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THE STATE OF TEXAS

BEFORE THE PUBLIC UTILITIES COMMISSION

RE: The Economic Viability of Unit 2 of the South Texas Electric Generating Station	DOCKET No. 6184

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF

THE COMMITTEE FOR CONSUMER RATE RELIEF

August 12, 1987

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TESTIMONY OF PAUL CHERNICK

1 INTRODUCTION AND QUALIFICATIONS

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

A: My name is Paul L. Chernick. I am President of PLC, Incorporated, 10 Post Office Square, Suite 950, Boston, Massachusetts.

1.1 Qualifications

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

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

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

At Analysis & Inference and in my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

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

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

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

A: Yes. I testified on inter-class cost allocations in Docket 3298, regarding Gulf States Utilities.

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

A: Yes. I have authored several papers and reports in those areas. These publications are listed in my resume.

1.2 The Purpose and Structure of this Testimony

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

A: It is my understanding that this case was docketed to evaluate the economic viability of STNP 2. During Phase 1 of the case, a financial model was developed for the purpose of this evaluation. My testimony will estimate future costs of STNP and alternatives for use in the financial model.

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

A: The last portion of this first Section provides a brief summary of the history of STNP 2, as a background for the discussion of events and decision points in the remainder of the testimony.

Section 2 provides the derivation of my estimates of the likely operating costs and capacity factor for STNP 2, which are the inputs to the financial model. Section 3 presents my estimates of likely costs and in-service dates for STNP2. Finally, Section 4 dicusses the potential of conservation in the service territories of the STNP2 owners.

The Appendices to this testimony provide more detailed explanations of various topics considered in the text. Appendix A is my resume, as referenced in the discussion of my qualifications, Section 1.1.

1.3 A Short History of STNP 2

Q: Please describe Unit 2 of the South Texas Nuclear Project.

A: The South Texas Nuclear Project is located in Palacios, Texas. The project is managed and operated by Houston Lighting and Power, but ownership is divided among four participants, of which HL&P currently owns 30.8%.[1] The project includes two units, each a Westinghouse Pressurized Water Reactor (PWR), with a Westinghouse turbine and a rated capacity of 1250 megawatts. Thus, HL&P's share of STNP 2 is 385 MW. Bechtel is the architect-engineer for the project, and Ebasco is the constructor. Both roles were held by Brown & Root prior to February 1982.

The owners' projections of cost and operating parameters will be attributed to HL&P throughout this testimony, although some of the projections may originate with Bechtel or Touche Ross, a consultant to the utilities in this proceeding.

The utilities currently project that STNP 1 will enter commercial operation in December 1987,[2] at a direct cost

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1. The other participants are Central Power and Light (25.2%), the City of Austin (16%), and the City of San Antonio (28%).

2. This target is quite optimistic, since STNP 1 does not yet have a low power operating license, or even a license to load fuel. As shown in Section 3, nuclear plants typically require

(excluding AFUDC) of $3.55 billion, and that STNP 2 will reach commercial operation in June 1989, at a direct cost of $1.427 billion.[3] Including AFUDC (at HL&P rates), the estimated costs are $5.138 billion for Unit 1 and $2.146 billion for STNP2.

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a year or so to reach commercial operation following receipt of their first operating license.

3. STEGS Capital Cost Data, 6/26/87.

2 OPERATING COST INPUTS

Q: What operating parameters have you examined for STNP2?

A: I have attempted to determine realistic estimates for the capacity factor of STNP2 and for the various costs of running the unit, including non-fuel O&M and capital additions. I have also reviewed HL&P projections for decommissioning costs and for the useful life of STNP2. Based upon analyses of historical performance and trends:

1. While HL&P projects a constant "nominal" capacity factor of 65% for STNP2, the capacity factors (based on design rating) will more likely average about 53% in the first five years, 56% in the mature years, and 52% after 12 years.

2. Non-fuel O&M has been escalating much faster than general inflation, at about 12-14% in real terms, while HL&P is projecting essentially no real increases. This trend has persisted for many years and may well continue. Including operating expenses which are accounted for separately from the station operating expenses, STNP2 O&M might reasonably be expected to start at about $95 million annually (about 34% higher than HL&P's estimate), doubling in real terms by early in the next century, and more than doubling again by the year 2020.

3. If historical rates of additions apply to STNP2, the capital cost of the plant will also increase significantly during its lifetime. HL&P's projection that capital costs will increase by $13.1 million annually in 1990 dollars should be increased by about 50%.

4. Decommissioning also must be expected to cost more than HL&P currently estimates.

5. HL&P appears to assume that STNP2 will operate for 35 years. This projection is not supported by experience to date.

Detailed analyses of these cost components are presented below, including comparisons of my estimates to those of HL&P.

