a rate case to consider its rate treatment is not needed and ought to be delayed. This is an alternative to having rate base treatment considered and rejected.

Many states now have statutory requirements for frequent rate hearings and may not be able to use this approach. Other states, however, may find it appropriate to adjust the regulatory lag to fit the amount of excess capacity. According to Bonbright, writing in 1961 about regulatory lag:

> Under prevailing methods of rate regulation, [efficiency] incentives are, indeed, provided to a limited degree....[by]"regulatory lag"--the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise.
>
> Commissions have....tended to let existing rate levels stand, subject to minor revisions in the rate pattern, until there appears to be an impelling reason for a new general rate case....Quite aside from the recognized undesirability of too frequent rate revisions, commissions recognize the "regulatory lag" as a practical means of reducing the tendency of a fixed-profit standard to discourage efficient management.
>
> [T]he most serious of all of the objections to a cost-of-service standard of reasonable public utility rates [is] that, as long as rates are fixed so as to assure even a company under mediocre management that it can recover its costs, including a "fair rate of return," ....there will be lacking under regulated private ownership a stimulus for efficiency comparable to the stimulus of actual competition.... But a plausible case, at least, could be made for the thesis that what has saved regulation from being a critical influence in the direction of mediocrity and tardy technological progress has been its very "deficiencies" in the form of regulatory lags....[2]

Another concern for commissions relating to carrying costs for a newly completed plant is whether a company, fearing that it would have excess capacity, intentionally delayed completion of construction in order to allow demand to catch up with system capacity. The delay could have been explictly announced, excused as part of a Nuclear Regulatory Commission action, or attributed to some other cause. The carrying costs associated

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[2]James C. Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961), pp. 53, 147, 262.

with such delay ought to be of concern to commissions because they represent a way of avoiding an overcapacity penalty and charging customers for inaccurate demand forecasting without commission approval. Another similar utility that finishes construction on time might be temporarily denied rate base treatment of its new facility and might not be allowed to recoup the carrying costs of the plant for the time between plant completion and rate base inclusion.

However, it may be difficult to distinguish deliberate construction delays from delays attributed to other causes. A management audit may be required for such a determination. If deliberate delay is identified, then the carrying costs associated with the delay need to be identified for possible exclusion from plant capital costs eligible for rate base treatment.

On the other hand, the commission can simply put a time limit on the accrual of AFUDC (allowance for funds used during construction) when inexplicable construction delays occur in an overcapacity situation. When the plant enters the rate base, whether immediately or eventually, the limitation on AFUDC is a partial exclusion of the company's claimed full plant cost. For our typical utility, 376 MW of the completed nuclear plant at a carrying cost rate of 12 percent would cost $99 million per year.

Commissions that allow the cost of construction work in progress (CWIP) in the rate base need to consider how this policy applies in an overcapacity situation. The same options apply here as apply to the rate base treatment of a completed plant: full exclusion, full inclusion, and partial exclusion. If CWIP inclusion is considered a useful policy for propping up earnings during construction, perhaps a policy of partial inclusion (such as debt but not equity) would appeal in an overcapacity situation.

Fully Include in Rate Base

With the set of options to be considered here, the overcapacity is determined not to represent excess capacity excludable from rate base.

The company is fully compensated for its investment. All capacity is fully included in rate base, but the timing of revenue flows may be modified from that traditionally used.

The timing of revenue flow can be modified so that the company collects the same number of dollars (same nominal revenue) or modified so that the net present value of the revenue flow is unchanged (same real revenue). If the nominal revenue collection is delayed, the company receives less compensation in real terms.

Three options are considered here: traditional rate base treatment, phase-in treatment, and rate trending.

Traditional Treatment

In the traditional regulatory treatment of investment, the full value of the investment goes into the rate base immediately, and (absent compensating fuel savings) rates undergo a step increase to a higher value. In future years, the value of the investment decreases as depreciation expense reduces the rate base. Hence, all other things being equal, the contribution of the investment to rates decreases over time.

For our typical utility, the traditional regulatory treatment of including all capacity in rate base results in an increase in the revenue requirement from $492 million to $633 million and a corresponding increase in the revenue per kWh--still assuming that demand does not respond to price--from 5.6 cents per kWh to 7.2 cents per kWh. This is a 29 percent rate increase.

The company earns the authorized return on equity, 15 percent, and has an interest coverage ratio of 2.51. This is the most favorable outcome from the company's point of view, but it will be realized only if demand really is insensitive to the price of electricity.

On the other hand, from the customer point of view this is the least attractive outcome. Customers were served at 5.6 cents per kWh with a 19 percent reserve margin. Provided this level of reserves is adequate, they now face a large increase in their electric bills without any real change in the quality of service.

From the viewpoint of intergenerational equity, this is an unfavorable approach. Assuming a 2 percent rate of growth in peak, the new capacity will not begin to be needed until the tenth year that the new unit is in rate base--at which time growth will have reduced the reserve margin to 20 percent (if there are no plant retirements during this period).

In the first such year, the required revenue per kWh is 7.2 cents per kWh: 4.2 cents for all expenses except income taxes, 1.9 cents for return and income taxes on the return associated with the nuclear unit, and 1.1 cents for return and income taxes associated with the rest of the rate base. If we continue to assume that there is no inflation in expenses over the ten-year period, that there is no change in the percentage cost of capital or in the capital structure of the company, and that there are no construction costs in rates, then the revenue level will decrease over time from 7.2 cents. The decrease has three causes. First, sales growth spreads the revenue requirement over more kilowatt-hours. Second, the non-nuclear components of the rate base decrease with depreciation. And third, the nuclear plant depreciates. In order to isolate the effects of depreciating the new facility, suppose that there is no sales growth and no depreciation of other plant. Then, over the ten-year period, revenue per kWh declines from 7.2 cents to 6.6 cents. Over the following ten years, it declines to 6.0 cents as the nuclear facility contributes progressively less to rate base.

The irony of this traditional approach in an overcapacity situation is that those customers in the first ten years who do not need the new facility pay more for it than those in the second ten years who do.

If a 2 percent growth in sales does occur over the ten-year period, electricity prices would decline by 22 percent due to this cause alone.

Combining the two causes, revenue per kWh goes from 5.6 cents before the rate case to 7.2 cents immediately after the rate case, and declines to 5.6 cents again in the tenth year. This effect is illustrated in the left-hand side of table 2-4.

Because of the unfairness of this approach (and because it is increasingly realized that electricity demand does respond to price), alternatives to traditional rate base treatment of new capacity have been suggestd both by commissions and by utilities.

Phase-In

Phase-in treatment of new capacity, a relatively new regulatory concept, changes the traditional time-pattern of revenue flows over the first few years of a plant's useful life. Typically, plant-related revenues are reduced, compared to the traditional treatment, for the first two or three years that a plant is in rate base. Over the next two or three years, such revenues are above the usual levels. After the phase-in period, which may last for five years or so, revenues follow the traditional pattern. The revenues can be set at such a level that the net present value of the altered revenue stream equals that of the traditional revenue stream. Then, setting aside differences in cash flow, the plant may be considered fully included in rate base.

As used by the Illinois Commerce Commission, for example, phase-in is a tool for dealing, not with overcapacity, but with rate shock--the sudden large increase in rates when a new plant comes into rate base. Consequently, even though the plant may be fully needed to maintain the desired reserve margin, a phase-in approach has attractive features for other reasons.

Clearly, however, a commission could use a phase-in treatment for capacity in excess of immediate needs. The commission could phase a new plant into rate base in such a way that included capacity matches peak load plus reserve requirements as demand grows. After the plant is fully

TABLE 2-4

COMPARISION OF A TRADITIONAL AND A PHASE-IN APPROACH

	A Traditional Approach			A Phase-In Approach		
Year	Revenue Requirement[a] ($ x million)	Revenue per kWh[b] (¢/kWh)	Present Value of Revenue Requirement[c] ($ x million)	Revenues Collected ($ x million)	Revenue per kWh[b] (¢/kWh)	Present Value of Revenues Collected[c] ($ x million)
1	633	7.2	633	519	5.9	519
2	628	7.0	610	556	6.2	540
3	622	6.8	586	594	6.5	560
4	617	6.6	565	634	6.8	580
5	611	6.4	543	676	7.1	601
6	606	6.2	523	663	6.8	572
7	600	6.1	503	645	6.5	540
8	595	5.9	484	627	6.2	510
9	589	5.7	465	621	6.0	490
10	584	5.6	448	584	5.6	448
			total: 5360			total: 5360

Source: Authors' calculations.

a. Assumes straight line depreciation for the nuclear unit of the hypothetical utility in appendix A over 30 years; assumes no inflation in expenses and no change in the percentage cost of capital; assumes no additions to rate base during the ten-year period; and assumes there is no depreciation of the non-nuclear component of the rate base in order to isolate the effect of treating the new addition of generating capacity.

b. Assumes generation grows at 2 percent per year regardless of the price of electricity.

c. Assumes a real rate of interest of 3 percent.

included and fully useful, the commission may choose to provide full compensation for the company's carrying costs by raising rates awhile above the traditional level. In this case, such costs are more appropriately borne by customers making full use of the new facility and are more easily borne when spread over a larger number of kilowatt-hours.

Of course, a commission may choose to phase in a new facility as described--matching capacity inclusion with capacity requirements--without raising rates above the traditional level thereafter. Such an action is essentially the same as the options discussed in previous sections for excluding capacity, fully or partially, from rate base until it is needed. Thus, phase-in plans may differ in their advantages and disadvantages according to the features of the specific plan. Here, phase-in treatment refers to the case in which cash flow is delayed for the first few years but the net present value of the revenue stream is the same as under traditional, full rate base treatment.

An illustration of a particular phase-in approach is presented in the right-hand side of table 2-4. Recall that in the traditional approach, shown on the left-hand side, revenues per kWh rise abruptly from 5.6 cents before the rate case to 7.2 cents afterward. Expenses, apart from income taxes, amount to 4.2 cents and interest on long-term debt contributes 0.7 cents. In every year, under both approaches shown in the table, revenues are adequate to cover these costs. All revenues over 4.9 cents go toward earnings on preferred and common stocks and income taxes.

Under the traditional approach, earnings are higher in the early years. Over the ten-year period, the present value of the revenue stream is $5360 million. This is determined using a discount rate of 3 percent, a rate assumed to be equal to the rate of interest in an inflation-free period.

With the phase-in approach, the revenues collected are less than the traditional revenue requirement for the first three years, and more for the next six years. In the tenth year and afterwards, the revenues are the same. However, the present value of the revenues collected over the ten-year period is the same with both approaches. Because the same expenses and interest are subtracted each year from the revenues, the two earnings streams also have the same value.

In theory, a utility would be indifferent to a choice between the two approaches. In practice, utilities may prefer the traditional approach for several reasons. It presents less of a cash flow problem; it calms worried investors who have waited through a lengthy construction period to start earning a return; and it presents less of a risk that commissioners and commission policy may change during the phase-in period.

However, utilities may prefer--even suggest--a phase-in approach to full cost recovery if they see it as an alternative to full or partial rate base exclusion of new capacity. Furthermore, a utility may favor a phase-in policy if it does not believe that a 29 percent rate increase leaves customer demand unchanged.

The phase-in example in table 2-4 is designed to ease rate shock by providing for increases in revenue per kWh of 3 mills a year, from the pre-rate-case level of 5.6 cents up to 7.1 cents. This example shows, of course, only one of many possible revenue rearrangements that could be designed to keep the present value of the revenue stream constant.

From the customers' viewpoint, this phase-in approach still has the disadvantage of granting full cost recovery for a 43 percent reserve margin.

Intergenerational equity is improved in the phase-in approach compared to the traditional approach because the burden on customers who least need the additional capacity is reduced and shifted toward future customers who may have a greater need. Nevertheless, in this example of 2 percent growth rate, a phase-in period of ten years fails to shift the burden sufficiently forward in time--to the second decade when the additional capacity is actually required.

Rate Trending

Phase-in disturbs only the first few years of traditional revenue flow. Rate trending changes the traditional flow over the entire depreciation-life of the plant.

Under traditional rate base treatment, customers pay for return on the full value of the plant initially and pay less each year as the plant is depreciated, until the payments shrink steadily to zero at the end of the plant's depreciation life. As a result, rate base is dominated by recent plant additions, not only because recent additions are large and more expensive, but because older units have undergone significant reduction in contribution to rate base. (An example of this effect is in table A-5 of appendix A.)

Such an approach loads investment costs on customers who are served in the early years, and especially in the first year, of a unit's life. Yet, these are the customers who have the least need for the plant in an overcapacity situation. Alternative regulatory approaches are, of course, possible. One is to provide for a schedule of repayments to investors like that of a 30-year home mortgage: each year the same payment is made. This approach is sometimes referred to as using "trended rates." This approach may be more equitable in that the plant is, presumably, equally useful to ratepayers over its 30-year life. While this approach may not shield early-year customers as well as a phase-in plan does, neither does it burden early-year customers more heavily than the later-year customers.

This approach is less attractive from the utility's point of view, however. The traditional approach provides for equal return of capital investment each year, along with an earned return on the remaining investment. The mortgage-approach provides mostly for return of the investment and little return on capital in the early years, just as a home mortgage payment consists mostly of interest payments in the early years with little return of principal.

Suppose our typical utility were to recover its $886 million investment in the nuclear unit and associated transmission facilities using a recovery schedule that behaved like a schedule of mortgage payments. The results, before provision for income taxes, would be those presented in table 2-5.

In the traditional approach, the constant factor from year to year is the amount of straight line depreciation. Depreciation expense is analogous to repayment of principal in a mortgage, just as regulatory return on rate base is like mortgage interest. The traditional approach leads to large total payments (depreciation plus return) in the early years and small payments in the later years of a unit's depreciation life.

In contrast, the total payment is the constant factor from year to year in the mortgage approach. The 30-year total interest (return) is greater in this case because customers take longer to return principal. Notice that the interest/return is the same in the first year in the two approaches. But the mortgage approach is slower to return principal/depreciation: it could be called "decelerated depreciation."

The motivation for this approach is two-fold: it enhances intergenerational equity because payments for the new unit are spread evenly over current and future customers, and it alleviates the problem of overcapacity by shifting some of the payments for the capacity into the future, when the capacity is needed more.

The advantages and disadvantages of this approach are similar to those of the phase-in technique. However, utilities prefer phase-in because, after the phase-in period, the traditional, early recovery of investment occurs. Furthermore, the mortgage approach is at a disadvantage because it is novel in the regulatory arena, where precedent is important and traditional techniques have a long history. Whether the mortgage approach would be more of a departure from tradition than the phase-in approach is an open question.

TABLE 2-5

COMPARISON OF A TRADITIONAL AND A MORTGAGE APPROACH*
(in millions of dollars)

	A Traditional Approach		A Mortgage Approach	
Year 1 :	Depreciation	29.5	Principal	3.7
	Return	106.3	Interest	106.3
	Total	135.8	Total	110.0
Year 10:	Depreciation	29.5	Principal	10.2
	Return	74.4	Interest	99.8
	Total	103.9	Total	110.0
Year 20:	Depreciation	29.5	Principal	31.6
	Return	39.0	Interest	78.4
	Total	68.5	Total	110.0
Year 30:	Depreciation	29.5	Principal	98.2
	Return	3.5	Interest	11.8
	Total	33.0	Total	110.0
30-year total:	Depreciation	886.0	Principal	886.0
	Return	1648.0	Interest	2413.7

Source: Authors' calculations.

*Based on an investment of $886 million at a cost of 12 percent per year for 30 years. Income taxes on return are omitted.

Note that the mortgage approach does not provide for truly equal treatment of customers over the years because inflation makes later dollars worth less than early dollars. If economic equality were the only goal, customers would make equal real dollar payments over the life of the plant. This would result in payments in nominal dollars increasing from year to year--just the opposite of the traditional approach. Such an approach is attractive from the customer's viewpoint in a period of overcapacity because it reduces early year payments even more than the mortgage approach. With respect to intergenerational equity, it may well be the ideal approach--still assuming that the plant is expected to be equally useful and valuable to the customer over its entire depreciation life.

But, from the investor's viewpoint this is the least desirable of the approaches that provide for full rate base treatment because significant cash flow is deferred further into the future, implying additional risk.

Summary

In summary, the supply-side options offer a variety of approaches, ranging from those that mostly favor customers to those that mostly favor the utility. We have seen a way of fully excluding excess capacity from rates that leaves the company virtually unharmed financially, and we have seen a way of fully including all capacity that defers much of the resulting rate increase into the future.

For each option of excluding some capacity, the effects of the option depend heavily on whether the newest capacity, the average capacity, or the least efficient capacity is excluded. The effects depend too on how the commission chooses to treat the expenses of the excluded plant, including depreciation expense, and how fuel cost savings are treated.

The examples in this chapter, based on a typical "average" utility are useful for illustrating the overcapacity option and for assessing the likely effects of each option. Table 2-6 and figure 2-1 summarize some key features of these results. Clearly, these effects will not be the same for every actual company, with a unique fuel mix, level of reserves, capital structure, and so on.

The principal fault in these examples, however, is the assumption that demand is unaffected by the price of electricity. We postulate a utility with a peak load of 1645 MW and annual generation of 8790 GWh at a price based on 5.6 cents per kWh of generation. We assume further that rates could increase by 29 percent (to cover 2350 MW of installed capacity) without decreasing sales at all.

In the next chapter, factors affecting the demand for electricity are discussed, including the important effect of electricity prices.

TABLE 2-6

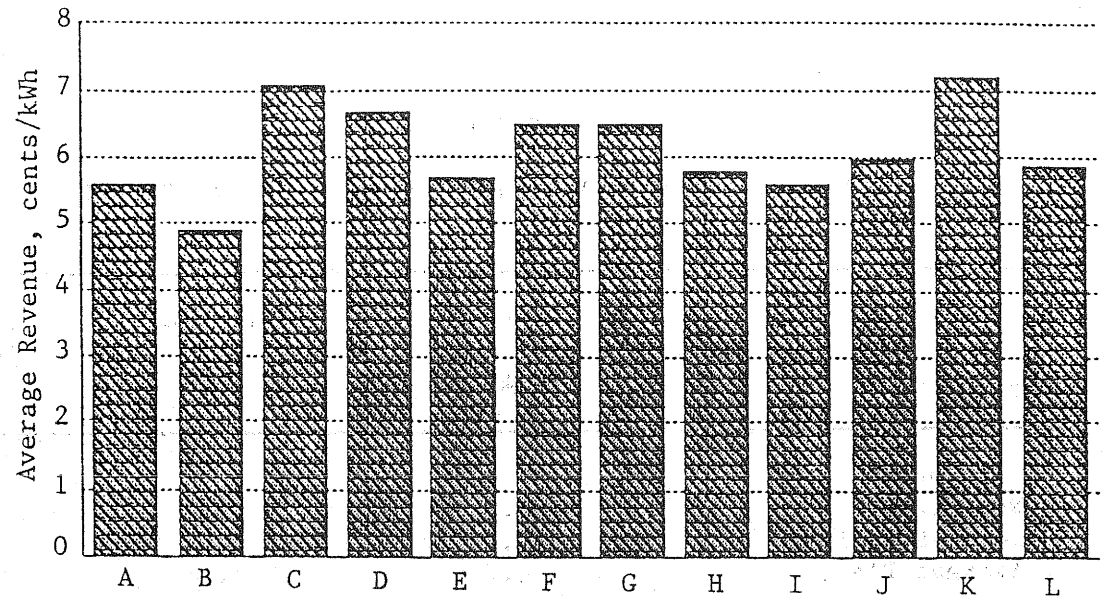
RESULTS OF THE SUPPLY OPTIONS FOR THE TYPICAL UTILITY*

Option	Revenue per kWh (¢/kWh)	Return on Equity (%)	Interest Coverage Ratio
Full Exclusion			
New Plant	4.9	0.0	0.92
Least Efficient	7.1	14.5	2.46
Average Plant	6.7	11.1	2.18
Partial Exclusion			
50%	5.7	3.0	1.50
2:1 Cov. Ratio	6.5	10.2	2.00
Graduated Exclusion	6.5	9.5	2.05
Equity Only	5.8	6.6	1.80
Constant Revenues	5.6	2.0	1.42
Imputed Sales	6.0	5.2	1.69
Full Recovery			
Traditional	7.2	15.0	2.51
Phase In (first year)	5.9	4.5	1.62
Trending (first year)	6.9	12.7	2.31

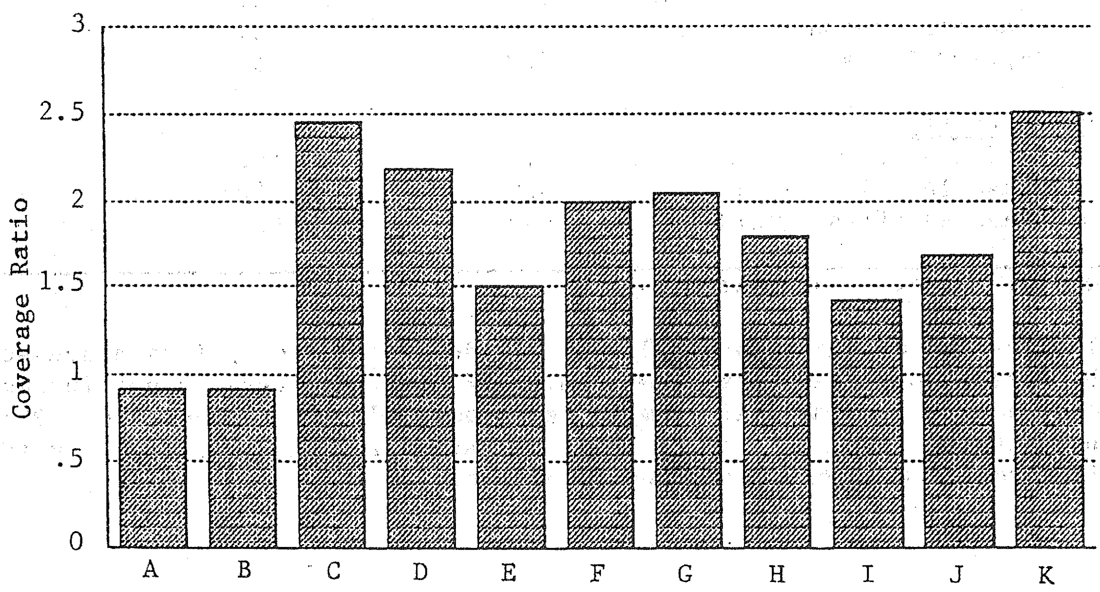
Source: Authors' calculations.

*The results depend importantly on the additional assumptions discussed in the text. Note that partial exclusion of carrying costs is not included here because no numerical example is associated with this option. Phase-in and trending results, based in part on tables 2-4 and 2-5, are only for the first year that these rates are in effect.

AVERAGE REVENUE, SUPPLY OPTIONS



COVERAGE RATIO, SUPPLY OPTIONS



Legend:

A	Exclusion of unused new plant	H	Equity only
B	Exclusion of used new plant	I	Constant revenues
C	Least efficient plant	J	Imputed sales
D	Avergage plant	K	Traditional recovery
E	50% exclusion	L	Phase-in
F	2:1 Cov. Ratio		
G	Graduated		

Fig. 2-1 Average revenues and coverage ratios for the typical utility under selected supply options

CHAPTER 3

OPTIONS ASSUMING VARIABLE DEMAND

A major regulatory option for treating overcapacity is the promotion of sales. The use of this option, however, assumes that demand can be increased sufficiently to soak up a substantial portion of the excess capacity. Promotion can involve increased sales to other regions, or within the region, as well as to the utility's own customers. The latter can involve stimulation of sales through price incentives or through marketing techniques.

In this chapter we discuss the efficacy of all of these methods, each of which assumes that demand can be made to vary. We start with a discussion of increased sales to other regions.

Promotion of Bulk Power Sales

The promotion of bulk power sales, both to neighboring utilities and to buyers in other regions, would appear to be a logical solution to the problem of excess capacity. Such a solution is viable, however, only if there are imbalances in the system. That is, bulk power sales can be utilized to reduce surplus generating capacity if one utility is short on capacity while another has overcapacity, or in those cases where one utility can produce and deliver electricity to a second utility at lower cost than the latter can produce from its own equipment. Electricity transfers of this type imply the existence of a regionally intertied transmission network, which may not exist in all areas of the country. In recent years, however, there has been a move toward tighter interties among individual utilities, as well as among regions. The reasons for the impetus to interconnection are briefly reviewed below.

Interconnection--Pros and Cons

The increased interconnection among systems has occurred primarily as a way to improve reliability and provide an emergency source of energy.[1] It has also been undertaken in some cases in order to achieve operating and investment economies through the use of central dispatch. Much of the current interconnection has occurred in recognition of the benefits that accrue to the individual systems. These include economies of scale, reduction in the need for generating reserves, and improved system reliability at lower cost. Interconnection permits the exploitation of load diversity among systems, permitting base load units to operate at higher capacity factors so that economies of scale can be realized. Reserve margins can also be reduced through the coordination of maintenance schedules, and by reducing the probability of outages. The latter occurs because there are more units available as backup.

It is felt by some students of the industry that further economies of scale from interconnection will not be available due to the erratic nature and uncertain magnitude of whatever load diversity may still remain untapped. In addition, load management and time-of-day pricing may further reduce the economies available through interconnection. These methods improve system load factors and equipment utilization so that it may not be advantageous to interconnect. Further, lower demand expectations and consequent reduced construction of new units may make utilities hesitant to build additional transmission in the coming years. Thus, the current ties among utilities may not be substantially expanded in the future. If so, it could result in difficulty in using the network for the management of excess generating capacity since many lines are currently fully loaded, or are needed for reliability purposes.

