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ESRG 82-59

TESTIMONY

OF

RICHARD A. ROSEN

On behalf of

Palmetto Alliance, Inc.

Docket No. 82-352-E

June 21, 1983

ENERGY SYSTEMS RESEARCH GROUP, INC.
120 Milk Street
Boston, Massachusetts 02109
(617) 426-5844

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QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Rosen. My business address is Energy Systems Research Group, Inc., 120 Milk Street, Boston, Massachusetts 02109.

Q. PLEASE DESCRIBE ESRG BRIEFLY.

A. ESRG is a non-profit organization specializing in research on energy-related issues, particularly research related to electric utilities. Among the electric utility issues which have been addressed by ESRG research are: demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, generation planning, avoided cost analysis, financial analysis, demand curtailment modeling, rate design, cost of capital analysis, and district heating. In addition, ESRG has done detailed analysis of nuclear and coal plant capital costs, and nuclear plant capacity factors and operations and maintenance costs.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS.

A. I am a senior research scientist at ESRG. In May, 1979, I completed directing a critique of the New England Power Pool Electric Demand Forecasting Model under contract to the New England Conference of Public Utility Commissioners. During 1980 I was project director of a study that culminated in testimony by Dr. D. Shakow regarding "Generation Planning and Reliability" in Case #EO-80-57 before the Missouri Public Service Commission.

I have presented expert testimony, in some cases on numerous occasions, before the utility regulatory commissions of Alabama, Indiana, Maine, Michigan, New Hampshire, North Carolina, and Pennsylvania, as well as before the Federal Energy Regulatory Commission and the Atomic Safety and Licensing Board of the Nuclear Regulatory Commission.

My generation planning testimony before the state commissions has included "Generation Planning and Reliability" in *Pennsylvania PUC v. Philadelphia Electric Company*, Docket No. R-79060865 (the 1979 rate case), before the Pennsylvania Public Utility Commission. I have also submitted extensive direct and sur-rebuttal testimony in Cases No. I-79070315 and -317 ("CAPCO" Investigation) before the Pennsylvania Public Utility Commission on generation planning and reliability; in Case No. I-80200342 (the "Limerick" Investigation); and on excess capacity of Pennsylvania Power & Light in Docket No. R-822169.

I have also testified before the North Carolina Utilities Commission on power plant performance standards and fuel adjustment clauses. Further, I have recently presented testimony before the Michigan Public Service Commission analyzing the use that the Consumers Power Co. has made of their own in-house dispatch model in preparing power supply cost recovery factors.

Q. PLEASE DESCRIBE YOUR BACKGROUND BEFORE JOINING ESRG.

A. I received my Bachelor of Science degree from M.I.T. in 1966 and my Master's and Ph.D. degrees in physics from Columbia University in 1970 and 1974, respectively. Before joining ESRG, I did research on industrial energy conservation at the National Center for the Analysis of Energy Systems at Brookhaven National Laboratory, serving as principal investigator on projects involving industrial process energy modeling for the U.S. Department of Energy. More information on my background can be found in my vita, provided as Exhibit ___(RAR-1).

FINDINGS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to elaborate on the major contentions made in the affidavit filed on behalf of the Palmetto Alliance, Inc. in the recent court case 83-CP-400044. A copy of this affidavit is attached as Exhibit ___(RAR-2). The reopening of this docket permits me to present new evidence before the South Carolina Public Service Commission which bears directly on its ultimate finding of mutual benefit of the proposed sale by Duke Power Co. of a 25 percent undivided ownership interest in Unit 2 of the Catawba Nuclear Station to the Piedmont Municipal Power Agency (PMPA).

Q. IN PREPARING YOUR TESTIMONY FOR THIS PROCEEDING, HAVE YOU UNCOVERED INFORMATION THAT WOULD CAUSE YOU TO ALTER YOUR CONCLUSIONS AS STATED IN EXHIBIT ___(RAR-2)?

A. No, I have not. My further review of the several analyses that R.W. Beck has performed for PMPA over the last few years has generally underscored the validity of the conclusions advanced in the affidavit.

Q. DO YOU STILL FIND A NEED FOR FURTHER STUDY OF THE ISSUES BEFORE THE COMMISSION MAKES A FINAL JUDGEMENT AS TO MUTUAL BENEFIT OF THE PROPOSED SALE?

A. Yes, I do. The record in this case is very incomplete as a basis for any final determination as to mutual benefit. Considerable additional study and review of the Beck assumptions and methodology is required. In addition, the

intervenor (the Palmetto Alliance) should have the opportunity to have the Beck analysis re-done with alternative assumptions of its own choosing, to determine the range of scenarios under which Beck's affirmative conclusion regarding the proposed sale does or does not hold up. The further analysis should include not only conventional supply alternatives, but also the cost-effectiveness of an accelerated customer conservation/load management program, a viable resource planning option that (as I shall show below) appears not to have been explicitly analyzed by R.W. Beck or PMPA.

Q. WOULD YOU PLEASE SUMMARIZE THE ADDITIONAL CONCLUSIONS THAT YOU HAVE REACHED IN YOUR RECENT REVIEW OF THE BECK RESEARCH?

A. Yes. I have reached six specific conclusions:

1. The load forecast upon which the R.W. Beck studies are based is flawed. It is founded in significant part upon utility personnel judgements that are not made explicit, and therefore it cannot be independently reviewed or verified. The methodologies upon which it is based are crude and do not represent state-of-the-art forecasting techniques. Finally, the forecast assumes a resumption of robust load growth after 1984, an eventuality against which a <u>prima facie</u> case can be made, pending completion of any systematic state-of-the-art load forecast that may be prepared for PMPA.

2. Beck has not made its assumptions regarding the operations and maintenance (O&M) costs for the Catawba station clear. Beck may not have used sufficiently high O&M assumptions in their most recent study up date of November 15, 1982. If they did not, this could prove to be a significant bias in their study.
3. Beck has made no independent analysis of the capital cost for Catawba, a figure that is crucial to its economic conclusions. Furthermore, extensive analysis that ESRG has performed on nuclear capital costs leads me to believe that the cost of Catawba will likely be about 20 percent higher than Duke and Beck have assumed.
4. Beck has made no independent analysis of the assumed capacity factor for Catawba. This parameter, too, has an important bearing on the validity of Beck's economic conclusions. Applying the results of ESRG studies of nuclear capacity factors to Catawba leads me to believe that the actual capacity factor of Catawba (after the first few "immature" years) will be about 10 percent below the level assumed by Beck.
5. Beck, again, has made no independent analysis of the required capital additions for Catawba. Initial ESRG analysis of this issue indicates that the Duke estimates for the cost of capital additions, which

Beck relies on, may be underestimated by a factor of four.

6. Not only are the benefits uncertain; there is a serious financial risk to PMPA ratepayers resulting from such a large investment in a single generating source. The chances of incapacitating accident, poorer than average plant performance, or plant cancellation, are sufficiently high as to overwhelm any possible economic benefit of the proposed purchase. Thus the economic case for the proposed PMPA purchase of 25 percent of Catawba #2 appears to be fatally flawed.

Q. WHAT ARE THE IMPLICATIONS OF THESE SPECIFIC FINDINGS?

A. Taken together, they throw the Beck conclusion of a positive benefit to PMPA ratepayers from the proposed project into serious doubt. Just my alternative capacity factor estimate and the likely 20 percent higher Catawba capital cost combined imply that the cost of power from Catawba could be about 40 percent more expensive than Beck has projected. This is a substantial difference and could strongly reverse the benefit that Beck found in the sale of 25 percent of Catawba to PMPA ratepayers.

Q. PLEASE DISCUSS THE SCOPE AND LIMITS OF YOUR REVIEW OF THE BECK RESEARCH.

A. I was able to analyze the basic Beck methodology, which in general I found to be a reasonable one. However, the studies are quite complex, and of necessity they make many key

assumptions for the values of certain input parameters which directly affect the results. There were many aspects of the Beck studies that I could not review. For example, I have not been able to review the details of how Beck modelled the power interchanges between Duke and PMPA in the cases where PMPA bought into Catawba versus the case when they did not. Nor have I been able to review the financial modelling that Beck did. Constraints precluded the type of review of these areas that such a complex study demands. In addition, there were insufficiencies in the information at my disposal.

I was able to review some of the methodology and results that determined the values of certain key parameters used by R.W. Beck in their original study and in subsequent updates. The Beck parameters that I reviewed are:

1) The demand forecast for the PMPA service territory;

2) Operations and maintenance costs for Catawba;

3) The capital cost of Catawba #2

4) The capacity factor for Catawba #2

5) Capital additions for Catawba.

These are generally among the most important parameters in a generation planning study. For each of these parameters with the exception of the demand forecast, I have prepared alternative estimates to the values Beck used, which were uniformly overly favorable towards the economics of the Catawba purchase. In the case of the demand forecast I will discuss reasons why I believe that the Beck forecast for PMPA is too high.

Q. WHAT IS THE GENERAL IMPLICATION OF YOUR REVIEW OF THE BECK ANALYSES?

A. Billions of dollars are at stake in this proposed Catawba purchase. In the key areas listed above, I uncovered reasons that throw Beck/PMPA conclusions into doubt. Thus, I believe that the South Carolina Public Service Commission should allow the intervenors in this case to perform a more thorough review of the Beck study, and to request that PMPA have Beck rerun its model with a set of input assumptions developed by the intervenors so that it can be determined how sensitive Beck's results are to the values they assumed for the key input parameters. The hearings in this case should not be concluded at this point.

Q. PLEASE DISCUSS THE FIVE AREAS THAT YOU HAVE INVESTIGATED IN TURN.

A. I shall begin with a review of the demand forecast that Beck has made for the PMPA service territory, discussing its adequacy in the light of historic load growth and changes in load growth patterns during the past ten years.

LOAD FORECAST

Q. PLEASE DISCUSS HISTORIC LOAD GROWTH FOR THE TOTAL PIEDMONT MUNICIPAL POWER AGENCY.

A. Table III-1 in the 1980 preliminary report by R.W. Beck shows a compound annual growth rate of 6.8 percent per year for energy requirements from 1967 through 1979. Closer examination of the numbers listed in that table reveals the sharp discontinuity between the period through 1973 and the years following 1973. The six-year growth rate in total energy requirements from 1967 to 1973 works out to over 10 percent per year, representing a very robust growth indeed. On the other hand, the six-year growth from 1973 through 1979 works out to an annual growth rate of approximately 3.5 percent per year, thus representing a much reduced rate of growth in energy requirements. There are numerous reasons, absent any detailed and systematic projection of future load, to expect a further decline in the rate of growth in the PMPA region. Real price increases will continue, full industrial recovery in the region is problematic, consumer consciousness of conservation benefits has increased, and energy management firms actively solicit business from commercial and industrial enterprises concerned with their energy bills, among other factors. A declining rate of growth in energy demand translates, of course, into a declining rate of growth in peak load, such as has also been experienced in the period since 1973.

Q. PLEASE DISCUSS PMPA'S FORECASTS OF FUTURE LOAD GROWTH.

A. In the 1980 Beck report, as shown on Table III-3, the 1979 to 1990 rate of growth in energy requirements was forecasted at 3.2 percent per year. The rate of growth in the peak demand, taking the 1990 forecasted peak of 414 megawatts compared to the 1979 demand of 294 megawatts, was 3.17 percent per year. Demand requirements were forecast to reach 580 megawatts in the year 2000.

In the Beck supplemental report dated October 15, 1982, there is no discussion of load forecast revisions, but figures for future energy and demand requirements that differ from those shown in the 1980 report appeared in the sections entitled "Analysis A" and "Analysis B." The year 2000 demand is now apparently forecast to be 470 megawatts (Table B-1, page 2), a full 110 megawatts less than in the 1980 forecast.

My review of the PMPA bond report "Preliminary Official Statement Dated November, 1982" shows that this reduction is apparently due to a temporary halt in energy and demand growth in the 1981-1983 period. Later, the rate of growth in forecasted demand is almost the same in the 1982 report as it was in the 1980 report. This may be seen by taking the years 1984 through 2000, where the annual growth rate of peak demand is 3.58 percent in the 1982 report and 3.52 percent in the 1980 report. Equally it may be seen by taking the years 1984 to 1990, where the rate of growth in peak demand is 3.73 percent per year in the 1982 report, and 3.65 percent in the earlier report.

Q. DO YOU THINK IT IS REALISTIC FOR PMPA TO BE FORECASTING A RESUMPTION OF THE 1980 FORECAST'S RATE OF INCREASE IN ITS PEAK DEMANDS?

A. No, in view of the sharp changes in load growth patterns we have seen in the recent past, both in the PMPA area and nationally, I do not. There is a <u>prima facie</u> case for expecting that actual load growth will be lower. Of course, systematic, quantitative, and verifiable forecasting procedures must be used to develop an accurate projection of future energy and demand for use in system planning.

Q. WHAT IS THE ROLE THAT A LOAD FORECAST SHOULD PLAY IN UTILITY PLANNING?

A. A long-range load forecast is the basis of utility planning to meet the service requirement of its ultimate customers. Utility system planning should be geared to expected levels of demand. Plans to purchase new capacity, as well as any other system plans, should be predicated upon providing reliable service at the lowest cost to ratepayers. This in turn entails matching supply to demand.

Q. FROM THE POINT OF VIEW OF SYSTEM PLANNING, WHAT NEGATIVE CONSEQUENCES MIGHT ENSUE AS A RESULT OF UNDER-FORECASTING?

A. The principal danger of under-forecasting is that the utility will find itself obliged, on relatively short notice, to purchase capacity or energy at a cost higher than that which would have been incurred had it entered into such commitments to meet its customers' needs at an earlier point in time.

Q. WHAT IS THE PRINCIPAL DANGER OF OVER-FORECASTING?

A. From the point of view of system planning, over-forecasting can lead the utility to make financial commitments to capacity that turn out not to be needed, or to be of a size or type that is economically sub-optimal.

Q. WE CANNOT FORECAST PRECISELY, CAN WE?

A. Of course not. Uncertainty is unavoidable; forecasting simply endeavors to reduce it. State-of-the-art forecasting techniques must be used to reduce the likelihood of over-forecasting or under-forecasting.

Q. HAVE YOU DETERMINED WHAT FORECASTING TECHNIQUE IS USED BY PMPA TO REDUCE UNCERTAINTY CONCERNING FUTURE LOADS?

A. Yes, I have. I note that in the R.W. Beck "preliminary report" of 1980, it is stated (in Section III, pages 1-3) that time trend analysis supplemented by econometric modeling and the judgement of utility personnel is used to forecast future loads. More recently, in attachment V to Palmetto Alliance interrogatory responses, the same approach is restated: the load forecast is produced by a time trend in energy use, adjusted on the basis of a single-equation econometric model and of "the judgement of each member's utility personnel."

Q. DOES THIS REPRESENT A STATE-OF-THE-ART FORECASTING METHODOLOGY?

A. Certainly not. The only component of the PMPA approach that comes close to so qualifying is the econometric component.

However, the use of one single econometric equation to explain all energy use is not an acceptable forecasting technique; and in addition to using just one such equation, PMPA does not tell us how it entered into the mix of trend, equation and judgements that formed the resulting forecasts. The PMPA forecasts are simply not based upon a reproducible mathematical model. They are not accessible to independent verification or analysis since they do not emerge from such a systematic forecast model where the mathematical structure is available for independent review. Even the particular judgements and adjustments made with the relatively crude technique employed, are not revealed or specified in any of the available documentation. Consequently, there is little reason to regard the PMPA load forecast as reliable at this time. In short, PMPA does not "make explicit the underlying assumptions and judgements that are inherent in any forecast, allowing them to be reviewed and evaluated in a systematic way," which is a criterion established by R.W. Beck itself on page III-2 of the 1980 report.

Q. WHAT CHANGES ARE REQUIRED FOR PMPA TO PRODUCE A RELIABLE FORECAST?

A. First, PMPA should move from forecasting energy and peak on an aggregate basis and move toward disaggregating their load into its major components. Secondly, PMPA should move away from trending and econometric techniques and toward end-use techniques in analyzing the components of load. Third,

whatever PMPA does, all calculations leading to the final load figures should be fully documented, and the sources of the underlying data upon which they are based explicitly shown.

Q. IS A DISAGGREGATED APPROACH TO LOAD FORECASTING THEORETICALLY SUPERIOR TO AGGREGATE ECONOMETRIC MODELLING?

A. Yes, it is. R.W. Beck is in error in identifying the "statistical analysis" of econometrics with cause-and-effect relationships, and equally in error in stating that the end-use modelling approach lacks "the causal sophistication of the econometric approach." In actuality, the end-use approach endeavors to identify the causes of electricity consumption. Typically, an end-use model will obtain electricity consumption in any given category by multiplying the number of uses in the category times the average consumption of each end-use. End-uses are the separate components of final electricity demand. Examples are refrigerators in homes and air conditioners in office buildings. The disaggregated approach separately models as many end-uses as feasible given the level of data available. To the extent that data constraints do not permit modelling end-uses per se, one still endeavors to break down electricity use into sectors and sub-sectors to get as close as possible to the physical processes through which electricity is consumed.

Q. DOES THE UTILITY INDUSTRY USE THE END-USE APPROACH IN ITS FORECASTS?

A. Yes, to a considerable and increasing extent. Despite recent and growing recognition that end-use modelling provides a superior forecasting approach, PMPA does not rely upon this approach even in part.

Q. IS AGGREGATE ECONOMETRIC MODELLING SCIENTIFICALLY SUPERIOR TO END-USE ANALYSIS?

A. No, the reverse is true. An aggregate econometric modelling strategy is based on developing quantitative relationships between sales and a theoretically appropriate set of determining variables. The quantification of these relationships relies on estimating coefficients, using techniques of statistical inference. The problem of relying on a limited data base to mathematically specify "best" theoretical relationships between variables to be "explained" and a set of determining (or independent) variables exists in all sciences addressing inherently stochastic systems, whether they be physical, biological, or social. When applied to forecasting, the procedure has come to be called "econometric" because of the presence of price and income variables among the set of independent variables, and the reliance on a set of statistical tests and techniques often used in macroeconomic analyses. But the validity of econometric forecasting rests on the satisfaction of several basic premises. First, it must be assumed that the

functional relationships between the variables gleaned from historic data persists to good approximation into the future. Second, it must be assumed that the primary causal structures can be identified and adequately quantified by methods of statistical analysis. Third, it must be assumed that important causal factors that are not directly specified within the econometric framework, or have no statistical analog in the historic data base (for example, conservation regulations, changes in the end-use mix in electricity usage, the approach of many appliances towards full saturation, the spread of energy-saving technologies, and fuel switching policies) either are adequately captured through the use of proxy variables like price, or are insignificant.

Q. ARE THE ASSUMPTIONS UNDERLYING THE APPLICATION OF AGGREGATE ECONOMETRIC APPROACHES VIABLE IN THE PERIOD OF HISTORIC CHANGE BEGINNING WITH THE OIL EMBARGO OF 1973?