2.1 Capacity Factor

2.1.1 Measuring and Comparing Capacity Factors

Q: How can the annual kilowatt-hours output of electricity from each kilowatt of STNP2 capacity be estimated?

A: The average output of a nuclear plant is less than its capacity for several reasons, including refueling, other scheduled outages, unscheduled outages, and power reductions. Predictions of annual output are generally based on estimates of capacity factors. Since the capacity factor projections used by HL&P are rather optimistic, it may be helpful to consider the role of capacity factors in determining the cost of STNP2 power, before estimating those factors.[4]

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

$$CF = \text{Output}/(RC \times \text{hours})$$

where CF = capacity factor, and

RC = rated capacity.

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4. This portion of my testimony will also discuss some common errors in utility treatment of nuclear capacity factors, and some of the justifications which utilities have offered in previous proceedings for projecting capacity factors which exceed historical experience.

In this case, it is necessary to estimate STNP2's capacity factor, so that annual output, and hence cost per kWh, can be estimated.

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

The difference between capacity factor and availability factor is illustrated in Figure 2.1. The capacity factor is the ratio of the shaded area in regions A and B to the area of the rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the un shaded portion of region B, and all of region C, which are not included in the capacity factor.

Capacity factors are also often compared with equivalent availability factors (EAFs). EAF is a subjective measure, reported by the operating utility and representing only the utility's opinion of what the unit might have done, if not for factors which the utility may wish to consider to be "economic". These "economic" factors include, for example, reductions in output to delay a refueling outage until other nuclear units have completed maintenance or repair procedures. Furthermore, the calculation of EAF assumes that the unit would have run perfectly if not for the "economic" limitation. Utilities frequently assume that new units will have capacity factor similar to historical EAFs, rather than historical CFs. Under the best of conditions, EAF is a performance measure of limited usefulness, due to its subjective nature.

Even if EAF were not such a flawed measure, there is little reason to believe that historical EAFs would provide as accurate predictors of STNP2 CF than would historical CFs. While utility terminology often suggests that EAFs differ from CFs only because of "load following" and "load leveling", essentially all nuclear units in the US are base-loaded, and the difference between EAF and CF is rarely due to load following, *per se*.

Table 2.1 compares the EAFs to the CFs of 10 Westinghouse reactors in areas of large amounts of oil and gas generation: the Northeast, Florida, and California. The differences between EAF and CF are sizable for these nuclear units, despite baseload operation. It is clear from Table 2.1 that EAFs are useless for predicting CFs for nuclear plants.

Q: What is the appropriate measure of "rated capacity" for determining historical capacity factors to be used in forecasting STNP2 power costs?

A: The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

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

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

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

Humboldt Bay has been retired after fourteen years, and Dresden 1 after 18 years, without getting their MDCs up to their DERs. Connecticut Yankee has not done it in 16 years; nor Big Rock Point in 19 years; nor many other units which have operated for more than a decade, including Dresden units 2 and 3, and Oyster Creek. For only about one nuclear plant in five does MDC equal DER, and in only one case (Pilgrim) does the MDC exceed the DER. Therefore, capacity factors based on MDC will generally continue to be greater than those based on DERs, throughout the unit's life.

The use of MDC capacity factors in forecasting STNP2 power cost would present no problem if the MDCs for STNP2 were known for each year of its life. Unfortunately, these capacities will not be known until STNP2 actually operates and its various problems and limitations appear. All that is known now is an initial estimate of the DER, which is 1250 MW.[5] Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and MGN capacity factors are useful for planning purposes. I use DER capacity factors in my analysis.

Actually, DER designations have also changed for some plants. The new, and often lower, DERs will produce different observed capacity factors than the original DERs. For example, Komanoff (1978) reports that Pilgrim's original DER was 670 MW, equal to its current MDC, not the 655 MW value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1250 MW expectation for STNP2. This problem can also be avoided through the use of the MGN ratings, although MGN ratings tend to be nominal, with limited relation to actual capability.

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5. HL&P may also have published an estimate of the MGN capacity of the unit, but I have not seen it. In general, MGN ratings average about 4% higher than DER ratings, so I will assume a 1300 MW MGN for STNP2.

2.1.2 Projecting STNP2 Capacity Factors

Q: Is HL&P's projection of STNP2 capacity factors appropriate for use in cost-benefit analyses?

A: No. Achievement of the capacity factor HL&P has projected is highly unlikely, if not completely inconceivable. HL&P assumes that STNP2 will exceed previous performance for similar reactors.

Q: How have you determined the expected capacity factor performance of STNP2?