Alternatively, the use of interconnections to help solve the excess generating capacity problem would be a relatively inexpensive solution. The magnitude and scope of sales among neighboring (intraregional) utilities are dependent upon the specific situation, and can be

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[1] Congressional Research Service, The National Electrical Grid--A Concept Whose Time Has Come?, Report 78-99S (Washington: Library of Congress, May 1978).

determined only in each individual case. It is somewhat easier to judge the efficacy of interregional transfers, on the other hand, since many regions are intertied. There are currently some 57 interregional connections, with another 20 planned over the 1983-1992 period.

One problem for commissions with regional exchanges is the fact that most of these will be outside of the direct control of the states and may be difficult to foster. In addition, there may be environmental problems that make such exchanges inappropriate. These include questions regarding space requirements for high voltage lines, aesthetics, audible noise, radio and TV interference, and perhaps of greater importance, the question of the biological effect of these voltages. The latter relates to the possible effects of the electric and magnetic fields on human beings.

With this sketch of the advantages and disadvantages of bulk power sales, we can now turn to a discussion of the potential for such sales, beginning with an outline of the current status of the transmission grid.

The Transmission Grid

In 1983 there were 129,000 circuit miles of high voltage transmission in the United States.[2] It is anticipated that an additional 40,000 miles will be added over the next ten years. This is some 6,000 circuit miles less than had been planned the previous year, but still represents a substantial increase. The bulk of the current system (50 percent) is at 230 kilovolts (kV), but a substantial portion of the planned additions are at 345 kV. There has been a steady increase in line voltage levels in recent years, in order to allow the economical movement of large blocks of energy over relatively long distances.

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[2]The information in this paragraph is from two sources: North American Electric Reliability Council, 13th Annual Review of Overall Reliability & Adequacy of Bulk Power Supply in the Electric Utility Systems of North America (Princeton: NERC, August 1983) and North American Electric Reliability Council, Electric Power Supply & Demand 1983-1992 (Princeton: NERC, 1983).

There are three major transmission networks in the United States: one each in the east, in the west, and in Texas. These have evolved primarily as a result of reliability requirements. The three networks are not currently interconnected, but the regions and utilities within each are intertied with connections of varying strength. The networks are designed to improve reliability and planning, but central dispatching of electricity is not employed on a network-wide basis. Within each network there are power pools, some of which do employ central dispatch.

Central dispatch involves the operation of generating units based on optimum economic considerations for the interconnected system as a whole, rather than optimum conditions for an individual utility. The centrally dispatched systems tend to be located in the east, and comprise approximately 40 percent of U.S. generating capacity. These groupings are of two kinds: those under the financial control of a holding company and those that are voluntary associations of independent utilities. Company groups include the Allegheny Power System, Commonwealth Edison and Central Illinois, the Southern Company, the Tennessee Valley Authority, and Middle South Utilities. Among the voluntary associations are the Pennsylvania-New Jersey-Maryland Power Pool, the New York Power Pool, the Michigan Coordinated System, and the Michigan Municipal Cooperative Power Pool. All of the centrally dispatched power pools undertake normal pool functions, along with the dispatching function.

The main purposes of the remaining power pools lie in coordinating the planning of new capacity, in controlling load frequency, in developing emergency procedures, and in coordinating maintenance scheduling. Dispatching is left to each utility. These activities improve the reliability of the coordinated network and can lead to greater economies of scale in terms of equipment components and through the pooling of reserves. Included among these are groups in California, the eastern Missouri River Basin, Eastern Wisconsin, Florida, Illinois-Missouri, the Pacific Northwest, and the Rocky Mountain area.

Overlaying the power pools are the nine regional councils, and various subcouncils, that make up the North American Electric Reliability Council. These help in coordinating planning and in assuring improved reliability. Virtually all of the electric utilities in the United States are represented on the councils, whether investor, publicly, or cooperatively owned.

The discussion above indicates that sufficient interconnections exist to make it physically possible to sell the output from excess capacity to other utilities. In recent years there have been a number of large scale energy transfers for economic reasons among systems. As a consequence, assuming these continue, the transmission capability margin will be somewhat lower than in the past, although still meeting accepted reliability standards. Whether transmission would be adequate to the task in a specific case can only be answered in the context of that case.

Sale Possibilities

Given the ability to move electrical energy among companies, the next question that requires resolution is whether anyone needs the surplus (i.e., is there a market?). This requires an indication of whether the price would be adequate to cover the costs of the seller and low enough to entice the buyer, as well as an indication that someone needs the energy.

Pricing

The costs incurred in building the excess plants are sunk costs, and as such constitute "water over the dam." Therefore, the seller should be willing to sell at a price that, at least, covers the running cost and some portion of the fixed costs. Presumably, the seller would not be able to collect all of his fixed costs. This would mean that whatever debt remained from the construction of the plant would be partially covered by electricity sales, and partially in some other way. In such a case, both the stockholders and customers would be better off than if no sale were made. In the latter instance, the full fixed costs would have to be paid by those groups, along with whatever maintenance expenses might accrue.

The buyer, on the other hand, should be willing to pay no more than his marginal cost of production. In some cases this will be the avoided cost of a new plant. In other cases, marginal cost will be the cost incurred by running an oil or gas fired base load unit, or some other high cost plant. In these cases, capital costs are sunk and should not be a part of the cost calculations.

In any case, it is apparent that the price acceptable to both the buyer and seller will have to be decided as a result of negotiation and will vary from case to case depending on the circumstances. There is, however, a great deal of room to maneuver, so that there should be no difficulty in arriving at a satisfactory price, assuming there is a need for the electricity.

Markets

One way of judging the availability of markets for electricity is through consideration of the reserve margin or capacity margin, because these both measure the adequacy of the capacity available to assure the reliability of the system. As mentioned, if a 20 percent reserve margin is considered adequate for reliability purposes, then the comparable capacity margin would be 17 percent. Therefore, a reserve margin in excess of 20 percent, or a capacity margin in excess of 17 percent, would indicate the possibility of excess capacity. The actual margin required will depend on the equipment configuration of the system, plant age, maintenance requirements, outage rates, and other factors discussed in chapter 1, as well as the uncertainties and risks facing the utility. Here, we use capacity margin as a measure of adequacy and assume that 17 percent is adequate for reliability purposes. A capacity margin above that level can be assumed to indicate excess capacity, while a margin below that level can be assumed to indicate a shortage.

In table 3-1, we list the computed capacity margins for each NERC region and certain subregions for 1982 and 1992. These regions and subregions are shown in figure 3-1. These computations are based on actual 1982 data, as well as on peak and capacity projections for 1992 by NERC.[3] The regions listed include all of the NERC regions; the western area, however, is broken down into subregions. The latter appears desirable because of the large area covered by the western region. The subregions tend to be more homogeneous than the region as a whole.

It will be noted that all of the regions, with the exception of California-Nevada, had large capacity margins in 1982. The California-Nevada region was marginal, being within 1 percentage point of our 17 percent capacity margin criterion.

In 1992, all of the regions should have adequate generating reserves, if current plans are carried out. Texas (ERCOT) would be at the 17 percent

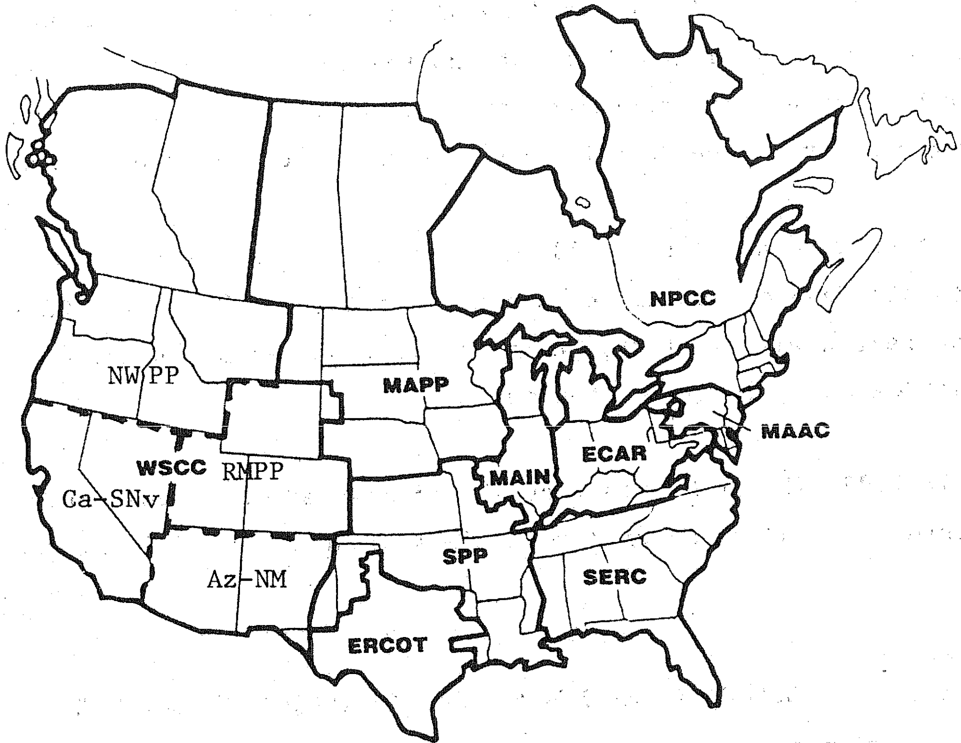
TABLE 3-1

CAPACITY MARGINS BY NERC REGION, 1982 AND 1992

		1992	
Region	1982	Planned	Adjusted
ECAR	33%	22%	21%
ERCOT	24	17	0
MAAC	27	24	24
MAIN	23	20	20
MAPP	29	19	12
NPCC	28	29	27
SERC	29	22	20
SPP	26	20	12
NWPP	35	23	19
RMPA	34	18	16
Az-NM	29	27	20
Ca-SNv	16	19	19
U.S.	29	23	20

Source: NERC, Electric Power Supply & Demand 1983-1992. Capacity margins computed by authors.

[3]Ibid.



ECAR--East Central Area Reliability Coordination Agreement

ERCOT--Electric Reliability Council of Texas

MAAC--Mid-Atlantic Area Council

MAIN--Mid-America Interpool Network

MAPP--Mid-continent Area Power Pool

NPCC--Northeast Power Coordinating Council

SERC--Southeastern Electric Reliability Council

SPP--Southwest Power Pool

WSCC--Western Systems Coordinating Council

The WSCC subregional borders (dotted lines) are approximate. The subregions are:

NWPP--Northwest Power Pool

RMPP--Rocky Mountain Power Pool

Ca-SNv--California-Southern Nevada

Az-NM--Arizona-New Mexico

Fig. 3-1 North American Electric Reliability Council map point, while the Rocky Mountain area would be at 18 percent. Other areas would have more robust reserves.

Alternatively, if it is assumed that only plant currently under construction will be available in 1992 (the adjusted case) and that plant planned or approved but not yet under construction will not be built within our time horizon, then a number of regions would have capacity margins below the safe level. Under this assumption, ERCOT would have no reserves, the MAPP and SPP regions would be very low, and the Rocky Mountain area would be marginal. The areas with a shortfall are not necessarily close by the surplus areas. It might, therefore, be difficult to move energy from those who have to those who need.

Considering all the above factors, we can conclude that an interregional market for the output of current excess plant is speculative, and at this point should not be regarded by state commissions as a viable solution to the overcapacity problem except in special cases.

Promotion of Jurisdictional Sales through Price Changes

Sales promotion can involve pricing efforts or marketing, or various combinations of these two methods. These can be aimed at specific customer groups or at all customers. Sales promotion has the potential to increase energy sales and revenues, thus reducing the need for general rate relief. On the other hand, these methods operate against the current "conservation" ethic. There is also the possibility that the surplus capacity problem may be of limited duration, with the consequent need for load control at a later date, assuming the sales promotion techniques are successful. In addition, sales promotion may raise the level of demand for the future, necessitating the construction of new, and more costly, plant compared with existing units. These various effects may provide conflicting and confusing signals to utility customers.

From the foregoing, it is apparent that the pros and cons of sales promotion are the same whether accomplished through adjustments in price or through the use of marketing techniques. Reduced prices, however, may not increase sales sufficiently to compensate for the revenues lost as a consequence of the lower prices. Therefore, price changes may have financial consequences not probable with marketing efforts. We deal first with price changes as a sales promotion tool. Marketing efforts are discussed afterwards.

It should be noted that several approaches can be used to estimate the effects of sales promotion and that a number of different criteria can be used to determine the desirability of sales promotion. It is also apparent that different conclusions concerning effect and desirability could be derived by various commissions depending on the situations in their areas and on their perceived regulatory goals. It is obviously not possible here to take account of every situation that may arise or to rate sales promotion against all possible regulatory goals.

Concepts and Assumptions

A limited literature exists regarding the use of pricing in the management of overcapacity. Further, there is little empirical evidence based on commission actions upon which judgements can be made. As a result, we constructed a model to test the effects of various price changes.

The model is based on the assumption that a change in average revenue (price) will cause a change in electric sales. In our study cases, the price changes may occur as a result of a decision to change prices to stimulate demand or because of the addition of plant. In order to achieve a dynamic model, virtually all items are recalculated for each year. That is, expenses are computed as the sum of fixed and variable costs. The latter is the product of O&M costs per kWh, including fuel, times generation. Fixed costs are computed as assets times a fixed charge rate covering depreciation and property taxes. Thus, expenses vary each year not only in response to output, but to changes in assets such as plant additions. Other factors are treated in a similar manner.

Data produced by the model is in nominal terms, although a zero inflation rate was assumed. This latter assumption is necessary in order to avoid complications in judging the results. In any case, since the same rate of inflation would have been used in all instances, there is little to be gained by including that factor.

Sample Utilities

The various mathematical relationships and constants used in the model are derived from samples of utilities. In the primary example, the data are based on the 204 class A and B electric utilities, resulting in the hypothetical typical utility of chapter 2 and appendix A with a capacity of 2350 MW. However, in chapter 2 the financial data are assumed or derived from the IEEE Test System and calculated associated costs. Here, the financial data are the actual averages of the 204 utilities. Therefore, the results of pricing scenarios derived here relating to revenue level, rate of return on rate base and equity, and interest coverage ratio are not directly comparable to the results of the supply options reported in chapter 2. Also, here a second utility is derived from a sample of six relatively large electric companies, each located in a different area of the country, in order to test the effect of utility size on the outcome of the model. This results in a utility with a capacity of 10,100 MW.

These two example utilities are called the "typical utility" and the "medium-size utility," respectively. Most of the price cases are run for each utility.

Elasticity

The relationship between sales and price is expressed in terms of elasticity. Demand or price elasticity can be defined as the percentage change in the quantity consumed that is induced by a given percentage change in price. That is, an elasticity of -0.5 would mean that a 10 percent increase in price would result in a 5 percent decline in sales.

This is what is generally called own-price elasticity. In addition, there is cross-price elasticity which measures changes in consumption resulting from changes in the price of substitute commodities, such as natural gas. Elasticity can also be computed for a number of other variables; for example, income elasticity. The latter would measure changes in sales as a result of changes in customers' income. For our purposes, we need only be concerned with own-price elasticity. In the case of electricity, this concept can apply not only to changes in overall price level, but to time-of-use rates. The latter is discussed in a later section dealing with that subject. The discussion that follows relates to the general concept of elasticity and to the possible effects of overall price changes.

There are usually a number of possible elasticities for a given product, each of which is dependent on a specific set of assumptions in regard to the customer's equipment and appliances, his time period for using these items, and other factors. Further, a particular value for elasticity reflects a specific price range along a stable demand curve. Price movements outside this range, or shifts in the demand curve, may result in a different elasticity value.[4] Therefore, elasticity estimates derived for a given electric rate structure may be of limited use in evaluating the utility of alternative pricing mechanisms, such as inverted block rates, time-of-use rates, and so forth. These mechanisms will have an effect on use patterns and consumption quantities. Therefore, elasticity estimates based on existing rate structures may not be valid when these are changed.

In any case, the elasticity of electric consumption is difficult to determine because of the block rate structure usually used. As a consequence of this structure, the quantity of electricity consumed is dependent on the price schedule, while the customer's location on that schedule is dependent on the quantity consumed. This circularity makes it difficult to

[4]W. S. Chern et al., Regional Econometric Model for Forecasting Electricity Demand by Sector and by State (Oak Ridge: Oak Ridge National Laboratory, 1978).

model the relationship between price and quantity, and raises the question of how best to represent price in econometric models.

These difficulties not withstanding, a number of elasticity studies have been prepared. These generally tend to deal with the period during which electricity prices were declining. The elasticities thus derived appear, nevertheless, to be close to those computed for the more recent rising price period. In any case, the falling price mode may be more appropriate for our purposes.

Elasticities are generally computed for a short run and a long run period. The short run is defined as that period during which adjustments can only be made by varying the intensity of use of existing equipment and appliances; new, and more efficient, capital items cannot be added. In the long run the adjustments to price changes come from variations in the capital stock. These long run adjustments are the major response to electricity price changes. For example, Sutherland, in a recent study, found that the reaction to a price change is relatively minor (15%) in the first year, rather large (51%) the second year, and somewhat smaller thereafter.[5]

The various elasticity studies, based on an analysis by Resources for the Future (RFF),[6] indicate a range for the residential sector of -0.03 to -0.54 in the short run, and -0.44 to -2.33 in the long run. The author of the RFF study concludes that residential price elasticity in the short run may approximate -0.10, and in the long term may be -0.75. The commercial sector is estimated at -0.2 or larger in the short run and in excess of -1.00 in the long run. This sector is so diverse, however, that these estimates may not mean very much. The elasticity estimates for the

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[5]Ronald J. Sutherland, "Distributed Lags and the Demand for Electricity," The Energy Journal 4, Special Electricity Issue (1983):141-151.

[6]Resources for the Future, Inc., Price Elasticities of Demand for Energy--Evaluating the Estimates, EA-2612 (Palo Alto: Electric Power Research Institute, September 1982).

industrial sector range between -1.00 and -1.50. In general, the relatively wide spread among the various elasticities indicates the uncertainty that prevails as to the appropriate estimated value.

In view of this uncertainty, in the subsequent sections of this chapter we use for our overall elasticity an average elasticity from some 19 studies involving all sectors; elasticity for the industrial sector is based on an average of six studies. Data for these were derived from the RFF study. Thus, the overall elasticity value assumed is -0.92, and the industrial elasticity value is -1.01. In other words, we assume that a 10 percent decrease in overall price causes a 9.2 percent increase in overall kilowatt-hour demand, and that a 10 percent decrease in industrial price causes a 10.1 percent increase in industrial kilowatt-hour demand.

Plant Costs

It is assumed that a new unit would cost $1500 per kW. This is based on the assumption that small increments of capacity would be needed and would be coal-fired. Inasmuch as nuclear units are generally much larger, it is unlikely that this kind of plant would be installed. Alternatively, gas and oil fired units are generally not acceptable because of relatively high operating costs.

A recent study in the Energy Economist indicated that nuclear plants under construction would have an estimated cost per kW ranging between $1100 and $3900, with an average of $2363.[7] Coal plants with pollution control equipment were estimated at $1200 per kW. An earlier study by the Energy Information Administration found coal plant costs ranging between $900 and $990 per kW, depending on location.[8] The Congressional Budget Office, on the other hand, estimated capital costs as ranging between $1078

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[7] "Can Anything Save the U.S. Industry?" Financial Times Energy Economist, March 1984, pp. 1-4.

[8] Energy Information Administration, Projected Costs of Electricity from Nuclear and Coal-fired Power Plants, DOE/EIA-0356/1, Vol. 1 (Washington: U.S. Government Printing Office, August 1982).

and $1285 per kW.[9] These were countered by an estimate prepared at approximately the same time as the CBO and EIA data by National Economic Research Associates.[10] They estimated a coal plant would cost approximately $800 per kW.

The unit contemplated for construction in our model is substantially smaller than the units costed out above. As a result the cost per kW might be higher, perhaps as much as 12 to 20 percent more. Given the need to adjust the construction cost data to our smaller plant size, and taking account of inflation since those estimates were prepared, we have selected $1500 as an appropriate estimate. This is substantially above the cost of most currently operating coal plants.

The Scenarios and Their Results

In the preceding chapter, it is assumed that the volume of electricity sales is unaffected by fluctuations in price. As we have seen, however, in our discussion of elasticity, constant kilowatt-hour demand in the face of price changes is unlikely. For example, in the cases discussed in chapter 2, a 13 percent decline in average revenue per kWh (price) is computed for the full exclusion case in which fuel savings more than compensate for new depreciation charges. Based on the assumed average elasticity, a price drop of that magnitude would cause an increase in long-run demand of about 12 percent. Conversely, with traditional full inclusion of all capacity in rate base, price would rise 29 percent, and demand would drop 26 percent over the long run, eliminating most of the expected revenue increase. These two examples represent the polar cases, and the other supply cases fall in between these two extremes. Such variations in demand will, of course, have an effect on revenues and, as a consequence, on the financial

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[9]Congressional Budget Office, Promoting Efficiency in the Electric Utility Sector (Washington: CBO, November 1982), p. 53.

[10]Lewis J. Perl, "The Current Economics of Electric Generation from Coal in the U.S. and Western Europe," presented at the International Scientific Forum on Reassessing the World's Energy Prospects, Paris, France, October 26, 1982.

health of the utility. We do not report these demand effects for the supply cases, since demand in chapter 2 is assumed to be determined without regard to price.

In this chapter, however, our purpose is to test the impact of price changes. Therefore, we compute variations of demand in response to such changes. As a consequence, revenues are determined by both the effect of lower prices and the resulting demand over time. This permits us to judge the impact of our postulated changes on both the utility and the customer.

In order to accomplish this, the model just discussed is used to test several scenarios. These include a base scenario, flat rate decreases, decreases for industrial customers, and time-of-use rate scenarios. Within each of these scenarios, a number of cases may be tested. The scenarios are run for each of our two example utilities. A summary of the various scenarios and cases is in table 3-2. As mentioned, the results are not directly comparable with chapter 2 results. The detailed results of all the scenarios are given in appendix B.

The Base Scenario

The base scenario (case 1) has no price reduction, but is designed to allow normal growth in demand to soak up the excess capacity. The amount of time for this to occur in the base scenario is taken as the test period for the other scenarios. Virtually every utility system increases its load each year. In the base scenario, a generation growth rate (2.5%) is selected that would result in a capacity margin in the 16 to 17 percent range in the tenth year.

The revenue requirement is determined by assuming that there is no change in rates during the ten-year period. Increased revenue results from increased sales. As a consequence, the utility has poor earnings in the early years, but this improves as sales rise, and with it equipment utilization.

TABLE 3-2

PRICE MODIFICATION CASES AND ASSUMPTIONS

Case	% Rate Decrease	Customer Class	Capacity Additions	Comments
Typical Utility				
1	0	---	0	Base scenario; business as usual; constant rev./kWh
2	5	All	0	Flat rate reduction
3	5	All	50MW/yr for 3 yrs	Flat rate reduction
4	10	Industrial	50MW/yr for 2 yrs	peak grows as generation
5	10	Industrial	0	Peak equals case 1
6	TOU	Industrial	0	Shoulder peak at ave. rev.; offpk at var. cost; pk at remainder
7	TOU	Industrial	0	Total & shoulder use grow at base case rate; pk drops at case 6 rate; off-peak = remainder
8	TOU	Industrial	0	Same as 6, except mid pk elasticity at one half case 6 value
Medium-Size Utility				
9	0	---	0	Base scenario
10	5	All	100MW ea/yr 8 & 10; 200MW/yr 9.	Flat rate reduction
11	10	Industrial	200MW/yr for 2 yrs.	Peak grows as generation
12	TOU	Industrial	0	Same as case 6
13	TOU	Industrial	0	Same as case 7

Source: Authors' assumptions.

Debt and interest charges are held constant throughout the period. One can maintain that a utility will rarely pay off any debt; it simply rolls it over into new debt. For the sake of simplicity, we assume that the interest rate remains constant over the period. Retained earnings are reinvested in the business each year, so equity increases. This capital is used primarily for transmission and distribution improvements. Assets increase in line with the increase in equity, but this is offset by depreciation.

The results of the base scenario for the typical utility are that load factor rises from 61 percent to nearly 64 percent at the end of the period. Capacity margin, on the other hand, declines from 30 percent to 16 percent. Rate of return improves steadily, rising from 7 percent to 12 percent in the tenth year. The coverage ratio also improves, almost reaching 3 by the tenth year. Levelized revenue per kWh, which as used here is the net present value of the stream of revenues divided by the kilowatt-hours produced over the ten-year period, equals 3.58 cents. The results for the medium-size utility were virtually the same.

Flat Rate Reduction

In the flat rate reduction scenario, we assume that all customers receive a flat 5 percent reduction in their bill, regardless of classification. Therefore, revenue per kWh drops and consumption rises in response to the reduced price of electricity. Assuming that the increased consumption is in line with an average total elasticity of 0.92, it can be inferred that a 5 percent reduction in price will cause a 4.6 percent increase in consumption over the long run. Based on our earlier discussion, the long run is defined as the period during which equipment, such as appliances and factory machinery, can be changed to take advantage of the lower rates. Since the price change occurs in the first year, it can be assumed that consumption increases at the short term elasticity rate (0.29) in the first year, at one half the long term rate in the second year, and at the remainder in the third year, based on our earlier discussion of Sutherland's estimate of the lagged response.

Three cases are examined for this scenario. Both the typical and medium-size utility are tested as outlined above, with capacity added as necessary (cases 3 and 10, respectively). In addition, a third case is run for the typical utility only, in which no capacity is added (case 2). In the latter case, the capacity margin declines below 17 percent by the eighth year. Thus, starting in that year, customers have to adjust to a less reliable system, or the utility has to add capacity.