A. No, they are not. The oil embargo in 1973, and subsequent energy price increases and policy changes, have lead to fundamental shifts in patterns of load growth, both nationally and in the PMPA region. Stable relationships between aggregate loads and aggregate indicators of demographic or economic activity can no longer be assumed. Thus, aggregate forecasting techniques of the type employed here are now generally not desirable. The problem with aggregate econometric forecasting has been aptly summarized by Dr. Charles Hitch, former head of the Economics Division

of the Rand Corporation, and a member of the Electric Power Research Institute (EPRI) advisory council. Writing in the EPRI Journal of May, 1980, Dr. Hitch stated:

> Certainly, projecting the relations that held before 1973 is not going to work in the future because in the period up to 1973 we had very cheap energy plus, in general, falling prices of energy and no period of rising prices. So we have no historical period in which we have had rising energy prices. All the economic projections based on relations before 1973 have led to gross over-estimates for energy demand. Since we don't have any econometric projections and won't have any for some time, except on a very short-term basis, we must use a different method: end-use analysis."

To Dr. Hitch's observation I would add that, because the underlying technological factors are still in a state of flux, it is not clear when, if ever, it might be reasonable to place a basic reliance upon aggregate econometric techniques to forecast a load pattern.

Q. DO YOU MEAN IT IS DESIRABLE OR POSSIBLE TO EXCLUDE ECONOMETRIC TECHNIQUES FROM FORECASTING ALTOGETHER?

A. It is not, and may never be, possible to have a forecast based on technological relationships alone. However, forecasts should first be as disaggregated as possible, consistent with the data available. Second, forecasts should be based on direct technical relationships, rather than aggregate econometric relationships, again to the extent that data permit. It may then be useful to use econometric methods to predict particular components of demand,

incorporating such methods selectively within the framework of the disaggregated model. If any econometric techniques are used, one should strive to use the most specific data available and to structure equations so as to conform as closely as possible to the technical details of the process under consideration.

Q. YOU REFERRED PREVIOUSLY TO THE LACK OF APPLICABILITY OF PRE-1973 DATA IN THE CURRENT SITUATION. DOES THE PMPA FORECAST RELY ON SUCH DATA?

A. We are not explicitly told. According to the attachment V referenced above, the 1967-1979 historical period is used as the basis of the time trending component. If the same years were used in performing the regressions that developed the one-equation econometric model, then the years 1967, 1968, 1969, 1970, 1971, 1972, and 1973 itself, or more than half of the years of data involved, would belong to the obsolete pre-1974 historical period. Moreover, it might well be that years before 1967 are used in the regression analyses; we simply are not informed.

Q. HAVE YOU EVALUATED THE FINAL ECONOMETRIC MODEL USED BY PMPA IN FORMING ITS LOAD FORECAST?

A. That model, with an evident typographical error therein, is given in attachment V referred to above. It is difficult to evaluate this model, not only because the years of data upon which it is based are not given, but also because the test statistics are not given and the way in which the equation's

results were applied in developing the actual load forecast numbers is not given. However, it is possible, just on the basis of the information given in attachment V, to establish that the equation, while it might possibly be plausible as an explanation of residential energy consumption alone, is not plausible as an explanation of commercial or industrial energy consumption. The reason is that there are no terms in the model to express any influence of either employment growth or industrial activity upon energy consumption; and the absence of such terms is not particularly plausible.

Q. MIGHT THERE BE SOME DIFFICULTY IN APPLYING A STRONGLY DATA-DEPENDENT END-USE FORECASTING MODEL TO A SERVICE AREA AS SMALL AND DISPERSED AS THAT OF PMPA?

A. Yes, there might. It is certainly far easier to develop appropriate data bases for large, concentrated service areas. However, there are two alternative ways in which the inherent advantages of the disaggregated/end-use approach might be brought to bear in forecasting PMPA's load. First, a systematic forecast using an end-use model might be performed for the entire region within which the PMPA towns are located. Then, the results of this larger load forecast could be scaled to the PMPA region based on the historical ratios between energy sales in the PMPA towns and energy sales in the rest of the region. As an alternative or supplement, secondly, it would be possible to develop end-use forecasts for those sectors of consumption in the PMPA towns

for which data on appliance saturations and usage levels could be developed. I would think this possible at least for the residential sector. As a cross-check on either of these approaches, econometric techniques might be used on a disaggregated basis: they could be used to attempt to explain residential, commercial, and industry sales separately, and the results of the distinct econometric equations considered alongside the results of the end-use approach.

OPERATIONS & MAINTENANCE COSTS

Q. ONE OF THE CRITICISMS THAT YOU MADE OF R.W. BECK IN YOUR AFFIDAVIT WAS THAT THEY DID NOT PERFORM A COMPREHENSIVE AND INDEPENDENT ASSESSMENT OF THE NUCLEAR O&M COSTS FOR THE CATAWBA #2 UNIT. DOES THIS FINDING STILL STAND?

A. Yes, it does. In the course of reviewing the responses to the interrogatories in this case, my initial view was confirmed. The Duke response to Question 31 of Palmetto Alliance (First Set) stated that "R.W. Beck requested that Duke make an estimate of the Operating and Maintenance costs for Catawba for the Piedmont Municipal Power Agency." Duke then proceeds to explain briefly how this was done, and the results are provided through 1992 in Duke's answer to Question 30 of the same set of interrogatories. Thus, R.W. Beck did not do their own assessment of Catawba O&M costs.

One noteworthy aspect of this Duke calculation is that once O&M costs for the first full year (1988) were estimated at $128.4 million for both Catawba units, this figure was then escalated at 16.4 percent per year to 1992. However, the reason for using 16.4 percent was not explained. In addition, it is not clear whether or not R.W. Beck used this Duke estimate in calculating the results presented in their November 11, 1982 letter, nor is it clear whether or not they continued to escalate the Catawba O&M costs at 16.4 percent through the year 2000. This uncertainty arises from the November 11 letter statement (p. 2), "In preparation of the Consulting Engineer's Report, we increased the Catawba O&M

costs supplied on November 1, 1982, to system average nuclear O&M costs for consistency and conservatism." The "Consulting Engineer's Report" referred to is Appendix B of the PMPA proposed Preliminary Official Statement draft of November 11, 1982.

Q. IS IT CLEAR TO YOU WHAT CHANGES R.W. BECK MADE IN DUKE'S ESTIMATE FOR THE FUTURE O&M COSTS FOR CATAWBA?

A. No, because the basis for the O&M assumptions in the November 11, 1982 letter, though requested in Question #35, was never received by me. The only new information on O&M cost assumptions for Catawba that I have received from Beck is Attachment III to PMPA's response to the first set of interrogatories, Question 35, that seems to only have been used in the Beck October 15, 1982 letter. In responding to Question 31, Duke provided the methodology used in their most recent update of November 1, 1982. From the PMPA "Preliminary Official Statement" for their proposed November bond sale (Appendix B, page B-29), it appears that Beck has used O&M costs amounting to about 82 percent of those estimated by Duke.

Q. HAVE YOU MADE AN INDEPENDENT ANALYSIS OF THE LIKELY O&M COSTS FOR THE CATAWBA NUCLEAR STATION?

A. Yes. Using the results of the latest update to the ESRG analysis of nuclear plant operations and maintenance costs, I have made a projection of the likely O&M costs for the Catawba unit. The results in current dollars appear below, compared to the Duke projections:

Year	ESRG Estimate	Duke Estimate
1985	36,290,000	28,493,000
1986	72,820,000	56,856,000
1987	116,190,000	91,917,000
1988	163,450,000	128,390,000
1989	176,930,000	149,446,000
1990	191,440,000	173,955,000
1991	207,040,000	202,484,000
1992	223,820,000	235,691,000

These ESRG results are derived from use of a multivariate regression analysis that allows plant specific projections for O&M costs to be made. It assumes a 6 percent underlying inflation rate after 1983. The ESRG study is described in Exhibit ___(RAR-3), appended below. The basis for the ESRG results is a sophisticated statistical analysis of variables that help explain the past O&M cost trends actually experienced by almost all nuclear stations operating in the U.S. through 1981. These variables include size, type, age, cooling type, multiple unit status, and vintage. Thus, the ESRG study provides a more dependable approach to estimating the likely Catawba O&M costs, given the high rates of escalation in nuclear O&M costs during the 1970's, than does either the Duke or Beck approach.

One example of this rapid escalation in O&M costs may be found on the last page of Attachment III (provided in interrogatory responses) where it is stated that Duke's O&M costs for the Oconee Nuclear Station escalated at an average rate of 30 percent per year from 1975-81. While the ESRG regression equation projects a slowing down of this high

growth rate, it still yields results that are 27 percent above the Duke estimates by 1988. By 1992, however, the ESRG result is somewhat below the Duke result. Therefore it is important to know how Beck utilized the Duke results after 1992 in performing any of their analyses.

Q. WHAT ARE THE IMPLICATIONS OF THESE DIFFERENCES FOR THE CONCLUSIONS THAT R.W. BECK COMES TO IN ITS NOVEMBER 11, 1982 LETTER?

A. Beck has found a narrowley positive economic benefit to PMPA ratepayers from the proposed project. O&M cost projections are important to this conclusion, but how they were actually arrived at is shrouded in mystery. There is evidence that Duke's own O&M cost projections are not the best and if Beck is using O&M cost estimates for Catawba that are lower than the Duke estimates after 1992, it is probably projecting the cost effectiveness of the proposed PMPA purchase to be more favorable than it would be. Thus, the issue of how Beck treats future O&M cost escalation must be resolved, and further analysis along this line conducted independently.

Along the way, certain specific puzzles with respect to Catawba O&M expenses must be cleared up. In response to the Palmetto discovery requests (Attachment B), PMPA has provided a letter dated April 29, 1982 to Mr. Holmes of R.W. Beck from Mr. Hatley, Manager of the Catawba Special Group. In an attachment to that letter enclosed here as Exhibit ___ (RAR-4), O&M expenses were listed for Catawba through the

year 1999. The interesting fact about these expense estimates is that they are considerably higher than the November, 1982 estimates made by Duke listed above, and they are also higher than the ESRG estimates. Before any firm conclusion can be drawn about the proposed sale, it is important to know why Duke lowered its Catawba O&M estimates from April, 1982 to November, 1982 (as provided in answer to Question 30). Again, if the April, 1982 estimates generated by Duke's Corporate Model Department were used in the Beck analysis, the results might change substantially. This is especially likely if Beck did use the $30.28 per KW figure for 1983 escalated at 9 percent as indicated in PMPA's answer to Question 33.

Another puzzling fact is that Beck's November 11, 1982 letter is the first place known to me where they mention that Duke has changed its O&M escalation rate to 16.4 percent. However, Exhibit ___(RAR-4) shows that this escalation was used by Duke as early as April, 1982. The question is why Beck didn't use this higher escalation rate sooner.

CATAWBA CAPITAL COSTS

Q. IN YOUR AFFIDAVIT YOU ALSO CRITICIZED R.W. BECK FOR NOT HAVING MADE AN INDEPENDENT ASSESSMENT OF THE LIKELY CAPITAL COST FOR THE CATAWBA #2 UNIT. DOES THIS FINDING STILL STAND?

A. Yes, it does. As far as I know, R.W. Beck has made no independent estimate of the capital cost of Catawba #2. Yet the capital cost of the plant will probably have the single largest effect on the cost effectiveness of the proposed purchase for the PMPA ratepayers. Because the capital cost projections have been a controversial and rapidly changing aspect of economic analyses of nuclear power plants, the absence of such an assessment is surprising. The capital cost estimates for all nuclear units have been rapidly increasing during their construction periods, often going up by a factor of ten. Even on an inflation-adjusted basis, the direct construction costs of nuclear units (the costs excluding financing costs) have often increased by a factor of four from initial planning to completion. This same general pattern has affected Duke's estimates of the cost of Catawba #2.

For example, as of May 10, 1983, Duke was estimating the total direct construction costs for Catawba #2, without the "profits on Contractual Entitlements" but with support facilities, at $1,295,463,000 and for the entire Catawba Station at $2,587,231,000. However, in the Preliminary Engineering Report prepared by R.W. Beck for PMPA in August, 1980, the direct construction costs of the Catawba #2 unit

were estimated at $1,063,856,000, with $2,114,055,000 estimated as the direct construction cost of the entire Catawba Station, presumably less some allotment for "Profits on Contractual Entitlements." This represents an increase of (at least) 22.4 percent in the cost of Catawba #2 in just about 2½ years. (These cost estimates cited here, and discussed in this portion of my testimony, are <u>exclusive</u> of any financing costs, costs for the initial fue[illegible]d, costs for any of the special bond reserve funds, [illegible] costs that the PMPA bonds will have to go towards p[illegible]g. The focus is on construction costs <u>per se</u>.)

Q. IS THERE ANY REASON TO BELIEVE THAT THE TREND OF INCREASING COST ESTIMATES FOR THE CATAWBA #2 UNIT WILL COME TO AN END WITH THIS LATEST MAY, 1983 DUKE ESTIMATE?

A. No, there is not. Generally when a nuclear unit still has about four years to go until it reaches its commercial operating date, as is the case for Catawba #2, projections of its total cost continue to escalate. One of the major causes of this cost escalation are changing NRC construction requirements for safety related purposes. Since there are still many outstanding technical issues related to nuclear power plant operations that NRC officially categorizes as "Unresolved Safety Issues," the changes in NRC construction requirements are likely to continue. In addition, further delays in the construction schedule for Catawba #2 will also cause the projections of direct construction costs for the unit to increase.

ESRG has made a comprehensive statistical analysis of the rate of change of direct construction costs for most non-price-fixed nuclear units in the U.S. This analysis is presented in Exhibit ___(RAR-5). The results show that even before the Three Mile Island (TMI) Unit #2 accident, direct construction costs for nuclear units in real terms (i.e., adjusted for inflation) went up rapidly and steadily. This general trend has continued through 1981, the most recent year for which our analysis has been done.

Q. DOES THE ESRG NUCLEAR CAPITAL COST ANALYSIS YOU HAVE REFERRED TO ALLOW YOU TO MAKE AN INDEPENDENT PROJECTION FOR THE COST OF CATAWBA #2?

A. Yes, it does. The result of the analysis is the equation listed on p. A-14 of Exhibit ___(RAR-5). The equation results from a statistical fit to real dollar direct construction cost data for 52 nuclear units. Note that the corrected R-squared for the equation is about 67 percent, which is quite high. Even more importantly, note that the T-statistics of the key independent variables are significant at greater than the 95 percent level. This equation allows capital cost projections to be made for future nuclear units as a function of the date they were licensed (LICDATE), their size, (MWDER), the experience of the plant architect-engineer (AEEXP), the period of time over which they are constructed (PERIOD), whether they are a multiple station (DUPLI), whether they are in the Northeast (NEAST), and whether they have a cooling tower (CTOWER). The equation

captures the key cost trends in the past that affect the total unit costs, and projects them into the future. It produces a probable value for the cost of any given unit being forecast. Already there are many nuclear units being built in the U.S. that are currently being estimated by their constructing utilities at costs above those predicted by the ESRG equation. Similarly, there are many plants that are currently assumed to cost less than the equation would predict.

Q. HAS ANY PUBLIC UTILITY COMMISSION ADOPTED THIS ESRG NUCLEAR CAPITAL COST EQUATION FOR USE IN A GENERATION PLANNING HEARING?

A. Yes. In Docket No. 81-114 concerning the economics of the Seabrook Nuclear Station, the Maine Public Utility Commission adopted this equation for use in estimating the cost of Seabrook in its final order. The Maine Commission supported my argument that by using this equation one was most likely to obtain the most accurate possible prediction of Seabrook's costs. They agreed that use of the other predominant cost estimation procedure, viz. the architectengineering approach, has proved to be unreliable precisely since cost estimates generated via this approach are constantly changing over time. (It is also noteworthy that in the same order the Maine Commission supported use of our nuclear O&M methodology as described above for calculating the future O&M costs for Seabrook.)

Q. IF THE ESRG NUCLEAR CAPITAL COST EQUATION IS APPLIED TO CATAWBA #2, WHAT IS THE PROBABLE COST OF THE UNIT?

A. At the end of Exhibit ___(RAR-5), I present the results of applying the ESRG capital cost equation to Catawba #2. The result is that for direct construction costs only, I project that Catawba #2 has a probable cost of $1,634,000. This figure assumes 6 percent inflation after 1983. This is only about 26.2 percent above the most recent Duke estimate that I have cited above. I believe that in the four years remaining for the construction of Catawba #2, if it is completed by mid-1987, it is quite reasonable to assume that Duke's estimate will rise by about 26 percent. In this context, recall that Duke's estimate went up by about 22 percent just over the last 2½ years, so a 6 percent per year re-estimate, over each of the next four years, is not improbable. This would certainly be well below the average rate of change in Duke' estimate since the project began.

Two subsidiary conclusions follow from this ESRG cost estimate. The first is that if interest during construction is added to the direct construction costs at 10.3 percent, the total cost for Catawba #2 will be $2.45 billion. The second is that a higher cost estimate implies that Catawba #2 has reached a lower percentage of completion than the Company is presently stating. (When total cost estimates increase, percent completion estimates drop.)

Q. IF THE ESRG COST ESTIMATE FOR CATAWBA #2 WERE CORRECT, WHAT WOULD BE THE IMPACT OF THIS CHANGE ON THE ECONOMICS OF THE PROPOSED SALE OF 25 PERCENT OF THIS UNIT TO PMPA?

A. It is quite likely that the 20 percent increase in the cost of Catawba #2 indicated by the ESRG equation would reverse the benefits claimed for the PMPA ratepayers by R.W. Beck in their report and testimony. Consequently, PMPA should be ordered to have R.W. Beck re-do its analysis with more up-to-date key assumptions regarding O&M costs, capital costs, and the capacity factor for the Catawba Station.

CATAWBA CAPACITY FACTOR

Q. WHAT DID R.W. BECK ASSUME IN MAKING THEIR ECONOMIC CALCULATIONS FOR THE CAPACITY FACTOR OF THE CATAWBA UNITS?

A. As far as I am aware, Beck has used the same capacity factor assumptions in all their studies, namely, that the Catawba capacity factor would go from 56 percent to 69 percent over the first nine years of operation. Assuming that Piedmont fully enforces the new Duke buy-back provisions of the contract in the period prior to the mid 1990s, the key period is after the ninth year, when PMPA will be taking the output of most of its 25 percent share.

Q. IS THE INCREASE THAT BECK PROJECTS FROM 56 PERCENT TO 69 PERCENT REASONABLE?

A. No, according to an analysis of nuclear capacity factors that I have done, it is not. A plant as big as Catawba is not likely to run as well as Duke or Beck is projecting, since there is a general tendency for large nuclear units to have poorer overall performance in terms of capacity factor than smaller plants. This is confirmed by a third comprehensive statistical analysis that ESRG has performed, dealing with the capacity factors of almost all nuclear plants. This study is presented here as Exhibit ___(RAR-6) and a complete description of the methodology that ESRG developed can be found there. Here I will briefly summarize the considerations involved.

A great deal of data is now available concerning the performance of base load generating units. With the aid of

this extensive data base, one can establish, via multivariate regression analysis, connections between various characteristics of a base load unit (age, type, size, manufacturer, vintage, cooling system design, etc.) and the performance of that unit as measured by its capacity or availability factor over time. The regression equations developed in the ESRG statistical analysis provide a guide to the likely future average performance of units of a given type, age, etc. These estimates indicate how well a particular plant is likely to perform based on industry-wide experience for plants of a similar type. They provide an objective standard of plant performance that we might call the "industry norm." This norm is calculated for nuclear capacity factors that have had the effects of refueling and NRC-mandated outages removed, so we have labelled it an "adjusted" capacity factor. The adjusted capacity factor is the capacity factor over the hours of an operating year exclusive of refueling and NRC-mandated outage hours.