A: I have conducted a series of regression analyses of actual PWR capacity factors, and they are fully explained in Appendix E. The data are listed in Appendix B, and the results of my regressions are given in Table 2.2. Projections for STNP2 performance, based on those results, are presented in Table 2.3. As shown in Table 2.2, I incorporated the following variables:

1. an indicator for units of more than 600 MW,
2. unit age, with maturation assumed at 5 years,
3. an indicator of unit age greater than or equal to 12 years,

4. the portion of a refueling or other major outage which occurred in the year, usually taking the values of 0 or 1,

5. an indicator for the period 1979-1983, and

6. indicators for large Westinghouse turbines and Combustion Engineering reactors.

Data were available for 447 full calendar years of operation at all PWRs from 1973 to 1985. A small amount of pre-1973 operating experience could not be used for lack of refueling data. Equation 1 is based on all available data, while Equation 2 excludes data from Palisades and San Onofre 1 (leaving 421 unit-years).

Equation 1 presents results which project a low PWR performance, by analyzing the historic experience of all PWRs. Equation 2 presents alternative results by excluding San Onofre 1 and Palisades and analyzing some different variables. San Onofre 1 had particularly bad experience after its twelfth year in operation, so once it is removed from the database, the aging problem is not as evident. Furthermore, Palisades is the only plant with a Combustion Engineering reactor and outstandingly low reliability: when Palisades is removed from the database, Combustion Engineering units demonstrate higher capacity factors than other PWRs. Finally, the capacity factor of plants with Westinghouse 44" turbines is not significantly less than other plants once those two plants are removed.

Both equations demonstrate that PWR performance from 1979 to 1983 was lower (by about 7%) than the pre-1979 period. In both regressions,

- large PWRs had capacity factors 11-15 points lower than small (400-600) units,
- maturation increased capacity factors by about two points annually until age five, and
- refueling decreased capacity factor by about 10%.

Table 2.3 provides the projections of Equations 1 and 2 for STNP2, under two sets of assumptions: first, that it operates at the levels demonstrated in the pre-1979 period (and 1984-85), and second, that it operates only as well as the average of PWR performance in the 1979-83 period.[6] Depending on the period used as a basis for extrapolation, the mature capacity factor before age 12 ranges from 53% to 60%. The "old age" capacity factor, after year 12, ranges from 45% to 60%. These are average results derived from the regression analysis of the historical record. There is a great deal of variation from the average, however; the regressions typically explain less than a third of the variation in the data, and Easterling (1979) derived 95% prediction intervals of about 8% for years 2 to 10 at 1100 MW

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6. For simplicity, I have treated STNP2 as if it will enter service on 1/1/90. This is more pessimistic than HL&P's projection, and more optimistic than historical experience would suggest.

PWRs. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.[7]

Predicting the future effects of regulation, of safety issues, and of aging is difficult at best. Projecting STNP2 performance based on the variables used in my equations raises such difficult questions as:

- Does a plant's performance really stabilize after year five, and then begin deteriorating after age 12, as represented by AGE5 and AGE_12? What will be the long-term deterioration in capacity factor after age 12?

- Did 1984 mark a recovery from the deterioration in performance seen during the previous five years, will performance continue at average 1980s levels, or will it settle at some intermediate level?

For the purposes of this analysis, I have assumed that long-run PWR performance will fall between pre-1979 and 1979-83 levels.

Thus, I have based my projections on an average of the results of Equations 1 and 2, evaluated at pre-1979 and then 1979-83 conditions. Since the AGE_12 variable is excluded from Equation 2, I have implicitly included only half of the observed aging effect for older units. I have also assumed

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7. On the other hand, some of the apparent variation would tend to average out for any individual unit.

that STNP2 will refuel in every year except the first.[8] Thus, I believe the best current estimates for STNP2 are 56%, 48%, 51%, 53% and 55% in years one to five, respectively (averaging 53%), an average of 56% in years six to eleven, and an average of 52% thereafter. This calculation is shown in Column [5] of Table 2.3.

Q: Are HL&P's projections for STNP2 capacity factor reasonable?

A: No. To compare the accuracy of the capacity factors I derived above, and HL&P's projections, to actual results, I have performed the calculations presented in Table 2.4. For the ten PWRs over 1000 MW which had entered service by 1983, the average capacity factor as of September 1986 was 55.1%. The capacity factor estimates which I derived in Table 2.3 predict an average of 54.5%, while HL&P would predict an average of 64.7% for the "nominal" case and 71.2% for the "target" case.[9] Clearly, HL&P's expectations are highly optimistic.

The actual ten-unit average will vary with refueling schedules, and has much less data than I used in my regressions. The actual data strongly supports the conclusion that HL&P's projections significantly overstate the capacity factors of large PWRs. On the other hand, my

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8. HL&P assumes that STNP2 will refuel in every year, including its first.