The latter is the more logical course of action. For the typical utility, capacity is added in 50 MW increments in the eighth, ninth, and tenth years in order to keep capacity margin at 17 percent. The addition of capacity results in an increased revenue requirement. This, in its turn, causes a decrease in demand growth because of the higher rates needed to cover the cost of the additional capacity.

As a consequence of the plant cost assumption, assets in the last three years of our test period increase to reflect the additions, while interest on long term debt rises. The latter is based on the assumption that all of the new plant construction cost is funded by debt, rather than retained earnings.

For the medium-size utility, 100 MW is added at the start of the eighth year, 200 MW in the ninth year, and 100 MW in the tenth year. Each addition results in an increase in the revenue requirement and a corresponding drop in the demand growth rate.

The capital costs in each case are annualized to reflect depreciation, interest, and property taxes. This capital charge is added to the revenue requirement for the respective years. Expenses are adjusted to account for depreciation and property taxes. Interest charges are part of the rate of return and are reflected in net revenue.

If no capacity were added, coverage ratios would rise steadily throughout the period, but capacity margins would decline dramatically.

Load and capacity factors would rise to 64 percent and 56 percent, respectively, from first year levels of 61 percent and 43 percent.

On the other hand, if capacity is added, the coverage ratio for the typical utility would rise from the second year through the seventh year; it would then decline. Load and capacity factor rise until the year capacity is added; thereafter these factors decline, reaching 62 percent and 51 percent, respectively, in the tenth year. The medium-size utility follows a similar pattern insofar as coverage ratios are concerned. Load and capacity factors dip in the ninth year, but rise in the last year of the period, reaching 63 percent and 53 percent the tenth year. These compare favorably with 61 percent and 42 percent in the first year.

For the typical utility, levelized revenue per kWh, if no capacity were added, would approximate 3.39 cents. If capacity is added, levelized revenue would be slightly higher at 3.43 cents per kWh. The medium-size utility would have a levelized cost of 2.99 cents per kWh.

Industrial Rate Decrease

In the industrial rate scenario it is assumed that only the rates for industrial customers would decline by 10 percent. This customer group is targeted because of its importance and because of its ability to adjust demand to circumstances.

Three cases are tested: one each for the typical and the medium-size utility, in which the peak increases at the same rate as generation (cases 4 and 11, respectively), and the third case in which the peak for the typical utility is permitted to grow only at the same rate as in the base scenario (case 5).

Case 5 is based on the assumption that use at the peak does not increase as a consequence of a rate decrease. This assumption appears logical, because industrials pay separate demand and energy charges. Thus, while there would be a decrease in the total bill, the price signal from the demand charge would remain the same as before the price decrease. The lower overall charges would result in increased industrial demand for electricity. Assuming that, on average, a 10 percent decline in electric rates would cause a 10.1 percent increase in the industrial sector demand for electricity, and assuming industrial demand comprises 32 percent of total demand, total electric demand would rise by 3.23 percent over the long term. However, because of the need for industry to phase in equipment and expand electrification to additional operations, as discussed earlier, the incremental increase in total demand is spread over a three-year period as in earlier cases.

Since peak does not grow beyond the "normal" estimate in the third case, no additional capacity is required. As a consequence, load factor rises to 66 percent and capacity margin drops to 16 percent. The rate of return increases from 6.2 percent to 11.0 percent by the tenth year. The coverage ratio rises from 1.63 to 2.64.

In the other two cases, peak demand is assumed to increase at the same incremental rate above "normal," for the same three years, as generation. As a consequence, the capacity margin would fall to a dangerous level by the tenth year, if no capacity were added. In order to maintain reliability, capacity is increased by 50 MW in each of the ninth and tenth years for the typical utility. For the medium-size utility, 200 MW additions are required.

The revenue requirement in the tenth year increases compared with the base case. The higher prices cause industrial demand to be somewhat lower in those years than would have been expected without the cost of the increased capacity.

Despite the need for additional capacity, the overall rate of return for the typical utility rises from 6.2 percent in the first year to 10.5 percent in the tenth year. The coverage ratio follows a somewhat different pattern. It increases from 1.63 in the first year to a high of 2.42 in the eighth year; it then declines to 2.23 in the tenth year. The ratio stays above 2.00 in all years except the first three. The medium-size utility follows a similar pattern.

Load factor rises steadily throughout the first nine years, declining in the tenth year.

Time-of-Use Pricing

Utilization of time-of-use (TOU) pricing as a means of managing excess capacity may appear to be a contrary move. As a general rule, this form of pricing is regarded as a method of controlling peak growth. Its major benefit is usually a reduction in capacity and energy costs as a consequence of the cancellation or deferment of new capacity.[11] Our need is to utilize the excess already available. In this scenario an attempt is made to test the ability of TOU rates to improve equipment utilization, while not providing an incentive to build additional plant.

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[11]Many recent reports have discussed the benefits and effects of TOU pricing; for example, Dennis J. Aigner and Dale J. Poirier, Electricity Demand Consumption by Time-of-Use: A Survey, EA-1294 (Palo Alto: Electric Power Research Institute, 1979); Daniel Z. Czamanski and G. Timothy Biggs, A Method for Computing the Main Benefits and Costs of Time-of-Use Rates for Colorado Utilities (Columbus: The National Regulatory Research Institute, 1981); Ahmad Faruqui, Dennis J. Aigner, and Robert T. Howard, Customer Response to Time-of-Use Rates, Electric Utility Rate Design Study, Topic Paper 1 (Palo Alto: Electric Power Research Institute, 1981); Raymond P. H. Fishe, "The Number and Placement of Rating Periods for Time-of-Day Pricing," in Innovative Electric Rates, ed. S. V. Berg (New York: Lexington Books, 1981), pp. 55-78; Joseph G. Hirschberg and Dennis J. Aigner, "An Analysis of Commercial and Industrial Customer Response to Time-of-Use Rates," The Energy Journal 4, Special Electricity Issue (1983):103-126; Ronald J. Sutherland, op. cit.; and University of Arizona Engineering Experiment Station, Modelling and Analysis of Electricity Demand by Time of Day, EA-1304 (Palo Alto: Electric Power Research Institute, 1979).

Schwartz has stated that, in an excess capacity situation, off-peak prices should be at variable cost, while peak prices should be set to cover operating costs and a large part of the capital costs that accrue under an optimal capacity mix in a static environment.[12] This is also the consensus for TOU pricing in general. Schwartz states that TOU pricing should operate as if excess capacity were not available, in order to give customers the appropriate signal that the proper amount of capital has been allocated in both the short and long run.

A major problem in implementing TOU rates is the cost of the special meters needed to record consumption. Large users normally have the appropriate meters available. As a result, the cost of implementing TOU rates for this customer class is minimal, with the benefits more clearly outweighing the costs than in other cases. As a consequence, the cases tested are all restricted to TOU rates for industrial customers.

Data for the large customer class tend to be spotty, with most of the effort concentrated on the residential class. Even in the latter case, however, the data are not very substantial. Information on customers in between the industrial and the residential is virtually nonexistent.

In any case, the magnitude of the response depends on the differential between the peak and off-peak rate and on the industrial mix in an area. That is, not all industry is able to adjust to the price changes in the same way. The lack of homogeneity in the industrial sector, therefore, makes it difficult to predict a response. For our purposes, elasticities are assumed that are based on averages from the various studies on the subject.

We vary elasticities and time periods to produce three cases for the typical utility and two cases for the medium-size utility. The two utilities are tested first by allowing the peak to decline and both the

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[12] Eli Schwartz, "Excess Capacity" in "Utility Industries: An Inventory Theoretic Approach," Land Economics (February 1984):40-48.

shoulder and off-peak to increase in line with the estimated elasticities (cases 6 and 12). Here, the peak constitutes 30 percent of industrial consumption; shoulder peak, 55 percent; and the off-peak, 15 percent. The workday is assumed to be eight hours.

Both utilities are tested again (cases 7 and 13) where peak consumption constitutes 25 percent of the industrial total; the shoulder peak, 50 percent; and the off-peak, 25 percent. The workday is assumed here to be sixteen hours. Industrial consumption is assumed to grow at the normal rate; the peak declines in line with elasticity; the shoulder peak grows at the normal rate; and the off-peak consumption is the difference between the total and that of the peak and shoulder peak.

The typical utility is tested again in a third way (case 8) which is similar to case 6, except that the elasticity for the shoulder peak is taken at one half the level for that case. In all these cases, the off-peak price is taken at variable cost, the shoulder peak price at average cost, and the peak price at a level that would provide the rest of the revenue requirement. The ratio of the peak and off-peak prices is approximately 2:1.

In case 6, by the tenth year load factor rises dramatically to approximately 74 percent, while capacity margin declines to 19 percent. The rate of return increases to 14 percent, and the coverage ratio rises to well over 3. The results for the medium-size utility (case 12) are similar. Levelized revenue is 3.55 cents per kWh for the typical utility and 3.10 cents for the medium-size utility.

Cases 7 and 13 give somewhat poorer results compared with other time-of-use cases. Rate of return is not quite 11 percent by the tenth year, when the coverage ratio is 2.6. Levelized revenue, on the other hand, is the lowest of the TOU cases, and lower than the base case.

Case 8 has somewhat intermediate results. Load factor rises to 69 percent by year 10; capacity factor increases to 56 percent compared with

60 percent in case 6. The rate of return rises from 7 percent to 12 percent, while the coverage ratio improves from 1.88 to almost 3. Levelized revenue is roughly the same as in case 6.

From the foregoing, it is apparent that of the three TOU cases for the typical utility, cases 6 and 8 have the best impact on the utility, while case 7 results in the lowest levelized cost.

Summary of the Price Reduction Options

A summary of the results of the various scenarios and cases is in table 3-3.

A comparison of the pertinent statistics for the various scenarios and cases indicates that the time-of-use scenarios give the best general results. This is true for both the typical and medium-size utilities. Insofar as the scenarios tested here are concerned, there is no difference in the results between the typical and the medium-size utility. Therefore, our ensuing discussion deals only with the typical utility.

Load factor in the tenth year for selected cases is illustrated in figure 3-2. It is in excess of 65 percent in all three cases of the TOU scenario, reaching a high of 74 percent when peak declines but the shoulder and off peak usage increases. The other scenarios give a result below 65 percent, with the exception of the case where peak is held equal to that in the base scenario but industrial rates are reduced 10 percent. Load factor in several of these cases is below that for the base scenario.

The tenth-year rate of return (shown in figure 3-3), return on equity, and coverage ratio (shown in figure 3-4) are also lower than in the base scenario in all instances except for two of the TOU cases. Levelized cost, on the other hand, as illustrated in figure 3-5, is lower in all cases compared with the base scenario. This is to be expected, since all of the scenarios involve price reductions. The TOU cases have the highest

TABLE 3-3

RESULTS OF SELECTED PRICE MODIFICATION CASES FOR THE TYPICAL UTILITY

Year & Scenario	Load Factor (%)	Rate of Return (%)	Return on Equity (%)	Coverage Ratio	Levelized Cost (cents/kWh)
Base Scenario (case 1)					
Yr 1	61.00	7.16	11.02	1.88	
5	62.20	9.03	13.68	2.28	
8	63.12	10.61	15.22	2.60	
10	63.74	11.77	16.05	2.82	3.58
5% Reduction, All Customers (case 3)					
1	61.00	5.40	5.24	1.42	
5	62.20	7.58	9.76	1.91	
7	62.81	8.51	10.93	2.10	
8	62.37	8.81	10.95	2.02	
10	61.60	9.38	10.98	1.90	3.43
10% Reduction, Industrial Customers (case 4)					
1	61.00	6.21	7.90	1.63	
5	62.20	8.37	11.90	2.11	
8	63.12	9.88	13.51	2.42	
9	63.18	10.26	13.73	2.33	
10	62.85	10.53	13.71	2.23	3.49
TOU for Industrial Customers (case 6)					
1	61.00	7.15	11.00	1.88	
5	69.38	10.54	17.76	2.66	
8	72.75	12.44	19.46	3.05	
10	74.04	13.76	20.25	3.30	3.55
TOU for Industrial Customers (case 7)					
1	61.00	7.15	11.00	1.88	
5	63.90	8.26	11.61	2.08	
8	64.85	9.76	13.23	2.39	
10	65.48	10.85	14.12	2.60	3.53
TOU for Industrial Customers (case 8)					
1	61.00	7.15	11.00	1.88	
5	65.94	9.42	14.73	2.38	
8	67.81	11.10	16.35	2.72	
10	68.70	12.30	17.18	2.95	3.56

Source: Authors' calculations.

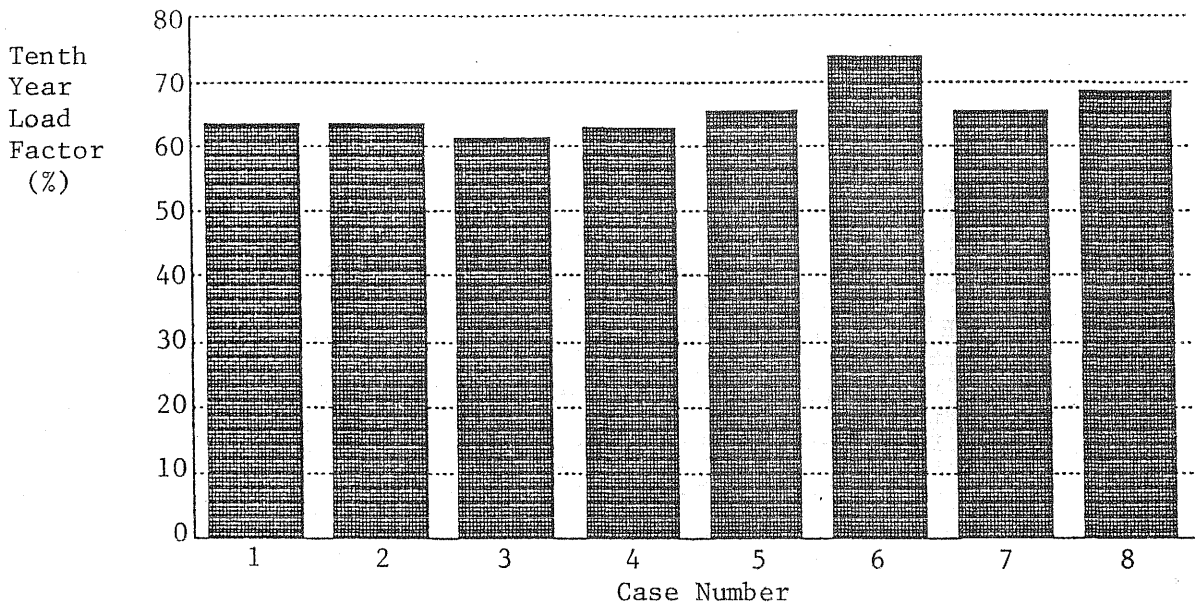

Fig. 3-2 Load factor in year 10 for the typical utility

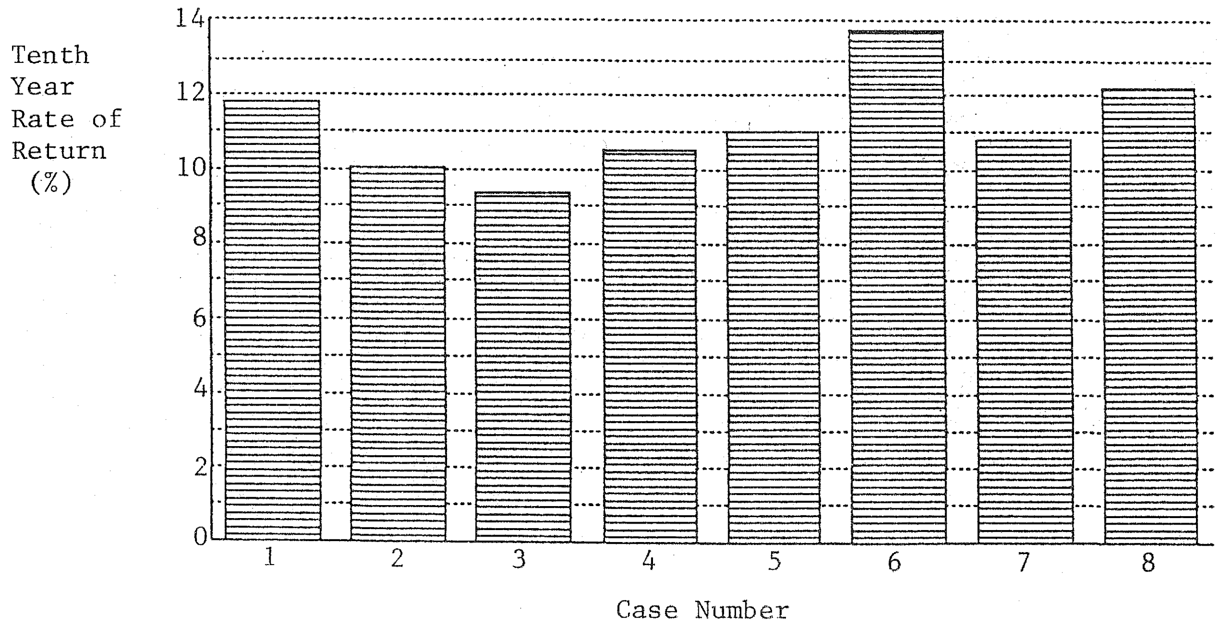

Fig. 3-3 Rate of return in year 10 for the typical utility

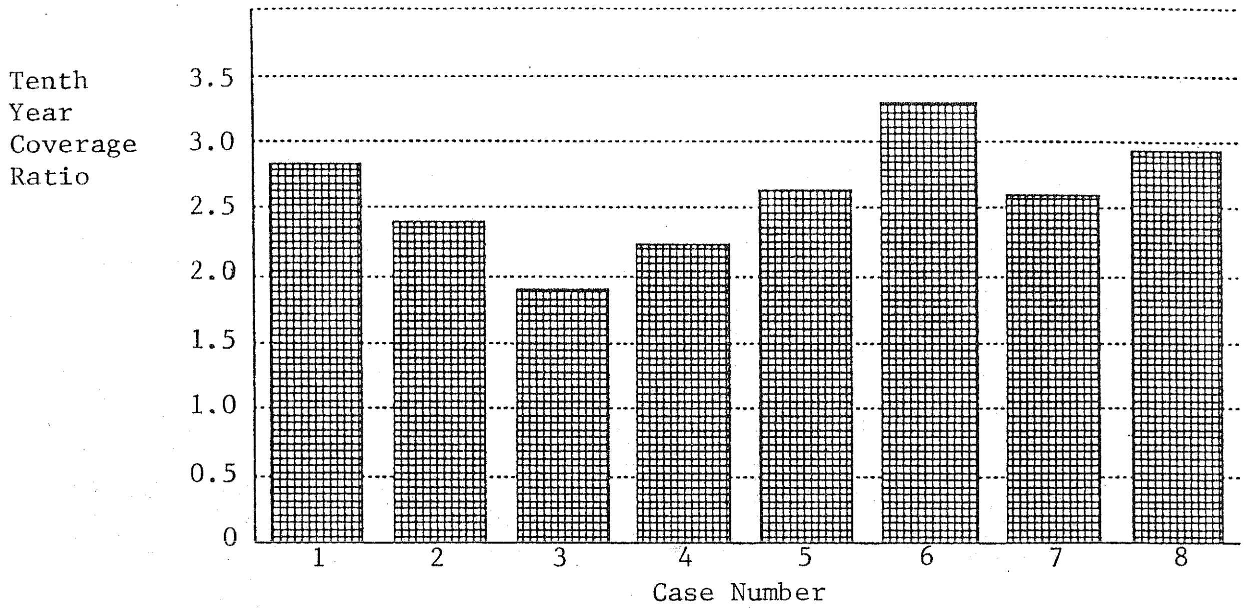

Fig. 3-4 Coverage ratio in year 10 for the typical utility

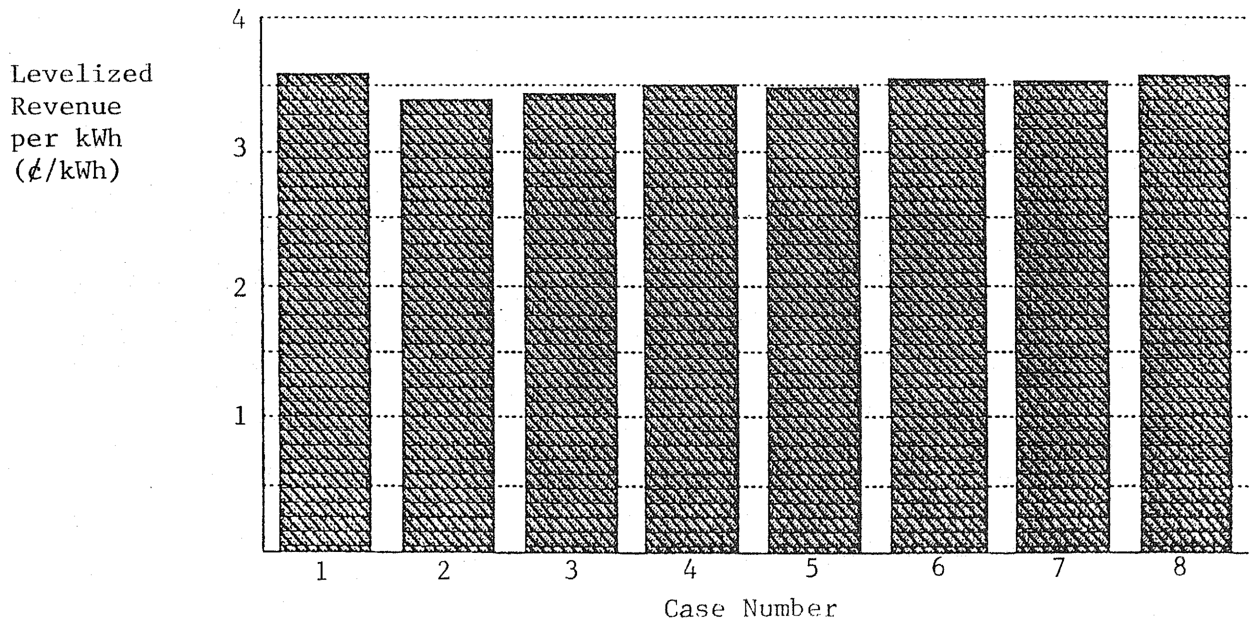

Fig. 3-5 Levelized revenue per kWh for the typical utility

levelized cost of the various price reduction scenarios, ranging from 98.6 percent to 99.4 percent of the base scenario. This would also be expected since rates increase for use at the peak, stay constant for use at the shoulder peak, and decline for off-peak usage.

It would appear that only the TOU cases give an overall result that is better than the base scenario.

Marketing

In the absence of price reductions, it may still be possible to stimulate retail sales through marketing.

Marketing can be defined as the management of consumer demand through creation of a new product or through design, packaging, performance standards, development of a sales strategy, and advertising. It can be assumed that if sales are not growing at the desired rate, a new selling formula can be found to correct the situation. This could include a change in sales methods, advertising strategy, product design, and so forth. This assumption is based on the belief that increasing affluence leaves the consumer more open to persuasion. That is, his wants are more psychological in origin, rather than oriented toward the fulfillment of physical needs. As a consequence, he is subject to management by appeal to the psyche.[13]

In the case of electricity, this appeal, or sales strategy, would probably have to be conveyed through advertising. Creation of a new product and redesign or repackaging of the product are not likely, given the physical characteristics of electricity. Thus, marketing electricity involves the development of a sales strategy based primarily on advertising.

Advertisements are of two general types: those that are designed to

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[13]John Kenneth Galbraith, The New Industrial State (Boston: Houghton Mifflin Co., 1967), pp. 198-210.

convey information and those that are designed to persuade the consumer to buy more of a product. It makes no difference to the producer whether he maximizes profits through changes in his price-output curve, by altering the physical condition of this product, or by spending money on advertising.[14]

All this implies that demand will increase when an advertising campaign is inaugurated. While this is a reasonable assumption, it is not inevitable. Consumers have been known to ignore advertisements, at least to such an extent as to make a continued campaign financially unwise.

In any case, even if the advertising effort is successful, it is not possible to predict the level of success. About all that can be said is that the development of a sales strategy and the institution of an advertising campaign may be the least expensive method of increasing demand. It should be kept in mind, however, that advertising, if successful, will cause demand to shift upward on a more or less permanent basis. This could result in the need to add more capacity than might otherwise be the case.

In other words, the use of marketing techniques to stimulate demand in order to soak up excess capacity could result in greater increases than desired. As a result, additional capital would have to be spent for new plant. If the latter continues to have higher costs than present plant, electric rates would rise. This could reduce demand at that time, possibly resulting in the creation of an excess capacity problem once again.

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[14]The classical economic theory of advertising is well-known; see, for example, Alfred W. Stonier and Douglas C. Hague, A Textbook of Economic Theory (New York: John Wiley & Sons Inc., 1961), pp. 190-197. It contends that as long as advertising adds more to the producer's revenues than it does to his costs, it will pay to continue increasing advertising expenditures. Those expenditures should be stabilized at the point where profits are maximized. Profits will be at their highest possible point when the incremental revenues derived from the incremental advertising expenditure equal the cost of that advertising. From that point on, increases in advertising expenditures will not bring in sufficient revenues to cover the increased cost. There is no point in increasing expenditures beyond the maximum profit level.

Conversely, consumers could greet the entire campaign with a yawn; in which case the funds expended would have been wasted.

CHAPTER 4

STATE COMMISSION POLICY: CHOOSING AMONG OPTIONS

In the past few years many states have been confronted with overcapacity and have determined a procedure for dealing with this problem. Some states have instituted experimental programs for dealing with it, while others are still considering their options. Other states have not yet faced the problem but expect to be presented with it over the next few years.