From the ESRG study, and particularly from the resultant regression equation for the adjusted capacity factor as presented in Table C-4 on p. C-21 in Exhibit ___(RAR-6), the adjusted capacity factor can be calculated for each year of operation of a nuclear unit such as Catawba #2. If the industry-wide average refueling rate of 13 percent is then subtracted appropriately, one obtains the normal capacity factor for each year of operation. Given the lack of data

for plants with ages of ten years or greater, the ESRG equation should only be directly applied up to that point.

When the ESRG capacity factor equation is applied to the Catawba #2 unit, the result is a capacity factor of about 43 percent in its first year, increasing to about 59 percent in its ninth year. Again, this is a probable figure. The real value has an equal chance of being higher or lower. However, I believe that it is very unlikely that the Catawba Station would average 10 percent higher than the 59 percent capacity factor that I have projected after the ninth year, as Beck has assumed. I believe that no very large PWR unit like Catawba has actually run that well for any significant length of time. Thus, I believe that Duke and Beck have certainly been unduly optimistic in establishing their capacity factor assumptions for Catawba. Had Beck performed an independent assessment of this issue, a different assumption might have been employed for this key parameter.

Q. WHAT ARE THE LIKELY IMPLICATIONS OF THIS ADDITIONAL CHANGE IN PARAMETERS ON THE RESULTS OF THE BECK STUDY?

A. As is the case with changes in the capital cost, a change in the capacity factor assumed for Catawba has a major impact on Beck's calculations. The change from 69 percent to 59 percent alone increases the cost of power from Catawba #2 by about 17 percent. Coupled with the 20 percent increase in capital cost that the ESRG analysis indicates, the cost of power from Catawba may actually prove to be about 40 percent

higher than Beck has assumed due to only these two factors alone. All of the Beck results and conclusions are thus thrown into serious doubt. I believe there is little basis in the record of this proceeding for the Commission to conclude that the proposed PMPA purchase is in the economic interest of PMPA ratepayers.

CATAWBA CAPITAL ADDITIONS

Q. IS THERE ANY OTHER KEY PARAMETER THAT YOU BELIEVE HAS BEEN SIGNIFICANTLY MIS-ESTIMATED IN THE BECK STUDIES?

A. Yes. I have reviewed the assumptions that Duke has made and that Beck has relied on with regard to capital additions to Catawba. The values projected are likely to prove far too low. Again, Beck has done no independent analysis of this issue. Moreover, Duke's responses to the Palmetto Alliance interrogatories evidence little serious analysis as to how to estimate such capital additions. Yet these capital additions are very important in computing the cost of power from the plant, and they are closely related to O&M costs. They represent those aspects of equipment repairs and new equipment required to operate the plant that are put into the rate base each year. Thus, their impact on rates has both an immediate and long-term effect. From Attachment 3 to Attachment B provided by PMPA in response to the Palmetto interrogatories, we see that Duke has estimated that capital additions for <u>both</u> Catawba units will rise from $5 million in 1985 to $35 million in 1992. For a $4-$5 billion dollar plant, this is much less than one percent per year spent on capital additions by 1992.

This is lower than the historic experience of the utility industry would suggest. For comparison, note that according to Mr. Eury, CP&L "had expended $167 million on capital additions at Brunswick [from 1975 through 1982]. We expect to spend an additional $233 million through 1986."

(p. 28 of Mr. Eury's direct testimony in NCUC Docket No. E-2, Sub 461). Since these dollars are much less inflated than the 1992 dollars of the Duke estimate will be, expenditures by 1992 could well be almost double the $58.25 million dollar a year average rate that CP&L projects for 1983-86 for Brunswick, a much smaller plant than Catawba. This would equal more than four times the level that Duke estimated on per-kilowatt basis for Catawba.

Initial ESRG studies on the subject of capital additions indicate that a realistic level of capital additions by 1990 for ´ awba may be four to five times the Duke projection. This factor will likely have a greater impact on the economics of the Catawba purchase than any inaccuracy in the Beck estimate of expensed O&M for Catawba. This area clearly warrants considerably more research.

CONSERVATION OPTION

Q. WHAT EVIDENCE IS THERE THAT PMPA HAS ANALYZED THE FEASIBILITY OF EMPLOYING A CONSERVATION AND LOAD MANAGEMENT PROGRAM AS AN IMPORTANT ELEMENT OF ITS RESOURCE PLANNING?

A. I have found none, at least not in the documentation available to me. Indeed, the R.W. Beck materials only refer to conservation in the most general way, making little effort to estimate the levels of conservation that may have been attained in the several towns.

Q. ARE THERE UTILITIES THAT HAVE INCORPORATED PROMOTION OF CONSERVATION AND LOAD MANAGEMENT AS RESOURCE PLANNING ELEMENTS?

A. Yes, there certainly are. Moreover, this is most commonly the case in regions where load growth has been relatively high, as in the PMPA area. In such regions of relatively rapid load growth, the long-run marginal costs of production tend to exceed the current average costs of production by a significant amount. If the utility is going to be producing new power at a higher cost than it is charging on average, it is losing money by expanding. An investment in conservation, through a properly designed program, can stem the losses and benefit the ratepayers. On account of such considerations, a number of utilities all around the country have embarked upon deliberate programs to encourage and incentivize customer conservation and load management. In fact, Duke Power Company, itself, embarked upon such a strategy. For example, houses that are weatherized to a high level qualify for a special rate (the RC electric rate). In addition, customers

installing controlled water heating (where electricity is drawn only during the off-peak periods when production costs are lower) receive a credit from Duke Power. Many different information programs, rate designs, and incentive programs have been developed to accelerate the adoption by households and businesses of energy management practices in these various utility systems.

Q. BUT CAN SMALL MUNICIPAL SYSTEMS INCORPORATE CONSERVATION/ LOAD MANAGEMENT PROGRAMS?

A. They not only can, but a number have. For example, Vermont's Burlington Electric Department floated bonds specifically for the purpose of mounting a direct service conservation program, in which utility personnel visit the house and install certain no-cost/low-cost conservation measures directly in the premises.

Q. IS THE BODY OF THE UTILITY EXPERIENCE WITH CONSERVATION PROGRAMS DEVELOPED ENOUGH FOR A SMALL AGENCY LIKE PMPA TO HAVE EXAMINED FEASIBLE CUSTOMER CONSERVATION PROGRAMS DURING THE TIMEFRAME OF THE R.W. BECK STUDIES?

A. Yes, it is, especially during the timeframe of the second study. Currently, ample information is available to permit PMPA to examine an appropriate conservation/load management strategy for near-term implementation. For the residential sector, which is the largest single subcategory of PMPA load, the body of experience is especially rich. I would recommend that, in addition to appropriate industrial/commercial

programs, PMPA immediately examine the cost-effectiveness of offering such residential programs as:

1. Accelerated information to households, including establishment of a centralized conservation "hot line" manned by an energy conservation specialist.
2. Incentive programs to encourage insulation of existing homes, in order to reduce demand for air cooling and space heating. Programs that have been successfully tried include Duke's RC Rate, low-interest loan programs, and direct service programs for installation of weatherization measures on the premises.
3. Simple rate designs to further encourage the use of load management practices, such as time-controlled electric water heating.
4. Cash or credit rebate programs of temporary duration to increase the percentage of customers purchasing high-efficiency appliance models when they are in the replacement market, applying certainly to air conditioners, and possibly to refrigerators and efficient luminares as well.

I think some combination of such programs would accelerate the rate of adoption of conservation practices by customers, and reduce the pressure put on PMPA supply planning due to substantial load growth, which, though it is much reduced from past years, is still clearly likely to be positive.

MAGNITUDE OF RISK TO RATEPAYERS

Q. IF FURTHER ANALYSIS DEMONSTRATED THAT A SLIGHT ECONOMIC BENEFIT FROM THE PROPOSED PMPA PURCHASE WAS LIKELY OVER THE LONG RUN, WOULD YOU THEN RECOMMEND THIS INVESTMENT TO PMPA RATEPAYERS?

A. No, even in the unlikely event that a rigorous independent analysis projected a slight economic benefit to PMPA ratepayers from the proposed sale, I would not recommend that these PMPA municipal systems would take the substantial risk of making such an investment. After all we are speaking here of an investment of about $15,000 or more per PMPA customer.

What if, for example, there is a problem with the North Carolina Municipal Power Agency part of the purchase, and the plant is cancelled after the PMPA bonds are issued? What if after ten years the plant suffers a major incapacitating accident such as TMI #2 has, or a prolonged NRC mandated outage? Or, more likely, what if the plant merely has below normal performance, i.e., below the levels that I have forecast? After all, many plants have had much poorer lifetime performance than the average for any given plant type. An example of very poor performance is quite close to home here, in the form of CP&L's Brunswick units. By investing so heavily in a single project, PMPA is subject to financial risks that are many times the size of the possible benefit (if any) of this proposed purchase. Thus, from the point of view of PMPA ratepayers, this proposed generation planning decision makes little economic sense to me. PMPA

can always get its power from the complete mix of Duke's generating units under their current type of rate agreements, an arrangement far less frought with risk.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT ___(RAR-1)

Richard A. Rosen Vita

RICHARD A. ROSEN

Research Scientist
Executive Vice-President
Energy Systems Research Group

Education

Ph.D.:	Physics, Columbia University, 1974
M.A.:	Physics, Columbia University, 1969
B.S.:	Physics and Philosophy, M.I.T., 1966

Experience:

1977 - present:	Energy Systems Research Group, Inc. Responsibility for a broad range of research on industrial energy conservation; electric generation planning issues; and modelling studies of long-range electric demand, utility system reliability, electric demand curtailment, and district heating systems.
1978 - 1980:	Consultant to Brookhaven National Laboratory.
1979:	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976 - 1978:	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974 - 1976:	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973:	Instructor - Putney - Antioch Graduate School.

Testimony

Agency	Case or Docket No.	Date	Topic
Pennsylvania Public Utilities Commission	R-822169	Mar. 1983	Excess Capacity for Pennsylvania Power & Light Company
North Carolina Utilities Commission	E-100, Sub 47	Feb. 1983	Power Plant Performance Standards and Fuel Adjustment Clauses
Papago Tribal Utility Authority	ER82-481	Dec. 1982	Overview of Conservation and Generation Options

Agency	Case or Docket No	Date	Topic
Kentucky Public Service Commission	83-14	Dec. 1982	Review of the Kentucky-American Water Company Capacity Expansion Program
Maine Public Utilities Commission	81-276	Dec. 1982	As to the Avoided Costs for Cogeneration and Small Power Producers
Public Utilities Commission of the State of Maine	81-114	Nov. 1982	Maine Public Service Co. Investigation of Power Supply Planning and Purchases
Public Utilities Commission of the State of Maine	81-174	Oct. 1982	Capital Costs of the Seabrook Nuclear Units
Indiana Public Service Commission	36818	Oct. 1982	An Economic Assessment of the Marble Hill Nuclear Station
New Hampshire Public Utilities Commission	DE81-312	Oct. 1982	Investigation Into Supply and Demand of Electricity for Public Service Co. of N.H.
Michigan Public Service Commission	U-6923	May 1982	Consumers Power Co. Electricity Case
Alabama Public Service Commission	18337	Jan. 1982	Long-Range Capacity Expansion Analysis
State of New York Energy Planning Board	SEMP II Hearings	Nov. 1981	Conservation and Generation Planning
Pennsylvania Public Utility Commission	80100341 (Sur-rebuttal)	Sept. 1981	Operating and Captial Costs: Limerick Nuclear Station
Maine Public Utilities Commission	MPUC 80-180 (Sur-rebuttal)	Apr. 1981	Electric Energy Costs: Seabrook Nuclear Power Plants
Pennsylvania Public Utility Commission	I-80100341	Feb. 1981	Operating and Capital Costs: Limerick Nuclear Generating Station
Ohio Public Utilities Commission	80-141 EL-AIR	Dec. 1980	CAPCO Construction Program (generation planning)
Michigan Public Service Commission	U-6360	Sept. 1980	Generation Expansion Planning: Consumers Power Co.
Pennsylvania Public Utility Commission	I-79070315 (Sur-rebuttal)	Aug. 1980	CAPCO Construction Schedule

Agency	Case or Docket No.	Date	Topic
Connecticut Power Facility Evaluation Council	F-80	June 1980	Renewable-Resource Electric Generation in CT
Pennsylvania Public Utility Commission	I-79070317	March 1980	CAPCO: Generation Planning and Reliability
Michigan Public Service Commission	U-5979	June 1979	Forecast Critique and Adjustments: Consumers Power Co.
Massachusetts Department of Public Utilities	19494	Aug. 1978	Long-range Electric Demand Forecast: Boston Edison Co.
Pennsylvania Public Utility Commission	438	March 1978	Long-range Forecast of Electric Energy and Demand (Philadelphia Electric Co.)

ESRG Research

October 1982: The Economics of Closing the Indian Point Nuclear Power Plants. ESRG Study No. 82-40. Principal investigator.

October 1982: Review of the Kentucky-American Water Company Capacity Expansion Program. Final Report of the Kentucky Public Service Commission. ESRG Study No. 82-45. Co-author.

August 1982: Nuclear Capacity Factors: The Effects of Aging and Salt Water Cooling, A Report on Research in Progress. ESRG Study No. 82-81. Co-author.

August 1982: The Impacts of Early Retirement of Nuclear Power Plants: The Case of Maine Yankee. ESRG Study No. 82-91. Co-author.

April 1982: A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company. ESRG Study No. 81-61. Principal investigator.

January 1982: Guidelines for Designing Rates for Sales to Qualifying Facilities Under Section 210 of the Public Utility Regulatory Policies Act. ESRG Study No. 81-32. Co-author.

June 1981: An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill. A Report to: Robert M. Herzog, Director, New York City Energy Office and Allen G. Schwartz, Corporation Counsel for the City of New York. ESRG Study No. 81-21. Co-author.

October 1980: The ESRG Electrical Systems Generation Model: Incorporating Social Costs in Generation Planning, ESRG Study No. 80-12. A Report to the U.S. Department of Energy. Co-author.

September 1980: Reducing New England's Oil Dependence Through Conservation and Alternative Energy, ESRG Study No. 79-29. A Report to the U.S. General Accounting Office. Co-author.

July 1980: Preliminary Economic and Need Analysis of the Proposed Brumley Gap Pumped Storage Facility for the AEP System, ESRG Study No. 80-08/P. Principal investigator.

July 1980: The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance, ESRG Study No. 80-09, A Report to the Connecticut Power Facility Evaluation Council. Co-author.

November 1979: South Carolina Electric Demand Curtailment Planning, ESRG Study No. 79-31, A Report to the South Carolina Office of Energy Resources. Principal investigator.

May 1979: Demand Curtailment Planning: Methodology, ESRG Study No. 78-18, Chapter submitted to Brookhaven National Laboratory and the Department of Energy for the Electric Demand Curtailment Planning Study. Principal investigator.

May 1979: Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model, ESRG Study No. 79-06, A Report to the New England Conference of Public Utility Commissioners. Co-principal investigator.

October 1978: The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993, ESRG Study No. 78-16. Co-author.

November 1977: Profile of Targets for the Energy Advisory Service to Industry, ESRG Study No. 77-09, A Report to the New York State Energy Office. Co-Author.

October 1977: The Effect on Air and Water Emissions of Energy Conservation in Industry, ESRG Study No. 77-04. Co-author.

July 1977: The Effects on Air and Water Emissions of Energy Conservation in Industry, ESRG Study No. 77-04. Co-author.

June 1977: Toward an Energy Plan for New York, ESRG Study No. 77-03, A Report to the Legislative Commission on Energy Systems. Co-author.

April 1977: Assessing Demand, Alternative Operating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities, ESRG Report No. 77-01. Co-author.

Other Publications

March 1978: The Use of the Pulp and Paper Industry Process Model for R&D Decision Making, Brookhaven National Laboratory Report No. BNL 24134. Co-author.

1976: A Non-Linear Model for the Linewidth, Intensity, and Coherence of Astrophysical Masers," Astrophysical Journal vol. 190.

Papers

July 24-28, 1978: "Energy Use Modelling of the Iron and Steel Industry," Summer Computer Simulation Conference.

November 12, 1977: "Energy Conservation in Industry," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Awards and Honors

1968 - 1974: Faculty Fellowship, Physics Department Columbia University.

1966 - 1970: New York State Regents Fellowship.

1967 - 1968: Adam Leroy Jones Fellow in Philosophy, Columbia University.

EXHIBIT ___(RAR-2)

Affidavit of Richard A. Rosen

Exhibit ___ (RAR-2)

COMMONWEALTH OF MASSACHUSETTS)
COUNTY OF SUFFOLK)

Affidavit of
Richard A. Rosen

I am Richard A. Rosen, Ph.D., Executive Vice-President of Energy Systems Research Group (ESRG), a non-profit multidisciplinary research organization with offices in Boston, Massachusetts. A description of ESRG experience and qualifications appears below at Part III, and my resume' appears at Part IV.

This affidavit represents my preliminary analysis of the proposed sale by Duke Power Company of a 25 percent interest in its Catawba Unit 2 to the Piedmont Municipal Power Agency (PMPA). In this analysis I identify the material issues that should be the subject of further detailed study in order to determine the "benefit" to the towns of the proposed purchase. I show, first, that recent studies by R.W. Beck are flawed and not adequate to reach a conclusion concerning benefit; second, what the components of a study adequate to reach such conclusions would be; and, third, the willingness and ability of my organization, Energy Systems Research Group, to conduct and conclude such a study.

This affidavit shall make reference to the six elements that are the minimum basis for a determination of project benefit as listed in Section 6-23-60 of the Code of Laws of South Carolina, these being the economies and efficiencies from the project; the need for power and energy; project useful life; time required to implement project; alternatives to the project; and forecasted load. An adequate study covering these six elements and other elements relevant to the issue of benefit can be performed in a period of three months. It would require that a full and adequate discovery from Duke and PMPA be permitted.

I. REVIEW OF PMPA ANALYSIS OF CATAWBA PURCHASE

Background

In August, 1980 R. W. Beck and Associate submitted its "Preliminary Engineering Report" to the Piedmont Municipal Power Authority (PMPA) analyzing the economic feasibility of a purchase by PMPA of a 25% ownership interest in the Catawba #2 nuclear unit. This initial analysis was then followed up with two up-dated revisions of the earlier calculations (October 15, 1982 and November 11, 1982) which involved changes in a large number of key assumptions. The central focus of the Beck analysis was the economies of the proposed purchase from the point of view of the PMPA ratepayers. The Beck studies contain no substantial analysis of the benefits of the proposed sale of 25% of the Catawba #2 unit from the perspective of the Duke Power Co. ratepayers. To the extent, therefore, that South Carolina law requires such an analysis, this requirement has not been fulfilled by the Beck studies.

In performing the type of complex generation planning study that R. W. Beck did on behalf of PMPA, it is very important that all the major numerical assumptions receive a full and independent review. Major assumptions employed in the Beck studies were made by the Duke Power Co. with respect to the capital cost of the Catawba #2 unit and alternatives to it, the cost of fuels, the cost of the purchased power that Duke would sell to PMPA if they did not buy into Catawba, the cost of operating Catawba #2, and the ability of this unit to operate efficiently within the Duke Power

system. System load growth, as forecast by PMPA, is also a key assumption. Yet in most cases R.W. Beck did not meet the standard cited above: they did not independently derive values for the important assumptions utilized in their study. This critical omission will be described in greater detail below, in the context of a discussion as to what a more comprehensive study than the one performed by R. W. Beck would consist of for each key area of analysis.