9. It is not at all clear what HL&P actually predicts for STNP2 performance.

results closely approximate actual capacity factors for similar plants.

Q: Have you performed any analyses on the data from these large PWRs, on an annual basis?

A: Yes. Table 2.5 presents the annual capacity factors for the units used in the previous analysis, through December 1984. No other large (over 1000 MW) PWRs had completed a full year of commercial operation as of the end of 1985. I have assumed that the very low capacity factors for Trojan, and for Salem 1 and Salem 2 in their second operating years are not generated by the same sort of random process which accounts for the other variation in nuclear capacity factor.[10] However, there is no reason to believe that some comparable (if not exactly identical) problem can not occur for STNP2. Hence, I delete these three observations from the individual year calculations, and instead reflect the probability of a major problem by computing the average effect. Compared to the results for all the other plants, these events reduced capacity factors by a total of 127.6 percentage points from average second year performance, in 70 unit-years of experience, for a 1.8% reduction in all capacity factors. The average capacity factor which results from this analysis is about 56.5% for the first four years, with a mature capacity factor (from year five) of 55.6%.

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10. This calculation recognizes that some of the other units do not have Westinghouse turbines, which caused the problems at Salem. STNP does use Westinghouse turbines.

This analysis also indicates that HL&P's projections for STNP2 capacity factor are much higher than the actual performance of large PWRs, even without adjusting for the turbine-related differences.[11]

Q: Is it appropriate to include the period since 1979, when the TMI accident and subsequent regulatory actions affected nuclear plant operation, in the analysis of nuclear capacity factors?

A: I believe that it is. Several more major nuclear accidents or near-misses are likely to occur before the scheduled end of STNP2 operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Minarick and Kukielka, 1982). These estimates are based both on the implicit probability assessments of nuclear insurers, who must actually bet their own money on being correct, and on engineering models of actual reactor performance. Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-85 period has been relatively favorable for nuclear operations.

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11. Through the first 11 months of 1986, the 10 units in Table 2.5 averaged a 50.7% capacity factor. The six younger 1000+ MW Westinghouse units which had completed their first fuel cycle (LaSalle 1&2, Catawba 1, McGuire 2, Callaway, and WPPSS2) averaged 50.2%, even though Catawba and Callaway have GE turbines. Thus, 1986 was not shaping up as a good year for nuclear plants comparable to STNP.

2.2 Non-Fuel Station O&M

Q: How have you estimated non-fuel O&M expense for STNP2?

A: I have examined the available historical data on nuclear O&M for domestic nuclear plants. Appendix D lists the non-fuel O&M for each U.S. nuclear plant for each full operating year from 1968 to the most recent available data. Plants were excluded from the analysis for years in which new nuclear units were added, so each observation represents a full year's O&M for a clearly defined number of units and of megawatts.

Table 2.6 presents the results of three regressions on all of the data in Appendix D for light water reactors, a total of 535 observations. Table 2.7 presents the results of the same three regressions using only the data for plants of more than 300 MW, from Appendix D. All costs are stated in 1983 dollars, deflated at the GNP deflator. A total of 457 observations were available for Table 2.7.

The equations in Table 2.6 indicate that real O&M costs for all plants have increased at about 12% annually, and that the economies-of-scale factor for nuclear O&M is about 0.50, so doubling the size of a plant (in Equation 1) or of a unit (in Equations 2 and 3) increases the O&M cost by about 44%. Equation 1 indicates that, once total plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant. Equations 2 and 3 both measure size as MW per unit, and they both find that the effect of adding a second identical unit is about the same as the effect of doubling the size of the first unit: 44% for Equation 2 and 40% for Equation 3. Equation 3 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 2. Indeed, there is a highly significant differential: Northeast plants cost 32% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). I will use this Equation 3 as the basis of my projection.

The results with the data set which excludes the smaller plants (Table 2.7) are quite similar: the most important difference is that the annual growth rate in large plant O&M is significantly higher than that of the overall data set. This effect would produce much larger O&M projections, if it were extrapolated out into the next century. O&M also rises faster as a function of plant size in Table 2.3. There is no clear basis for choosing between the two data sets.

Q: What O&M projections would your regression results predict for STNP2?

A: Table 2.8 extrapolates the results for Equation 3 for plants of one and two units, each of 1300 MW MGN,[12] and displays the annual nominal O&M cost implied for STNP2 over the period 1990 - 2024, which is HL&P's projection of the unit's useful life. Results are shown for both datasets. The same Table presents alternative projections from the historical data, assuming that the annual O&M expense increases linearly in real terms, at the real increment projected by Equation 3 between 1990 and 1991. Finally, Table 2.8 compares these results with HL&P's current projections: the "Tentative Assumptions" from July 1986 were a bit higher.