In this chapter, we present first some examples of commission treatment of overcapacity and then consider the factors that affect a commission's choice among options, including importantly the three regulatory criteria introduced in chapter 2.

Examples of Commission Treatment of Overcapacity

This section provides an overview of the regulatory activities that have taken place in various states where excess capacity has been an issue. The information came from a review of certain commission orders, testimonies, studies, and news releases available as of June 1, 1984. This is not an all inclusive survey of the regulatory activities relating to this issue. Certainly, more has taken place than is presented here; this presentation is intended to provide useful examples of commission actions.

This information is organized in a manner consistent with the presentation of the options presented in chapters 2 and 3.

Supply Options

Following are several examples in which states have considered or implemented an excess capacity adjustment where the revenue requirement is lowered using some type of rate base adjustment. However, the adjustment may or may not be explicitly linked to a particular component of the capitalization.

Exclude Excess Capacity

An example of a commission adjusting the rate base for excess capacity can be found in several cases which recently occurred in Pennsylvania. The Pennsylvania Public Utility Commission uses two criteria for determining whether an investment should be allowed a return. In order to receive a return on an investment, the utility must show (1) the investment decision was prudent when made, and (2) the investment property will be used and useful during the time the rate will be in effect. In applying the "used and useful" test, the Commission determines, from an economic perspective, whether the ratepayers will be "better off" without the investment.[1]

If certain capacity additions are deemed "excess," the rate base is reduced by that amount. In a recent decision, the Pennsylvania Commission ruled that the Pennsylvania Power and Light Company's share of Susquehanna Unit 1 (945 MW) is excess; consequently, they excluded from rate base a proportional amount of the company's complete capacity mix: "Under this approach, PP&L will be allowed to recover depreciation and other operating costs associated with the excess megawatts, but will not earn a return on the net plant investment."[2]

This approach is very similar to that undertaken by this commission in a case involving Philadelphia Electric Co., with the following justification:

> ...By allowing PECO to continue to recover annual depreciation, we are imposing upon the ratepayer the burden for sharing responsibility for these units, because the term of their usefulness was, to some extent, unpredictable at the time of investment.[3]

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[1]Pennsylvania Public Utility Commission v. Pennsylvania Power and Light Co., 55 PUR4th 185 (1983).

[2]Id.

[3]Pennsylvania Public Utility Commission v. Philadelphia Electric Co., 54 PaPUC 220, 37 PUR4th 381 (1980).

It should be noted that the method of adjusting for excess capacity applied by the Pennsylvania PUC allows the company to recover operating costs as well as normal depreciation on the plant considered "excess." Hence, it should be recognized that the adjustment is only to the return on rate base.

In one state the legislature took action to vest the Commission with the power to adjust a company's rate base for excess capacity. The Kansas Corporation Commission was recently given power by the state legislature to eliminate portions of a utility's rate base if excess capacity due to managerial imprudence is proven. According to House Bill 2927, which passed easily, the Kansas Commission is allowed to exclude from the rate base any plant deemed excess, even if it is presently included in the rate base of the company. The new law places the burden of proof on the utility to prove that any existing excess generating capacity is not a symptom of managerial imprudence. If the company fails to provide such proof, the excess is to be excluded from the rate base.[4] As of the date of this writing, this law has not been tested or applied.

Recent decisions by the Iowa Commission (discussed next) allowing partial compensation for excess capacity caused a move by members of the state legislature to limit the amount of excess capacity allowed any electric company operating in their jurisdiction. The bill, which passed the House but stalled in the Senate, would have set a basic reserve margin limit of 15 percent.[5] The legislative bill would also have required the commission to use the cost of the newest plant when determining the rate base adjustment, rather than the average system costs implemented by the latest orders.[6] The failure of this bill allows the Iowa Commission to continue ruling on excess capacity using the method described below.

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[4]"Kansas Lawmakers Vote to Boost Power of Commission to Deal With Rate Shock," Electric Utility Week, April 9, 1984, p. 1.

[5]"Iowa House Votes Excess Capacity Cap As It Finds Commission Ruling Too Soft," Electric Utility Week, March 26, 1984, p. 1.

[6]"Iowa Legislature Adjourns Without Putting Tight Cap on Excess Capacity," Electric Utility Week, April 30, 1984, p. 3.

Partially Compensate the Utility

The Iowa State Commerce Commission[7] has determined excess capacity to be anything above a 25 percent reserve margin. When a company is deemed to have excess capacity, an adjustment is made to the return on rate base. This operating income adjustment is calculated by applying the weighted cost of common equity to the net investment in generating capacity considered to be in excess. This is then multiplied by the ratio of excess capacity to peak load. The formula is:

$$\text{Return Adjustment} = \left(\frac{\text{Excess Capacity}}{\text{Total Generating Capacity}}\right)\left(\begin{array}{c}\text{Net Investment}\\ \text{in Total Gene-}\\ \text{rating Capacity}\end{array}\right)\left(\begin{array}{c}\text{Weighted}\\ \text{Cost of}\\ \text{Common}\end{array}\right)\left(\frac{\text{Excess Capacity}}{\text{Annual Peak Load}}\right)$$

The factor in this formula called the "weighted cost of common" is the product of the allowed rate of return on common equity and the proportion of the capital structure invested in common equity. For example, if the allowed rate of return on common equity were 17 percent and common equity comprised 40 percent of the capital structure, then the weighted cost of common would be .068, the product of 0.17 and 0.40.

The last factor in the formula adjusts the equity return on excess capacity by the degree to which the generation needs were overestimated. For example, if a utility has excess capacity which equals annual peak load, the entire equity return on excess capacity would be eliminated from the revenue requirement. However, if excess capacity amounted to 50 percent of the peak, one-half of the equity return would be allowed. This Commission stated:

> We have devised a formula which allows us to deny a greater percentage of the overall return on excess capacity that is clearly unreasonable than on excess capacity that only minimally exceeds the acceptable 25 percent reserve margin. We believe our formula provides an

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[7]Re Iowa Power and Light Company, 51 PUR4th 405, 410 (1983); and Re Iowa-Illinois Gas & Electric Co., 46 PUR4th 616 (1982).

incentive to utilities to avoid the construction of excess capacity and will encourage utilities to fine tune their planning methodologies to more accurately predict demand.[8]

This commission's stand was supported by the State Supreme Court in a ruling on an appeal by a utility that had its equity adjusted for excess capacity. The Court ruled that Iowa-Illinois G&E was not deprived due process by the adjustment.[9] Therefore, the Iowa Commission's method of adjusting for excess capacity has withstood challenge from both the legislature (as discussed above) and the Court.

The North Dakota Public Service Commission was confronted with the excess capacity issue in cases dealing with the Coyote generating facility.[10] In these cases the Commission determined excess capacity to be the difference between a utility's peak generating capability and its annual peak load plus reserve obligation. The Commission ruled that return on rate base should be adjusted for the excess capacity by eliminating the allocable common equity return on the generation plant responsible for the excess (in this case, Coyote). The Commission states: "We find that ratepayers should bear only the debt costs associated with surplus capacity and not the cost of providing shareholders with a return on common equity allocable to Coyote's surplus capacity."[11]

The method applied by North Dakota is very similar to Iowa's except the former specifically identifies the excess generating unit and directly uses this information to adjust the return on rate base. The North Dakota Commission ruled that the Coyote unit was responsible for the excess

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[8]Re Iowa Power and Light Company, 51 PUR4th 405,413 (1983).

[9]"Iowa Legislature Adjourns Without Putting Tight Cap On Excess Capacity," Electric Utility Week, April 30, 1984, p. 3.

[10]For two cases dealing with the Coyote facility, see Re Otter Tail Power Co., 44 PUR4th 219 (1981); and Re Montana-Dakota Utilities Co., 44 PUR4th 249 (1981).

[11]Re Montana-Dakota Utilities Co., 44 PUR4th 249 (1981).

capacity; therefore, the adjusted common equity return should be that which is directly related to the investment in the Coyote generating facility.

The South Carolina Public Service Commission found that the addition of the V. C. Summer nuclear plant creates aproximately 73 percent excess capacity for South Carolina Electric and Gas. Consequently, the PSC removed 400 megawatts from the rate base as an excess capacity adjustment.[12] The terms of this adjustment are as follows:

(1) the capacity excluded is valued at the average system capacity cost;
(2) the company is allowed to recover all the operating and maintenance costs incurred for the Summer plant;
(3) all depreciation costs associated with Summer may be recovered; and
(4) the carrying costs associated with the removed 400 MW may be booked at the overall allowed rate of return as a non-cash credit to income (similar to AFUDC).[13]

Essentially, this decision allows the company to recover all costs associated with the excess capacity except the return on rate base (which is valued at average system cost). The Commission will decide whether to allow some type of recovery of the deferred return at a later date.

In a 1982 case, the New York Public Service Commission used the imputed sales approach. It ruled that excluding excess capacity from rate base was too drastic a strategy and one that made it difficult to tie capacity additions to load growth. Hence, the PSC assumed sales were at the highest level reasonably attainable.[14]

Fully Compensate the Utility

Approaches for fully compensating the utility include the traditional approach, phase-in, and rate trending.

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[12]Nuclear Plant Phased in with Rate Base Reductions for Excess Production," Public Utilities Fortnightly, May 24, 1984.

[13]"PSC Trims 400 MW from ICE&G Rate Base, But At Average System Cost," Electric Utility Week, March 26, 1984, p. 5.

[14]Niagara Mohawk Power Corp. (NY PSC March 8, 1982) Opinion No. 82-4, Case Nos. 27984 et al.

Traditional Approach: In a recent case the Pennsylvania Commission turned down a proposal to adjust an electric utility's rate base for excess capacity. In an April 1984 decision this commission rejected an administrative law judge's recommendation that certain portions of rate base be excluded due to excess capacity. In this case the commission allowed the Pennsylvania Power Company to receive a return on all of its generating capacity, even though the company had a 32.6 percent reserve margin.[15] The commission reasoned that the present level of excess capacity in Penn Power is due primarily to the depressed economy; consequently, a reduction in the reserve margin will occur in the near future with the expected upswing in business conditions. In its order, the commission explained:

> This is not to state that a generating capacity reserve margin adjustment would be improper in all circumstances when attributable to depressed economic conditions. However, in the case of Penn Power, the economic conditions existing in the service area have contributed to the existing reserve margin which we do not find to be excessive in accordance with the foregoing discussion. Accordingly, the [proposed] adjustment will not be made.[16]

Some other states have ruled that overcapacity is not excess capacity unless conditions are severe. For example, the Public Utilities Commission of Ohio has rejected excess capacity adjustments in several cases over the last few years. In one such case, the Dayton Power and Light Company was operating with a 25.3 percent reserve margin. An intervenor in the case recommended some type of adjustment for excess capacity. The commission staff applied the following multistep test for excess capacity, which was subsequently adopted by the commission:

(1) Compare the annual peak with the company's installed capacity. If the reserve margin is greater than 20 percent perform step two.

(2) Compare the peak against available capacity without the company's largest unit. If the reserve margin

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[15]"PUC Rejects Excess Capacity Penalty Sought By Law Judge for Penn Power," Electric Utility Week, April 16, 1984. p. 3.

[16]Pennsylvania Public Utility Commission v. Pennsylvania Power Co., Order in Docket # R-832409, p. 13 (1984).

> is now less than 15 percent, no excess exists. If the reserve is greater than 15 percent, the staff will undertake a "more detailed investigation of the circumstances of the individual company."[17]

In a 1982 DP&L case the company's capacity passed the aforementioned test, thus the "more detailed investigation" was not required. However, the following language from the order hints that the commission considers managerial imprudence to be another test.

> There has been no showing that applicant's capacity planning has, in any way, been imprudent, and their is no evidence in this record upon which to base a conclusion that applicant has excess capacity.[18]

In a similar case between the Ohio Commission and Cleveland Electric Illuminating Company, the Commission ruled against an excess capacity adjustment stating that:

> In making the determination we must point out that we have previously explained the conceptual problems associated with a rate base adjustment for excess capacity. It is obvious that it is impossible for a company to add increments of capacity at a rate which will precisely match the increase in demand over a period of time. Capacity is added in large incremental amounts which may lead to a possible excess in capacity at a given point in time. A specific recommendation on a reduction in rate base, however, must be judged against the reasonableness of the actions taken by the company.[19]

In a 1981 decision, the Ohio State Supreme Court ruled in favor of the Commission's method of handling the excess capacity issue. In its decision the court said:

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[17] Re Dayton Power and Light Co., 45 PUR4th 549 (1982).

[18] _Id._

[19] Re Cleveland Electric Illuminating Co., 46 PUR4th 63,74 (1982).

> Limited judicial review of an excess capacity determination is sound for the reason that while excess capacity analyses have an aura of precision about them, they are fraught with judgements and assumptions. Given the inherent problems of accurately projecting load growth, we are satisfied that the commission's excess capacity methodology is reasonable and that the factual findings are supported by the record.[20]

In 1983 the Indiana Public Service Commission used several criteria in making its decision not to adjust a utility's revenue requirement for excess capacity. In a case concerning the Public Service Company of Indiana the Commission ordered no adjustments to the 50 percent excess reserve margin caused by the Gibson Unit No. 5. The decision was based on the following reasoning.[21]

(1) No reason was found to label Gibson an imprudent investment;
(2) the reserve margin will be lowered substantially by the time the next unit is due to go on line;
(3) larger generating units cause economies of scale lowering rates in the long run; and
(4) the company's financial condition would be endangered if the excess is not included in the rate base.

Other, less traditional methods of fully compensating the utility when large plants suddenly enter rates are phase-in approaches and rate trending.

<u>Phase-In Methods</u>: Several states have considered phasing in rate base additions over a number of years. With this method the consumer is not burdened with the "rate shock" of a large capacity addition; and, if the issue is excess capacity, the company and its investors can see a definite plan of capacity additions which may coincide with the reductions in excess

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[20]Counsel v. P.U.C., 67 Ohio St. 2d 153, 158-159 (1981).

[21]Re Public Service Company of Indiana, 51 PUR4th 6, 10-13 (1983).

reserves. The actions in several states where some type of phase-in method was considered are reviewed next. It is important to note that some of these phase-in plans do not fit with our narrow definition of phase-in in chapter 2. That is, some plans do not provide for full recovery of costs.

In a recent Iowa-Illnois Gas & Electric Company (IIGE) rate request, the Illinois Commission was confronted with the addition of the Louisa Generating station (Louisa) to rate base.[22] Louisa is a 650 MW coal-fired plant, of which IIGE owns 44 percent (282.75 MW). In its request, the company proposed a mechanism that would moderate the proposed rate increase by "phasing" the Louisa investment into rates over several years.

This request and the subsequent commission decision were not directed at the issue of "excess capacity," but at the issue of rate shock. However, the method is applicable to excess capacity concerns.

The Commission agreed conceptually with the Company's proposal, stating:

> The Commission recognizes that the traditional approach to ratemaking should not be applied under all circumstances. If economies of scale require that plants be built larger than required to meet the immediate needs of ratepayers, then the costs associated with that capacity are more appropriately borne by future ratepayers who will be the primary recipients of the benefits of those plants.[23]

In its decision, the Commission approved a "Phase-In Clause" whereby the utility defers recovery of portions of the equity return, depreciation, and investment tax credit amortization on its investment in Louisa. According to the decision, all of the investment will be deferred in the first year, with total recovery of deferred amounts spread over the subsequent six years. A rider will be attached to the company's tariffs to implement the recovery phase of the clause. Each year, the company is

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[22]Re Iowa-Illinois Gas & Electric Co., 56 PUR4th 361 (1983.)

[23]<u>Id</u>., at p. 16.

required to revise the rider, using the most current sales forecasts and other information. The rider will be reviewed by the Commission on an annual basis.

The Commission justified its decision in this way:

> ...the price path resulting from the application of the Louisa Phase-In is more defensible on economic grounds than the price path resulting from traditional regulatory practice. No abrupt changes have occurred in the economics of electrical generation which could justify the "price spike" caused by traditional ratemaking. Under the Clause, the Company's prices more closely reflect the true economic costs of capacity and consequently promote more efficient allocation of resources.[24]

The State Public Service Commission of New Mexico is faced with the problem of excess capacity in the Public Service of New Mexico (PNM) generating system. PS New Mexico will have reserve margins which may reach 65 percent when the Palo Verde unit one begins generating electricity next year. The company proposed a phase-in plan for bringing the new generating facility on line, which included the following terms:[25]

* PNM places excess capacity in inventory, i.e., outside of rate base;
* the inventoried capacity may be used for non-firm sales;
* carrying charges associated with the inventoried capacity will be capitalized in an AFUDC manner;
* if revenues from non-firm sales exceed costs, this net amount will be used to reduce the capitalized carrying charges;
* current ratepayers will not bear carrying costs, property taxes, or depreciation costs on inventoried capacity;
* property taxes, depreciation, and variable operation and maintenance costs will be recovered from the "opportunity sales";

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[24] Id.

[25] "Plant Phase-Ins: PNM Floats Novel Plan to Handle Rate Shock, Excess Capacity," Electric Utility Week, September 19, 1983.

* capacity comes out of inventory to meet growth in demand or decline in net generation supply.

The Commission created a task force to consider this proposal.[26] As of the date of this writing, the task force is still considering the matter.

A similar phase-in case dealing with the Palo Verde plant of the Arizona Public Service Company was heard by the Arizona Corporation Commission. The company proposed a phase-in which includes five rate increases over a two-year period.[27] As of this writing the case has not been decided.

The Kansas Commission was confronted with the excess capacity issue in a case dealing with Sunflower Electric Company. The company proposed a phase-in which would include 50 percent of the Holcomb plant in rate base immediately and would add the remainder in increments over a five-year period. The commission did not reject the phase-in plan conceptually, but deferred judgement on such a proposal until a later date. The commission ruled that 47 percent of the Holcomb plant should be included in the rate base with no promise of future inclusion.[28] In its order the Kansas commission voiced its concern regarding this dilemma:

> Given this history and given the future rate implications, it would be totally irresponsible and a failure to meet our responsibility as a commission to place none of the plant in rate base and provide Sunflower no mechanism for meeting its financial obligations. However, the commission recognizes that a deferred plan placing 35, 40, 50, or any other proposed percent of the plant into the rate base does not address the grave underlying economic difficulties that are now being and will continue to be encountered in paying for the Sunflower plant.[29]

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[26] Re Public Service New Mexico, Order in Case # 1833 (1983).

[27] "Rate Moderation Plans - Cushioning 'Rate Shock'," Public Utilities Fortnightly, February 16, 1984.

[28] Re Sunflower Electric Co., Order in Docket 137,068-U (1983).

[29] Id., at p. 10.

The Kansas Commission may have to consider the phase-in concept for another company. Kansas Gas and Electric would like to phase in the cost of its share of the Wolf Creek nuclear plant over five years. The plans calls for 39.5 percent, 10.2 percent, 8.9 percent, 7.7 percent, and 8.4 percent increases in years 1985 through 1989, respectively. However, the company stated that a change in state law may be needed to allow the proposal to be approved. Such a bill will be heavily supported by the utility.[30]

As stated above, a Kansas law was recently passed giving the commission power to reduce a utility's rate base for excess capacity if imprudence is evident. Therefore, in Kansas it seems likely that any successful proposal for a phase-in plan must be accompanied by proof that managerial imprudence was not the cause of the utility's excess capacity.

An unusual phase-in proposal was examined and subsequently denied by the Connecticut Department of Public Utility Control (DPUC). In a case where the financial stability of the company was a key issue, the DPUC denied Connecticut Light and Power Company's request to phase in the Millstone 3 plant over the period 1984 to 1988.[31] The plant is scheduled to begin service in the summer of 1986; therefore, the phase-in would have started two years prior to the planned in-service date of the plant. The company was requesting a phase-in plan because Connecticut traditionally excludes CWIP from rate base. Since the company was experiencing serious financial difficulty, the commission allowed a limited amount of CWIP in rate base instead of approving the phase-in plan. Although this particular case did not have excess capacity as an issue, it serves to show how the phase-in concept has been considered and therefore could be considered in an overcapacity situation.

30"KG&E Details Wolf Creek Phase-In; Claims Some Trying To Bankrupt Company," Electric Utility Week, February 22, 1984.

31"Connecticut DPUC Decides CL&P Rate Case," NARUC Bulletin No. 7-1984, February 13, 1984, p. 22.

Another example of the phase-in concept can be found in an unusual case before the Arkansas Public Service Commission concerning the Arkansas Electric Cooperative Corporation. The addition of the Independence 1 plant is expected to create a 73 percent reserve margin for the company. This case is different from others in that the ratepayers are also the owners. The commission did not want to overburden the ratepayers by including the entire excess capacity at once; thus, it accepted a novel plan proposed by a consulting firm that participated in the rate case. This proposal, called the delayed depreciation recovery plan, includes the following aspects:

(1) a certain amount of depreciation will be deferred each year for three years; and
(2) after the third year, the depreciation will be recovered over 27 years.

This results in a two-step phase-in in which 80 percent of the full costs will be paid by the ratepayers initially with the additional 20 percent collected after the the third year.[32]

Rate Trending: The staff of the California Public Utilities Commission proposed a method of alleviating the effects of rate shock on current customers by the addition of large generating facilities. In a study performed regarding the San Onafre Units (SO2&3) due on line soon, the staff recommended a method of rate base trending which would employ a depreciation schedule with low payments in the early years growing to larger payments by the end of the units' lives.[33] The staff report stated the advantages of the method to be as follows:

(1) It will substantially reduce the rate shock caused by conventional ratemaking.
(2) It will remove most subsidies by today's ratepayers of future customers due to choice

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[32]"Excess Capacity Ruling Delays Co-ops Depreciation Recovery for Plant," Electric Utility Week, December 19, 1983, p. 3.

[33]"California PUC Proposes Rate-Base 'Trending' for San Onofre Units," Electric Utility Week, May 21, 1984, p. 5.

of a ratemaking method, thus minimizing income transfers from the relatively poor to the well-off.

(3) It will cut by half the $1.5-billion loss that ratepayers would suffer from SO2&3 under conventional ratemaking, and it will reduce the risks to customers. The cost of doing this is a minor increase in risk to utility investors.

(4) It will keep utility investors whole, and it will maintain or enhance the credit-worthiness of SCE and SDG&E by improving their financial indicators over the next few years from the levels they were driven down to by building SO2&3 to the levels they were at prior to the start of heavy spending on the project.

(5) It will be a significant improvement over conventional ratemaking in helping to promote economic efficiency, which maximizes growth and total economic well-being in our society. This method is also simpler, more logical, more direct, less arbitrary and less subject to unintended results than the "phase-in" methods that resemble it.[34]

The staff contended that conventional rate treatment is unacceptable in situations where very large capacity additions occur. Both electric utilities affected by this proposal were skeptical of the plan. They expressed serious concern over their financial stability with a plan such as this, stating that negative readings were coming from financial experts. The Commission did not accept the staff proposal.

Demand Options

The demand options covered are promoting bulk power sales, promoting jurisdictional sales with prices reductions, and marketing.

[34]Ronald L. Knecht et al., "Ratemaking for San Onofre Nuclear Units #2 and #3: Economic, Financial and Policy Analysis of Options," Report of the Special Economic Projects Section of the Revenue Requirements Division of the California Public Utilities Commission Staff, Work Assignment #448, April 24, 1984.

Bulk Power Sales

The Bonneville Power Administration (BPA), playing a role that could be played by one or more state commissions, surveyed most of the Northwest's large public and investor-owned utilities and Canada's British Columbia Hydro to see if they had power available for sale to California. A regional total of 1800 MW for five years was identified,[35] potentially easing the overcapacity problems of the Northwest.

Price Reductions

As a means of eliminating present excess capacity, some commissions have considered reducing rates to increase electricity sales.

In late 1983 the Rhode Island Public Utilities Commission approved an experimental rate discount plan filed by Narragansett Electric Company. The discount applies only to the commercial and industrial users. The Commission determined that such an experiment is "safe" because the New England Electric System (Narragansett's parent) enjoys 36 percent excess generating capacity. Thus, it is improbable that the rate will necessitate new capacity additions. The rate was favored by Rhode Island's Director of the Department of Economic Development, who testified that "...the plan provides an opportunity to exploit the excess capacity of a utility by encouraging greater industrial use."[36]

The South Dakota Public Utilities Commission encouraged Northwestern Public Service to lower its rates in order to reduce the present level of excess capacity. The Commission hired a consulting firm to develop discount rates which will add load without creating a revenue shortfall. According to the consultant's price elasticity study, a 10 percent

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[35] "BPA Tallies up to 1800 MW for Brokered Northwest Sales to California," Electric Utility Week, April 23, 2984, p. 3.

[36] "Rhode Island PUC Approves Electric Utility Discount Plan," NARUC Bulletin, No. 51-1983, December 19, 1983.

increase in rates results in an average 4.6 percent drop in residential demand and a 0.9 percent drop in commercial and industrial demand. Based on the consultant's study, the commission concluded that promotional rates for industrial customers alone might be considered as unfair by other consumers, while restrictive seasonal rates might result in needle peaks.

It was also held that: "Load control procedures normally do not address systems with under-utilized capacity. They may tend to shift load rather than to actually control it. They may not stimulate usage in off-peak hours, and therefore, may not effectively increase load factor."[37]

As a result of these studies and simulations, South Dakota proposed a reduction in the residential rate for those who use up to 250 kWh per month from 8 cents per kWh to 7.2 cents per kWh; a minor reduction for 500-750 kWh use; and a 1 mill increase for large residential users. In addition, a special electric heating rate was proposed. Commercial-industrial customers were to receive incentives for increased use rather than a tariff change. In the case of these customers, a 10 percent increase in energy use by existing consumers, compared with the previous year, would earn a 13 percent reduction in total cost the first year, and 20 percent the second year. New commercial and industrial customers would be granted a 20 percent reduction per year for a five-year period.