Results of this Review

In the most recent study update (November 11, 1982) Table 1 of the Beck letter to PMPA indicates that the changes in key assumptions that have arisen just in the month since mid-October have significantly reduced the earlier projected favorable economics of the proposed purchase of the Catawba facility for PMPA ratepayers. In fact, without "rate stabilization" the proposed purchase is now projected to be a money loser through the year 2000. Generally, the changes in assumptions just between Beck's October 15 status report to PMPA and its November 11 report caused the 1983-2000 savings to drop by more than 20%. Yet, as we shall describe below, R. W. Beck had not made updates to independent estimates of the PMPA load forecast, the capital cost of Catawba #2, the likely capacity factor of Catawba #2, and the cost of conservation as an alternative to Catawba #2. Thus given these inadequacies in even the most recent Beck analysis, we believe that it is not possible to rely on their results to determine:

whether the sale to PMPA of 25% of Catawba #2 is to the benefit of the PMPA ratepayers. The remedial analytical measures that follow must be undertaken before such a study can be relied on by the South Carolina Public Service Commission in carrying out Section 6-23-60.

Base Case Load Forecast

An independent "Base Case" or "business-as-usual" load forecast for peak demand and energy sales must be the first stage in a generation planning study. Achieving an accurate estimate for future load growth is critical in terms of assessing how much new generating plant capacity is needed, and what type of capacity it should be. The R. W. Beck load forecast assumptions in the most recent study update are seriously flawed in two ways. First, the assumptions appear to rely on forecasts made in the "Preliminary Engineering Report" of August, 1980 thus are two years out-of-date. As Beck states in their October 15 update "Our projections of electric power and energy requirements assume that the Piedmont region of the states of North and South Carolina will continue to experience moderate economic growth. . ." (p. 13). They do not mention here any revision to their 1980 demand forecast. Yet by October of 1982 there was increased reason to qualify the long-term assumption of "moderate economic growth".

More importantly, in the 1980 report Beck states that their PMPA forecast was dependent on trend analysis and econometric techniques. However, we find that these are not state-of-the-art techniques. In the next sections of this affidavit, describing

the type of work that should be done, I will describe the need, for the sake of accuracy, to incorporate more detailed analysis into the load forecast than has apparently been done by PMPA. The likely consequence of an inadequate forecast is that the need for Catawba #2 for both PMPA and Duke Power will be over-estimated. In fact, just last month the North Carolina Utilities Commission has indicated that they believe that Duke Power's demand growth rate will be about 1.5% per year rather than the Company's estimate of 2.8% per year. These figures sharply contradict with the 3.4% that R. W. Beck has used in 1982 for the PMPA load growth rate; and calls this key Beck assumption into serious question. The implication of this likely error on Beck's part is that the Catawba #2 unit may not be required or economical for either PMPA or Duke ratepayers (or other South Carolina ratepayers) in the 1983-2000 time frame.

Conservation Assessment

It is generally accepted among professional energy analysts that there remains a substantial potential for conserving a kilowatt-hour of electricity through efficiency improvements at less than the cost of supplying new kilowatt-hour with a new generation station such as Catawba #2. Thus another major flaw in the Beck study is that the economics of utility promotion of customer conservation or load management as an alternative (see 6-23-60(n)) to the project was not addressed. Without such a prior assessment it is incomplete to proceed to analyze the cost/benefit of Catawba #2 for PMPA ratepayers as Beck did. In the next section of this

affidavit I describe the incorporation of conservation promotion as an "alternative" into the cost benefit assessment of the project. To the extent that the (properly forecasted) load growth can be moderated through conservation and load management, the rate of load growth can be abated. Duke has a deliberate strategy to do so on its own system.

The Capital Cost of Catawba #2

R. W. Beck did not make any independent assessment of the likely capital cost of Catawba #2 in any of their studies. In each they used the current Duke Power Co. estimate. The Duke estimate for Catawba #2 has been increasing rapidly over the last few years, just as have the estimates made by all utilities building nuclear units. Since the completion date for Catawba #2 is now delayed until 1987, the cost estimate is very likely to continue to rise substantially over the next few years. Thus by relying on the present Duke capital cost estimate Beck is guaranteeing that this analysis will become rapidly out-dated. They must attempt to make a final cost estimate at this time based on cost trends that have affected nuclear units that have already been completed. Statistical techniques for making such independent cost estimates do exist and have often been applied to similar generation planning assessments by organizations such as ESRG. It is also imperative for Beck to make an independent estimate of the likely completion dates for the Catawba units, which it has not done. Given recent developments, these units are likely to be delayed by Duke again in the next couple of years.

The Operations and Maintenance (O&M) Costs of Catawba #2

Just as for the capital costs of Catawba #2, R. W. Beck failed to make an independent estimate of the likely O&M costs of running Catawba #2. One way to develop such an estimate that has been used by me is to extrapolate from actual historical data on the costs of operating other nuclear units. Again, techniques for doing this are available. In their most recent study update, R. W. Beck merely relied on Duke's new O&M cost estimates which they stated were "significantly higher" than those previously furnished. The changing nature of the Duke estimate further supports the need for independent estimates to be made. Furthermore, Beck does not provide the basis for these new Duke estimates so their reasonableness can not be determined. Yet nuclear O&M costs can have a major impact on the attractiveness of the proposed PMPA purchase of Catawba #2 for PMPA ratepayers. Clearly, additional discovery is required in this area, as in the other areas discussed here.

Projected Capacity Factor of Catabwa #2

The proposed sale of Catawba #2 to PMPA is a "take-or-pay" contract, namely PMPA has to pay for Catawba whether it runs well or not. This introduces an extremely high degree of risk to PMPA into the proposed sale, for by the 1990's well over 50% of PMPA's demand would be often served by this one station, in conjunction with the two McGuire units. If PMPA were to simply rely on purchased power from Duke, on the other hand, as they have in the past, their exposure to financial risk would be

substantially less. If the Catawba and McGuire stations generate more poorly than R. W. Beck has assumed, then PMPA ratepayers will have to pay the Catawba fixed costs in addition to replacement purchased power costs from Duke.

The operating efficiency of Catawba #2 is measured by its expected "capacity factor", or the percentage of time it runs in a year. During 1982 Beck has assumed that the capacity factor of the Catawba Station will average over 60% and will rise towards 69% in the later years. Actual historical averages for large nuclear units, especially PWR's, have been lower than this, often considerably lower (as with Carolina Power & Light Company's three nuclear units). Thus, again, it is critical to a study of the type that Beck has undertaken to do a thorough and independent review of the capacity factors for Catawba as projected by Duke. In this area there is prima facie evidence that Duke (and therefore Beck) is being overly optimistic as to these projections and that the proposed purchase would prove unfavorable to the PMPA on these grounds alone. Simple statistical techniques are available to expolate capacity factors for new plants from historical data on existing nuclear plants, but Beck did not use these techniques, nor any other.

Fuel Prices

Beck's report indicate reliance on Duke Power Company's most recent fuel price estimates. While these estimates may not be as problematic as those made for other key assumptions, it is incumbent on Beck to review these estimates carefully and alter

than if their judgment dictates. There is no discussion in the Beck documents of such a review.

Purchased Power Alternatives

The entire focus of the R. W. Beck study is to compare the economies of the proposed purchase by PMPA of Catawba to PMPA buying power from Duke. However, Duke is not the only alternative. Lately, the cost of purchased power from Mid-Western utilities is falling and its availability is increasing, as demand in that region falls. This trend due to the economic downturn was well underway by November, 1982. Thus Beck should have also compared the economies of the proposed purchase to the economies of other long term purchased power arrangements that PMPA might be able to make with other utilities, notably the American Electric Power System. Such a long term purchased power contract would likely prove to be considerably less financially risky to PMPA ratepayers, even if its direct economics were only compared to the proposed purchase, and therefore this alternative could well be preferable to PMPA. As a general principle it is financially wise for a small distribution utility not to get locked into a single power source for a large fraction of its requirements, so that it can make the most out of the changing market conditions for purchased power.

The Economics of the Catawba Project for PMPA vs. Duke Power Ratepayers

By selling 25% of Catawba #2 to PMPA Duke will have an easier time financing the remainder of its construction program. However, once Catawba #2 is complete, the generous buy-back arrangement

that Duke has offered PMPA will cause Duke ratepayers to have to pay most of the high fixed costs of PMPA's share of Catawba #2 in the fist 10 years of its lifetime, these being the years when the plant is not likely to be cost effective for any set of ratepayers. If Catawba #2 is cost effective at all to the citizens of South Carolina it is only likely to be so over the very long run (beyond the mid-1990's). Beck has not studied the issue of the impact of the proposed Catawba sale to PMPA on Duke ratepayers, a subject that must also be of concern to the South Carolina Public Service Commission.

II. ElEMENTS OF AN ADEQUATE GENERATION PLANNING STUDY

An adequate study of the Catawba purchase project would not be greatly different from the Beck study in its methods of economic analysis, but the input assumptions (on load forecasts, plant costs, plant performance, etc.) would be independently developed, and the scope of the consideration of alternatives would be much greater, as it would encompass (a) purchase power from other sources than Duke, and (b) active PMPA promotion of customer conservation and load management as an alternative method of reliably meeting expected load growth or a substantial portion thereof.

Load Forecast

While it is difficult to forecast load for dispersed communities, a good load forecast is the proper basis of all system planning. Ideally, a forecasting approach would establish a disaggregated structure among and within major customer classes, preferably at the level of the major end uses of electricity, in an effort to analyze the effects of the diverse factors that shape consumption (employment changes, household growth, appliance saturation, conservation technology penetration, etc.), upon the various components of that consumption. Even if it is difficult to use a fully disaggregated end-use analysis for PMPA, it should be possible to incorporate elements of such an analysis, probably by performing a systematic independent load forecast for the region within which PMPA is situated, then allocating

appropriate portions of the forecasted demand to the PMPA communities.

(ervation and Load Management

In preparing a load forecast for planning purposes, an important step is to determine likely levels of penetration of demand-reducing practices and technologies during the forecast period, given current estimates of future market behavior and given estimates of the future effects of policies and programs now in place. An explicit identification of the likely levels of conservation and load management must be an important component of the load forecast analysis described immediately above.

Beyond that, it is necessary to view the utility option of developing a deliberate strategy to induce higher-than-expected levels of conservation and load management as a resource planning alternative on a par with new capacity or purchased power. To the extent that this approach is a cheaper way to cope with increasing demand, it is the preferred alternative. Some utilities, including Duke Power, have embarked upon a policy of requiring and inducing customers to adapt demand-reducing practices and technologies, a strategy that is usually embodied in a conservation and/or load management plan.

A study of the desirability of the project should therefore include an assessment of the potential for conservation, consisting of an accounting of electric energy and electric peak conservation potential for each customer class, where conservation is defined in terms of measures that cost less to implement than would the

supply of the energy otherwise required. This assessment of conservation potential would then form a basis for the development of long-range conservation achievement goals, including expansion of present programs and the development of new ones as found appropriate.

If an end-use forecasting model is being employed as the load forecast model, which would be the preferred approach, a conservation scenario can be constructed by specifying changes that impact specific end-uses and groups of end-uses during the forecast period. The effects of such demand-reducing measures as a reduction in the use of electric space heating in office buildings and an increase in the insulation levels of homes can be quantified explicitly in the conservation scenario. Using these scenario inputs, a "conservation case" forecast can interrupt base case computations to produce a second, slower growth year-by-year long-range forecast. When compared with the base case forecast, the Conservation Case forecast presents a quantitative estimate of the energy that can be saved and the winter and summer peak reductions that can be attained if a deliberate policy of pursuing additional conservation is found acceptable and is successfully pursued.

The conservation measures and levels incorporated in the scenario should satisfy three criteria. They should be technically feasible; their incremental costs to electricity consumers will be less than the costs of additional electricity; and they can be effected through actions that it is feasible for PMPA to undertake.

Supply Analysis

The supply analysis should be an integrated assessment of the economic and financial assessments of the proposed project and the viable alternatives thereto (including conservation promotion and power purchased from other sources than Duke). It should include independently derived estimates, not only of the basic load to be met, but also of capacity costs, operations and maintenance costs, likely capacity factor (for capacity options), costs of fuels, and financial implications of alternative investments, transmission constraints, etc.

Time Frame

It is estimated that a full professional review would take three months to complete, from inception to final report and prefiled testimony. Full discovery is crucial to incorporating the necessary accurate data regarding the Duke and PMPA systems. ESRG is prepared and able to conduct such a study. The final section describes the qualifications of my organization to complete the required study.

III. ESRG EXPERIENCE AND QUALIFICATIONS

Load Forecasting

No organization outside the electric utility industry itself has had more extensive experience in the field of load forecasting than energy Systems Research Group. When ESRG was organized in 1976, it began a comprehensive review of forecasting experience and methods. Based on this review, ESRG commenced construction of its own forecasting model. From the beginning, the ESRG model was designed to improve the accuracy of the forecasting process by solving problems of mis-forecasting that were plaguing the energy utility industry.

The ESRG forecasting model established a disaggregated end-use structure within which to examine the elements shaping consumption of energy and other resources including water. Beyond this basic commitment to the use of end-use disaggregation in order to examine the detailed components of demand, ESRG hold no brief for any one "Method" of forecasting. Within its end-use framework, the ESRG model incorporates econometric, engineering, and trending methods in an eclectic endeavor to capture the diverse forces (economics, regulation, population growth, conservation awareness, technical change, etc.) that will determine demand in the future.

ESRG's forecasting expertise has been widely recognized. On the basis of this expertise, ESRG was awarded a bid from the New England Conference of Public Utility Commissioners to scrutinize and assess the forecasting model of the New England Power Pool for the several state commissions of New England.

In 1980, ESRG was retained by the General Accounting Office of the U. S. Congress to perform demand forecasts, conservation forecasts, and conservation option analyses for all New England states, a technical analysis that constituted the basis of GAO's two-volume Report EMD-81-58, issued in 1981.

ESRG has produced electric system forecasts for the utility commissions of Maine, Vermont, Connecticut, Wisconsin, Alabama, and Oklahoma, and has been technical consultant to the Public Utility Commission of New Hampshire, assisting in forecasting model evaluation and development.

The ESRG forecasting model is designed to maximize reliance on data specific to the locality under study and minimize reliance on generic national data. Numerous local data concerning weather, population, appliance saturation, employment, housing characteristics and other relevant factors are reviewed when ESRG performs a forecast critique and incorporated as input data when ESRG makes a forecast of its own. For example, a recent forecast for the Sierra Pacific Power Co. service area, performed for Nevada's Consumer Advocate, explicitly accounted for the growth in employment and floorspace in the casino business, and its effect upon electricity consumption.

Economic and Technical Analysis of Supply Alternatives

ESRG has had wide experience assessing supply options facing utility systems on both a service area and a regional basis. These assessments have encompassed generation plant, transmission plant, purchases of capacity and energy, central station and decentralized cogeneration, and alternate sources of energy such as wind, biomass,

and solar energy connected to electricity grids. The assessments have reviewed the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relations between supply planning, load forecasting, rate design, and revenue requirements.

In 1978/79 ESRG began developing the ESGEM Electricity Supply/Generation Expansion Model, designed to develop optimal reserve margin levels for electric utility systems and to develop production cost estimates for alternative expansion plans. This model was enhanced under contract with the U.S. Department of Energy for reliability analysis purposes. Starting in 1979, ESRG conducted a series of investigations of the power supply alternatives of electric utility systems. The ESGEM model was used in these analyses in 1979 and 1980.

By the end of 1980, ESRG acquired the SYSGEN Electric System Production Costing and Reliability Model developed at the Massachusetts Institute of Technology, and substituted it for the ESGEM model in power and supply evaluations. It has proved to be a flexible, accurate and economical model to use to calculate power production costs and reliability indices for annual, seasonal and time-of-day periods for purposes of power supply planning analyses and rate design/costing studies.

A third methodological development was ESRG's introduction of the ELFIN electric utility financial model, developed by the Environmental Defense Fund, into power supply evaluation studies. This model is a corporate financial simulation model which calculates the revenue requirements and financial implications of power

supply alternatives. In the proposed power supply study it will be used in tandem with the SYSGEN model.

Finally, there have been four major statistical studies undertaken by ESRG research staff over the past years. These have provided a statistical basis for predicting:

1. Nuclear power plant capital costs
2. Coal-fired power plant capital costs
3. Nuclear power plant O&M costs
4. Nuclear power plant capacity factors.

These analyses have strengthened our power supply data in specific areas.

From a methodological viewpoint, ESRG has retained flexibility by maintaining familiarity with other widely used power supply models such as the WASP and PROMOD models. We have critiqued the application of these models in specific cases.

From a practical viewpoint, ESRG staff have had experience with a wide range or utility systems including such major interconnected systems as AEP, CAPCO and the Southern Company, as well as a regionally dispersed range of other utility systems.

In addition to numerous analyses of conventional supply options, ESRG has performed numerous studies of alternative (i.e. non-conventional) supply, beginning with a survey of the potential for industrial cogeneration in New York State sponsored by that state's Energy Office in 1978. ESRG has studied the potential for wind energy, wood energy, small-scale hydropower, and energy from solid waste, as in a report to the Connecticut Power Facility Evaluation Council in 1980. Currently, ESRG is studying the feasibility of district heating from existing power

plants for the Boston Redevelopment Authority. ESRG has also developed a multi-resource supply planning system, the LEAP system, for the Royal Swedish Academy of Sciences, and applied this system to several African nations.

Numerous of ESRG's supply studies have involved integrated reviews of the technical and financial implication of various types and levels of capacity expansion in the light of anticipated loads, alternative supply sources, and the potential for conservation. Supply studies in which the ELFIN model has been employed have included scenarious in which the implications for utility finances of utility investment in customer-side conservation have been traced in quantitative detail. An example is the comprehensive economic analysis of the proposed Arthur Kill Plant and the alternatives thereto recently completed for the New York City Energy Office.

Conservation Analysis

ESRG has assessed conservation programs of utilities and state agencies, conducted quantitative studies of the potential for additional cost-effective conservations, and identified conservation program priorities in a series of governmental agencies and citizen groups. A study that is representative of many of ESRG's capabilities in this area is "Utility Promotion of Customer Energy Conservation: An Assessment of the Existing Programs and Potential Role of the Public Service Electric and Gas Company". This study was prepared for the Public Advocate of New Jersey in August 1981, and has been widely circulated by the Department. ESRG's PSE&G study contained: an original analysis of the regulatory

issues and practical problems involved in utility conservation program design, based on a nationwide review of utility conservation program development experience; a detailed review of PSE&G's existing customer conservation programs; a quantitative analysis of the most promising options for further conservation program development, based on customer usage data specific to the PSE&G service area; and recommendations for specific regulatory actions to realize the potential for cost-effective conservation. It formed the basis for detailed conservation program recommendations that influenced, and were specifically referenced by, the New Jersey Board of Public Utilities in its November 1982 order establishing a new, comprehensive PSE&G conservation program.

ESRG has conducted several assessments of utility conservation programs based on its detailed research into conservation techniques, costs, and programs, and the particular circumstances of the given utility systems. Such assessments have also been conducted on a regional basis, as for example in the recent report "Priority Incentive Programs to Save Electricity in Massachusetts," funded by the Massachusetts Executive Office of Energy Reseources.