Q: Are HL&P's O&M projections reasonable?

A: Based on the historical data, HL&P's projections for STNP2 O&M are reasonable in the first year or two.[13] Since HL&P assumes that the persistent real escalation in nuclear O&M will abruptly drop to about 1% annually, even the most favorable projection I present (linear escalation, based on all plants) is twice HL&P's projection by the turn of the century, and over four times as large by 2024. Thus, HL&P's long-term projection of STNP2 station O&M costs is inconsistent with historical experience, and is extremely optimistic.

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12. In general, MGN ratings average about 4% greater than DER ratings.

13. HL&P's O&M projections are not reasonable if they are intended to include non-station expenses, as discussed below.

Protracted geometric growth in real O&M cost at historical rates would probably lead to retirement of this plant (and most nuclear plants) fairly early in the century, as it would then be prohibitively expensive to operate (unless the alternatives were even more expensive than HL&P predicts). High costs of O&M and necessary capital additions were responsible for the retirement (formal or de facto) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Yankee Rowe remain from that cohort.

On the other hand, our experience with nuclear O&M escalation stretches over only 17 years (1968-1984), so projecting continued constant real escalation past the year 2000 (another 16 years into the future) is rather speculative. It is more likely that the actual outcome will fall somewhere around the moderate real growth implied by my linear projections.

2.3 Capital Additions

Q: Is HL&P's estimate of capital additions to STNP2 reasonable?

A: Not currently. The Touche-Ross Tentative Assumptions (July 1986) projected annual capital additions (or interim replacements) of $23 million in 1990 dollars, which is fairly representative of historical patterns. The "STPEGS Capital Cost Data" projections of HL&P (6/26/87) lists much more optimistic additions of just $13.1 million in 1990 dollars, starting in 1991, with somewhat lower additions in earlier years. These lower levels are not supported by experience to date.

Q: How did you estimate capital additions?

A: Appendix D lists annual capital additions for all plants for which cost data was available, from FERC Form 1 and DOE compilations of FERC Form 1 data (now reported on p. 403), through 1984. Each plant is included for all years in which no units were added or deleted, and for which the data were not clearly in error. The available experience totaled 520 plant-years of operation, and the average annual capital addition in the database was $20.7/kW expressed in MGN terms, or about $26.9 million annually for STNP2 in 1983 dollars.[14] The capital additions are deflated at the appropriate regional Handy-Whitman index for nuclear construction, which has itself increased at 1.4% above the GNP inflation rate.[15] The July 1984 Handy-Whitman index was estimated by escalating the July 1983 index at the growth rate of the January index from 1983 to 1984.

Capital additions vary with a number of factors, and vary greatly from year to year, complicating statistical analyses. Review of the data indicates that:

- large plants have lower capital additions per kilowatt-year than do small plants,
- multi-unit plants have lower capital additions per kilowatt-year than do single-unit plants,
- Northeastern plants have higher capital additions than those in other parts of the country, and
- capital additions per kilowatt-year have generally been rising over time, despite the greater prevalence of large and multi-unit plants in the later data.

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14. The STNP2 capacity used in these calculations was 1300 MW, 4% higher than the unit's DER, representing my estimate of the MGN rating.

15. From 1970 to 1983, the GNP deflator rose from 91.45 to 215.63, for an annual rate of 6.8%. In the same period, the July Handy-Whitman nuclear index for Region 1 rose from 81 to 227, an annual increase of 8.2%.

Figure 2.2 and Table 2.9 show the average capital additions for each year since 1972, for all plants, and for large single units. Levels of capital additions for both groups have increased over time, at least since the mid-1970's.[16] Over the last seven years, the average for all plants was \$27.7/kW-yr: over the last five years, the average has been \$32.3/kW-yr. The rate of capital additions may have stabilized in the 1980's, or it may be increasing at about \$4/kW-yr/yr. If capital additions continue at \$32.3/kW-yr in 1983 Handy-Whitman dollars, and if the nuclear Handy-Whitman index continues to run 1.4 points above the GNP deflation (for which I use the Touche-Ross projections of 5.25% from 1990 on, and assume 4% until 1990), the annual capital additions for STNP2 would be as shown in Column 2 of Table 2.11; Column 1 of that table shows HL&P's projections of capital additions.

Some of the recent trend in the data may result from plant aging, and another portion is undoubtedly related to TMI-inspired regulatory changes, so extrapolating the trend out is somewhat speculative. Thus, I have used a recent average, rather than continuing the increases. However, there is some evidence of an overall upward trend in the period 1972-78, as well, so any TMI-related effect constitutes a continuation of the historical conditions, rather than a unique event.