Prior to the implementation of this proposal, a poll indicated that price changes can cause variations in demand, but this is limited by a disinclination on the part of consumers to spend more money on electricity than currently. The poll indicated that lower rates would not increase electricity use enough to recover the lost revenues resulting from the lower prices. It was suggested that promotional rates should be targeted to new loads, with possible emphasis on heating and air conditioning.

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[37]Hon. Kenneth D. Stofferahn, "Utilizing Excess Capacity through Price Elasticity and Marginal Cost Considerations in Rate Design," presented at the 15th Annual Conference, Institute of Public Utilities, Williamsburg, Virg., December 13, 1983.

Subsequent to the poll, and the withdrawal of the Commission's suggestion, Northwestern Public Service Company filed a discount rate for all non-demand customers.[38] Under this proposal, a base period monthly charge would be computed. This would be accomplished by taking the customers bill for the 12 months prior to acceptance of the rate, deducting 3.3 cents per kWh used over the period, and then calculating a monthly average. The customer would pay this base period monthly charge each month plus 3.3 cents for every kWh actually used. The utility maintained this proposal would minimize the risk of a revenue shortfall, would be easy to administer and easy for customers to understand, and would represent a built-in budget payment plan. Those customers who consumed more electricity than their monthly average would save the difference on the incremental use between 3.3 cents and the average residential rate of 8 cents per kWh; those who used less would pay more than the standard rate. The Commission agreed to the company's plan.

The Public Service Company of New Hampshire developed an incentive rate, called the development incentive rate contract (DIRC), for commercial and industrial customers with incremental load requirements of more than 300 kilowatts. This new program, approved by the New Hampshire Commission, allows the sale of incremental loads at a price less than average system cost, but more than the incremental cost of serving the new demand. This rate is intended to reduce the frequency of rate cases and to use up any idle capacity.[39]

Other companies that are offering commission-approved discount rates include the following:

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[38]"Novel Incentive Rate Proposal Pegs Individual Discounts to Prior Usage," Electric Utility Week, May 14, 1984, p. 1-2.

[39]"Electric Utility Offers Development Incentive Rate Contract," Public Utilities Fortnightly, May 10, 1984, p. 53.

* Philadelphia Electric, which is offering a 1¢ per kWh discount to industrial customers expanding their load;[40]

* Detroit Edison, which gave McLouth Steel Corporation a 30 percent discount during its off-peak hours;[41]

* Georgia Power Company, which is offering 60 percent discounts to chemical companies using more than their base-load requirements;[42] and

* Consumers Power, which is reducing rates for metal-melting companies.[43]

All of these companies offer a discount exclusively to commercial and industrial customers for additional electricity usage, i.e., usage or demand higher than historical levels.

The Wisconsin Public Service Commission also studied the use of sales promotion and decided against it.[44] The precise method of study was not specified, but a number of different growth rates were tested for their impact on the cost of electricity on the Eastern Wisconsin Utility System (four companies), as well as on employment, air pollution, and other natural resources.

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[40]"New Ads Pop Up in EEI Marketing Effort, Member Utilities Home Programs," Electric Utility Week, May 7, 1984, p. 7.

[41]Incentive Rates: Blessing or Bane?" Elcon Report, N. 24, Fourth Quarter 1983, p. 2.

[42]Id.

[43]Id.

[44]Wisconsin Public Service Commission, "Final Environmental Impact Statement on the Promotion of Electric Utility Sales," Docket 05-E1-15, April 1984.

The Wisconsin simulations did not test specific options, but rather developed a number of scenarios using different growth rates and load factors. A base case was developed using the utilities' forecast. This was modified by varying industrial employment growth rates, labor productivity, load factor, and by assuming low levels of load growth. Energy demand growth rates were 2.7 percent for the base case, 3 percent for the high case, 2.5 percent for the low case, and 1.8 percent as an adjusted low case. In addition, one percent and zero growth with the same load curves as in the four cases above were tested. It was assumed that generating reserves of 15 percent were required for reliability. To meet this latter need, 400 MW coal units were added as required.

The PSC concluded that (1) increased sales lead to a short term generating cost reduction; (2) increased sales result in long term cost increases and an increase in levelized cost, unless the incremental sales either occur over a limited number of years or are confined to non-peak periods; (3) air pollution increases with increased energy sales; (4) coal and oil use increases, but the related addition of base load coal plants displaces some of the oil; (5) non-utility impacts include increased industrial and commercial employment and output, together with an increased population and regional income, but accompanied by increased pollution; (6) local impacts include an expanded tax base and more jobs and income, countered by an increased demand on local services.

Marketing

We found no example of a commission ordering a utility to undertake a marketing campaign. On the contrary, the Wisconsin commission has come out against utility marketing efforts.[45] The utilities themselves, however, have recently been strongly in favor of various marketing strategies to use excess capacity--the best example being the marketing activities of the Edison Electric Institute.[46]

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[45] Id.

[46] "EEI Launches Its Marketing Campaign with A Full-Page Ad in Time Magazine," Electric Utility Week, March 12, 1984, p. 1.

Options and Regulatory Criteria

In regulating rates and service quality for an electric utility, a state commission normally uses four primary criteria for making decisions. One is that the rates should be correct, that is, properly reflecting the true costs of providing the service. The correct price can be said to be economically efficient: set neither too high nor too low, neither encouraging unduly nor discouraging unduly the customer's use of electricity. Second, rates should be fair and equitable, both between customer classes and between present and future customers. Third, rates should be sufficient to provide for the financial stability of the company and for a fair return to investors. Fourth, rates should be sufficient for the company to provide adequate and reliable service.

In an overcapacity situation, the adequacy of capacity to provide service is not in question. In those instances, however, where the utility may find itself in dire financial straits, maintenance activities for generation, transmission, and distribution may be curtailed in order to improve short term cash flow. Fuel inventories may be reduced for the same reason. The result could be a decline in equipment capability and availability, with a consequent threat to the reliability of service. Because poor reliability may result from inadequate cash flow instead of inadequate capacity, in this situation we treat the financial stability criterion and the adequate-and-reliable-service criterion as one. That is, options for treating overcapacity that result in poor cash flow result both in poor financial standing and poor reliability. Therefore, these two criteria are treated as a single criterion here.

This results in three criteria, which can usually be considered equal in stature. However, in a particular rate proceeding, one criterion may be treated as more important, depending on the needs of customers, the circumstances of the company, and the inclinations of regulators. It is not our intent to assign priority to any of the criteria. Rather, in this section we discuss how the various options for treating overcapacity measure up against the three criteria.

Before this discussion, however, we mention other factors--constraints and other important criteria--that may affect a commission's choice among options.

Constraints and Other Criteria

Instead of choosing an option based on the three criteria that we consider, regulators may consider certain constraints on their choice or use criteria other than our three.

A regulator's choice may be constrained by the wording of the state's statutes, particularly the wording of the "used and useful" test. Also, state judicial precedents may constrain the regulator's choice among options. Some states may permit considerable commission discretion in applying the "used and useful" test, and a commission might judge any capacity actually used to be obviously useful. Other states may require a more narrow interpretation, and the commission might find that duplicative capacity is not useful regardless of whether it is used.

A regulator may feel constrained to treat all utilities with overcapacity similarly, so that if a treatment was selected for one utility the same treatment must apply to another. Other regulators feel free to select a treatment based on the circumstances of the individual company.

Many regulators select a treatment for overcapacity based on the cause of the problem. Then, the choice of option is constrained by the determination of who is at fault. If overcapacity resulted from gross mismanagement or even the imprudent judgment of management, then exclusion from rate base may be deemed appropriate. However, if it resulted from imperfect forecasting of a kind that most utilities experienced nationally, from a slack economy, or from bad luck, then "penalizing" the company may not be considered appropriate.

Other regulators, however, would choose the solution to the problem without regard to cause. They say that in a competitive environment a company would have held prices down in an overcapacity situation to avoid losing business, regardless of the cause of the overcapacity, and argue that, similarly, regulators should not allow high prices to result from overcapacity, regardless of whether anyone is at fault.

Some regulators may feel constrained to permit rate base treatment of excess capacity if the commission had any role in approving construction of the capacity. Some 32 state commissions report making a needs determination for plant investment as part of a certification of convenience and necessity, a power plant siting hearing, or some other process. In addition, most commissions must grant approval for the issuance of new securities to finance construction. But, other regulators do not believe that these determinations bind the commission in case of cost overruns or excess capacity. (The issues raised here are discussed in detail in another report by The National Regulatory Research Institute.)[47]

Besides constraints, a regulator's choice among options may be affected by other regulatory goals and related criteria.

One such goal is energy conservation. Each overcapacity option could be judged according to whether it stimulates or retards the growth in electricity generation--with slower growth preferred. Energy conservation may be a goal to be achieved by the commission under the state's statutes.

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[47] R. J. Profozich, R. E. Burns, P. J. Hess, and K. A. Kelly, Commission Preapproval of Utility Investments (Columbus: The National Regulatory Research Institute, 1981).

Also under federal law, PURPA[48] supplements state law to make the goals of state electricity regulation include the three purposes of PURPA in certain instances. The first of these three purposes is "conservation of energy supplied by electric utilities." This supplementary goal of state regulation applies during commission consideration of the PURPA standards, covering topics such as time-of-day rates, load management techniques, and promotional advertising--topics that relate to several of our options for treating overcapacity.

Two views of energy conservation are wide-spread and relevant here. One is that conservation means simply less energy consumption. Carried to the extreme this conservation criterion would mean that the best policy is one where electricity generation and consumption of primary fuels shrink to zero. Another view is that conservation means no wasteful use of energy, that customers consume the "correct amount" of electricity--neither too much or too little. Upon consideration, this second conservation criterion is hard to distinguish from the correct price/economic efficiency criterion discussed earlier. Hence, a regulator's decision is likely to be affected by the importance attributed to the conservation criterion and by which view of conservation is believed to be appropriate.

On the other hand, some state regulators may see the contribution of an overcapacity policy to state economic development as a more important criterion. Growth in the industrial and commercial sectors, with associated growth in jobs and state tax revenues, may be viewed as more important than conservation, interclass equity, and other criteria. If so, then a policy of using excess capacity to spur such growth may be preferred.

Special treatment of excess capacity is warranted where it results from an oil-backout program. Such a program was strongly supported by the federal government and by many commissions. Several studies in the late 1970s concluded that it would be more expensive for electricity customers

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[48]Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617 Stat. 3117 (1978).

if the utilities were to burn oil than to abandon oil-fired capacity and construct new nuclear or coal capacity. An obvious result of such a cost-minimizing strategy is some duplicative capacity, if the utilities have not retired and written off the oil-fired capacity.

In a similar vein, regulators may take into account any fuel cost savings afforded by new capacity. Such savings can occur if coal-fired plants replace natural gas burners or if nuclear plants replace coal. Also, some benefits in terms of fuel supply reliability may be associated with increasing the diversity of fuel types. This reduces, for example, the threat of a coal miner's strike to an all-coal system of generation.

Aside from the goal of controlling the growth in electric energy, some regulators want to control the growth in electric capacity. The motivation here is not energy conservation itself, but the avoidance of electricity price increases as the high cost of new capacity forces up the average cost of power. As a result, a regulator may judge an overcapacity option according to its effect on the timetable for adding new capacity to the system.

Still another criterion for judging an overcapacity option is how equitably it shares risks and rewards among the company's customers, creditors, and equity owners. One may argue that investors, in constructing new capacity, assumed the risk that the capacity would not be needed for a period of time after completion. If the period is short or nonexistent, the investors earn profits. If the period is longer, profits shrink and losses can occur.

Alternatively, one can argue that the company built the capacity in question because it might be needed by customers, because the company has a legal obligation to provide service, and because the consequences for society of too little capacity are much graver than the consequences of too much. In this view, the company assumes no risk. It acts as an agent for the customer, building enough capacity to assure the adequacy of service.

The customer ought to pay for the excess capacity, considering the payment a sort of insurance premium.

From the point of view of risk theory, the question is not which of these two viewpoints is correct. Each view is valid. The question is whether the bearer of risk receives the rewards.

In the first view, the investor assumes the risk and ought to earn a rate of return commensurate with that risk when he "wins his bet" that the capacity will be needed. A substantial return justifies the risk that he may lose a portion of his capital.

In the second view, the customer pays the insurance premium, that is, the customer assumes the risk. His reward is that he need pay the investor only a small rate of return, close to the risk-free rate of return, since he imposes little or no risk on the investor.

Clearly, a regulator may want to use a risk criterion in choosing among the options for treating overcapacity. The criterion is applied by seeing whether the bearer of risk has the opportunity for an appropriate reward. The situation to avoid is one in which the party sheltered from risk earns the reward. (A more detailed discussion of the application of risk theory to electric utility regulation is contained in another report of The National Regulatory Research Institute.)[49]

Several other legitimate criteria may be considered also. These include avoidance of sudden large rate changes, avoidance of adverse environmental effects, freedom from controversy as to proper interpretation of the tariff and as to the expected effects of the tariff, and public understanding of the commission's action and its motivation.

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[49]A. Kaufman, S. J. Bodilly, R. D. Poling, and R. J. Profozich, Unplanned Electric Shutdowns: Allocating the Burden (Columbus: The National Regulatory Research Institute, 1980).

Regulatory Options

Let us now consider how the overcapacity options of chapters 2 and 3 measure up under our three main regulatory criteria: efficiency, equity, and financial stability. In discussing the options, we group these options broadly. On the supply side, we consider full and partial exclusion of plant costs, as well as full recovery. On the demand side, we consider the available options to be bulk power sales, sales promotion through price changes, and marketing. The various subsets of these broad categories are essentially variations on a theme. In those instances, however, where a specific option might have a different effect, we note that fact. Our discussion attempts to relate each category of option to each regulatory criterion.

Economic Efficiency

Economic efficiency can be defined as the allocation of resources throughout the economy in such a way that the needs and wants of consumers are met in an optimal manner. This is generally accomplished by setting prices at a level that reflects the costs of the economic resources involved in the production of the marginal item. In a competitive market this would occur automatically, with market discipline enforced by extracting penalties from those who make mistakes. All firms' prices drop to the price level of the firm that made no mistake--a price representing the cost of efficient production. The nature of the mistake is immaterial. It could be mismanagement, imprudence, misjudging economic conditions, or misfortune. As a consequence of its errors, the company might suffer reduced profits, reduced credit worthiness, even bankruptcy.

Given that a major purpose of regulation is to simulate the competitive market and to set prices that represent the cost of production, including a reasonable profit, we can restrict our discussion of economic efficiency to the question of whether an option forces those who make an error to pay and results in a price that equals the cost of efficient production. In the course of our discussion, we consider management and stockholders as a single entity--the utility or company.

The discussion in chapters 2 and 3 makes it clear that the demand options are intended to eliminate some portion of excess supply. Price reduction options require the company to lower its prices, just as a competitive firm would be forced to lower its prices as much as needed to meet competition, provided the resulting price did not fall below the running costs plus other variable costs associated with providing service. Sunk costs associated with excess capacity would not be considered in setting prices. Writing off excess plant would be considered, however. To the extent that a demand option lowers price toward, but not below, the cost of efficient production, there is an improvement in economic efficiency.

Demand options are essentially neutral in terms of directly assessing penalties. The price options do not "penalize" the utility in the sense that capacity is excluded from rate base. However, they may indirectly "penalize" the utility in that rate of return and return on equity may be lower than if there were no price reductions. In our examples, returns are computed, with one exception, to be consistently below the rates earned in the base scenario. But, lower returns are not necessary or intended: in one of our time-of-use cases the rate of return and return on equity rise above their base scenario values. Lower return, if it occurs, is largely fortuitous. (However, one could make the case that customers are entitled to lower rates, and the utility to consequent lower returns on capital as a result of judgemental or other errors.) In large measure, the rate of return is dependent on the actual elasticity of demand. That is, if the reaction to lower rates is greater than postulated in our cases, the utility could earn more than anticipated. In view of the state of knowledge concerning elasticity of demand, use of the price options to "penalize" those who made an error is imprecise at best.

The supply options, on the other hand, are well suited to precision of result: a commission, after a determination that an error has occurred and that some rate base adjustment is called for, could establish the size of the adjustment and the resulting rate of return with some precision by deciding how much of what kind of plant cost to exclude from rate base. If the major regulatory goal is to assure economic efficiency by penalizing those responsible for mistakes, it is apparent that the supply options are preferred.

An option that combines some features of the demand and supply options is the imputed sales option. While we list it as a partial exclusion option, it could be considered also as full exclusion of excess capacity (because it assumes incorrectly that demand is sufficient to utilize the excess capacity), as full inclusion (because all capacity is included in rate base), or as a price reduction option (because the result is to lower the prices). This option sets price equal to the cost of efficient production at a higher-than-actual level of demand. It permits automatic increases in revenue as sales grow, without having periodic rate hearings to reconsider how much capacity belongs in rate base or to reconsider whether low prices set to stimulate demand need to be raised.

Equity

For our purposes, we can consider equity in terms of two groupings; one involves equity among customer classes, and the other between present and future customers. Insofar as the latter is concerned, equity between the present and the future can be defined as the payment of excess capacity costs by those who will eventually benefit from the availability of that capacity, i.e., future consumers.

In this regard, the price options tend to push the cost of excess capacity off to future customers. This is indicated by the lower levelized cost in each of these cases compared with the base case. Thus, in regard to future customers, the price options appear equitable.

The other demand options, on the other hand, appear to be essentially neutral. This would not only apply to intergenerational equity, but to interclass equity as well. That is, those undertaking bulk power sales are recovering the cost of producing that power from those who are receiving the benefit; and franchise customers, present as well as future, are benefitting through more efficient operations. Insofar as marketing efforts are concerned, it can be assumed these will return benefits commensurate with the funds expended, or will be cancelled.

The supply options, on the other hand, are mixed in terms of equity between present and future customers. The equitable distribution of costs is dependent upon the specific option selected. For example, full exclusion of the new plant from the rate base shifts these costs to future customers, while several of the partial exclusion options result in both present and future customers paying the bill. Exclusion of the cost of the least efficient plant, or of average capacity, can be assumed to result in a similar situation. Alternatively, the full recovery option using traditional costing tends to put more of the burden on present customers. On the other hand, if new plant costs are phased-in, the intergenerational effect tends to be relatively benign.

In terms of equity among customer classes, however, the supply options will tend toward neutrality, assuming the regulators apportion the costs in the normal manner. The demand options, on the other hand, may be perceived to be inequitable since these often involve a rate reduction for a single customer class. The time-of-use pricing scenarios tend to produce higher load factors than the base scenario. This greater efficiency may ultimately benefit all customer classes. In any case, the TOU cost savings apply only to those industrial users who utilize electricity during the off-peak period. Inasmuch as the excess capacity problem is at its worst at that time, the inducement to additional use may not constitute an inequity, but may be advantageous to all customers.

In general, the inequities resulting from the supply options depend on the specific option. It is possible to virtually eliminate any one inequity by choosing the appropriate option. The demand options, on the other hand, tend toward overall neutrality, at least insofar as marketing and bulk power sales are concerned. The price options probably have little impact on customer equity, with inequality possibly more a perception than a fact. In terms of intergenerational equity, the price options tend to be fair by pushing excess capacity costs off to the future.

Financial Stability

The financial stability of the utility is of considerable concern to the regulator because of its potential impact on the reliability and quality of service. Considering the fact that the problem facing the regulator is overcapacity, all of the options can assure adequate and reliable service in terms of installed capacity. In those instances, however, where the utility may find itself in dire financial straits, maintenance activities for generation, transmission, and distribution may be curtailed in order to improve short term cash flow. The result could be a decline in equipment capability and availability, with a consequent threat to adequate and reliable service.

That is, a company in poor financial condition is not able to adequately fund maintenance and system upkeep to assure a high level of service. In addition, financial problems can ultimately result in higher costs for the consumer due to increased debt financing charges. Investors would perceive a greater risk in investing in a troubled company, compared with a financially sound one, and would expect a return commensurate with the perceived higher risk. Thus, financial condition can be important not only in terms of the ability to provide adequate and reliable service, but also in terms of the cost of that service. The various supply and demand options tested in this study result in a wide range of financial effects with a consequent impact on investor perceptions and service quality.

With the demand options, the price reduction cases result in substantially lower capital returns in the early years, compared with the base scenario, as well as lower coverage ratios. One TOU case (case 6, explained in table 3-2) results in a utility better off than the base scenario, while the other two TOU cases (7 and 8) result in a somewhat weaker, but still strong, financial condition.

The bulk sales option, if able to be utilized, should enhance the financial stability of the utility through increased revenue and improved efficiency. Marketing efforts should have effects similar to bulk sales, if successful; in the event these efforts are unsuccessful, the financial impact on the utility should be minor.

Of the supply options, the full cost recovery options would lead to the strongest financial condition, followed by exclusion of the costs of the least efficient plant. The weakest financial condition results from the application of the full exclusion option to the newest plant, with bankruptcy a real possibility in this case. The other supply options would fall somewhere between these extremes.

These supply option conclusions are valid only if customers are insensitive to price over a period of a year or two. If customers react quickly to large price increases by consuming less, then there might be no financially favorable option. At best, utilities could hope to maximize revenues by trading off price increases and associated sales losses. Selecting the best price, from the financial stability viewpoint, requires a knowledge of demand elasticities.

On balance, it appears that the demand options tend toward relatively benign effects on financial stability, while the supply options have variable impacts. In the latter case, the full and partial exclusion cases have deleterious effects, except where the cost of the least efficient, and perhaps of the average, plant is used. Then, financial stability is improved even with full exclusion. The full recovery options contribute substantially to financial stability, although the degree of contribution is dependent upon the method used. That is, if elasticity effects are ignored, the trending and phase-in methods have a somewhat less beneficial financial effect than the traditional revenue computation.

Goals and Options

In terms of goals, it is apparent that the demand options tend to be relatively inflexible in their impact. That is, the bulk power and marketing options are neutral to positive in all cases, although these do have a positive effect on financial stability. The price reduction options have a positive effect on economic efficiency and equity, but may have a negative effect on financial stability. The time-of-use options tend to have a positive effect on all goals.

If one assumes that a major goal of regulation is to simulate competition, then the demand options may be the appropriate means of achieving that goal. That is, in a competitive environment, a company would attempt to solve the problem of excess capacity by reducing the price in the hope of stimulating demand. It would be unlikely to raise the price, and thus take a chance on making the supply problem worse. From this perspective, the price options would best fulfill the need, with the time-of-use rate possibly the least disruptive to other regulatory goals.

Flexibility in impact is possible through use of the various supply options. These permit choice of almost any degree of financial effect. Also, the detrimental effects on economic efficiency and on equity of full recovery of new plant costs can be mitigated by use of trending, or by phasing-in, the requisite costs. Doing so would result in a relatively minor decline in financial stability.

The preceding discussion, summarized in table 4-1, has attempted to delineate which options may be best for which criteria. It is apparent that a regulatory body has available to it a tool kit adequate to the job. The costs of excess capacity can be distributed in a manner that will achieve any set of regulatory goals, in virtually any order of priority. It is for individual regulatory bodies to determine which goals may have precedence over others and, therefore, which option may be preferable.

TABLE 4-1

OPTIONS RATED BY THREE REGULATORY CRITERIA*

Option	Economic Efficiency	Equity	Financial Stability
Supply			
Full Exclusion			
New Plant	+2	+2	-2
Least Efficient	-1	-1	+2
Average	+1	0	+1
Partial Exclusion			
50%	+1	0	-1
2:1 Cov. Ratio	-1	-1	0
Graduated	-1	-1	+1
Equity Only	+1	0	-1
Constant Revenues	+2	0	-2
Imputed Sales	+2	0	-1
Full Recovery			
Traditional	-2	-2	+2
Phase-in	-1	0	+1
Trending	-1	+2	+1
Demand			
Bulk Power	+1	+1	+1
Price Options			
Flat Reductions	+1	+2	-1
Time-of-use	+1	+1	+1
Marketing	+1	0	+1

Legend
- -2 = Substantial, negative effect
- -1 = Moderate, negative effect
- 0 = Little or no effect
- +1 = Moderate, positive effect
- +2 = Substantial, positive effect

Source: Discussions in chapters 2, 3, and 4.

*The option of excluding a portion of carrying costs is not rated here because the effects depend so importantly on the amount of costs excluded.

CHAPTER 5

AVOIDING OVERCAPACITY IN THE FUTURE

Strategies for avoiding future overcapacity in the electric utility industry must take account of the trends that may affect that future. The industry was once considered to be a blue chip, stable industry, but now appears to be in substantial disarray. The signs of trouble include the possibility of what once would have been considered unthinkable--namely, bankruptcy and the abandonment of plants in which billions of dollars have been invested, as well as talk of the need for diversification and deregulation.

Many of these problems stem from overbuilding and its attendant financial strain. The overbuilding is itself a product of changing times. In this instance the utility industry has been caught by the conjunction of two broad, major trends that affect the demand for electricity.

One of these has been a structural shift in the economy. Traditional industries are becoming less important, while new ones take their place; services are becoming more important in terms of national income, compared with manufacturing; and, finally, automation is becoming a way of doing business.

Along with these structural economic shifts, the industry itself has suffered a major change. The economies of scale in generation that permitted the electric utility industry to experience declining costs are thought to be largely exhausted. As a result, costs have been rising. The full impact of this profound change has probably not yet been felt.