ESRG has been extensively involved in the development of customer programs to promote cost-effective conservation in utility service areas. As consultants to the Advocate for Customers of Public Utilities in Nevada, ESRG has provided guidelines for an optimal conservation effort on the part of the Sierra Pacific Power Co. For the Papago Tribal Utility Authority, constructive proposals for enhancements to conservation program activity by the Arizona Public Service Company have been advanced in testimony

recently submitted to the Federal Energy Regulatory Commission. Currently, as consultants to the Public Advocate in New Jersey, ESRG is reviewing the conservation programs of all investor-owned utilities to recommend expansion, contraction, continuation, or restructuring of programs to promote conservation where it is cost-effective for the utility to do so.

ESRG pioneered in the development of conservation case forecasts and analysis of the economic effects of conservation. In each of the "conservation case" forecasts identified in the "Forecast Experience" table in subsection A, below, ESRG identified a set of technically feasible and economically attractive conservation measures and levels which went beyond "Base Case" levels. A conservation scenario was constructed to explicitly modify several of the input assumptions contained in the "business-as-usual" scenario underlying the Base Case energy forecasts. A "Conservation Case" long-range forecast of electricity (and, in most cases, heating fuel consumption) was developed to quantify the energy and capacity savings that can be realized through implementation of the additional conservation measures in the conservation scenario for the region. In several of the studies, the chief direct cost tradeoffs involved in implementing the conservation scenario also were quantified. The stream of costs and benefits were computed on an annual and cumulative basis, using our CONCOST model, and discounted to their present worth to the consumers.

TABLE 1

ESRG LONG-RANGE LOAD FORECAST EXPERIENCE*

Utility or Region	State	Independent Base Case Forecast	Critique of Utility Forecast	Independent Conservation Case Forecast
New York Power Pool:	New York	xx	x	x
Central Hudson Gas & Electric Co.	New York	xx	x	x
Consolidated Edison Company	New York	xx	x	x
Long Island Lighting Company	New York	xxx	xxxx	xx
New York State Gas & Electric Corp.	New York	xx	x	x
Niagara Mohawk Power Corp.	New York	xx	x	x
Orange & Rockland Utilities	New York	xxx	x	x
Power Authority of the State of N.Y.	New York	xx	xx	x
Rochester Gas & Electric Co.	New York	xx	x	x
Statewide Forecast	New York	x		x
Central Area Power Coordination Group (CAPCO):				
Philadelphia Electric Company	Pennsylvania	xx	xx	x
Pennsylvania Power Company	Pennsylvania	xx	xx	
Duquesne Light Company	Pennsylvania	xx	x	x
Cleveland Electric Illuminating	Ohio	x		
Toledo Edison Company	Ohio	x		
Ohio Edison Company	Ohio	x		
American Electric Power Co. (AEP):				
AEP System			x	
Appalachian Power Company	Virginia and W. Va.	x	x	x
Columbus & Southern Ohio	Ohio	x		
Ohio Power Company	Ohio	x		
New England:				
New England Power Pool			x	
Boston Edison Company	Massachusetts		x	
Maine Public Service Co.	Maine	x		
Central Maine Power Company	Maine	x		x
Mass. Municipal Wholesale Electric	Massachusetts	x	x	
New Bedford Gas & Electric	Massachusetts		x	
Northeast Utilities System	Connecticut	xxx	x	xx
United Illuminating Company	Connecticut	xx	xx	x
Statewide forecasts	Each State	x(6)		x(6)
	Vermont	x		x
	New Hampshire	x		
Regionwide forecast	Six-state region	x		
Other:				
Alabama Power Company	Alabama	x		x
Arizona Public Service Co.	Arizona		xx	
Atlantic City Electric Co.	New Jersey	x	x	x
Sierra Pacific Power Co.	Nevada	x	x	x
Cincinnati Gas & Electric Company	Ohio	x		
Dayton Power & Light Company	Ohio	x		
Detroit Edison Company	Michigan	x	x	
Consumer Power Company	Michigan	x	x	
Indiana Public Service	Indiana	x	x	
Public Service Company of Oklahoma	Oklahoma	x		x
Dallas Power & Light Company	Texas		xx	
Texas Electric Service Company	Texas		x	
Utah Power and Light	Utah	x		x
Western Wisconsin Utilities (Dairyland Power Coop., Lake Superior District Power, Northern State Power Co.)	Wisconsin	xx	x	
Eastern Wisconsin Utilities (Madison Gas & Electric, Wisconsin Power & Light, Wisconsin Public Service Corp.)	Wisconsin	x		

* Each x represents one study.

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TABLE 2

ESRG ELECTRICITY SUPPLY PROJECTS -

SYSTEM RELIABILITY, GENERATION PLANNING, PRODUCTION COSTS

Year	Utility or Power Pool	Brief Project Title	Docket of Regulatory Agency
1979	Power Authority of the State of N.Y.	Greene County Power Plant Generation Cost Analysis	N.Y. P.S.C. 80006 N.R.C. 50-549
1979	Detroit Edison Company	D.E.C.O. System Reliability/ Reserve Margin Requirements	Michigan P.U.C. Case U-6006
1979	Long Island Lighting Company	L.I.L.C.O. Jamesport Plant, Generation Costs and Alternatives	New York P.S.C. 80003
1979	Philadelphia Electric Company	P.E.C.O. System Reliab.lity, Generation Plan, Optimal Costs (ESGEM Model)	Pennsylvania P.S.C. R-79060865
1980	Duquesne Light Co., Pennsylvania Power Co., CAPCO	CAPCO System Reliability, Cost Analysis of Delayed Construction (ESGEM Model)	Pennsylvania P.S.C. R-79070315 through 79070331
1980	Union Electric Company	U.E. System Reliability/ Optimal Construction, Reserve Margin Analysis (ESGEM Model)	Missouri P.S.C. Case EO-80-57
1980	New York Power Pool	Testimony on Generation Planning and Economic Analysis	F.E.R.C. Project 2729
1980	Central Area Power Coordinating Group, Cleveland Electric Illuminating	Analysis of CAPCO/CEI Generation Construction Plan	Ohio P.U.C. 79-537-EL-AIR
1980	Consumer's Power Company	Technical/Economic Assessment of CPC's Generation Construction Program (ESGEM Model)	Michigan P.U.C. Case U-6360

TABLE 2
(Continued)

ESRG ELECTRICITY SUPPLY PROJECTS -

TEM RELIABILITY, GENERATION PLANNING, PRODUCTION COSTS

Year	Utility or Power Pool	Brief Project Title	Docket of Regulatory Agency
1980	-	D.O.E./B.N.L. Development and Refinement of ESGEM Model	-
1980	American Electric Power System	A.E.P. System Optimal Capacity Plan, PURPA Rate Structure Alternatives (SYSGEN, ESGEM Models)	F.E.R.C. Project 2812 (Brumley Gap)
1980	Long Island Lighting Company	Nuclear vs. Conservation Investment Comparative Economics Analysis; LILCO Shoreham Plant	N.Y. State P.S.C. 27774
1980	CAPCO, Ohio Edison Company	Analysis of CAPCO/OE Generation Construction Plan	Ohio P.U.C. 80-141-EL-AIR
1981	Appalachian Power Company	Analysis of APCO System Reliability Generation Planning (SYSGEN Model)	West Virginia P.S.C. 79-140-E-42T
1981	Power Authority of State of New York	Comparative Economics Analysis; Conservation Investment vs. PASNY's Prattsville Pumped Storage	F.E.R.C. Project 2729
1981	Idaho/Utah	Idaho P.U.C. Innovative Rate Study - Interruptible Rates (SYSGEN)	-
1981	Central Maine Power Company	Economics/Financial Comparison of CMPC's Planning Alternatives (ELFIN)	Maine P.U.C. U-3238, U-3239
1981	Philadelphia Electric Company	PECO Limerick Station/ Alternate Capacity Reliability, Economic and Financial Analysis (SYSGEN, ELFIN Models)	Pennsylvania P.U.C. I-80100341
1981	Alabama Power Company/ Southern Company System	Power Supply and Financial Analysis of APCO System Reliability/Generation Expansion Planning (SYSGEN and ELFIN Models)	Alabama P.S.C. 18337

TABLE 2
(Continued)

ESRG ELECTRICITY SUPPLY PROJECTS -

SYSTEM RELIABILITY, GENERATION PLANNING, PRODUCTION COSTS

Year	Utility or Power Pool	Brief Project Title	Docket of Regulatory Agency
1981	Consolidated Edison Co. and Power Authority of State of New York	Evaluation of the Travis/ Arthur Kill Coal Plant Proposal and Alternatives (SYSGEN and ELFIN models)	U.S. Army Corps. of Engineers Environmental Hearing
1981	Public Service Co. of Oklahoma	Evaluation of Black Fox Nuclear Station — Completion vs. Cancel-lation	Oklahoma Corporation Commission 27068
1981	Long-run Marginal Cost of Power Supply (SYSGEN model)	Appalachian Power Co./ American Electric Power System	Virginia State Corporation Commission PUE 80076
1981	Maine Public Service Co.	Power Supply/Financial Evaluation of Seabrook Nuclear Station (SYSGEN and ELFIN models)	Maine PUC 81-114
1982	Public Service Co. of New Hampshire	Power Supply Alternative (ELFIN model)	New Hampshire Public Utility Commission DE 81-312
1982	Montaup Electric Company	Evaluation of Power Supply Planning	F.E.R.C. ER 82-325-000
1982	Public Service Co. of Indiana	Power Supply Plan and Evaluation of Co. Plan	Indiana P.S.C. 36818
1982	Public Service Co. of Oklahoma	Evaluation of Power Supply Planning	Oklahoma Corpora-tion Commission

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IV. RESUME

RICHARD A. ROSEN

Research Scientist
Executive Vice-President
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Education

Ph.D.:	Physics, Columbia University, 1974
M.A.:	Physics, Columbia University, 1969
B.S.:	Physics and Philosophy, M.I.T., 1966

Experience

1977 - present:	Energy Systems Research Group, Inc. Responsibility for a broad range of research on industrial energy conservation; electric generation planning issues; and modelling studies of long-range electric demand, utility system reliability, electric demand curtailment, and district heating systems.
1978 - 1980:	Consultant to Brookhaven National Laboratory.
1979:	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976 - 1978:	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974 - 1976:	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973:	Instructor - Putney - Antioch Graduate School.

Testimony

Agency	Case or Docket No.	Date	Topic
Maine Public Utilities Commission	81-114	Apr. 1982	Investigation of Power Supply Purchases and Planning, Maine Public Service Co.
Maine Public Utilities Commission	81-276	Apr. 1982	As to the Avoided Costs for Cogeneration and Small Power Production Facilities on the Maine Public Service Company System

Agency	Case or Docket No.	Date	Topic
Maine Public Utilities Commission	81-114	Mar. 1982	Investigation of Power Supply Purchases and Planning, Maine Public Service Co.
Alabama Public Service Commission	18337	Jan. 1982	Long-Range Capacity Expansion Analysis
State of New York Energy Planning Board	SEMP II Hearings	Nov. 1982	Conservation and Generation Planning
Pennsylvania Public Utility Commission	80100341 (Sur-rebuttal)	Sept. 1981	Operating and Capital Costs: Limerick Nuclear Station
Maine Public Utilities Commission	MPUC 80-180 (Sur-rebuttal)	Apr. 1981	Electric Energy Costs: Seabrook Nuclear Power Plants
Pennsylvania Public Utility Commission	I-80100341	Feb. 1981	Operating and Capital Costs: Limerick Nuclear Generating Station
Ohio Public Utilities Commission	80-141-EL-AIR	Dec. 1980	CAPCO Construction Program (generation planning)
Michigan Public Service Commission	U-6360	Sept. 1980	Generation Expansion Planning: Consumers Power Co.
Pennsylvania Public Utility Commission	I-79070315 (Sur-rebuttal)	Aug. 1980	CAPCO Construction Schedule
Connecticut Power Facility Evaluation Council	F-80	June 1980	Renewable-Resource Electric Generation in CT
Pennsylvania Public Utility Commission	I-79070317	Mar. 1980	CAPCO: Generation Planning and Reliability
Michigan Public Service Commission	U-5979	June 1979	Forecast Critique and Adjustments: Consumers Power Co.

Agency	Case or Docket No.	Date	Topic
Massachusetts Department of Public Utilities	19494	Aug. 1978	Long-range Electric Demand Forecast: Boston Edison Co.
Pennsylvania Public Utility Commission	438	Mar. 1978	Long-range Forecast of Electric Energy and Demand. (Philadelphia Electric Co.)

ESRG Research

April 1982: A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company. ESRG Study No. 81-61. Principal investigator.

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July 1980:	Preliminary Economic and Need Analysis of the Proposed Brumley Gap Pumped Storage Facility for the AEP System, ESRG Study No. 80-08/P. Principal investigator.
July 1980:	The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance, ESRG Study No. 80-09, A Report to the Connecticut Power Facility Evaluation Council. Co-author.
November 1979:	South Carolina Electric Demand Curtailment Planning, ESRG Study No. 79-31, A Report to the South Carolina Office of Energy Resources. Principal investigator.
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May 1979:	Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model, ESRG Study No. 79-06, A Report to the New England Conference of Public Utility Commissioners. Co-principal investigator.
October 1978:	The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993, ESRG Study No. 78-16. Co-author.
November 1977:	Profile of Targets for the Energy Advisory Service to Industry, ESRG Study No. 77-09, A Report to the New York State Energy Office. Co-Author.
October 1977:	The Effect on Air and Water Emissions of Energy Conservation in Industry, ESRG Study No. 77-04. Co-author.

July 1977: The Effect on Air and Water Emissions of Energy Conservation in Industry, ESRG Study No. 77-04. Co-author.

June 1977: Toward an Energy Plan for New York, ESRG Study No. 77-03, A Report to the Legislative Commission on Energy Systems. Co-author.

April 1977: Assessing Demand, Alternative Operating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities, ESRG Report No. 77-01. Co-author.

Other Publications

March 1978: The Use of the Pulp and Paper Industry Process Model for R&D Decision Making, Brookhaven National Laboratory Report No. BNL 24134. Co-author.

1976: "A Non-Linear Model for the Linewidth, Intensity, and Coherence of Astrophysical Masers," Astrophysical Journal vol. 190.

Papers

July 24-28, 1978: "Energy Use Modelling of the Iron and Steel Industry," Summer Computer Simulation Conference.

November 12, 1977: "Energy Conservation in Industry," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Awards and Honors

1968 - 1974: Faculty Fellowship, Physics Department Columbia University.

1966 - 1970: New York State Regents Fellowship.

1967 - 1968: Adam Leroy Jones Fellow in Philosophy, Columbia University.

STATE OF MASSACHUSETTS)
) ss
COUNTY OF SUFFOLK)

AFFIDAVIT OF RICHARD A. ROSEN

Richard A. Rosen, being first duly sworn, on oath, deposes and says that the attached statement was prepared by him or under his supervision and the information contained in such is true and correct to the best of his knowledge, information and belief.

Richard A. Rosen

Richard A. Rosen

Subscribed and sworn to me before this 15th day of March, 1983.

David R. McAnulty

Notary Public

My Commission Expires Nov. 12, 1987.

EXHIBIT ___(RAR-3)

OPERATIONS AND MAINTENANCE

C. OPERATIONS AND MAINTENANCE

C.1 Introduction

The operations and maintenance (O&M) costs of nuclear generating stations together with nuclear fuel expenses comprise the total electricity production costs at these facilties. These costs are directly passed on to electricity consumers as direct expense items in required revenues. Other costs associated with nuclear power include the capital costs of the facilities (including capital additions) which enter required revenues through their inclusion in the rate base, upon which interest or a rate of return can be earned. In addition, the costs of decommissioning and spent fuel disposal can impact required revenues insofar as funds for their implementation are collected during the operating years of the nuclear station.

Nuclear power plant operations and maintenance costs fall into 13 broad subcategories, as reported by utilities to the Federal Energy Regulatory Commission (FERC) in annual Form 1 submissions and to the U.S. Department of Energy (Ref. C.1). These are listed below in Table C.1.

Data on these O&M costs for nuclear generating stations for the years 1970 through 1980 have been collected from utility FERC Form 1 reports and the U.S. Department of Energy (Ref. C.1). A total of 49 nuclear stations, virtually all commercial units that have operated in the U.S., are included in this data base.

TABLE C.1

NUCLEAR O&M SUBCATEGORIES

Operations	Maintenance
Supervision and Engineering	Supervision and Engineering
Coolants and Water	Maintenance of Structures
Steam Expenses	Maintenance of Reactor Plant
Steam from Other Sources	Maintenance of Electric Plant
Steam Transferred	Maintenance of Miscellaneous Nuclear Plant
Electric Expenses	
Miscellaneous Nuclear Power Expenses	
Rents	

Some of the salient features of nuclear power plant O&M cost experience average directly from examination of industry-wide averages. In the industry as a whole nuclear O&M costs have increased from about one-half of nuclear fuel costs in 1970 and 1971 to about twenty percent greater than nuclear fuel costs in 1979 and 1980. Thus, these costs have begun to dominate the production costs for nuclear facilities. Within the O&M costs themselves the split has remained rather stable at about 55 percent for operations and 45 percent for maintenance throughout the 1970-1980 period. Of the 13 subcategories, the two largest are miscellaneous nuclear power expenses (23.5 percent in 1980) and maintenance of miscellaneous reactor plant (20.5 percent in 1980). These two subcategories plus maintenance of miscellaneous nuclear plant have increased their share of total O&M costs from about 39 percent in 1970/71 to over 50 percent in 1979/80.

Total costs for operations and maintenance of nuclear stations have increased dramatically from about $20 million in

1970 to about $1,400 in 1980, a seventy-fold increase. Table C.2 shows the industry-wide nuclear station, annual O&M costs from 1970 through 1980 on a per-kilowatt installed capacity basis in both nominal and constant (i.e. 1983) dollars. The second column, nuclear O&M costs in 1983 dollars per kilowatt, shows the growth trend in real per unit costs during the 1970-1980 period, thus correcting for both inflation and the increasing size of the industry. The increase was from about $12.5 per kilowatt in 1970 to about $35.9 per kilowatt in 1980. The average annual growth rate in real (i.e. above inflation) O&M costs per kilowatt for nuclear stations in the U.S. was 9.3 percent per year from 1970 through 1978 (the last full year before the TMI reactor accident) and 11.0 percent per year from 1970 through 1980.

TABLE C.2

OPERATIONS AND MAINTENANCE COSTS FOR NUCLEAR STATIONS IN THE U.S.
1970-1980

	Average Industry Dollar per Kilowatt	Average Industry 1983 Dollars Per Kilowatt
1970	5.25	12.53
1971	5.02	11.40
1972	6.91	15.08
1973	6.38	13.16
1974	8.73	16.58
1975	9.94	17.27
1976	11.98	19.78
1977	13.65	21.29
1978	16.78	24.39
1979	20.93	28.04
1980	29.21	35.93
Average Annual Growth Rate (Percent)		
1970-1978	16.6	9.3
1970-1980	18.6	11.0

C.2 Statistical Analysis

Nuclear generating station operations and maintenance costs have varied widely by facility and year of operation. In the present analysis linear regression techniques have been used to explain this variation in terms of independent variables expressing the characteristics of the nuclear stations. Various models or equations were selected for analysis. These equations expressed the dependent variable (O&M costs in 1980 dollars per kilowatt) as a linear combination of several independent or explanatory variables. Numerous independent variables were explored in various combinations with each other. These included plant size (in Megawatts) and age, chosen to test whether economies of scale and cost increases associated with aging have been occurring. Other variables which were explored for statistical significance in explaining the variation in O&M costs were plant vintage (date of initial commercial operation), geographic location, demonstration unit status, salt-water cooling, multiple unit siting, 1980 operation, reactor manufacturer, cooling towers, turbine manufacturer, utility size, and utility experience with nuclear plant operation. The last five variables were not found to have statistical significance. Definitions of the variables for which statistical significance was found are provided in Table C.3.