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16. The data for large single units in the early 1970's is from a very small sample.

Q: Did you perform a regression analysis on capital additions data?

A: Yes. Appendix F contains a detailed description of the regression analysis and an interpretation of the results, which are summarized in Table 2.10. The significance of the resulting regression equations is better than I had expected, and yields reasonable projections, also shown in Table 2.11.

Q: What are your recommendations with regard to projections of STNP2 capital additions?

A: I believe that it is prudent to assume that capital additions at STNP2 will continue at recent levels, starting at $19.24 million in 1990 and rising at 6.65% thereafter.

In comparison, HL&P assumes annual capital additions of $13.1 million in 1990 dollars, rising at 5.25%. HL&P also assumes slightly lower additions in 1990.

2.4 The Cost of Decommissioning

Q: What is meant by "decommissioning"?

A: The decommissioning of a retired nuclear power plant involves the transition of the plant from a nuclear facility, subject to attendant health and safety regulations, to a non-nuclear facility, posing no radiation-related risks to human health or to the general environment. Current NRC policy envisions the use of any of three approaches to decommissioning:

1. DECON: The prompt decontamination and dismantlement of the plant.

2. SAFSTOR: The mothballing of the plant under continuing surveillance, until decontamination and dismantlement.

3. ENTOMB: The enclosure of all radioactive portions of the plant within a secure entombment structure, until decontamination and dismantlement.

Of these three approaches, only DECON is considered to be a permanent solution to isolation of the plant's accumulated radiation burden from the environment. It is generally assumed that plants will be dismantled promptly upon retirement.

Q: **What is the basis of HL&P's estimate of the cost of decommissioning STNP 2?**

A: HL&P apparently relies on a conventional engineering estimate of the cost of decommissioning through the prompt dismantling (DECON) method. The source of the estimate is not yet clear.

Q: **What is HL&P's estimate of the cost of decommissioning STNP 2?**

A: The cost estimate is $168,115,000 for the entire unit, stated in 1990 dollars. I derived this value by adding the Touche-Ross assumptions (from July 11, 1986) for the four participants.

Q: **Are these values consistent with other recent estimates for nuclear decommissioning costs?**

A: The STNP 2 assumptions appear to be considerably lower than recent estimates for other units. Table 2.12 lists the decommissioning costs estimated for other nuclear units by TLG Engineering personnel.[17] The values are shown as reported by TLG, and restated in 1990 dollars, assuming inflation at GNP levels to 1986, and 4% thereafter. The STNP 2 estimates are about 39% less than other recent (1985/86) estimates, which range from $206 to $315 million per unit in 1990 dollars, for units over 1000 MW.

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17. These estimates were prepared for the various utilities. I have not been able to obtain similar data from and other decommissioning cost consultant to the utility industry.

Q: How much experience is available in the prompt dismantling (DECON) process for nuclear power plant decommissioning?

A: There is very little direct experience. The only nuclear power plant to have been dismantled was Elk River, which was decommissioned in 1974.[18] As can be seen in Table 2.12, estimated DECON costs have doubled in real terms since 1975: the Elk River experience is clearly out of date.

As significant as the lack of experience is the apparent reluctance of utilities to undertake the DECON process. Table 2.13 lists retired nuclear power plants, with their dates of operation. Some of the units have been placed in a "safe storage" mode, but dismantlement has not started at any of them.[19]

Q: Does a delay in decommissioning, following retirement, allow the size of the decommissioning fund to grow?

A: The fund would tend to grow, due to the accumulation of investment income. However, the cost of the original

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18. Portions of the technology have been demonstrated in various capital additions, such as the replacement of steam generators.

19. Perhaps the best example of this reluctance is the Department of Energy's decision to float the reactor pressure vessel of the retired Shippingport unit on a barge, down the Ohio and Mississippi Rivers; through the Gulf of Mexico, the Caribbean and the Panama Canal; along the Pacific Coast to the Columbia River; and finally up the Columbia to DOE's Hanford Reservation. The vessel will then be buried intact. This procedure would not be undertaken for commercial-scale units, whose pressure vessels will be disassembled on site.

decommissioning tasks would also increase, due to inflation. In addition, the decommissioning fund would be reduced by the cost of the preparations for the delay, such as sealing structures, securing equipment, and cleaning and drying surfaces which should not deteriorate during the delay, and by the continuing maintenance and surveillance expenses. These costs would reduce the level of the fund during the delay, and so would reduce the rate at which the investment income would accumulate. It is not clear whether a significant delay in decommissioning would result in the fund rising faster than the decommissioning expense.