Uncertainties in Future Demand and Capacity

Demand growth estimates for the early 1990s range from a low of 2 percent per year (2.9 million GWh in 1995) to a high of 5 percent (4.3 million GWh), with NERC currently estimating the energy growth rate at 2.7

percent, and peak growth at 2.6 percent.[1] The wide band exhibited by these estimates indicates the uncertainty facing the industry. This uncertainty is not only in terms of markets, but in terms of the relationship between electric demand and economic growth, as well as uncertainty in regard to the rate of economic growth. Some electric forecasts assume a relatively low growth economy (2 percent per year for GNP), while others postulate as much as 4 percent GNP growth per year. This differential encapsulates substantially different perceptions of the importance of the various social and economic currents and cross currents that may affect the future demand for electricity.

The Consuming Sectors

The factors that offset electricity demand can best be sorted out by discussing separately each of the consuming sectors and the factors that may affect them.

Residential Sector

Of primary importance to the residential sector may be a number of conflicting demographic trends. Among these is the movement to more, but smaller, households. That is, between 1970 and 1982, the number of households increased 32 percent, but the number of people comprising a household declined 18 percent.[2] The increased use of electricity generated by a larger number of households may be partially offset by their smaller size.

In addition, there is uncertainty about the overall population growth rate. It has been expected that this rate will decline, so that population in the year 2000 will only be 7 percent greater than in 1990, compared with 11 percent in 1980 relative to 1970.[3] The birthrate, however, appears to

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[1]North America Electric Reliability Council, "Electric Power Supply & Demand, 1984-1993," Advance Release (Princeton: NERC, April 1984).

[2]U.S. Bureau of the Census, Statistical Abstract of the United States: 1984 (Washington: U.S. Government Printing Office, 1983), pp. 8,48,49,63.

[3]Ibid.

have bottomed out in 1976, and is now rising. Should this continue, residential electric use may be higher than anticipated.

These demographic trends may be offset by the effects of future electricity prices and the cost of alternative fuels. Residential electricity prices are forecast by some to decline, and by others to increase as much as 4 percent per year in real terms. This kind of price range obviously indicates a great deal of uncertainty regarding future demand.

The price of alternative fuels is also uncertain. For example, in the case of natural gas there is a great deal of controversy over the status of the gas supply bubble, the potential impact of deregulation on prices, and so forth. Even if gas prices were to double by the early 1990s, however, electricity could still be twice as expensive, compared with three times in 1983.[4] While this shift in relative cost might have an impact on electric use, particularly in the space heating market, the magnitude of the effect is difficult to measure.

Commercial Sector

Nor is the picture any clearer for the commercial sector. There are limited data available on the use of electricity by such establishments, but this may well be the fastest growing sector, particularly if financial and informational services are included. These latter groups are particularly heavy users of computers and other electrically operated equipment. These, however, tend to have relatively low power requirements.

The sector as a whole tends to be a major user of air conditioning, and this has been an important factor in increased use by commercial customers. It may be that a substantial portion of commercial space is already air conditioned, so that future electricity requirements may not be substantially affected by this factor.

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[4]Energy Information Administration, Annual Energy Outlook 1983 (Washington: U.S. Government Printing Office, 1984), DOE/EIA-0383 (83), p. 199.

Industrial Sector

The industrial sector also represents an uncertain outlook. The effects of automation, the electrification of process heating, the reduction in the intensity of use for electromechanical drives, the use of cogeneration by major using industries, and other imponderables, make it difficult to predict industrial electric demand.

This sector, however, is of considerable importance to electric utilities. It is the largest consuming sector, accounting for approximately one-third of total sales. At the same time, it has the biggest potential and best financial ability to substitute electricity for other energy sources, and vice versa. For example, there appears to be a movement to replace current process heating methods with those based on electricity, particularly in the primary metals industries. These, however, are expected to be relatively slow growing at best.[5] As a result, the impact of this trend may be relatively minor. In any case, electroheating only accounted for 10 percent of industrial use in 1983. Therefore, increases in the intensity of use for process heat may be more than compensated for by savings elsewhere.

Electromechanical drives account for 70 percent of industrial use. It is expected, however, that high-efficiency motors, adjustable speed drives, and cogeneration will reduce the intensity with which electricity is used for these purposes. In this regard, it should be noted that the five industries (textiles, paper, chemicals, stone-clay-glass, primary metals) that account for 60 percent of purchased electricity and 85 percent of self-generated electricity have real cost incentives to move to cogeneration. Should this come to pass, electric loads could decline.

On the plus side are the possible effects of automation. It is expected that more and more industrial installations will automate in order to reduce costs and meet the threat of international competition; if the

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[5]U.S. Department of Commerce, 1984 U.S. Industrial Outlook (Washington: U.S. Government Printing Office, 1984).

threat is not met, industrial electric demand will probably decline. The impact of automation on electric use is uncertain. It may result in savings if air conditioning and ventilation requirements are lower than at present. On the other hand, automation may result in an increase, although this is not expected to be of major importance. The impact on electric demand will depend on the use to which the robots are put. At the moment, there are approximately 6000 robots in use, primarily for heavy payloads. By 1990, there may be as many as 100,000, but the trend is toward smaller robots with possibly lower power requirements.[6] Among the complicating factors in determining the effect of automation on electric use are the requirements imposed by auxiliary equipment such as conveyors. These may consume more than half of the electricity needed for operation of an automated facility. Such equipment is quite important in current robotic uses; whether this will be true in the future is unknown. Altogether, while automation is not expected to add significantly to electric consumption, it does add one more imponderable to the future electric demand picture.

Uncertainty in Demand and Supply

The uncertainty noted above carries over to forecasts of system peak load. This depends not only on the peak loads of the consuming sectors but on when they occur. The difficulty of forecasting the system peak is compounded by the need to predict load factor as well.

For example, if the 1983 NERC peak forecast of approximately 560 GW in 1992 comes to pass, some 672 GW of capacity would be needed, including a 20 percent reserve margin. This forecast assumes a load factor of 63.9 percent. If load factor in 1992 were at the current 62 percent level, the peak would be 577 GW, and required capacity 693 GW, 3.1 percent more than expected. Load factor in more recent years has been lower than in the past. It is generally expected, however, that load factor will improve over the next decade as a result of load management programs, including time-of-use rates.

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[6]Science Management Corporation, The Impact of Industrial Robots on Electric Loads in U.S. Industry (Palo Alto: Electric Power Research Institute, 1984) EM-3325.

The uncertainties on the demand side carry over to supply as well. Not only is there uncertainty about the quantity of capacity that will be necessary, but there is considerable controversy over how much will be available. A number of assumptions can be postulated concerning future equipment retirements, as well as assumptions regarding cancellation, abandonment, and slippage in construction schedules. As these are varied, reserve margins can range from levels indicating an overbuilt system, to one requiring massive construction in order to assure future reliability. Utility planners and regulators are obviously faced with great uncertainty in both demand and supply.

Future Strategies

In a situation of uncertainty, utilities should not be building to meet a forecasted peak, but rather should be aiming toward a flexible system able to adjust as necessary to unfolding events. Early on, this means building small, and utilizing modular units, when construction is needed. It also means, where technically and economically feasible, using cogeneration and renewables, as well as rehabilitating old plant in order to extend useful life.

The measures listed above tend to minimize risk in the light of great uncertainty by reducing financial exposure and the possibility of over-building. Because a small plant costs less to build in the aggregate than a large one and financing requirements are less, the effect of a mistake will tend not to be catastrophic. The small plant, however, may cost more per kilowatt. In that event, the differential in unit cost can be viewed as an insurance premium in that it prevents the possible waste of billions of dollars. Further, if an incorrect estimate of future requirements were made, it would take much less time to "grow into" the new capacity than would be necessary if large plants were built. Thus, risk exposure is less than would occur if the latter were built. Given the size of the risks to which a utility is exposed, it may be better for the customer to pay more for smaller units than to face the possibility of catastrophic losses in the event of an error in judgement.

It may, however, be possible to minimize construction by instituting changes in rate structure such as time-of-use (TOU) and interruptible rates, and by building strong interties among regions as well as within regions. The TOU rates serve essentially as a means of controlling the peak and shifting demand to off-peak periods. This improves the efficiency of overall operations and reduces the eventual need for construction.

Interruptible rates, on the other hand, permit the utility to shift part of its generating reserve requirements from the supply to the demand side of the equation, thus reducing its need for capacity. This not only reduces its costs, but increases its operating flexibility. The utility might eventually be able to derive the major portion of its reserve requirement from interruptible load.

Both the TOU and the interruptible rates, if coupled to a tightly intertied interregional transmission network, would permit the utility to profit from its efficiencies, or suffer from its mistakes. That is, it could buy electricity above base load requirements on the open market. If it were astute enough to buy at low enough rates, it would earn additional profit; if not, it would lose money or earn relatively little. Utility management would shift from a regulatory risk minimizer, to a profit maximizer with a constraint to reduce overall risk. It would have minimal incentive to build plant other than base load. If it misjudged the local electricity market, it could attempt to sell its surplus on the regional or interregional markets.

The above implies the eventual development of a computerized clearing house for purchases, with buyers and sellers tightly connected through a high capacity communications network. The clearing house would probably have to be accompanied by an electric futures market as a hedging operation to minimize risk. It also means the development of an adequate transmission technology to allow economical bulk transfers over long distances.

Eventually, under this strategy, utilities would operate very little capacity other than base load, with some additional equipment held in reserve for emergencies. The major reserves, however, would be derived from interruptible load. Peak, including shoulder peak, demand would be met through a combination of spot or contract purchases, hedged by futures contracts. Market signals would thus determine if more plant need be built.

From the foregoing, it is apparent that a strategy can be developed that will minimize the possibility of future excess capacity, but it will require innovation in rate structure, operating philosophy, and in the way utilities do business. As a consequence, both regulation and the provision of electric service in the future may be far different from that of the present. At the same time, the possibility of suffering from excess capacity should be drastically reduced.

APPENDIX A

HYPOTHETICAL UTILITY WITH OVERCAPACITY

Let us consider a hypothetical typical utility with an overcapacity problem, which is used for illustrating the options and discussion of chapters 2, 3, and 4. Since the recent average installed capacity of U.S. class A and B electric utilities is 2350 MW, we choose the hypothetical utility's installed capacity equal to this amount. In table A-1, the number and characteristics of the utility's 22 generating units are listed; these data represent the authors' modification of an IEEE reliability test system. Table A-2 shows the generation mix by fuel type; it is approximately the same as for the test system.

Further suppose that the peak load on the hypothetical utility is 1645 MW, the recent average peak load of all class A and B utilities. Then the utility's reserve margin is 43 percent.

How could a utility arrive at such a large reserve margin? What is its effect on the composition of the rate base? What methods are available for calculating the effects of commission actions? The three sections of this appendix address these questions.

Recent History of Capacity Additions

Consider the following history, beginning in 1969 and illustrated in table A-3. While this "typical utility" and its history are fictional, the peak demand growth rates used to construct table A-3 equal actual U.S. electric industry averages, and the intent of the history is to give a realistic picture of how a typical utility could have arrived at an overcapacity situation.

In 1969, the system had 18 generating units, as shown in the first six lines of table A-1. The largest units are the 150 MW coal-fired units. Since the company was founded, peak demand has been growing at a fairly

TABLE A-1

GENERATING UNITS AND CAPACITY OF THE HYPOTHETICAL UTILITY

(1) Number of Units	(2) Unit Size (MW)	(3) Type	(4) Fuel	(5) Capacity (col.1 x col.2) (MW)
2	10	fossil steam	#6 oil	20
4	20	comb. turbine	#2 oil	80
4	50	hydro	N.A.	200
2	75	fossil steam	coal	150
3	100	fossil steam	#6 oil	300
3	150	fossil steam	coal	450
2	200	fossil steam	#6 oil	400
1	350	fossil steam	coal	350
1	400	nuclear steam	UO_2	400

Source: These data are the authors' modifications of a test system established by the Reliability Test System Task Force of the IEEE Application Probability Methods Subcommittee; see "IEEE Reliability Test System," IEEE Transactions on Power Apparatus and Systems PAS-98, 6 (Nov./Dec. 1979):2047-2054. The modification was to reduce the system size from the 3405 MW set by the task force to 2350 MW, which represents the average size of all U.S. class A and B electric utilities.

TABLE A-2

GENERATION CAPACITY BY TYPE OF CAPACITY FOR THE HYPOTHETICAL UTILITY

Capacity Type	Number of Units	Capacity (MW)	Capacity (%)
Steam			
fossil oil	7	720	31
fossil coal	6	950	40
nuclear	1	400	17
Combustion turbine	4	80	3
Hydro	4	200	9
Total	22	2350	100

Source: Authors' calculations based on table A-1.

TABLE A-3

PEAK LOAD, INSTALLED CAPACITY, AND RESERVE MARGIN FOR THE HYPOTHETICAL UTILITY

Year	Peak Load (MW)	Installed Capacity (MW)	Reserve Margin (%)
1969	975	1200	23
1970	1040	1200	15
1971	1104	1400	27
1972	1206	1400	16
1973	1301	1600	23
1974	1320	1600	21
1975	1350	1600	19
1976	1403	1600	14
1977	1497	1950	30
1978	1543	1950	26
1979	1578	1950	24
1980	1614	1950	21
1981	1618	1950	21
1982	1569	1950	24
1983	1607	1950	21
1984	1645	2350	43

Source: Peak loads are calculated by assuming the 1984 load is 1645 MW, the recent average of all U.S. class A and B electric utility loads, and by assuming the 1969-1984 peak load growth rate each year equalled that of the total U.S. electric industry, as given in table 1-1, column 5. The 1979 peak load is adjusted to correct for the discontinuity in table 1-1. The peak load growth rate for 1983 is assumed to be equal to the 1983 generation growth rate of 2.39 percent, calculated from data in Electrical World, April 1984. The 1984 growth rate is assumed to equal the 1983 growth rate. Installed capacity is derived from a scenario assumed by the author and explained in the text.

steady 7 percent per year. The company received a lot of criticism in the late 1960s for environmental pollution with coal-fired generation. In 1969, Congress created the Environmental Protection Agency with promises to crack down on utility coal use. The utility was encouraged by the government and the public to switch to oil-fired generation. At that time, the average U.S. well-head price of petroleum was only $3.09 per barrel.

In 1969, the company had a 200 MW oil-fired unit under construction and was starting construction of another such unit. Its installed capacity was 1200 MW, and the 1969 summer peak was 959 MW, giving a reserve margin of 23 percent. By the summer of 1970, the reserve margin dropped to 15 percent as the peak grew by 6.6 percent. In 1971, the first 200 MW oil unit came on line, and the peak grew by only 6.2 percent. As a result, the reserve margin jumped up to 27 percent in 1971, only to fall to 16 percent the next year as the 1972 summer peak surged up by 9.2 percent over that of 1971. In 1973, another 200 MW oil unit was added bringing installed capacity to 1600 MW, but since demand jumped up by almost 100 MW (7.8 percent growth) the reserve margin increased only to 23 percent.

In 1973, the company saw that the compound annual growth rate in summer peak for the past five years was 7.7 percent. At this rate the peak would double in less than ten years, and another 1600 MW would have to be constructed to maintain the reserve margin. It did not seem economical to add eight 200 MW units, when larger units of 350 to 800 MW were reputed to be possible with significant economies in capital cost per megawatt. Moreover, toward the end of 1973 the oil embargo occurred, petroleum allocation plans were set, and the assurance of an oil supply for generation was in doubt. Coal and nuclear units seemed the only alternatives (the company had no new significant hydroelectric generation sites, and there were warning signs that natural gas curtailments could occur in a year or so), and their higher initial capital costs argued for trying to capture economies of scale. With many utilities still leery of the environmental consequences of coal generation, a record 46 nuclear units were sold in the U.S. in 1973 as companies sought diversity in the generation mix.

As a result, in 1973 the company planned the construction of a 350 MW coal-fired unit, a 450 MW coal unit, and an 800 MW nuclear unit to come on line over the next ten years. The left-hand side of table A-4 shows the company's 1973 projected reserve margins through 1984, starting from the

TABLE A-4

HISTORICAL PROJECTIONS OF FUTURE RESERVE MARGINS

	Projection made in 1973 with a 7 percent peak growth rate			Projection made in 1978 with a 4 percent peak growth rate		
Year	Peak (MW)	Capacity (MW)	Reserve Margin (%)	Peak (MW)	Capacity (MW)	Reserve Margin (%)
1973	1301	1600	23			
1974	1392	1600	15			
1975	1490	1600	7			
1976	1594	1950	22			
1977	1705	1950	14			
1978	1825	1950	7	1543	1950	26
1979	1952	2400	23	1605	1950	21
1980	2089	2400	15	1669	1950	17
1981	2235	2400	7	1736	1950	12
1982	2392	3200	34	1805	1950	8
1983	2559	3200	25	1877	2350	25
1984	2738	3200	17	1952	2350	20

Source: Table A-3 and authors' calculations.

known 1973 peak of 1301 MW from table A-3 and based on a peak growth rate of 7 percent and the strategic addition of new capacity. The 350 MW coal unit was planned to be available in the summer of 1976. A larger unit would have been less expensive on a per-kW basis, but would have taken longer to build, and the company forecast that, without new capacity in 1976, reserve margin would shrink almost to zero. In fact, reserve margin was allowed to become as small as 7 percent three times in the 10-year projection, as the company accelerated construction to keep pace with projected demand. The 7-percent reserves were not particularly troublesome because they lasted only for one summer each time, and purchased power was expected to be available to fill the temporary need for additional reserves. The company asserted that it was more costly in the long run to construct many small generating units to match demand growth than to build a few larger units and occasionally purchase high cost power from a neighboring utility. Reserve margin would dip to 7 percent again in 1978 and 1981, but the addition of a 450 MW coal unit in 1979 and an 800 MW nuclear unit in 1982 would restore the reserve margin to appropriate levels.

This plan was severely affected by the recession of 1974-75, the high level of interest rates, and the shocks to the energy markets. The cost of energy jumped suddenly. Not only did the internationally set prices of crude oil and yellowcake (uranium) increase dramatically, but prices determined principally by the U.S. domestic market rose sharply also. OPEC cartel pricing in the face of the oil embargo drove up the price of oil to electric utilities by 180 percent in 1974 alone.[1] Even so, there was not enough oil to satisfy demand, so energy users turned to other fuels. As demand for other fuels increased, so did their prices. Westinghouse defaulted on contracts to supply twenty reactor customers with yellowcake as the price more than tripled. A natural gas shortage was imminent: the ratio of reserves to production had been declining since 1950, new gas wells had declined since 1962; and since 1969 annual gas consumption exceeded additions to reserves.[2] The U.S. average well-head price for a thousand cubic feet of natural gas, which was 23 cents in 1973, rose to 27 cents in 1974 and 36 cents in 1975.[3] The price of coal began rising dramatically in 1974. Substitution of coal for oil by many large users and inflexible demand for coal by electric utilities put sharp upward pressure on prices. At the same time, increasingly strict interpretations of the Federal Coal Mine Health and Safety Act of 1969 reduced tonnage per man-hour and increased the number of health and safety related jobs--tending to raise

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[1]Staff Report, Council on Wage and Price Stability, A Study of Coal Prices (Washington: U.S. Government Printing Office, March 1976).

[2]E. J. Mitchell, U.S. Energy Policy: A Primer (Washington: American Institute for Public Policy Research, 1974).

[3]Thomas Wood, Federal Power Commission, personal communication, 1977.

prices. Anticipation of a prolonged mine workers' strike to begin in November 1974 led to near-panic efforts to stockpile coal by electric utilities, the steel industry, and foreign purchasers. In fact, the 1974 strike lasted only a month. But, in 1973 a ton of bituminous coal cost $8.42 at the mine mouth, and the U.S. average price in 1974 rose to $15.72, with spot prices going as high as $40. In 1975 coal averaged $19.24 per ton.

For our hypothetical electric company, the result of all this was that the rate of peak growth decreased sharply. Instead of the robust growth forecast in table A-4, the actual peak growth (in table A-3) was 1.5 percent in 1974 and 2.3 percent in 1975. While some of the change may have been due to the emergence of an energy conservation ethic, the primary factor was the increase in the price of electricity, resulting from the action of the company's fuel adjustment clause on these volatile fuel costs. In the previous ten years, the price of electricity had increased from 1.65 cents per kWh in 1963 to 1.86 cents per kWh in 1973,[4] a compound annual growth rate of 1.2 percent, representing a decreasing price in real terms. In 1974, the price of electricity jumped 24 percent to 2.30 cents per kWh and increased again in 1975, by 17 percent, to 2.70 cents per kWh.

In the period, 1975 through 1978, the company re-evaluated its generation construction plans several times. The first step, taken in 1975, was to delay the completion of the 350 MW coal unit, the construction of which was well underway, from 1976 to 1977. The second step was to put on hold beginning the construction of the 450 MW coal plant due on line in 1979. Because of the lead time for nuclear construction, early construction activities for the 800 MW nuclear unit were continued.

The next step was to evaluate what the future growth rate would be after this disruptive two-year period of 1974-75. One view was that the

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[4]Based on average revenue per kWh sold to all ultimate customers, from Edison Electric Institute, <u>Statistical Yearbook of the Electric Utility Industry 1982</u> (Washington: EEI, 1983), p. 71.

disruption was over and the historical growth rate of 7 percent would resume, though starting from a lower 1976 peak load than previously planned. Another view was that the electricity growth rate was permanently reduced, perhaps tending to zero growth. The company took a wait-and-see attitude. The actual peak loads realized are those shown in table A-3. In 1976, the peak grew by 3.9 percent and in 1977 growth reached the historical rate of 6.7 percent. However, in 1978 it dropped to 3.0 percent again. The company was unsure what growth rate to expect. In the five years since 1973 the peak grew at an average rate of 3.5 percent, but in the three years since 1975 it averaged 4.6 percent, indicating an upward trend in demand growth. Based on these data, in 1978 the company selected a 4.0 percent growth rate for planning new generation capacity. The company's 1978 forecast of peak demand is shown on the right-hand side of table A-4, starting with the known 1978 peak of 1543 MW from table A-3.

The forecast shows that, with 4 percent growth, by 1984 the company would need another 400 MW of capacity. The question in 1978 was whether to go ahead with the 800 MW nuclear plant, then partially constructed, or to build the 450 MW coal plant for which plans were drawn up but construction was suspended. The company chose the nuclear option, giving several reasons: a large capital investment had already been made in its construction; nuclear power had then (1978) completed twenty years of commercial electricity generation in the U.S. without a significant accident; the price of yellowcake had stabilized while the price of coal continued to rise; a major three-month coal miners' strike was anticipated for 1979 with uncertain results; Secretary of Energy James Schlesinger reported to Congress that coal prices had doubled again since 1975 and warned that "the cost advantage enjoyed by coal from the increase in world oil prices in the 1970s is disappearing";[5] executives of some major utilities called for a diversity of generation fuel types to allow competition with other fuels to

[5]James R. Schlesinger, statement to 96th Cong. First Sess. 134(1979) in Inflation in Utilities and Energy, Hearings before the Task Force of the House Committee on the Budget (Washington: U.S. Government Printing Office, 1979).

hold down coal costs;[6] factors outside the coal industry proper, such as state severance taxes and imminent rail rate deregulation, contributed to the uncertainty in coal costs; and, in addition, coal costs and availability over a thirty-year plant life were made uncertain by a host of bills before the Congress dealing with such issues as surface reclamation, miners' black lung disease, sulfur emissions, nitrogen oxide pollution, acid rain, the effect of carbon dioxide emissions on the earth's climate, and the disposal of enormous quantities of coal ash and scrubber sludge.

Perhaps equally important, our hypothetical company found a neighboring utility that agreed to purchase a 50 percent ownership in the 800 MW nuclear plant. Therefore, with a one-year delay in the construction schedule, the company planned to add 400 MW of nuclear capacity in 1983. The 450 MW coal unit was cancelled.

As shown in table A-4, the plans in 1978 were for peak demand to grow at 4 percent per year and for the reserve margin to fall as low as 8 percent in 1982, with purchased power under contract providing the balance of reserves. The addition of nuclear capacity in 1983 was expected to restore company-owned reserves to the 20-25 percent level in 1983-84. Such were the 1978 plans.

In 1979, the price of oil in the U.S. (expressed as a weighted average of domestic and imported oil prices) rose 42 percent.[7] A major, extended coal strike threatened the reliability of coal-fired electric generation. On March 28 of that year a relief valve on top of the pressurizer of Unit 2 at Three Mile Island failed to close, creating enormous dislocation in the nuclear industry. Inflation returned to the double-digit level, and the price of electricity rose 10 percent. The U.S. Department of Energy, the Federal Energy Regulatory Commission, and state regulatory agencies began

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[6]Statement of Gordon R. Carey, Vice Chairman of the Commonwealth Edison Company, Ibid, pp. 83-84.

[7]United States Energy Data Book (Fairchild, Conn.: General Electric Corporation, 1982).

implementing the provisions of the Public Utility Regulatory Policies Act and the National Energy Conservation Policy Act--laws designed in part to encourage electricity conservation and load controls, marginal cost-based (higher) electricity prices, and the displacement of utility generation by the generation of qualifying cogeneration facilities and small power producers, as well as to discourage growth in electric utility peak loads.

Similar conditions continued for the next two years. The U.S. retail price of oil rose by another 58 percent in 1980 to $28.07 per barrel and rose to $35.75 in 1981.[8] The cost of coal for electricity generation increased by about $3 per ton every year from 1979 through 1982,[9] for a net increase of 50 percent in four years. Increased Nuclear Regulatory Commission scrutiny of nuclear plant construction followed the accident at Three Mile Island, and resulted in construction delays, which were especially costly in 1980 with 13.5 percent CPI inflation and the associated high carrying costs. In 1981-82, economic recession, caused in part by rising energy prices, reduced demand for all goods, including electricity.