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TABLE C.3

DEFINITIONS OF INDEPENDENT VARIABLES USED IN NUCLEAR O&M COST REGRESSION MODEL

Variable	Definition
AGESTEP	Cumulative years of commercial operation to the end of the year for which the O&M cost observation is made. For multiple unit stations, AGESTEP equals the age of the first unit until the second unit comes on-line. With multiple units in operation the variable will equal the average age of all units.
NEMASK	1 if station located in the Northeast 0 if otherwise
DERSTEP	The station's net design electrical rating (DER) in megawatts. For multiple unit stations, DERSTEP equals the first unit's capacity until the second unit commences operation. With multiple units operating the variable will equal the average (DER).
SALT	1 if station is salt-water cooled. 0 if otherwise
DEMO	1 if station was built as a demonstration project 0 if otherwise
MULTSTEP	For multiple unit stations MULTSTEP is 0 until the year the second unit begins commercial operation. With multiple units operating MULTSTEP will equal 1. 0 at all times for single unit stations.
BIRTHSTP	Date of commercial operation. BIRTHSTP includes the actual calendar on-line date through the use of fractional years. For multiple unit stations, BIRTHSTP equals the birth date of the first unit prior to commercial operation of the second unit, after which BIRTHSTP equals the average birth date if both units are operating.
TMI	1 if year of operation is 1980 0 if otherwise

The model chosen, including the values found for the coefficients and the measures of statistical significance and goodness of fit (t-statistics, R-Squared, etc.) is given in Table C.4. All of the variables in the model show strong statistical significance.

Several of the variables are time related. The result for general age term (AGESTEP) indicates that real (1980 dollars) O&M costs have been increasing at over $3/KW per year for every additional year of operation of nuclear stations. The aging effect of operating salt-water cooled plants, (SALT x AGESTEP) is found to be an additional $.92/KW per year, probably the result of the corrosive impacts of salt-water in the cooling systems and steam generators of these units. Economies of scale were found to increase with age. The value for the coefficient for the size times age term (DERSTEP x AGESTEP) implies that for a 1200 MW plant O&M costs would be $.40/KW lower than for a 800 MW in the first year of operation. Another way of examining the effect of this term is to compare it with the general age term. For a 1000 MW plant the two terms together imply O&M cost increases of about $1.20/KW per year, while for a 800 MW the increases would be about $1.60/KW per year.

TABLE C.4+

NUCLEAR STATION O&M COST REGRESSION MODEL

Equation Coefficient			Independent Variable	Value of Coefficient*	T-Statistic*	Confidence Level
	A			-139.21	-8.45	> 99.8%
+	B	x	AGESTEP	3.19	7.00	> 99.8%
+	C	x	NEMASK	5.15	5.75	> 99.8%
+	G	x	DEMOX AGESTEP	3.24	4.78	> 99.8%
+	H	x	DEMO	-31.71	-3.87	> 99.8%
+	J	x	MULTSTEP	-2.98	-3.21	> 99.8%
+	K	x	BIRTHSTP	2.02	9.28	> 99.8%
+	M	x	DERSTEP X AGESTEP	-.002	-3.28	> 99.8%
+	Q	x	SALT x AGESTEP	.915	5.65	> 99.8%
+	N	x	TMI	8.59	6.25	> 99.8%

Number of Variables = 10 Standard Error of Regression - 7.16

R-Squared = .675 F(9/317) = 73.21

Corrected R^2 = .666 COND(X) = 131.98

*Rounded

+Dependent variable is nuclear station O&M costs in 1980 dollars per kilowatt.

Two other time related variables proved significant. The variable TMI was found to have a coefficient of 8.59, implying that on average an additional $8.59/KW was experienced by nuclear stations in the year 1980 (the first full year of operation after the TMI accident). Whether this represents a one-time effect, a permanent shift, or an acceleration of O&M cost increase trends is difficult to determine at this time. Analysis of 1981 and 1982 data will be helpful in this regard. The variable BIRTHSTP is also time related. It measures the calendar year (and fractions thereof) of initial commercial operation. The finding of an additional $2/KW for each year later of commercial operation indicates that there are higher costs for maintaining a kilowatt of capacity which is built later. This may be a result of greater complexity and more safety features embodied in later vintage plants.

REFERENCES

C.1 *Steam- (Thermal-) Electric Plant Construction Cost and Annual Production Expenses* (DOE/EIA-0323), U.S. Department of Energy.

EXHIBIT ___(RAR-4)

Excerpt from R.W. Beck Study

Exhibit __ (RAR-4)

R. W. BECK STUDY
DUKE POWER COMPANY
Catawba O&M Adjustment
SR 2915, SR 2916, SR 2317
(Thousands of Dollars)

	O&M	Property Taxes	Net Additions To Operating Inventory	Catawba Special Group	Total	Times 4 Sold 147,531	5% Of O&M Fee	Training Costs	Total O&M Adjustment
982								2,552	2,659
983								2,977	2,[illegible]
1984								3,465	3,465
1985	29,373	11,326	4,074	138	44,921	[illegible]	1,326	2,857	43,489
1986	58,612	16,412	546	314	75,884	66,193	2,410	2,347	71,155
1987	108,022	32,068	576	645	141,311	123,547	7,969	1,118	132,754
1988	158,825	31,800		839	191,464	167,531	5,095		172,617
1989	184,872	33,500		920	219,292	191,881	5,501		197,382
1990	215,191	35,100		1,007	251,298	219,886	5,949		225,835
1991	250,483	33,300		1,108	284,891	249,230	6,427		255,707
1992	291,552	31,400		1,218	324,180	283,659	6,938		290,596
1993	339,378	29,600		1,340	370,318	329,028	7,490		331,518
1994	395,036	27,913		1,474	424,423	371,370	8,063		379,459
1995	459,822	26,[illegible]2		1,621	487,765	426,294	8,736		435,5[illegible]0
1995	535,233	24,821		1,784	561,838	491,608	9,835		501,043
1997	623,011	23,407		1,962	648,380	567,333	10,190		577,523
1998	725,185	22,072		2,158	749,415	655,738	11,005		666,743
1999	844,115	20,818		2,374	857,303	753,890	11,886		770,776

Corporate Model Department
1/26/82

EXHIBIT ___(RAR-5)

ESRG NUCLEAR COST ANALYSIS REVISED

FOR 52 PLANT DATA BASE

Exhibit ___(RAR-5)

ESRG NUCLEAR COST ANALYSIS

REVISED FOR 52 PLANT DATA BASE

November, 1982

ESRG NUCLEAR COST ANALYSIS

ESRG Nuclear Plant Cost Data Base

The ESRG nuclear data base was constructed in order to assess the impact of different parameters on the cost of commercial nuclear power plants in the United States.

The data base includes all of the commercial light water reactors built in the U.S. prior to 1982 with several exceptions. Seven demonstration plants and fifteen turnkeys were excluded from the data base. Also excluded were Ft. St. Vrain, because it is a high-temperature gas-cooled reactor, and Sequoyah 1, because cost data was unavailable.

The 52 plants were arranged roughly in order of obtainment of a construction permit from the NRC (or AEC). That date (LICDATE), expressed as a decimal -- April 5, 1967, for instance, becomes 67.26, as April 5 is the 95th day of the year; 95/365 = .26 -- was available in the Electrical World annual survey of commercial nuclear power plants.

The capacity of each plant is measured by its design electrical rating (DER). This figure was chosen because it is a good measure of the full size of a plant and because it remains fairly constant over time. For units whose DER's did change between the operation date and the present, the larger of the two ratings was used. DER's were obtained from the NRC "Grey Book."

The data base records the cost of each plant in 1980 dollars, excluding AFUDC. This data base cost was estimated on the basis of reported costs using a procedure that is described in detail below. The input data for this estimation was available for most plants in Steam-Electric Construction Cost and Annual Production expenses. Because these EIA/FPC documents report data by site and not by plant, many common-sited plant and duplicate costs had to be estimated. Additionally, some plants' costs were obtained or calculated from other sources.

The date of first commercial operation (COMODAT) is expressed as a decimal for each plant and was obtained from the NRC "Grey Book." Construction time (PERIOD) is simply the period in years from the license date to the commercial operation date.

The data base also contains 4 dummy variables. The variable for duplicate (DUPLI) shows whether a plant is the second or third unit of a common-sited set to be constructed. The variable FIRST1 indicates whether or not a plant is the first unit of a common-sited set. A dummy variable is included which indicates whether the plant is equipped with a cooling tower (CTOWER).

Another dummy variable, NEAST, indicates whether the plant is located in the northeast. Northeast is defined as Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

Finally, included in the data base is a measure of experience in terms of numbers of plants for architect-engineers (AEEXP). For A-E experience, each plant engineered by a given firm and licensed previous to the plant under question counts as one unit of experience. (This includes turnkeys, demos, and Ft. St. Vrain, as well as uncompleted plants licensed before Hatch 2). The number assigned to the plant in the data base is equal to the units of previous experience plus one. In the cases where more than one firm was involved in the architecture-engineering phase of plant construction, the AEEXP number refers to the firm with the greater experience. The firm with the lesser experience is nonetheless given credit for one unit of experience, which is included in the next plant which was A-E'd by that firm. A-E 's were reported in NUC Corporation's Commercial Nuclear Power Plants.

The data in the data base is listed in Table A.1, which follows. Notes to Table A.1 are listed in Table A.2.

TABLE A.1

NUCLEAR COST DATA BASE

NUCLEAR.NUCOST - DATE REVISED: 11/22/82
ANNUAL DATA FROM 1 TO 82

[illegible]	350760.	224950.	241840.	[illegible]
[illegible]	156480.	307560.	[illegible]	[illegible]
[illegible]	356130.	681100.	668740.	[illegible]
[illegible]	[illegible]	157080.	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	1.261230E+06	[illegible]	[illegible]
[illegible]	[illegible]	418990.	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	612780.	[illegible]	[illegible]
[illegible]	[illegible]	1.0[illegible]5510E+06	[illegible]	[illegible]
[illegible]	734400.	631810.	813630.	[illegible]

NUCLEAR.[illegible] - DATE REVISED: 11/24/82
ANNUAL DATA FROM 1 TO 82

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	815.	[illegible]	[illegible]	[illegible]

NUCLEAR.[illegible] - DATE REVISED: 11/03/82
ANNUAL DATA FROM 1 TO 82

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	21.14	[illegible]	[illegible]

TABLE A.1
(Continued)

NUCLEAR_COMOPDAT - DATE REVISED: 11/03/82
ANNUAL DATA FROM 1 TO 52

1	71.99	72.94	73.69	74.58
5	75.16	[illegible]	74.69	[illegible]
[illegible]	[illegible]	74.51	74.99	[illegible]
13	74.47	[illegible]	[illegible]	[illegible]
[illegible]	73.96	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	74.97	74.	74.
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	75.09	[illegible]	[illegible]
41	[illegible]	[illegible]	[illegible]	[illegible]
45	[illegible]	[illegible]	[illegible]	[illegible]
49	81.58	80.96	81.[illegible]	81.[illegible]

NUCLEAR [illegible] - DATE REVISED: 11/03/82
ANNUAL DATA FROM 1 TO 52

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	10.	[illegible]	4.

NUCLEAR [illegible] - DATE REVISED: 9/07/82
ANNUAL DATA FROM 1 TO 52

[illegible]	1.	0.	0.	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TABLE A.1
(Continued)

NUCLEAR_FIRST1 - DATE REVISED: 11/03/82
ANNUAL DATA FROM 1 TO 52

1	0.	1.	0.	1.
5	0.	1.	0.	0.
9	0.	1.	0.	1.
13	0.	0.	1.	0.
17	1.	0.	0.	0.
21	1.	1.	0.	0.
25	0.	1.	1.	0.
29	1.	0.	1.	0.
33	0.	1.	0.	1.
37	0.	0.	0.	1.
41	1.	0.	0.	1.
45	0.	1.	0.	0.
49	0.	0.	0.	1.

NUCLEAR_DUPLI - DATE REVISED: 11/03/82
ANNUAL DATA FROM 1 TO 52

1	0.	0.	1.	0.
5	1.	0.	1.	1.
9	0.	0.	1.	0.
13	0.	0.	0.	1.
17	0.	1.	1.	0.
21	0.	0.	0.	0.
25	0.	0.	0.	1.
29	0.	1.	0.	1.
33	1.	0.	1.	0.
37	1.	0.	0.	0.
41	0.	0.	0.	0.
45	0.	0.	1.	1.
49	1.	1.	1.	0.

NUCLEAR_NEAST - DATE REVISED: 11/03/82
ANNUAL DATA FROM 1 TO 52

1	0.	0.	0.	0.
5	0.	0.	0.	0.
9	1.	1.	1.	1.
13	0.	0.	0.	0.
17	0.	0.	0.	0.
21	1.	1.	0.	0.
25	1.	0.	0.	0.
29	0.	0.	0.	0.
33	1.	0.	1.	0.
37	0.	0.	1.	1.
41	0.	1.	0.	0.
45	0.	0.	0.	0.
49	0.	0.	1.	0.

TABLE A.1 (Cont.)

NUCLEAR_PLNTNM -

1	PALISADES	51	Salem 2
2	TURKEY POINT 3	52	McGuire 1
3	TURKEY POINT 4		
4	BROWN S FERRY 1		
5	BROWN'S FERRY 2		
6	OCONEE 1		
7	OCONEE 2		
8	OCONEE 3		
9	VERMONT YANKEE		
10	PEACH BOTTOM 2		
11	PEACH BOTTOM 3		
12	THREE MILE ISLAND 1		
13	FORT CALHOUN 1		
14	COOPER		
15	SURRY 1		
16	SURRY 2		
17	PRAIRIE ISLAND 1		
18	PRAIRIE ISLAND 2		
19	BROWN S FERRY 3		
20	KEWAUNEE		
21	PILGRIM 1		
22	SALEM 1		
23	CRYSTAL RIVER 3		
24	RANCHO SECO 1		
25	MAINE YANKEE		
26	ARKANSAS NUCLEAR ONE #1		
27	ZION 1		
28	ZION 2		
29	COOK 1		
30	COOK 2		
31	CALVERT CLIFFS 1		
32	CALVERT CLIFFS 2		
33	INDIAN POINT 2		
34	HATCH 1		
35	THREE MILE ISLAND 2		
36	BRUNSWICK 2		
37	BRUNSWICK 1		
38	ARNOLD		
39	FITZPATRICK		
40	BEAVER VALLEY 1		
41	ST. LUCIE 1		
42	MILLSTONE 2		
43	TROJAN		
44	NORTH ANNA 1		
45	DAVIS BESSE 1		
46	FARLEY 1		
47	ARKANSAS NUCLEAR ONE #2		
48	HATCH 2		
49	FARLEY 2		
50	NORTH ANNA 2		

TABLE A.2

NOTES TO NUCLEAR COST DATA BASE

1. Turnkeys:

Robinson 2
Dresden 2
Dresden 3
Quad Cities 1
Quad Cities 2
Connecticut Yankee
Oyster Creek
Millstone 1
Monticello
Ginna
San Onofre 1
Point Beach 1
Point Beach 2
Indian Point 2
Nine Mile Point 1

Demonstration Plants:

Dresden 1
Indian Point 1
Big Rock Point
La Crosse
Shippingport
Yankee-Rowe
Humboldt Bay

2. Uncompleted plants covered for AEEXP

Diablo Canyon 1
Sequoyah 2
Diablo Canyon 2
Fermi 2
Zimmer
Midland 1
Midland 2

TABLE A.2
(Continued)

NOTES TO NUCLEAR COST DATA BASE

		Source
3.	Common sited plants for which individual costs were unavailable:	
	Browns Ferry 1	- Cost of each unit #1, year of comm. op., not reported
	Browns Ferry 2	- Cost of each unit assumed to be half of 1975 total-site figure.
	Oconee 2	- Cost of units #2 and #3 assumed to be half of difference between 1974 (total 3-unit site) and 1973 (only#1 unit) figures.
	Peach Bottom 2 Peach Bottom 3	- Cost of each assumed to be half of 1974 total-site figure.
	Turkey Point 4	- Cost assumed to be difference between 1973 total-site figure and 1972 (only unit #3) figure.
	Surry 2	- Cost assumed to be difference between total-site figure and 1972 (only unit #1) figure.
	Prairie Island 2	- Cost assumed to be difference between 1974 total-site figure and 1973 (only unit #1) figure.
	Browns Ferry 3	- Cost assumed to be one-third of 1977 total-site figure.
	Zion 2	- Cost assumed to be difference between 1974 totalsite figure and 1973 (only unit #1) figure.
	Calvert Cliffs 2	- Cost assumed to be difference between 1977 total-site figure and 1976 (only unit #1) figure.
	Brunswick 1	- Cost assumed to be difference between 1977 total-site figure and 1976 (only unit #1) figure.
4.	Cost not obtained from Steam-Electric Plant Production Costs:	
	Hatch 1	- Georgia Power Company
	Hatch 2	- Georgia Power Company
	Arkansas Nuclear One #2	- Arkansas Power & Light Company
	Indian Point 3	- Report of Member Systems of N.Y. Power Pool, 1977.
	Fitzpatrick	- Komanoff
	Farley 2	- Alabama Attorney General's Office
	North Anna 2	- Virginia Public Utilities Commission
	Salem 2	- Atlantic City Electric Company
	McGuire 1	- Duke Power Company

Calculation of Constant Dollar Direct Construction Costs

As mentioned above, published data regarding the cost of nuclear plants is in the form of "mixed current dollars" (i.e., not adjusted for inflation) and includes the cost of interest during construction in the form of AFUDC, in addition to actual construction expenditures. For the purpose of predicting the future cost of power plants, it is necessary to separate out the effects of inflation, AFUDC, and trends in actual construction costs net of inflation. To do this, the direct construction cost in 1980 dollars of each plant in the data base was estimated on the basis of the available mixed current dollar costs. This estimation involved both the removal of AFUDC costs and correction for inflation in the cost of inputs to nuclear power plants construction.

The first step in this estimation procedure is to reproduce the flow of construction expenditures for the power plant over time. This is necessary for two reasons. First, the conversion of the actual ("current") construction dollars to 1980 construction dollars depends on the year in which the expenditure was made. Second, the accumulation of interest during the construction or AFUDC depends in each construction year on total expenditures prior to that year. Therefore, the fraction of the observed total cost attributable to AFUDC (and hence excluded from the direct construction cost) depend on the pattern of expenditures over the construction period.

This pattern of construction expenditures was approximated by an equation developed by William Mooz for the Department of Energy (Refs. A.1 and A.2). Mooz took a typical "cash-flow curve" for nuclear power plants developed by ERDA and applied a standard "curve-fitting" routine to yield the following equation:

$$\frac{Y_t}{Y_{(total)}} = \left[1 - \cos \frac{\pi}{2} \frac{t}{t_{(total)}}^{\text{[illegible]}}\right]^{\text{[illegible]}}$$

where Y_t is the total construction expenditure up to time is the ultimate total expenditure and $t_{(total)}$ is the length of the construction period.