A delay in initiating DECON would tend to make the decommissioning process more nearly resemble SAFSTOR or ENTOMB, which are generally estimated to be more expensive (even in constant dollars) than DECON.

Q: **Do you consider the current STNP 2 decommissioning cost estimates to be reliable?**

A: No. It is clear from Table 2.12 that estimated costs of nuclear decommissioning have been increasing rapidly. Table 2.14 displays the results of a regression analysis on the data from Table 2.12: the coefficient of the YEAR variable indicates that TLG cost estimates have been increasing at the rate of $e^{0.174}$ annually, or a compound growth rate of 19% in real terms.[20] The data from Table 2.12 and the regression

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20. All of the coefficients are highly statistically significant, except for the TWIN coefficient.

results from Table 2.14 (using average values for the set of plants estimated in each year) are graphed in Figure 2.3. The pattern of increases in the estimated cost of decommissioning raises considerable question about the validity of the current estimates.

Of course, the current estimates could represent the final set of increases in decommissioning cost estimates, and actual decommissioning costs could turn out to be similar to those estimates.[21] However, experience with other nuclear power costs suggests that the industry is characterized more by persistent cost growth than by cost stability. Virtually all nuclear cost components have been increasing for most of the history of the commercial nuclear power industry:

- The estimated and actual costs of constructing nuclear power plants have been increasing consistently since the late 1960s. Typically, cost estimates for completed plants have increased about 10% annually in real terms (excluding inflation due to schedule slippage) from the issuance of the construction permit to commercial operation.

- Nuclear non-fuel operating and maintenance costs have been increasing (and exceeding expectations) since the early 1970s. Through 1984, the average annual rate of increase was approximately 12-14%.

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21. In any case, the STNP 2 decommissioning estimate is quite low for a contemporary estimate.

- Capital additions to nuclear power plants in commercial operation, generally ignored in cost projections into the early 1980s, were significant cost elements in the 1970s: since the Three Mile Island accident capital additions have increased dramatically.

These patterns of cost increases are documented elsewhere in this testimony.

The pattern of increases in decommissioning cost estimates, combined with the persistent increases in projected and actual costs for those nuclear cost components with which we have greater experience, strongly suggests that decommissioning costs will exceed current estimates.

Q: **What is the relationship between the pattern of cost increases in other nuclear cost components, and the increases in cost estimates for decommissioning?**

A: Decommissioning cost estimates have increased for reasons similar to those which have produced large and persistent increases in other nuclear cost components. The earlier estimates have been determined to have underestimated the complexity (and hence the cost) of such problems as disposal of radioactive wastes, and the supervision of workers in radioactive areas. In general, the problems with estimates of other nuclear cost components can be attributed to similar underestimation of the problems inherent in operations as complex as nuclear power production, and the failure to anticipate the costs of complying with nuclear safety regulations.

Q: **How do the current cost estimates for decommissioning compare to the costs you projected in your report to the NRC?**

A: In that report (Chernick, et al., 1981), I projected costs of $250 million per unit for an 1150 MW unit in 1981 dollars. In the 1990 dollars we have been using in this testimony, that would be about $360 million, inflating at the GNP non-residential building deflator for 1981-86 and assuming 4% annual inflation from 1986 to 1990. These projections were based on increasing the standard industry projections of about $50 million[22] by a factor of 5, based on the pattern of cost overruns experienced in the nuclear construction industry. The industry cost estimates have nearly caught up to my estimates in only five years: at the past rate of increase, the TLG estimates will reach my 1981 estimates around 1988.

Q: **What decommissioning cost would you suggest the Commission use in estimating the cost of power from STNP 2?**

A: Table 2.15 displays the increase in costs which would result if the growth rates in Table 2.12 continued, with either

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22. The primary bases were the estimates by Battelle Pacific Northwest Laboratories from 1978-80.

linear or compound growth after 1986. If the TLG decommissioning cost estimate trends (based on data spanning 8 years) continue for just another 8 years, the cost estimate will rise another 150% to 300%.

Overall, I would suggest that the Commission base its decommissioning cost estimate for STNP 2 on the assumption that the cost will exceed current estimates by at least 150% in constant dollars.[23] Thus, the review of STNP 2 should assume a final cost for decommissioning of at least $600 million in 1990 dollars.

Q: **Should the same value be used for to establish the level of contributions to the decommissioning funds for STNP 1, for the owners who are regulated by the PUCT?**

A: I believe that would be reasonable, but it is not necessary. Decommissioning funding can start with a smaller, more optimistic figure. If future developments indicate that the final costs are likely to be different than that initial target, accumulation of the decommissioning fund can be accelerated or delayed, to aim for a larger or smaller final fund balance. Given experience to date, it is likely that an increase in funding would be required, if the inital target is much lower than the $600 million level.