For our hypothetical electric company, rising electricity prices (18 percent in 1980) and the weak economy reduced the rate of growth in peak to 2.3 percent in both 1980 and 1981. In 1982, the summer peak decreased by 3 percent from the 1981 value. As the recession ended, peak growth resumed in 1983 and 1984 at 2.4 percent.

The corresponding peak loads and reserve margins are shown in table A-3. By historical standards, the results are startling. For five straight years, 1979 through 1983, the reserve margin remained at the 21-24 percent level without any additions to generation capacity.

Now that the nuclear capacity of 400 MW is ready to come on line in 1984 (after another year of construction delays) it is not needed. Adding 400 MW results in a 1984 reserve margin of 43 percent.

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[8]Ibid.

[9]EEI, op. cit., p. 34.

Rate Base Components of the Utility

In order to test the effect on the hypothetical utility of various commission actions to deal with overcapacity, it is necessary to know in some detail how the 22 units contribute to rate base.

We have worked out a generation rate base structure, which we believe is not atypical, shown in table A-5. The way in which this table is derived is as follows.

TABLE A-5

GENERATING UNITS' CONTRIBUTION TO RATE BASE
FOR THE HYPOTHETICAL UTILITY

Unit	Age (yrs)	Contribution to Rate Base: Depreciated Original Cost ($ x million)	Part Replacement & Pollution Control ($ x million)	Total ($ x million)
20 MW turbine #1	20	0.0	0.1	0.1
20 MW turbine #2	18	0.2	0.1	0.3
20 MW turbine #3	17	0.3	0.1	0.4
20 MW turbine #4	16	0.4	0.1	0.5
10 MW oil #1	42	0.0	0.2	0.2
10 MW oil #2	40	0.0	0.2	0.2
50 MW hydro #1	56	0.0	1.8	1.8
50 MW hydro #2	52	0.0	1.8	1.8
50 MW hydro #3	48	0.0	1.8	1.8
50 MW hydro #4	44	0.0	1.8	1.8
75 MW coal #1	39	0.0	1.4	1.4
75 MW coal #2	35	0.0	1.4	1.4
100 MW oil #1	31	0.0	1.8	1.8
100 MW oil #2	27	1.9	1.6	3.5
100 MW oil #3	25	3.7	1.5	5.2
150 MW coal #1	22	8.3	2.1	10.4
150 MW coal #2	19	11.8	1.8	13.6
150 MW coal #3	15	17.7	1.4	19.1
200 MW oil #1	13	30.0	1.6	31.6
200 MW oil #2	11	36.7	1.3	38.0
350 MW coal	7	131.3	1.9	133.2
Subtotal		242.3	25.8	268.1
400 MW nuclear	0	878.0	0.0	878.0
Total		1120.3	25.8	1146.1

Source: Authors' calculation based on tables A-1 and A-2 and the method described in the text.

Briefly, the 1969 peak load (from table A-3) is reduced by 7 percent per year moving into the past, and units are added to the system when necessary to maintain a 20 percent reserve margin. Before 1950, units are added both to account for peak growth and to allow for retirement of older plants. Units are added to the system in order of size except for hydro units, which are added before 1940, and combustion turbines, which are added beginning in 1964.

The original costs of the units are estimated using recent unit costs ($ per kW) deflated using the Handy-Whitman Index. Lack of economies of scale, which tends to raise older unit costs, and the addition of new unit features, the absence of which tends to lower older unit costs, are not taken into account. The original cost contribution to rate base is depreciated by straight line over 30 years for steam and hydro units and over twenty years for combustion turbines.

The cost of the nuclear plant coming on line in 1984 is $2196 per kW, based on an average of September 1983 cost estimates for 23 nuclear plants over 80 percent complete.[10] Older units that are fully depreciated still make a contribution to rate base because of equipment and parts replacement and efficiency improvements. Coal units are retrofit with pollution control equipment and so contribute more to rate base than simply depreciated original cost. The contribution to rate base of all such costs for each unit is estimated as 2.5 percent of the original cost of the units inflated to the current level using the Handy-Whitman Index, times a factor that accounts for the age of each unit. This method is used because it is simple and not unreasonable, and because the end result is a rate base structure similar to that seen in recent utility cost studies.

Revenue, Price, and the Interest Coverage Ratio

In order to determine the effect of commission treatment of

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[10] Electric Utility Week, November 14, 1983, p. 5.

overcapacity on the revenue requirement, the price of electricity, and the financial position of the utility, three simple equations have been developed, as shown in figure A-1.

These three equations are based on essentially two assumptions. One is that the revenue requirement is determined by flow-through accounting, i.e., it equals return on rate base plus straight line depreciation of rate base, fuel and other expenses, property and other non-income taxes, and income taxes less any investment tax credit. The formula expressing this assumption can be solved for the revenue requirement (R) yielding the first equation. This equation lumps together a set (Z) of terms that are assumed not to vary with commission action.

Revenue per kilowatt-hour is a surrogate for the price of electricity, which is typically about 6 percent greater because of line losses.

The after-tax interest coverage ratio is the ratio of the funds available to pay common and preferred stockholders and creditors divided by interest on long-term debt. The numerator is equivalent to return on rate base in most cases, that is, after-tax earnings plus interest on long-term debt. However, in cases (discussed in chapter 2) where the full depreciation expense is not allowed in rates, earnings are reduced by the disallowed expense.

Data and additional assumptions that are used in and with this model are as follows. It is assumed that there is no inflation in the cost of individual expenditures to be accounted for in a rate case. This helps to isolate the effect of the commission's action on the level rates.

Our hypothetical utility has a capital structure shown in table A-6. The weighted average cost of capital is 12 percent.

The depreciation rate is assumed to equal 0.0333 here and in chapter 2. In chapter 3, a lower rate is assumed.

Definitions

r = rate of return on rate base
r_d = depreciation rate (straight line)
r_t = income tax rate
R = revenue requirement
B = rate base
F = fuel expense
O = O&M expenses (non-fuel)
D = accelerated depreciation
P = property and other non-income taxes
I = interest
T = investment tax credit
G = annual generation
p = revenue per kilowatt-hour of generation
C = after-tax interest coverage ratio
N = depreciation expense not included in rates

Assumptions

$$R = rB + r_d B + F + O + P + r_t(R-D-F-O-P-I)-T$$

$$Z = O + P - \frac{r_t(D+I)+T}{1-r_t} = \text{constant}$$

Equations

$$R = \frac{(r+r_d)B}{1-r_t} + F + Z$$

$$p = \frac{R}{G}$$

$$C = \frac{rB-N}{I}$$

Fig. A-1 Definitions, assumptions, and equations used in chapter 2

TABLE A-6

CAPITAL STRUCTURE AND RATE OF RETURN

Source of Capital	Amount[a] ($ x millions)	Percentage of Total Capital	Cost of Capital (%)	Return on Capital ($ x million)
Common Stock	560	40	15.0	84
Preferred Stock	140	10	12.0	17
Long-term Debt	700	50	9.6	67
Total	1400	100	12.0[b]	168

Source: Total capital based on recent utility averages for all class A and B electric utilities; capital structure based on industry averages from the EEI Statistical Yearbook/1982; capital costs based on average of 1984 rate cases reported in the NRRI Quarterly Bulletin No. 18 (Columbus: The National Regulatory Research Institute, April 1984).

a. Typically, a utility's rate base equals about 80 percent of the company's assets. In the data presented here and in chapter 2 we make the simplifying assumption that, when all construction is completed, when there is no construction in progress, and when all capacity is included in rate base, then rate base equals assets.

b. Weighted average cost of capital.

The corporate income tax rate is assumed to be 0.48, equal to the federal rate. Utilities actually pay considerably less. In 1982, for example, electric utility federal and state income taxes averaged about 19 percent of pre-tax earnings. However, because we are concerned with new taxes associated with new capacity-related earnings, the marginal tax rate is used. But, because the new capacity is added in a very large increment, this assumption may overestimate income taxes.

The rate base is $514 million excluding the new nuclear plant and $1400 million including it, as shown in table 2-2 of chapter 2.

Fuel expense for 8790 GWh of annual generation is $220 million before the nuclear plant is on line and $102 million after it is on line, as shown in table A-7.

TABLE A-7

ANNUAL FUEL EXPENSE FOR THE HYPOTHETICAL UTILITY

Capacity Type	Fuel Cost (¢/kWh)	Generation (GWh)[a]	Expense ($ x million)
Before the Nuclear Plant Is On-line			
Hydro	-0-	1139	-0-
Coal	1.6	5409	87
Oil	6.0	2202	132
Peaker	7.0	40	3
	Total:	8790	222
After the Nuclear Plant is On-line			
Hydro	-0-	1139	-0-
Nuclear	0.6	2277	14
Coal	1.6	5334	85
Peaker	7.0	40	3
	Total:	8790	102

Source: Authors' calculations based on table A-1.

a. Assumes economic dispatch with hydro dispatched first; steam units are simultaneously needed and available 65 percent of the time; peakers are needed for load following for 40 GWh of energy. With the nuclear plant on-line, oil capacity is required only on the peak days (to supply the last 30 MW) for which fuel expense is negligible (ignoring the cost of maintaining spinning reserve).

The term Z is assumed to be independent of commission treatment of overcapacity; it equals $119 million. Factors that enter into Z are: O = $219 million; P = $45 million; D = $59 million; I = $67 million; and T = $15 million. If the commission should exclude some plant from rate base, the utility can continue to use it to generate power, mothball it until it is needed, or write if off as a loss. It is assumed in most cases that the company will use the new capacity regardless of commission action. Then Z is constant. If the company should choose not to use the plant, then Z can vary. Non-fuel O&M expenses could be affected by this choice, but not in a major way. Non-income taxes could be affected slightly, but would not make a major difference in the revenue requirement. Accelerated depreciation for tax purposes is calculated for the case in which the company uses the plant, but is affected otherwise.

Taxes and tax credits will be affected if the utility should choose to write off the excess plant. Oil-fired units and very old units are the best candidates for write-off. Writing off old units would not significantly affect the revenue requirement. Writing off a fairly new oil unit would. Aside from oil units, which are no longer being constructed, abandonment of a large new facility is unlikely because simply mothballing such a unit does not qualify for a tax write-off and because the investment cannot be legally written off if there is an eventual opportunity to recover costs. The write-off, if taken, cannot be deducted from taxes but only deducted from income; only income for the three past years and for 15 future years qualifies for such an offset. Furthermore, a company that has taken investment tax credits on construction payments in prior years incurs an immediate liability to pay back the credits if the investment is written off. These important tax consequences are not captured by the equations because it is assumed that either the company will use the plant or variations in the calculated results will be small.

In chapter 2, these data and the equations in figure A-1 are used to calculate the revenue requirement, the revenue per kWh, and the coverage ratio before and after the new nuclear facility is in the rate base, and used to examine other commission options for treating the overcapacity situation.

APPENDIX B

DETAILED RESULTS OF THE DEMAND VARIATION ANALYSIS

In chapter 3, a number of price reduction cases are described, and summary results are presented. In this appendix, we include the detailed output of the models upon which these summary results are based.

Tables B-1 through B-13 contain these results. Table B-1 contains the results of case 1 (the base scenario) described in chapter 3 and listed in table 3-2. Table B-2 corresponds to case 2, table B-3 to case 3, and so on for the thirteen cases listed in table 3-2. Recall that cases 1 through 8 are for the typical utility, and cases 9 through 13 are for the medium-size utility.

Each table displays the principal assumptions used in the model at the top of the table. In reading these assumptions, note that many of the abbreviations (necessary to meet printer space requirements) are self explanatory, while others may need some elaboration. To this end, we define those abbreviations below.

"Generation Incrse" is the ratio of annual generation to the previous year's annual generation.

"Peak Incrse" is the ratio of annual peak to the previous year's annual peak.

"Revenue/kwh" is the ratio of the annual revenue in dollars to the annual generation in kilowatt-hours.

"O & M Expense/kwh" is the ratio of annual operation and maintenance expense in dollars to the annual generation in kilowatt-hours.

"Dep Rte" is the depreciation rate.

"EqtyGrwth" is the ratio of stockholders' equity one year to the previous year's value.

"Dbt cst" is the cost of debt, expressed as a decimal.

"FxdCst%" is the ratio of the fixed costs to total costs.

"Cptl/asts" is the ratio of capitalization to assets.

"Debt/cptl" is the ratio of debt to capitalization.

"Eqty/cptl" is the ratio of equity to capitalization.

The values for these variables are shown to two decimal places; hence, the rate of growth in generation, which is assumed to be 2.5 percent, results in a table listing for "generation increase" of 1.03.

Below the assumptions are ten columns of numbers, which are the results of the particular case over a ten-year period. The years are labelled 1.00 through 10.00 at the top of each table. For each year (i.e., in each column) are shown the annual generation in gigwatt-hours (GWH), the annual peak in megawatts (MW), and so on, as indicated by the row names at the extreme left of the table.

As explained in chapter 3, first year entries for the typical utility in case 1 (table B-1) equal recent average values for 204 class A and B electric utilities. Values for years 2 through 10 are calculated based on the assumptions at the top of the table, on the assumptions about elasticities, financing, and capital costs presented in chapter 3, and on standard regulatory accounting relationships. The same calculations are repeated in cases 2 through 8 (tables B-2 through B-8), except that prices and demand are modified according to the conditions of each case. For example, in table B-2 (case 2) it is assumed that generation would grow at 3 percent annually if there were no price reduction but that, since price is reduced by 5 percent, generation grows at a correspondingly faster rate.

In cases involving time-of-use rates for industrial customers, the generation for these customers in megawatt-hours (MWH) during the peak, shoulder (labelled "Md Pk"), and off-peak periods is displayed, along with the industrial revenues associated with each of these periods.

In order to test the sensitivity of the results to utility size, several of the price and demand conditions are applied to a larger company, called the medium-size utility, with first year data based here on a sample of six relatively large electric companies located in six areas of the country. Tables B-9 through B-13 represent the results of cases 9 through 13, respectively.

Not shown in these tables is the ten-year levelized revenue per kilowatt-hour. This is the ratio of two numbers. The numerator is the net present value of the ten-year revenue stream, in millions of dollars, assuming a discount rate of 11 percent. The denominator is the total generation in GWH during the ten-year period.

TABLE B-1

BASE SCENARIO FOR THE TYPICAL UTILITY: CASE 1

Assumptions

Generation Incrse	1.03	Dep Rte	.99	Cptl/asts	.80
Peak Incrse	1.02	EqtyGrwth	1.04	Debt/cptl	.51
Revenue/kwh	.06	Dbt cst	.09	Eqty/cptl	.38
O & M Expnse/kwh	.04	FxdCst%	.05		

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Generation	GWH	8790.00	9009.75	9234.99	9465.87	9702.52	9945.08	10193.71	10448.55	10709.76	10977.51
Peak	MW	1645.00	1677.90	1711.46	1745.69	1780.60	1816.21	1852.54	1889.59	1927.38	1965.93
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	63.12	63.43	63.74
Capacity Factor	%	42.70	43.77	44.86	45.98	47.13	48.31	49.52	50.76	52.02	53.33
Capacity Margin	%	30.00	28.60	27.17	25.72	24.23	22.71	21.17	19.59	17.98	16.34
Revenue	million $	492.24	504.55	517.16	530.09	543.34	556.92	570.85	585.12	599.75	614.74
Expenses	million $	392.04	399.95	406.56	414.13	421.91	429.92	438.15	446.61	455.31	464.25
Net Revenue	million $	100.20	104.60	110.60	115.96	121.43	127.01	132.70	138.51	144.44	150.49
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1291.84	1278.92
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29
Net Earnings	million $	46.91	51.30	57.31	62.67	68.14	73.71	79.41	85.21	91.14	97.20
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20
Rate of Return	%	7.16	7.55	8.06	8.54	9.03	9.54	10.07	10.61	11.18	11.77
Return on Equity	%	11.02	11.59	12.45	13.09	13.68	14.24	14.75	15.22	15.65	16.05
Coverage Ratio		1.88	1.96	2.08	2.18	2.28	2.38	2.49	2.60	2.71	2.82
Net Erngs/Asset	cents/$	3.35	3.70	4.18	4.61	5.07	5.54	6.02	6.53	7.06	7.60
Revenue/kwh	cents/$	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60

Source: Authors' calculations

TABLE B-2

FIVE PERCENT PRICE REDUCTION FOR ALL CUSTOMERS OF THE TYPICAL UTILITY
WITH NO CAPACITY ADDITIONS: CASE 2

Item		Year									
		1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03	Dep Rte		.99		Cptl/asts	.80				
Peak Incrse	1.02	EqtyGrwth		1.04		Debt/cptl	.51				
Revenue/kwh	..05	Dbt cst		.09		Eqty/cptl	.38				
O & M Expnse/kwh	.04	FxdCst%		.05							
Generation	GWH	8790.00	9135.89	9579.66	9897.71	10145.15	10398.78	10658.75	10925.22	11198.35	11478.31
Peak	MW	1645.00	1701.39	1775.33	1825.33	1861.83	1899.07	1937.05	1975.79	2015.31	2055.61
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	63.12	63.43	63.74
Capacity Factor	%	42.70	44.38	46.53	48.08	49.28	50.51	51.78	53.07	54.40	55.76
Capacity Margin	%	30.00	27.60	24.45	22.33	20.77	19.19	17.57	15.92	14.24	12.53
Revenue	million $	467.63	486.03	509.64	526.56	539.72	553.22	567.05	581.22	595.75	610.65
Expenses	million $	392.04	404.49	418.96	429.67	437.85	446.25	454.89	463.77	472.90	482.28
Net Revenue	million $	75.59	81.54	90.67	96.89	101.88	106.96	112.15	117.45	122.85	128.36
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1291.84	1278.92
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29
Net Earnings	million $	22.30	28.24	37.38	43.59	48.58	53.67	58.86	64.16	69.56	75.07
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20
Rate of Return	%	5.40	5.88	6.61	7.13	7.58	8.03	8.51	9.00	9.51	10.04
Return on Equity	%	5.24	6.38	8.12	9.11	9.76	10.37	10.93	11.46	11.94	12.39
Coverage Ratio		1.42	1.53	1.70	1.82	1.91	2.01	2.10	2.20	2.31	2.41
Net Erngs/Asset	cents/$	1.59	2.04	2.72	3.21	3.61	4.03	4.47	4.92	5.38	5.87
Revenue/kwh	cents/$	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32

Source: Authors' calculations

TABLE B-3

FIVE PERCENT PRICE REDUCTION FOR ALL CUSTOMERS OF THE TYPICAL UTILITY
WITH CAPACITY ADDITIONS ALLOWED: CASE 3

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03		Dep Rte	.99		Cptl/asts	.80				
Peak Incrse	1.02		EqtyGrwth	1.04		Debt/cptl	.51				
Revenue/kwh	.05		Dbt cst	.09		Eqty/cptl	.38				
O & M Expnse/kwh	.04		FxdCst%	.05							
Generation	GWH	8790.00	9135.89	9579.66	9897.71	10145.15	10398.78	10658.75	10794.11	10953.33	11092.43
Peak	MW	1645.00	1701.39	1775.33	1825.33	1861.83	1899.07	1937.05	1975.79	2015.31	2055.61
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2400.00	2450.00	2500.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	62.37	62.04	61.60
Capacity Factor	%	42.70	44.38	46.53	48.08	49.28	50.51	51.78	51.34	51.04	50.65
Capacity Margin	%	30.00	27.60	24.45	22.33	20.77	19.19	17.57	17.68	17.74	17.78
Revenue	million $	467.63	486.03	509.64	526.56	539.72	553.22	567.05	584.73	602.40	621.24
Expenses	million $	392.04	404.49	418.96	429.67	437.85	446.25	454.89	463.10	472.14	480.42
Net Revenue	million $	75.59	81.54	90.67	96.89	101.88	106.96	112.15	121.62	130.26	140.82
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1379.89	1441.09	1501.68
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	60.29	67.29	74.29
Net Earnings	million $	22.30	28.24	37.38	43.59	48.58	53.67	58.86	61.33	62.97	66.54
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	646.20	721.20	796.20
Rate of Return	%	5.40	5.88	6.61	7.13	7.58	8.03	8.51	8.81	9.04	9.38
Return on Equity	%	5.24	6.38	8.12	9.11	9.76	10.37	10.93	10.95	10.81	10.98
Coverage Ratio		1.42	1.53	1.70	1.82	1.91	2.01	2.10	2.02	1.94	1.90
Net Erngs/Asset	cents/$	1.59	2.04	2.72	3.21	3.61	4.03	4.47	4.44	4.37	4.43
Revenue/kwh	cents/$	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.42	5.50	5.60

Source: Authors' calculations

TABLE B-4

TEN PERCENT PRICE REDUCTION FOR INDUSTRIAL CUSTOMERS OF THE TYPICAL UTILITY WITH CAPACITY ADDITIONS ALLOWED: CASE 4

Assumptions

Generation Incrse	1.03	Dep Rte	.99	Cptl/asts	.80
Peak Incrse	1.02	EqtyGrwth	1.04	Debt/cptl	.51
Revenue/kwh	.05	Dbt cst	.09	Eqty/cptl	.38
O & M Expnse/kwh	.04	FxdCst%	.05		

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Generation	GWH	8790.00	9050.29	9426.83	9771.69	10015.96	10266.38	10523.04	10786.12	11011.55	11173.97
Peak	MW	1645.00	1685.45	1747.01	1802.09	1838.13	1874.89	1912.39	1950.64	1989.65	2029.44
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2400.00	2450.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	63.12	63.18	62.85
Capacity Factor	%	42.70	43.96	45.79	47.47	48.65	49.87	51.12	52.40	52.38	52.06
Capacity Margin	%	30.00	28.28	25.66	23.32	21.78	20.22	18.62	16.99	17.10	17.17
Revenue	million $	478.95	493.13	513.65	532.44	545.75	559.39	573.38	587.71	610.50	629.74
Expenses	million $	392.04	401.41	413.46	425.14	433.20	441.48	450.01	458.76	470.23	479.38
Net Revenue	million $	86.91	91.72	100.19	107.30	112.55	117.91	123.37	128.95	140.27	150.36
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1366.84	1428.17
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	60.29	67.29
Net Earnings	million $	33.62	38.43	46.89	54.01	59.26	64.62	70.08	75.66	79.98	83.07
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	646.20	721.20
Rate of Return	%	6.21	6.62	7.30	7.90	8.37	8.86	9.36	9.88	10.26	10.53
Return on Equity	%	7.90	8.68	10.19	11.28	11.90	12.48	13.01	13.51	13.73	13.71
Coverage Ratio		1.63	1.72	1.88	2.01	2.11	2.21	2.32	2.42	2.33	2.23
Net Erngs/Asset	cents/$	2.40	2.77	3.42	3.98	4.41	4.85	5.32	5.80	5.85	5.82
Revenue/kwh	cents/$	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.54	5.64

Source: Authors' calculations

TABLE B-5

TEN PERCENT PRICE REDUCTION FOR INDUSTRIAL CUSTOMERS OF THE TYPICAL UTILITY
WITH NO CAPACITY ADDITIONS: CASE 5

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03		Dep Rte	.99		Cptl/asts	.80				
Peak Incrse	1.02		EqtyGrwth	1.04		Debt/cptl	.51				
Revenue/kwh	.05		Dbt cst	.09		Eqty/cptl	.38				
O & M Expnse/kwh	.04		FxdCst%	.05							
Generation	GWH	8790.00	9050.29	9426.83	9771.69	10015.98	10266.38	10523.04	10786.12	11055.77	11332.16
Peak	MW	1645.00	1677.90	1711.46	1745.69	1780.60	1816.21	1852.54	1889.59	1927.38	1965.93
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00
Load Factor	%	61.00	61.57	62.88	63.90	64.21	64.53	64.84	65.16	65.48	65.80
Capacity Factor	%	42.70	43.96	45.79	47.47	48.65	49.87	51.12	52.40	53.71	55.05
Capacity Margin	%	30.00	28.60	27.17	25.72	24.23	22.71	21.17	19.59	17.98	16.34
Revenue	million $	478.95	493.13	513.65	532.44	545.75	559.39	573.38	587.71	602.41	617.47
Expenses	million $	392.04	401.41	413.46	425.14	433.20	441.48	450.01	458.76	467.77	477.02
Net Revenue	million $	86.91	91.72	100.19	107.30	112.55	117.91	123.37	128.95	134.64	140.45
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1291.84	1278.92
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29
Net Earnings	million $	33.62	38.43	46.89	54.01	59.26	64.62	70.08	75.66	81.35	87.15
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20
Rate of Return	%	6.21	6.62	7.30	7.90	8.37	8.86	9.36	9.88	10.42	10.98
Return on Equity	%	7.90	8.68	10.19	11.28	11.90	12.48	13.01	13.51	13.97	14.39
Coverage Ratio		1.63	1.72	1.88	2.01	2.11	2.21	2.32	2.42	2.53	2.64
Net Erngs/Asset	cents/$	2.40	2.77	3.42	3.98	4.41	4.85	5.32	5.80	6.30	6.81
Revenue/kwh	cents/$	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45