To use this equation, it is necessary to define the construction period for a particular plant. The Mooz equation gives very small proportions for the first and last years.* This is consistent with the interpretation that it includes the initial planning phase of the project as well as final expenditures after construction is essentially complete. Therefore, for the plants in the data base, the total construction period is taken as commencing two years before the date the reactor was ordered and ending one year after the date of the commercial operation.

Using the Mooz equation, a yearly stream of expenditure proportions was estimated for each plant. Given this stream of proportions, the total cost of the plant is given by:

$$TC = \sum_{i=1}^{n} (DC)\,(FRAC_i/D_i)\,(1 + IDC_i/2) \prod_{j=i+1}^{n} (1 + IDC_j)$$

where:
- TC = total cost in mixed current dollars including interest during construction;
- DC = direct construction cost in 1980 dollars
- $FRAC$ = fraction of DC spent in year i
- D_i = cumulative deflation factor for year i
- IDC_i = interest rate in year i; and,
- n = total number of years in construction period.

What this equation says is that each year the amount spent on construction in constant dollars is the total constant dollar construction cost (DC) times the Mooz fraction for that year ($FRAC_i$). To convert this from 1980 dollars to current dollars, we divide by the cumulative inflation from that year to 1980 (D_i). This direct construction expenditure is increased by interest costs in the form of AFUDC. In the first year, this cost is one-half the interest costs for that year (assuming that expenditures are evenly spent over

* For example, for a ten-year construction period, .006% would be spent in the first year, .48 in the second year, and .17% in the last year.

the period). Thus the actual amount spent in year i due to construction in year i is $(1 + IDC_i/2)$ times the actual construction expenditure in year i $(CDC)(FRAC_i/D_i)$. There is however an additional cost due to this expenditure in all subsequent years because of interest. The original expenditure in year i will be increased each subsequent year by an amount equal to that year's interest rate. Therefore, the total cost resulting from year i's expenditure is the expenditure in year i times the product of the series of terms of the form (1 + IDC), with <u>one such term</u> for each year after year i, up to the last year (n)*.

Finally, the total cost (TC) is the sum over all years of each year's total cost impact.

This equation may be easily rearranged to give DC as a function of TC. Since DC appears in every term of the sum, it can be taken outside the summation sign. Dividing through by the sum gives:

$$DC = \frac{TC}{\sum_{i=1}^{n} (FRAC_i D_i)(1 + IDC_i/2) \prod_{j=i+1}^{n} (1 + IDC_j)}$$

This equation was used to calculated the 1980 dollar direct construction cost (DC) on the basis of the total mixed current dollar cost (TC).

The yearly inflation rates and interest rates used for this purpose are presented in Table A.3, inflation rates were calculated from Reference A.3. Interest rates are from Reference A.4.

* This is not strictly correct because interest in the last year will generally not accumulate for the full year. In the actual calculation, the interest rate for the last year was reduced proportionately to the fraction of the year before the operation date.

Regression Results

A series of statistical analyses of the nuclear cost data base were used to try to determine the factors affecting the cost of nuclear plants after inflation and interest have been removed. The variables that were considered as possible factors affecting the construction cost were:

LICDATE - construction permit issue date;

MWDER - Capacity of the plant in MW (design electrical rating);

AEEXP - "experience" of the architect-engineer;

PERIOD - construction period (commercial operation date minus construction permit issue date);

FIRST1 - whether or not the plant is the first of a common-sited set;

DUPLI - whether or not the plant is a "duplicate" on its site;

NEAST - whether or not the plant is located in the Northeast;

CTOWER - whether or not the plant has cooling towers.

The last four (4) variables are "dummies" having the value of one (1) if the plant has the attribute, and otherwise having the value zero (0). For all the statistical analyses, the cost data were standardized to a cost (1980 dollar direct construction expenditures) per continuous KW basis.

TABLE A.3

COST ESCALATION AND INTEREST RATES

Year	Nuclear Construction Inout Cost Escalation (%)	Cumulative Deflation Factor to 1980	Interest Rate (%)
1965	2.7	2.832	3.8
1966	2.2	2.758	3.9
1967	3.6	2.697	4.0
1968	4.4	2.605	4.3
1969	5.8	2.495	4.6
1970	8.1	2.358	5.1
1971	10.1	2.182	5.5
1972	4.4	1.982	5.7
1973	6.4	1.898	5.9
1974	17.8	1.783	6.3
1975	10.8	1.514	6.8
1976	7.9	1.366	7.0
1977	5.9	1.267	7.1
1978	9.3	1.196	7.3
1979	9.4	1.094	7.6
1980	11.4*	1.0	8.6
		0.898	9.6

*estimate

The equation used to represent the effect of these factors on cost:

$$\text{cost/kw} = A + A1 \times \text{LICDATE} + A2 \times \log(\text{MWDER}) + A3 \times \log(\text{AEEXP}) + A4 \times \text{PERIOD} + A5 \times \text{DUPLI} + A6 \times \text{NEAST} + A7 \times \text{CTOWER} + A8 \times \text{FIRST1}$$

The results of simple least square estimation of the coefficients in these equations are given below:

	COEFFICIENT	T-STATISTIC
LICDATE	98.0901	6.84*
LOG(MWDER)	-243.1260	-2.39**
LOG (AEEXP)	-31.1383	-1.36
PERIOD	34.9633	2.18**
DUPLI	-129.9980	-2.32**
NEAST	190.8200	4.38*
CTOWER	62.2815	1.61
FIRST1	95.6245	1.92**
CONSTANT	-4713.9300	-4.10*

R^2	0.720
CR^2	0.668
$\hat{\sigma}$	132.52
F	13.80
DW	1.51

* significantly non-zero at 99.0% confidence;
** significantly non-zero at 95.0% confidence;

This equation indicates that the cost per kw for nuclear plants increased $98 per year over the data base period. This effect is extremely significant statistically, and also by far the largest effect in magnitude in explaining the cost variation in the data base. All other things equal, a plant licensed at the start of the data base period (March, 1967) cost about $600/kw less than one licensed at the end (February 1973).

The coefficient for the term log (MWDER) measures "economies of scale" in nuclear plant construction. It indicates that a doubling of plant size reduces the cost/kw by about $169/kw. This is a fairly modest effect, since most of the plants are in the 800 to 1100 MW range. Though small, the effect is quite significant statistically.

The third term represents the reduction in costs that occur because the architect-engineer gains nuclear construction experience. This effect is not very sitnificant statistically, and its magnitude is moderately small for most plants. AE experience in the sample ranges from one (1) to thirty-one (31); this corresponds to a variation of about $107/kw from the experience effect. Most engineers now have experience with at least six (6) plants; the difference predicted by the equation between a plant built by an AE with thirty-one (31) plants compared to six (6) plants is about $51/kw.

As for the dummy variables FIRST1 and DUPLI, the effects of both are quite significant statistically, and both are moderately large in magnitude. The variable FIRST1 indicates that plants which are the first of a common-sited set are $96/kw more expensive than others. The variable DUPLI indicates that second and third plants on a site are $130/kw cheaper than other plants. It is not clear, however, to what extent this effect is an artifact of the way the costs of common-sited plants are allocated. As noted above, reliable data was unavailable for some of these pairs, necessitating the use of somewhat crude assumptions to derive separate cost estimates.

The dummy variable CTOWER is fairly significant statistically. It shows that cooling towers add about $62/kw to the cost of a plant.

The dummy variable for plants in the Northeast, NEAST, is very significant statistically. It is also large in magnitude, adding $191/kw to the cost of a plant.

Application of Nuclear Capital Cost Equation to Catawba #2

The equation described above was used to predict the direct construction cost of Catawba unit #2. For the currently forecast date of commercial operation, the resulting direct construction cost is $1525/KW (in 1983 dollars). The total cost of the unit in current dollars, including AFUDC, is $2,455 million.

The direct construction cost was calculated according to the equation using the following data:

LICDATE	1,975.60
MW	1,145
AEEXP	6
PERIOD	11.86
DUPLI	1
NEAST	0
CTOWER	1
FIRST1	0
SCENT	0

Through 1982, a total of $722/KW had been spent on direct construction of Catawba #2. This figure is based upon information in the Preliminary Official Statement for the North Carolina Municipal Power Agency's Catawba Electric Revenue Bonds, Series 1983 A, dated May 10, 1983. After the expenditures through 1982 were taken out, the remaining construction costs were spread out over time based upon an inflation rate of 6%. The Mooz equation, described above, was used to derive the shape of the annual expenditure curve.

The AFUDC total cost through 1982 was estimated as 20 percent of the direct construction experienced through that date. In future years, the AFUDC was determined based upon the annual direct construction cost projections and an AFUDC rate of 10.3 percent. This rate is the average rate on the Series 1983 A Bonds.

The annual construction costs and AFUDC for Catawba #2 are listed in Table A.4.

TABLE A.4

CATAWBA UNIT #2 CONSTRUCTION COSTS
(In Millions of $)

	1982	1983	1984	1985	1986	1987
DIRECT CONST.	722.	276.	218.	136.	63.	12.
AFUDC	114.	0.	129.	160.	187.	97.
YEAR TOTAL	[illegible]	276.	346.	296.	251.	109.
RUNNING TOTAL	866.	1132.	1488.	1734.	2035.	2144.

TOTAL DIRECT CONSTRUCTION 1322. $/KW 1634. MILLION DOLLARS TOTAL PLANT

TOTAL AFUDC 717 821.

GRAND TOTAL 2144 245..

REFERENCES

A.1 William E. Mooz Cost Analysis of Light Water Reactor Power Plants, The Rand Corporation R-2304-DOE (June, 1978)

A.2 William E. Mooz A Second Cost Analysis of Light Water Reactor Power Plants R-2504-RC (De:ember, 1979)

A.3 Handly-Whitman Index of Public Utility Construction Costs, Baltimore.

A.4 United States E.I.A., Statistics of Privately Owned Electric Utilities in the United States; 1977. The "Average Interest Rate" from Tables 12 and 13 "Interest on Long-Term Debt" was used.

EXHIBIT ___(RAR-6)

Capacity Factors

B. CAPACITY FACTORS

B.1 Introduction

The maximum output of a power plant over the course of a full year of operation is the product of the total number of hours in a year (8,760) and net full rated capacity of the unit. Thus, for a 1,000 MW plant it would be 8,760 GWH.* This output is never achieved for a number of reasons. First, power plants require outages for scheduled maintenance and equipment repair. Second, they often suffer unscheduled or forced out-- ages which require maintenance and equipment repair. Finally, some power plants are operated to perform load following and are consequently brought on- or off-line as system loads experience upward or downward swings. Peaking units are an extreme example of this latter phenomenon, often being run only several percent of their available hours during the year.

Nuclear power plant operation differs from this in a number of respects. Nuclear units do suffer forced outages and require scheduled outages whose magnitude and character are specific to this technology and its requirements. But only rarely have some nuclear units been operated to load follow. The costs and technical characteristics of nuclear units require that they be operated in the baseload mode, generating electricity at all hours when they are available to do so, and

*A GWH (gigawatt-hour) is one million kilowatt-hours or one thousand megawatt-hours.

coming off-line only when necessary. For nuclear plants, however, the necessity of coming off-line extends beyond the imperatives of forced and scheduled maintenance and equipment outages. Nuclear units require rather long down times for refueling, on a twelve to eighteen month cycle. Moreover, Nuclear Regulatory Commission mandated outages for inspection, safety, training and licensing can also temporarily remove nuclear units from service.

Capacity factors are generally defined as the net electrical generation divided by the maximum possible generation over the course of a year (or any other time period). For a full year of service the capacity factor can be expressed:

$$\text{Annual Capacity Factor (in Percent)} = \frac{\text{Net Generation (MWH)}}{\text{Design Electrical Rating (Net MW)} \times 8{,}760} \times 100$$

In effect, the capacity factor is the fraction of time (e.g., a year) a unit is generating electricty at full rated capacity.

Nuclear power plants have had capacity factors which on average have been far below the expectations of the industry. A simple compilation of this industry-wide experience is provided by the U.S. Department of Energy (Ref. B.1), and is reproduced here for the last ten years in Table B.1 below. A number of observations can be made regarding this simple compilation. First, in only three out of ten years were the average industry-wide capacity factors above sixty percent. Second, both the ten year average experience of 56.7 percent and the last four years experience of 56.1 percent fall far

below industry expectations, which have ranged between 65 percent and 80 percent. There is no evidence here of an industry-wide learning process, that is, no general improvement over time.

Thus, on the basis of the experience of the industry as a whole, a capacity factor of about 57 percent would be a plausible assumption for a nuclear facility.

TABLE B.1

NUCLEAR POWER PLANT CAPACITY FACTORS IN THE UNITED STATES 1973-1982

YEAR	CAPACITY FACTOR (Percent)
1973	63.2
1974	43.5
1975	55.2
1976	53.5
1977	62.9
1978	63.9
1979	57.6
1980	55.1
1981	56.6
1982	55.0
Average	56.7

B.2 Statistical Analysis

While the above industry-wide average capacity factors are instructive in themselves, it is useful to explore further the rather wide variation in plant-by-plant and year-by-year experience. The first step in this process is to segregate the nuclear plants by reactor type and size to see whether major differences emerge. Another characteristic, whether salt-water is used for cooling, may be important insofar as corrosion

related problems could emerge. Table B.2, below, summarizes industry-wide average capacity factors from 1975 through 1981, segregating by reactor type (PWR or BWR*), size (greater or less than 800 MW), and cooling system (salt-water or not). For this table, maximum potential electrical generation is the product of hours in-service and the net design electrical rating (DER) of the unit.

TABLE B.2

NUCLEAR POWER PLANT AVERAGE CAPACITY FACTORS
1975-1981
(Percent)

	PWR			BWR			ALL REACTORS		
	SALT	NO SALT	ALL	SALT	NO SALT	ALL	SALT	NO SALT	ALL
≤ 800 MW	61.7	72.8	69.9	59.7	59.7	59.7	60.7	65.0	64.0
> 800 MW	59.2	55.3	56.8	46.4	57.7	55.6	57.5	56.1	56.5
ALL SIZES	59.7	60.2	60.0	54.5	58.8	58.0	58.4	59.6	59.3

* Pressurized Water Reactor (PWR), Boiling Water Reactor (BWR).

Regression Analysis: Introduction

More detailed examination and analysis of the variation in nuclear power plant capacity factors has been performed by ESRG. This undertaking is applied to a data base consisting of 68 nuclear power plants (essentially all commercially operating units) in the U.S. and their electricity production and outage experience from 1975 through 1981. The source of this data is the Nuclear Regulatory Commission (NRC) "Grey Books" (Ref. B.2). The analytical technique applied is multivariate regression analysis, which explains the observations (experienced annual capacity factors) in terms of a linear combination of independent variables selected because they are believed to have a causal or associative relationship to the observations. The variables explored in regression analysis include unit size, reactor type, unit age, presence or absence of cooling towers, salt-water cooling or not, steam system supplies, and commercial operation date.

The age (years of operation) variable is interesting in two respects. First, it can express a maturation effect, i.e., improvement after the first few years (or "shakedown" period) of operation. Second, it can express aging phenomena, i.e., deterioration of performance with age, after mature levels have been reached. In order to test for such phenomena it is necessary to use broken linear, rather than a single linear age variable. In addition, to examine whether aging effects differ with plant characteristics, i.e., reactor type, size, salt-water cooling, product terms of age times these variables have been employed.

A further discussion of the data base used for regression analysis deserves attention here. Since NRC mandated outages occur somewhat episodically or randomly over the data base period, these outage hours have been removed from the analysis. Similarly, refuelling outage hours have been removed, since these too add a degree of scatter or randomness because they sometimes overlap calendar years and the cycle itself can vary rather widely. While regression could readily be performed on the raw or unadjusted capacity factors, here we have applied it to adjusted capacity factors in order to obtain a better analysis of the factors which contribute to forced and scheduled maintenance and equipment outages. The adjusted capacity factor is:

$$\text{Adj. Cap. Fac.}^* = \frac{\text{Net Electrical Generation}}{\text{Design (Net) Electrical Rating} \times (8{,}760 - \text{Refuelling and NRC Outages})}$$

Average Refuelling and Regulatory Outages

Before turning to the analysis of adjusted capacity factors, then, it is important to examine the magnitude of these adjustments themselves. Once results are obtained for the adjusted capacity factors, refuelling and NRC-related outages must be factored back in to obtain the net result, i.e., experienced capacity factor. Table B.3, below, shows the magnitude of these adjustments on an industry-wide basis for PWR's, BWR's and all reactor types.

*For plants that commence commercial operation after January 1st, the start-up year adjusted capacity factor is calculated as:

$$\text{Adj. Cap. Fac.} = \frac{\text{Net Electrical Generation}}{\text{Design (Net) Electrical Rating}} \times [(8760 \times \text{fraction of year in operation}) - \text{refueling and NRC outages}]$$

TABLE B.3

NUCLEAR POWER PLANT REFUELLING AND NRC-RELATED OUTAGE RATES (1975-1981)

	PWR	BWR	ALL REACTORS
REFUELLING	.13	.13	.13
NRC-RELATED	.04	.01	.03
TOTAL ADJUSTMENT	.17	.14	.16

The table shows that, on average, nuclear units have experienced outages of 13 percent per year (6.8 weeks) for refuelling*, and about 3 percent per year for NRC-related shutdowns+, during the 1975-1981 period.

Regression Analysis: Discussion

The independent variables selected in the multivariate regression specification for adjusted capacity factors are defined below in Table B.4.

The results of the multivariate regression analysis are provided below in Table B.5. The first column designates the variable, defined in Table B.4, the second column provides the regression coefficient, the third column gives the T-statistic, and the fourth column gives the confidence level. The regression coefficient is the measure of the magnitude of a variable's contribution to the observed result (here, adjusted capacity factor). Thus, for example, the values .066 for the TOWERSU

*Since outage hours are reported to the NRC for each major outage mode, refuelling outages can sometimes include time for scheduled maintenance.

+Including NRC-mandated outages, licensing and training outages.

variable and -.157 for the TOWERSU x PWRU term show that a BWR plant with cooling towers will experience, on average, a 7 percent higher adjusted capacity factor than a once-through cooled BWR or PWR, whereas a PWR with towers will experience a 9 percent lower adjusted capacity factor than a PWR or BWR with a once-through cooling system. The T-statistic is the measure of the significance of the variable in explaining the observed variation in adjusted capacity factors. The confidence level indicates the probability that the independent variable will have an absolute value significantly greater than zero.

Finally, summary statistics, including the corrected R-SQUARED and F-ratio which are measures of the goodness-of-fit of the entire equation, are also provided in Table B.5.

TABLE B.4

INDEPENDENT VARIABLES SELECTED FOR REGRESSION SPECIFICATION FOR NUCLEAR POWER PLANT ADJUSTED CAPACITY FACTORS

Variable Name	Definition
DERU	Unit size in megawatts
PWRU	1 if unit is PWR 0 otherwise
SALTU	1 if unit is salt-water cooled 0 otherwise
AGE	Years of commercial operation according to calendar years. The first calendar year of operation averages only one-half a year of plant operation
TOWERSU	1 if unit has cooling tower 0 otherwise
AGE4	AGE-4 for Age $\leq$ 4 0 otherwise
AGE6	AGE-6 for Age $\leq$ 6 0 otherwise
AGE10	AGE-10 for Age $\leq$ 10 0 otherwise
BWSTM	Babcock and Wilcox Steam System
WESTM	Westinghouse Steam System

TABLE B.5

REGRESSION RESULTS FOR NUCLEAR POWER PLANT ADJUSTED CAPACITY FACTORS
1975 Through 1981

Equation Coefficient		Independent Variable	Value of Coefficient*	T-Statistic*	Confidence Level
	A		.697	8.24	99.8%
+	B x	DERU	-1.77×10^{-4}	-1.32	80.0%
+	Z x	DERU x PWRU	-2.49×10^{-4}	-3.15	99.0%
+	C x	PWRU	.418	4.79	99.8%
+	G x	SALTU	1.38	3.96	99.8%
+	E x	AGE	-.007	-.945	50.0%
+	X1 x	SALTU x DERU	-3.95×10^{-4}	-3.02	99.0%
+	K x	PWRU x TOWERSU	-.157	-4.23	99.8%
+	W x	AGE x PWRU	-.016	-2.79	99.0%
+	D x	AGE x DERU	3.63×10^{-5}	2.48	98.0%
+	L x	TOWERSU	.066	2.35	95.0%
+	S x	SALTU x AGE	-.112	-3.90	99.8%
+	F x	SALTU x PWRU	.085	1.17	50.0%
+	H x	SALTU x PWRU x AGE	-.020	-1.99	95.0%
+	L3 x	AGE6	.026	1.06	50.0%
+	M2 x	AGE4 x DERU	9.28×10^{-5}	3.44	99.8%
+	M3 x	AGE6 x DERU	-6.54×10^{-5}	-1.67	90.0%
+	N2 x	AGE4 x SALTU	-.064	-1.58	80.0%
+	N3 x	AGE6 x SALTU	.063	1.56	80.0%
+	N4 x	AGE10 x SALTU	.093	2.44	98.0%
+	X2 x	BWSTM	-.074	-2.34	95.0%
+	X3 x	WESTM	-.019	-.781	50.0%

Number of Variables = 22
R-Squared = .333
Corrected R^2 = .298

Standard Error of Regression = .139
F(21/398) = 9.48
COND(X) = 114.43

*Rounded

Regression Analysis: Results

It is instructive to apply these regression results to prototypical nuclear plants to examine the predictions of the entire equation. In Figures B.1 through B.4, the results are applied to four generic types (PWR and BWR, salt-water cooled and non-salt-water cooled). The impact of plant size (600 MW, 800 MW, 1,000 MW, and 1,200 MW) is also shown. The capacity factors used in these figures are the product of the regression result for each given prototype and a correction factor for refuelling and NRC-related outages (1-.17 = .83 for PWR's and 1-.14 = .86 for BWR's from Table B.3).* The cooling tower effects, about +7 percent for BWR's and -9 percent for PWR's, applicable to some non-salt-water cooled units are not incorporated in the results presented in Figures B.1 through B.4.

*The correction factor is not applied to the estimated capacity factor for the first year of operation.

Figure B.1

PROJECTED CAPACITY FACTORS FOR GENERIC PLANTS

BWR: FRESH WATER COOLED

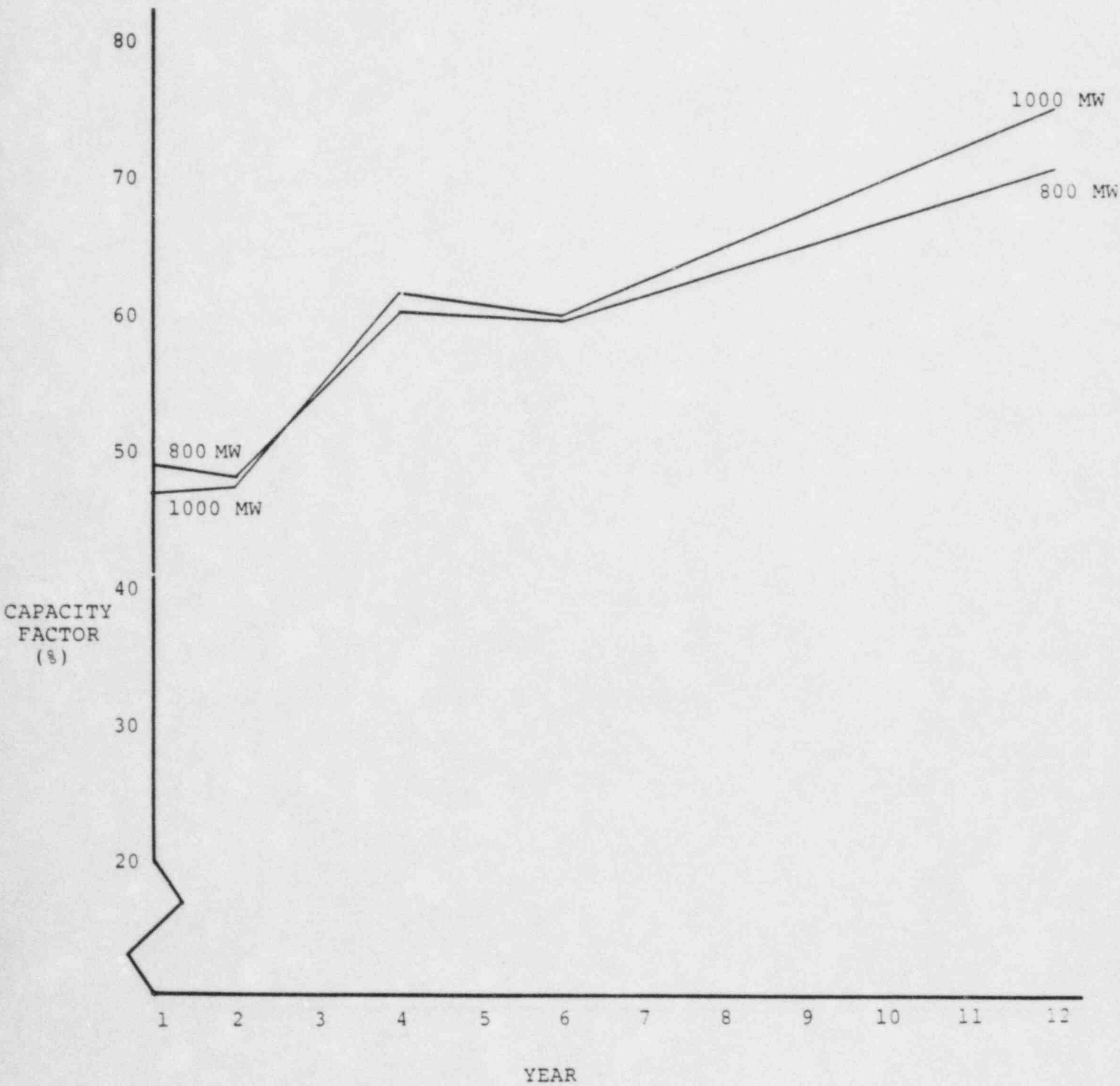


Figure B.2

PROJECTED CAPACITY FACTORS FOR GENERIC PLANTS

BWR: SALT WATER COOLED

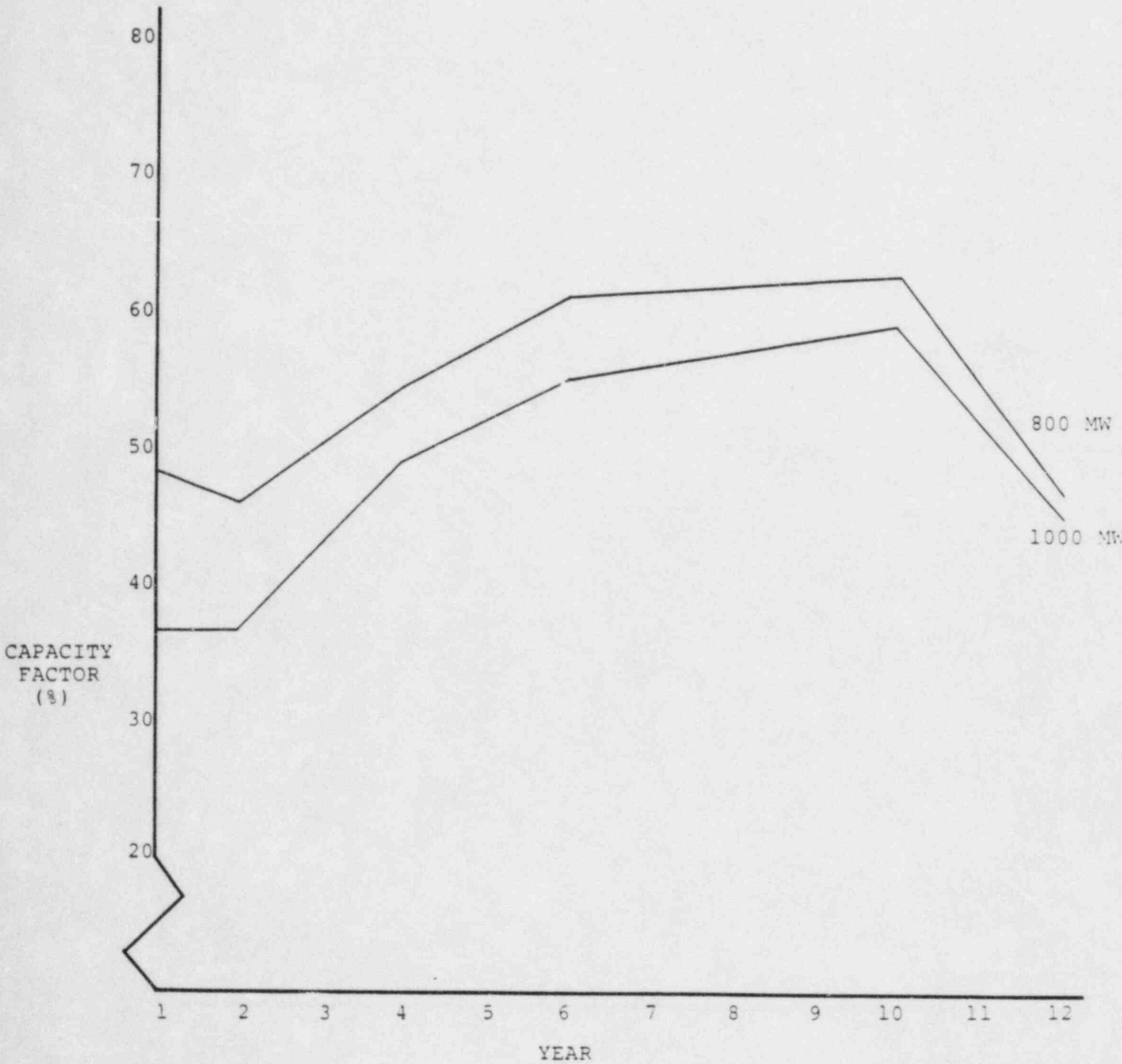


Figure B.3

PROJECTED CAPACITY FACTORS FOR GENERIC PLANTS

PWR: FRESH WATER COOLED

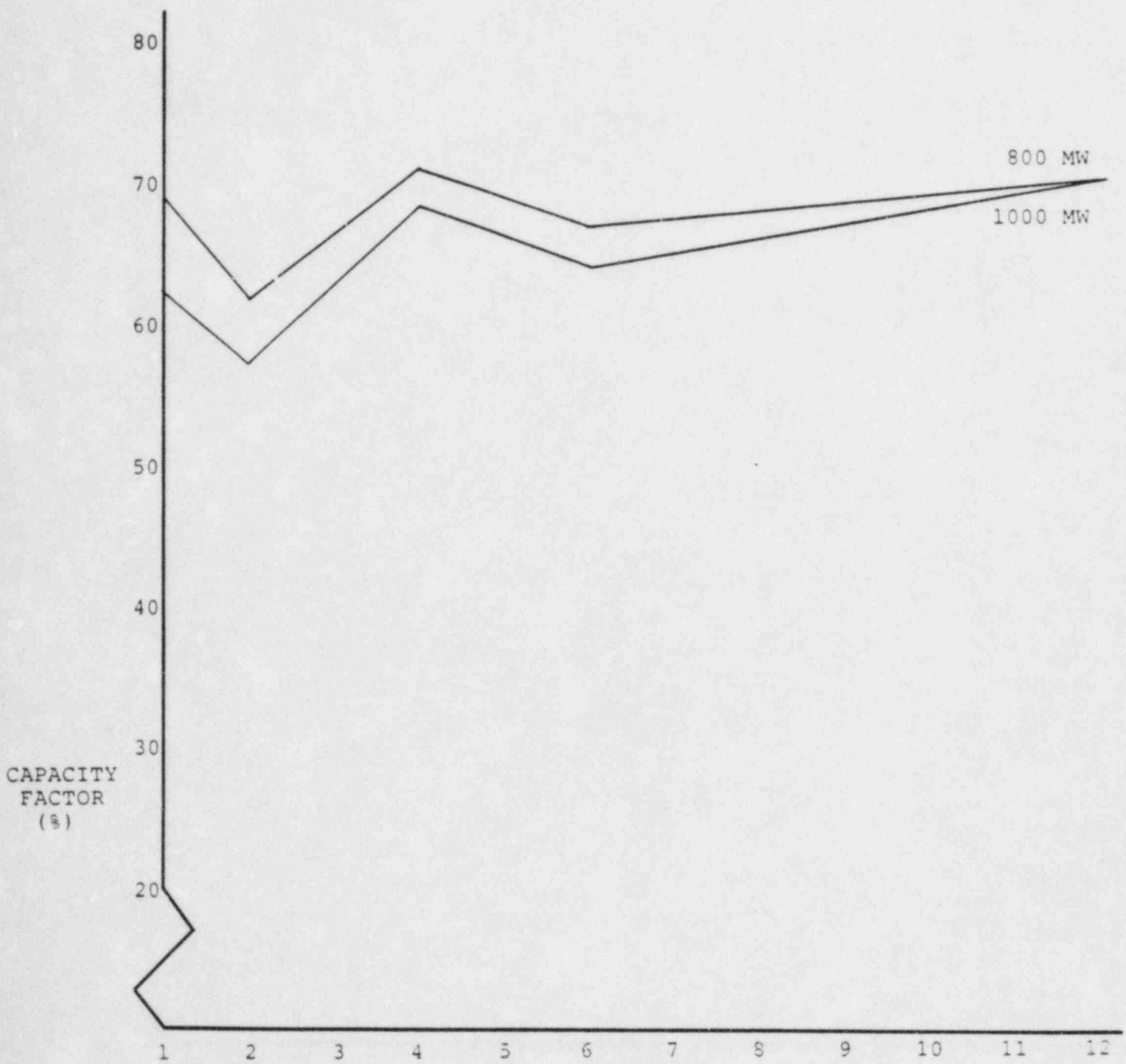
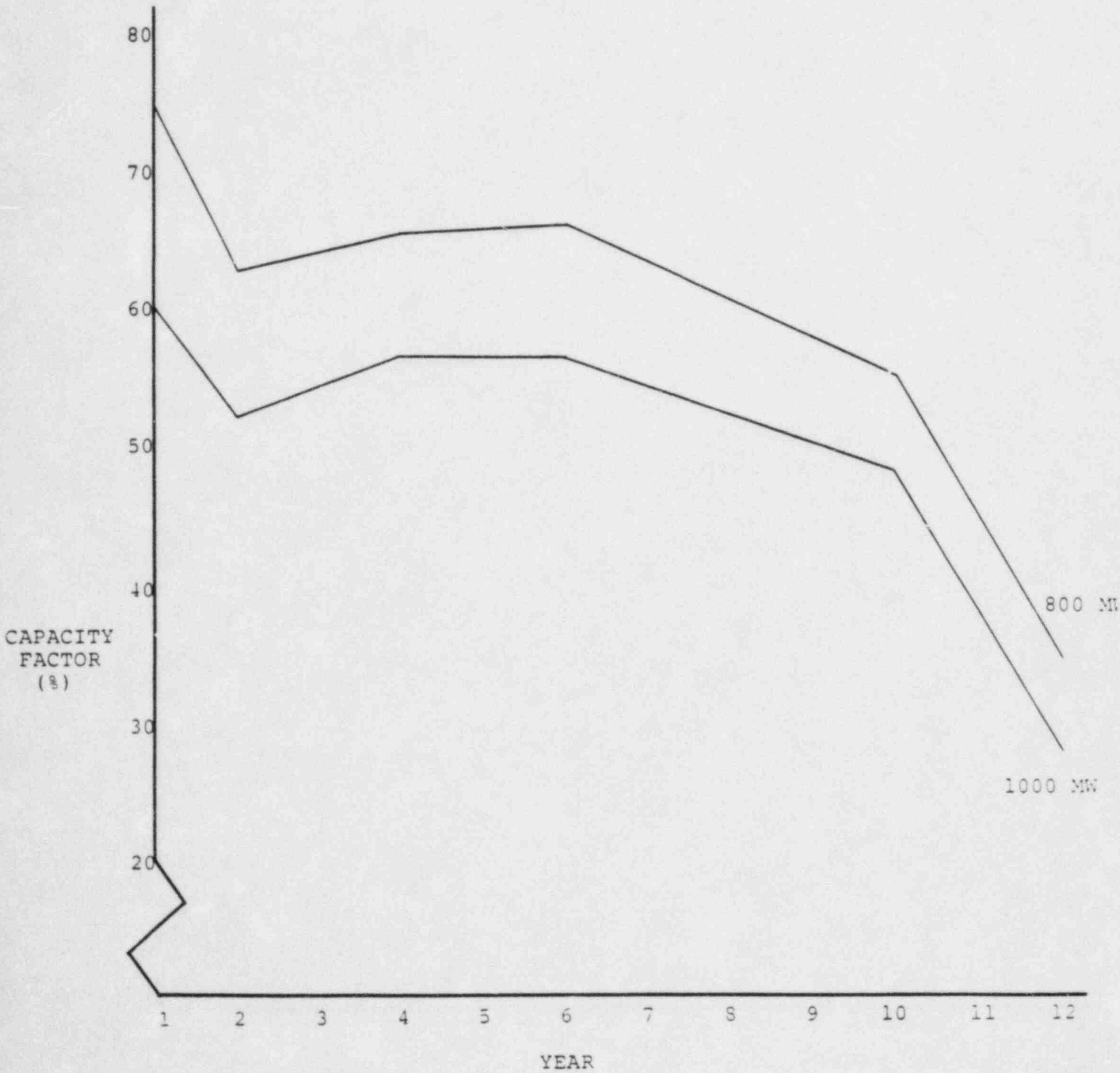


Figure B.4

PROJECTED CAPACITY FACTORS FOR GENERIC PLANTS

PWR: SALT WATER COOLED



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B.1. Monthly Energy Review, DOE/EIA (83/04), April, 1983, p. 76.

B.2 Licensed Operating Reactors: Status Summary Report (NUREG-0020), Nuclear Regulatory Commission, Office of Resource Management.

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 82-352-E

In the matter of:)) Application of Piedmont Municipal Power Agency for Authority to Acquire a Portion of the Catawba Nuclear Station)	Certificate of Service

I, Michael F. Lowe, do hereby certify that I have this 21st day of June 1983 served copies of the attached "Testimony of Richard A. Rosen" on the below named persons by hand-selivering same to the addresses set forth below.

Robert T. Bockman
Eighteenth Floor
Bankers Trust Tower
Columbia, South Carolina

James H. Still
Executive Director
South Carolina Public Service Commission
111 Doctors Circle
Columbia, South Carolina

Michael F. Lowe
Palmetto Alliance, Inc.