Source: Authors' calculations

TABLE B-6

TIME-OF-USE PRICING FOR INDUSTRIAL CUSTOMERS OF THE TYPICAL UTILITY
WITH NO CONSTRAINTS: CASE 6

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03		Dep Rte	.99		Cptl/asts	.80		%Revnue	.74	
Peak Incrse	1.02		EqtyGrwth	1.04		Debt/cptl	.51		Pk Rvnue	.05	
Revenue/kwh	.06		Dbt cst	.09		Eqty/cptl	.38		Md Pk Rev	.05	
O & M Expnse/kwh	.04		FxdCst%	.05		% Mwh	.68		OffPk Rev	.03	
Generation	GWH	8790.41	9060.75	9528.10	10042.89	10534.72	10965.65	11356.41	11721.49	12071.01	12412.10
Peak	MW	1645.00	1633.27	1665.93	1699.25	1733.24	1767.90	1803.26	1839.32	1876.11	1913.63
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00
Load Factor	%	61.00	63.33	65.29	67.47	69.38	70.81	71.89	72.75	73.45	74.04
Capacity Factor	%	42.70	44.01	46.28	48.79	51.17	53.27	55.17	56.94	58.64	60.29
Capacity Margin	%	30.00	30.50	29.11	27.69	26.25	24.77	23.27	21.73	20.17	18.57
Revenue	million $	492.16	508.30	538.49	567.57	593.58	615.32	635.50	654.73	673.42	691.88
Expenses	million $	392.05	401.79	417.11	434.90	451.87	466.66	480.01	492.44	504.32	515.90
Net Revenue	million $	100.10	106.51	121.38	132.68	141.71	148.66	155.50	162.29	169.11	175.98
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1291.84	1278.92
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29
Net Earnings	million $	46.81	53.22	68.09	79.38	88.42	95.37	102.20	109.00	115.82	122.69
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20
Rate of Return	%	7.15	7.69	8.85	9.77	10.54	11.17	11.80	12.44	13.09	13.76
Return on Equity	%	11.00	12.02	14.79	16.58	17.76	18.42	18.98	19.46	19.88	20.25
Coverage Ratio		1.88	2.00	2.28	2.49	2.66	2.79	2.92	3.05	3.17	3.30
Net Erngs/Asset	cents/$	3.34	3.84	4.96	5.84	6.57	7.16	7.75	8.35	8.97	9.59
Revenue/kwh	cents/$	5.60	5.61	5.65	5.65	5.63	5.61	5.60	5.59	5.58	5.57
Peak Mwh Indstry	Gwh	847.00	834.32	744.00	722.95	725.46	743.59	762.18	781.24	800.77	820.79
Md Pk Indstry	Gwh	1552.00	1657.61	1953.91	2122.93	2228.22	2283.93	2341.03	2399.55	2459.54	2521.03
Off Peak Indstry	Gwh	423.00	450.92	524.12	565.70	591.44	606.23	621.38	636.92	652.84	669.16
Pk Rev Indstry	mill $	46.08	45.39	40.47	39.33	39.46	40.45	41.46	42.50	43.56	44.65
Md Pk Rev Indstry	mill $	71.70	76.58	90.27	98.08	102.94	105.52	108.16	110.86	113.63	116.47
Off Pk Rev Ind	mill $	12.56	13.39	15.57	16.80	17.57	18.00	18.46	18.92	19.39	19.87

Source: Authors' calculations

TABLE B-7

TIME-OF-USE PRICING FOR INDUSTRIAL CUSTOMERS OF THE TYPICAL UTILITY
WITH THE CONSTRAINT THAT TOTAL INDUSTRIAL CONSUMPTION GROW AT THE BASE SCENARIO RATE: CASE 7

Item								
Assumptions								
Generation Incrse	1.03	Dep Rte	.99	Cptl/asts	.80	%Revnue	.74
Peak Incrse	1.02	EqtyGrwth	1.04	Debt/cptl	.51	Pk Rvnue	.06
Revenue/kwh	.06	Dbt cst	.09	Eqty/cptl	.38	Md Pk Rev	.05
O & M Expnse/kwh	.04	FxdCst%	.05	% Mwh	.68	OffPk Rev	.03

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Generation	GWH	8791.41	9011.15	9236.40	9467.29	9703.96	9946.54	10195.20	10450.08	10711.32	10979.11
Peak	MW	1645.00	1655.58	1666.24	1699.56	1733.55	1768.22	1803.59	1839.66	1876.45	1913.98
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00
Load Factor	%	61.00	62.13	63.28	63.59	63.90	64.21	64.53	64.85	65.16	65.48
Capacity Factor	%	42.70	43.77	44.87	45.99	47.14	48.32	49.52	50.76	52.03	53.33
Capacity Margin	%	30.00	29.55	29.10	27.68	26.23	24.76	23.25	21.72	20.15	18.55
Revenue	million $	492.21	502.62	509.31	520.27	533.06	546.39	560.05	574.05	588.40	603.11
Expenses	million $	392.09	400.00	406.61	414.18	421.96	429.97	438.20	446.67	455.37	464.31
Net Revenue	million $	100.12	102.62	102.71	106.10	111.10	116.42	121.84	127.38	133.03	138.80
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1291.84	1278.92
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29
Net Earnings	million $	46.82	49.33	49.42	52.80	57.80	63.12	68.55	74.09	79.74	85.51
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20
Rate of Return	%	7.15	7.40	7.49	7.81	8.26	8.74	9.24	9.76	10.30	10.85
Return on Equity	%	11.00	11.14	10.73	11.03	11.61	12.19	12.73	13.23	13.69	14.12
Coverage Ratio		1.88	1.93	1.93	1.99	2.08	2.18	2.29	2.39	2.50	2.60
Net Erngs/Asset	cents/$	3.34	3.56	3.60	3.89	4.30	4.74	5.20	5.68	6.17	6.69
Revenue/kwh	cents/$	5.60	5.58	5.51	5.50	5.49	5.49	5.49	5.49	5.49	5.49
Peak Mwh Indstry	Gwh	706.00	667.21	505.39	464.15	469.09	480.82	492.84	505.16	517.79	530.74
Md Pk Indstry	Gwh	1411.00	1446.28	1482.43	1519.49	1557.48	1596.42	1636.33	1677.24	1719.17	1762.15
Off Peak Indstry	Gwh	706.00	779.07	977.04	1055.34	1088.39	1115.60	1143.48	1172.07	1201.37	1231.41
Total Indstry	Gwh	2822.00	2892.55	2964.86	3038.99	3114.96	3192.83	3272.65	3354.47	3438.33	3524.29
Pk Rev Indstry	mill $	44.20	41.77	31.64	29.06	29.37	30.10	30.85	31.62	32.41	33.22
Md Pk Rev Indstry	mill $	65.19	66.82	68.49	70.20	71.96	73.75	75.60	77.49	79.43	81.41
Off Pk Rev Ind	mill $	20.97	23.14	29.02	31.34	32.33	33.13	33.96	34.81	35.68	36.57

Source: Authors' calculations

TABLE B-8

TIME-OF-USE PRICING FOR INDUSTRIAL CUSTOMERS OF THE TYPICAL UTILITY WITH THE CONSTRAINT OF LESS ELASTIC SHOULDER PEAK INDUSTRIAL DEMAND: CASE 8

Item		Year									
		1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											

Generation Incrse	1.03	Dep Rte	.99	Cptl/asts	.80	%Revnue	.74
Peak Incrse	1.02	EqtyGrwth	1.04	Debt/cptl	.51	Pk Rvnue	.05
Revenue/kwh	.06	Dbt cst	.09	Eqty/cptl	.38	Md Pk Rev	.05
O & M Expnse/kwh	.04	FxdCst%	.05	% Mwh	.68	OffPk Rev	.03

Item		1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Generation	GWH	8790.41	9027.35	9340.61	9678.92	10013.11	10327.62	10630.47	10927.32	11222.14	11517.75
Peak	MW	1645.00	1655.58	1666.24	1699.56	1733.55	1768.22	1803.59	1839.66	1876.45	1913.98
Capacity	MW	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00	2350.00
Load Factor	%	61.00	62.25	63.99	65.01	65.94	66.67	67.28	67.81	68.27	68.70
Capacity Factor	%	42.70	43.85	45.37	47.02	48.64	50.17	51.64	53.08	54.51	55.95
Capacity Margin	%	30.00	29.55	29.10	27.68	26.23	24.76	23.25	21.72	20.15	18.55
Revenue	million $	492.16	505.38	523.18	541.81	559.72	576.35	592.60	608.70	624.80	641.04
Expenses	million $	392.05	400.58	410.36	421.80	433.09	443.69	453.87	463.85	473.76	483.70
Net Revenue	million $	100.10	104.80	112.83	120.01	126.63	132.66	138.73	144.85	151.05	157.34
Assets	million $	1400.00	1386.00	1372.14	1358.42	1344.83	1331.39	1318.07	1304.89	1291.84	1278.92
Equity	million $	425.60	442.62	460.33	478.74	497.89	517.81	538.52	560.06	582.46	605.76
Debt Interest	million $	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29	53.29
Net Earnings	million $	46.81	51.51	59.53	66.72	73.33	79.37	85.43	91.55	97.75	104.05
Debt	million $	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20	571.20
Rate of Return	%	7.15	7.56	8.22	8.83	9.42	9.96	10.53	11.10	11.69	12.30
Return on Equity	%	11.00	11.64	12.93	13.94	14.73	15.33	15.86	16.35	16.78	17.18
Coverage Ratio		1.88	1.97	2.12	2.25	2.38	2.49	2.60	2.72	2.83	2.95
Net Erngs/Asset	cents/$	3.34	3.72	4.34	4.91	5.45	5.96	6.48	7.02	7.57	8.14
Revenue/kwh	cents/$	5.60	5.60	5.60	5.60	5.59	5.58	5.57	5.57	5.57	5.57
Peak Mwh Indstry	Gwh	847.00	834.32	744.00	722.95	725.46	743.59	762.18	781.24	800.77	820.79
Md Pk Indstry	Gwh	1552.00	1624.21	1789.67	1889.45	1959.92	2008.92	2059.14	2110.62	2163.39	2217.47
Off Peak Indstry	Gwh	423.00	450.92	524.12	565.70	591.44	606.23	621.38	636.92	652.84	669.16
Pk Rev Indstry	mill $	46.08	45.39	40.47	39.33	39.46	40.45	41.46	42.50	43.56	44.65
Md Pk Rev Indstry	mill $	71.70	75.04	82.68	87.29	90.55	92.81	95.13	97.51	99.95	102.45
Off Pk Rev Ind	mill $	12.56	13.39	15.57	16.80	17.57	18.00	18.46	18.92	19.39	19.87

Source: Authors' calculations

TABLE B-9

BASE SCENARIO FOR THE MEDIUM-SIZE UTILITY: CASE 9

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03		Dep Rte	.99		Cptl/asts	.80				
Peak Incrse	1.02		EqtyGrwth	1.04		Debt/cptl	.51				
Revenue/kwh	.05		Dbt cst	.09		Eqty/cptl	.38				
O & M Expnse/kwh	.03		FxdCst%	.05							
Generation	GWH	37500.00	38437.50	39398.44	40383.40	41392.98	42427.81	43488.50	44575.72	45690.11	46832.36
Peak	MW	7018.00	7158.36	7301.53	7447.56	7596.51	7748.44	7903.41	8061.48	8222.71	8387.16
Capacity	MW	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	63.12	63.43	63.74
Capacity Factor	%	42.38	43.44	44.53	45.64	46.78	47.95	49.15	50.38	51.64	52.93
Capacity Margin	%	30.51	29.13	27.71	26.26	24.79	23.28	21.75	20.18	18.59	16.96
Revenue	million $	1837.50	1883.44	1930.52	1978.79	2028.26	2078.96	2130.94	2184.21	2238.82	2294.79
Expenses	million $	1413.66	1440.85	1462.22	1487.59	1513.70	1540.58	1568.24	1596.70	1625.98	1656.09
Net Revenue	million $	423.84	442.59	468.30	491.20	514.55	538.38	562.70	587.51	612.84	638.69
Assets	million $	6040.00	5979.60	5919.80	5860.61	5802.00	5743.98	5686.54	5629.67	5573.38	5517.64
Equity	million $	1836.16	1909.61	1985.99	2065.43	2148.05	2233.97	2323.33	2416.26	2512.91	2613.43
Debt Interest	million $	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92
Net Earnings	million $	193.92	212.67	238.38	261.27	284.63	308.46	332.78	357.59	382.92	408.77
Debt	million $	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32
Rate of Return	%	7.02	7.40	7.91	8.38	8.87	9.37	9.90	10.44	11.00	11.58
Return on Equity	%	10.56	11.14	12.00	12.65	13.25	13.81	14.32	14.80	15.24	15.64
Coverage Ratio		1.84	1.92	2.04	2.14	2.24	2.34	2.45	2.56	2.67	2.78
Net Erngs/Asset	cents/$	3.21	3.56	4.03	4.46	4.91	5.37	5.85	6.35	6.87	7.41
Revenue/kwh	cents/$	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90

Source: Authors' calculations

TABLE B-10

FIVE PERCENT PRICE REDUCTION FOR ALL CUSTOMERS OF THE MEDIUM-SIZE UTILITY WITH CAPACITY ADDITIONS ALLOWED: CASE 10

Assumptions					
Generation Incrse	1.03	Dep Rte	.99	Cptl/asts	.80
Peak Incrse	1.02	EqtyGrwth	1.04	Debt/cptl	.51
Revenue/kwh	.05	Dbt cst	.09	Eqty/cptl	.38
O & M Expnse/kwh	.03	FxdCst%	.05		

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Generation	GWH	37500.00	38975.63	40868.87	42225.71	43281.36	44363.39	45472.47	46609.29	47115.23	48293.11
Peak	MW	7018.00	7258.58	7574.03	7787.32	7943.07	8101.93	8263.97	8429.25	8597.83	8769.79
Capacity	MW	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10200.00	10400.00	10500.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	63.12	62.56	62.86
Capacity Factor	%	42.38	44.05	46.19	47.73	48.92	50.14	51.40	52.16	51.72	52.50
Capacity Margin	%	30.51	28.13	25.01	22.90	21.36	19.78	18.18	17.36	17.33	16.48
Revenue	million $	1745.63	1814.32	1902.45	1965.61	2014.75	2065.12	2116.74	2185.45	2250.05	2320.10
Expenses	million $	1413.66	1456.45	1504.87	1541.02	1568.47	1596.71	1625.77	1663.77	1691.52	1730.53
Net Revenue	million $	331.97	357.86	397.58	424.59	446.28	468.40	490.97	521.68	558.53	589.57
Assets	million $	6040.00	5979.60	5919.80	5860.61	5802.00	5743.98	5686.54	5779.67	6021.88	6111.66
Equity	million $	1836.16	1909.61	1985.99	2065.43	2148.05	2233.97	2323.33	2416.26	2512.91	2613.43
Debt Interest	million $	229.92	229.92	229.92	229.92	229.92	229.92	229.92	243.92	271.91	285.90
Net Earnings	million $	102.04	127.94	167.66	194.67	216.36	238.48	261.05	277.76	286.62	303.67
Debt	million $	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2614.32	2914.32	3064.32
Rate of Return	%	5.50	5.98	6.72	7.24	7.69	8.15	8.63	9.03	9.28	9.65
Return on Equity	%	5.56	6.70	8.44	9.43	10.07	10.68	11.24	11.50	11.41	11.62
Coverage Ratio		1.44	1.56	1.73	1.85	1.94	2.04	2.14	2.14	2.05	2.06
Net Erngs/Asset	cents/$	1.69	2.14	2.83	3.32	3.73	4.15	4.59	4.81	4.76	4.97
Revenue/kwh	cents/$	4.66	4.66	4.65	4.65	4.65	4.65	4.66	4.69	4.78	4.80

Source: Authors' calculations

TABLE B-11

TEN PERCENT PRICE REDUCTION FOR INDUSTRIAL CUSTOMERS OF THE MEDIUM-SIZE UTILITY WITH CAPACITY ADDITIONS ALLOWED: CASE 11

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse		1.03	Dep Rte	.99	Cptl/asts	.80					
Peak Incrse		1.02	EqtyGrwth	1.04	Debt/cptl	.51					
Revenue/kwh		.05	Dbt cst	.09	Eqty/cptl	.38					
O & M Expnse/kwh		.03	FxdCst%	.05							
Generation	GWH	37500.00	38610.47	40216.86	41688.09	42730.29	43798.55	44893.51	46015.85	47147.38	48311.57
Peak	MW	7018.00	7190.57	7453.20	7688.17	7841.93	7998.77	8158.75	8321.92	8488.36	8658.13
Capacity	MW	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10300.00	10500.00
Load Factor	%	61.00	61.30	61.60	61.90	62.20	62.51	62.81	63.12	63.41	63.70
Capacity Factor	%	42.38	43.64	45.46	47.12	48.30	49.50	50.74	52.01	52.25	52.52
Capacity Margin	%	30.51	28.81	26.21	23.88	22.36	20.80	19.22	17.60	17.59	17.54
Revenue	million $	1787.89	1840.83	1917.42	1987.56	2037.25	2088.18	2140.39	2193.90	2289.15	2385.55
Expenses	million $	1413.66	1445.86	1485.96	1525.43	1552.49	1580.33	1608.99	1638.46	1684.44	1731.23
Net Revenue	million $	374.23	394.97	431.46	462.14	484.77	507.85	531.40	555.44	604.72	654.33
Assets	million $	6040.00	5979.60	5919.80	5860.61	5802.00	5743.98	5686.54	5629.67	5873.38	6114.64
Equity	million $	1836.16	1909.61	1985.99	2065.43	2148.05	2233.97	2323.33	2416.26	2512.91	2613.43
Debt Interest	million $	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	257.91	285.90
Net Earnings	million $	144.31	165.05	201.54	232.21	254.84	277.93	301.48	325.51	346.81	368.43
Debt	million $	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2764.32	3064.32
Rate of Return	%	6.20	6.61	7.29	7.89	8.36	8.84	9.34	9.87	10.30	10.70
Return on Equity	%	7.86	8.64	10.15	11.24	11.86	12.44	12.98	13.47	13.80	14.10
Coverage Ratio		1.63	1.72	1.88	2.01	2.11	2.21	2.31	2.42	2.34	2.29
Net Erngs/Asset	cents/$	2.39	2.76	3.40	3.96	4.39	4.84	5.30	5.78	5.90	6.03
Revenue/kwh	cents/$	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.86	4.94

Source: Authors' calculations

TABLE B-12

TIME-OF-USE PRICING FOR INDUSTRIAL CUSTOMERS OF THE MEDIUM-SIZE UTILITY
WITH NO CONSTRAINTS: CASE 12

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03	Dep Rte	.99		Cptl/asts	.80		%Revnue	.74		
Peak Incrse	1.02	EqtyGrwth	1.04		Debt/cptl	.51		Pk Rvnue	.05		
Revenue/kwh	.05	Dbt cst	.09		Eqty/cptl	.38		Md Pk Rev	.04		
O & M Expnse/kwh	.03	FxdCst%	.05		% Mwh	.68		OffPk Rev	.02		
Generation	GWH	37500.50	38716.64	40922.84	43397.90	45659.24	47619.45	49379.76	51010.83	52562.11	54068.26
Peak	MW	7018.00	6967.95	7107.31	7249.45	7394.44	7542.33	7693.18	7847.04	8003.98	8164.06
Capacity	MW	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00
Load Factor	%	61.00	63.43	65.73	68.34	70.49	72.07	73.27	74.21	74.97	75.60
Capacity Factor	%	42.70	43.76	46.25	49.05	51.61	53.82	55.81	57.65	59.41	61.11
Capacity Margin	%	30.00	31.01	29.63	28.22	26.79	25.32	23.83	22.31	20.75	19.17
Revenue	million $	1839.01	1903.38	2027.87	2150.66	2252.15	2337.94	2416.91	2491.61	2563.84	2634.86
Expenses	million $	1413.67	1448.94	1506.43	1575.01	1637.43	1691.14	1739.09	1783.32	1825.26	1865.93
Net Revenue	million $	425.34	454.44	521.44	575.65	614.72	646.80	677.82	708.30	738.58	768.93
Assets	million $	6040.00	5979.60	5919.80	5860.61	5802.00	5743.98	5686.54	5629.67	5573.38	5517.64
Equity	million $	1836.16	1909.61	1985.99	2065.43	2148.05	2233.97	2323.33	2416.26	2512.91	2613.43
Debt Interest	million $	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92
Net Earnings	million $	195.42	224.52	291.52	345.73	384.80	416.88	447.90	478.38	508.66	539.01
Debt	million $	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32
Rate of Return	%	7.04	7.60	8.81	9.82	10.59	11.26	11.92	12.58	13.25	13.94
Return on Equity	%	10.64	11.76	14.68	16.74	17.91	18.66	19.28	19.80	20.24	20.62
Coverage Ratio		1.85	1.98	2.27	2.50	2.67	2.81	2.95	3.08	3.21	3.34
Net Erngs/Asset	cents/$	3.24	3.75	4.92	5.90	6.63	7.26	7.88	8.50	9.13	9.77
Revenue/kwh	cents/$	4.90	4.92	4.96	4.96	4.93	4.91	4.89	4.88	4.88	4.87
Peak Mwh Indstry	Gwh	3611.00	3531.02	3058.30	2940.40	2953.64	3027.48	3103.16	3180.74	3260.26	3341.77
Md Pk Indstry	Gwh	6621.00	7146.21	8614.04	9465.11	9876.37	10123.28	10376.36	10635.77	10901.66	11174.20
Off Peak Indstry	Gwh	1806.00	1940.01	2304.68	2511.12	2625.38	2691.01	2758.28	2827.24	2897.92	2970.37
Pk Rev Indstry	mill $	176.94	173.02	149.86	144.08	144.73	148.35	152.06	155.86	159.75	163.75
Md Pk Rev Indstry	mill $	268.15	289.42	348.87	383.34	399.99	409.99	420.24	430.75	441.52	452.56
Off Pk Rev Ind	mill $	43.34	46.56	55.31	60.27	63.01	64.58	66.20	67.85	69.55	71.29

Source: Authors' calculations

TABLE B-13

TIME-OF-USE PRICING FOR INDUSTRIAL CUSTOMERS OF THE MEDIUM-SIZE UTILITY WITH THE CONSTRAINT THAT TOTAL INDUSTRIAL CONSUMPTION GROW AT THE BASE SCENARIO RATE: CASE 13

Item		Year 1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
Assumptions											
Generation Incrse	1.03		Dep Rte	.99		Cptl/asts	.80		%Revnue	.74	
Peak Incrse	1.02		EqtyGrwth	1.04		Debt/cptl	.51		Pk Rvnue	.06	
Revenue/kwh	.05		Dbt cst	.09		Eqty/cptl	.38		Md Pk Rev	.04	
O & M Expnse/kwh	.03		FxdCst%	.05		% Mwh	.68		OffPk Rev	.02	
Generation	GWH	37498.50	38436.97	39398.59	40384.05	41393.99	42429.07	43489.96	44577.33	45691.84	46834.19
Peak	MW	7018.00	7063.15	7108.60	7250.77	7395.79	7543.70	7694.58	7848.47	8005.44	8165.54
Capacity	MW	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00	10100.00
Load Factor	%	61.00	62.12	63.27	63.58	63.89	64.21	64.52	64.84	65.16	65.47
Capacity Factor	%	42.70	43.44	44.53	45.64	46.79	47.96	49.15	50.38	51.64	52.93
Capacity Margin	%	30.00	30.07	29.62	28.21	26.77	25.31	23.82	22.29	20.74	19.15
Revenue	million $	1837.97	1874.94	1893.42	1932.65	1980.49	2030.01	2080.76	2132.79	2186.11	2240.76
Expenses	million $	1413.62	1440.83	1462.23	1487.61	1513.73	1540.62	1568.28	1596.74	1626.03	1656.14
Net Revenue	million $	424.35	434.11	431.20	445.04	466.75	489.39	512.48	536.04	560.08	584.62
Assets	million $	6040.00	5979.60	5919.80	5860.61	5802.00	5743.98	5686.54	5629.67	5573.38	5517.64
Equity	million $	1836.16	1909.61	1985.99	2065.43	2148.05	2233.97	2323.33	2416.26	2512.91	2613.43
Debt Interest	million $	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92	229.92
Net Earnings	million $	194.43	204.19	201.28	215.12	236.83	259.47	282.56	306.12	330.16	354.70
Debt	million $	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32	2464.32
Rate of Return	%	7.03	7.26	7.28	7.59	8.04	8.52	9.01	9.52	10.05	10.60
Return on Equity	%	10.59	10.69	10.13	10.42	11.03	11.61	12.16	12.67	13.14	13.57
Coverage Ratio		1.85	1.89	1.88	1.94	2.03	2.13	2.23	2.33	2.44	2.54
Net Erngs/Asset	cents/$	3.22	3.41	3.40	3.67	4.08	4.52	4.97	5.44	5.92	6.43
Revenue/kwh	cents/$	4.90	4.88	4.81	4.79	4.78	4.78	4.78	4.78	4.78	4.78
Peak Mwh Indstry	Gwh	3009.00	2809.73	2018.86	1823.08	1853.71	1900.05	1947.55	1996.24	2046.15	2097.30
Md Pk Indstry	Gwh	6018.00	6168.45	6322.66	6480.73	6642.75	6808.81	6979.03	7153.51	7332.35	7515.66
Off Peak Indstry	Gwh	3009.00	3360.77	4305.90	4659.80	4791.24	4911.03	5033.80	5159.65	5288.64	5420.85
Total Indstry	Gwh	12038.00	12338.95	12647.42	12963.61	13287.70	13619.89	13960.39	14309.40	14667.13	15033.81
Pk Rev Indstry	mill $	171.51	160.15	115.08	103.92	105.66	108.30	111.01	113.79	116.63	119.55
Md Pk Rev Indstry	mill $	243.73	249.82	256.07	262.47	269.03	275.76	282.65	289.72	296.96	304.38
Off Pk Rev Ind	mill $	72.22	80.66	103.34	111.84	114.99	117.86	120.81	123.83	126.93	130.10

Source: Authors' calculations