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23. In selecting this relatively modest increase (by past standards), I have taken into account the inclusion in most estimates of a 25% contingency.

While many decisions regarding the STNP 1 decommissioning fund can be delayed for several years, decisions must be made today regarding the fate of STNP 2. For that purpose, I would recommend that the Commission assume a moderate continuation of the historical experience in decommissioning cost estimation.

2.5 The Useful Life of STNP 2

Q: How long does HL&P expect each STNP 2 unit to be in commercial operation?

A: The projected life of each unit is 35 years.

Q: Is this a reasonable projection for the purpose of designing a nuclear decommissioning fund?

A: No, for two reasons. First, there has been very little experience with the longevity of nuclear power plants, and second, what little experience is available suggests that the useful lives of nuclear units may be much shorter than 39 years.

Q: What experience is available regarding the longevity of nuclear power plants?

A: The five small plants which entered commercial service in the early 1960's would be 20-26 years old today, if all had survived.[24] Of this cohort, Indian Point 1, Humboldt Bay, and Dresden 1 have been retired (formally or de facto), after

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24. This group excludes the exotic demonstration reactors, some of which used liquid metal coolant, organic moderation, and other technologies very different than the light water reactors which have prevailed in US nuclear power plant design. I have also excluded some very small demonstration reactors which operated for only a few years.

only 12, 13, and 18 years of operation, respectively. Only Big Rock Point and Yankee Rowe remain from that cohort. Even the older and larger of the survivors, Yankee Rowe, has been in service only since 1961, and is thus only 26.[25] LaCrosse, a 50MW unit which entered service in November 1969, was retired in April 1987, after 17.5 years of operation.

The first units of more than 300 MW went commercial in January 1968: they have just reached age 19. The only clear retirement among this group is Three Mile Island 2, which operated for only a few months prior to its accident. Various nuclear units which are currently on protracted shutdowns due to safety and design problems (such as Pilgrim) may never reopen, but such units may be shut down for an extended period before it becomes clear that they have reached the end of their useful lives.

To summarize, HL&P is projecting that STNP 2 will survive twice as long as has the oldest domestic unit over 300 MW, and 50% longer than the oldest domestic commercial power reactor of any size. Basing cost-benefit on this projection would be unwise.

Q: **How do the design differences between STNP 2 and older units affect the likely useful lives of STNP 2?**

A: There is simply no way to know. The measures taken at STNP 2 to correct safety, maintenance, and reliability problems at

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25. It is also only a 175 MW unit.

other plants may be successful, and may result in STNP 2 operating longer than will older nuclear power plants. Alternatively, the added equipment at STNP 2 may result in additional problems, rendering STNP 2 uneconomic to operate at an earlier age than the retirement ages of the older units. Also, it is important to remember that STNP 2 is starting life at a time when nuclea*r O&M expenses are already quite high: if historic trends continue, STNP 2 will become uneconomic at about the same date as older units, and thus at a much earlier age.

Q: **Given the limited experience and uncertainties, what do the data suggest about the useful life of nuclear power plants?**

A: In the decommissioning insurance study (NUREG/CR-2370), I found that the available data suggested a median useful life of approximately 20 years. Michael B. Meyer (1986), one of my co-authors on NUREG/CR-2370, updated the analysis of the operating life of nuclear power plants contained in the NRC report.[26] Depending on the data set utilized, the median useful life of nuclear power plants would appear to be 20 to 35 years. Unfortunately, the data, no matter how defined, are quite sparse.

Q: **Are the same forces which resulted in the early retirement of older units still in operation?**

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26. This analysis does not include the LaCrosse retirement.

A: Yes. High costs of O&M and necessary capital additions, mostly driven by regulatory considerations, were responsible for the retirement of most of the small pre-1965 reactors during the 1970s and of LaCrosse. O&M expenses have continued to grow much faster than inflation, and capital additions have been much higher in the 1980s than in the 1970s.

Large nuclear power units, such as the STNP units, show considerable economies of scale in O&M. Multiple unit sites, such as STNP 2, also show strong economies of duplication: two nuclear units can be operated for less (and require less additions) than twice the cost of one unit. Thus, STNP 2 will be less vulnerable to the operating cost economics than were the small (and often single) units built in the 1960s. Nevertheless, protracted growth in real O&M costs at historical rates, especially combined with the continuation of recent rates of capital additions, could prompt retirement of STNP 2 (and most nuclear plants) fairly early in the next century, as it would then be prohibitively expensive to operate.

Q: **What useful life would you recommend the Commission use for STNP 2 in this proceeding?**

A: While all parties certainly hope that STNP 2 (if it is* completed and enters commercial operation), and other nuclear units, remain economical and in operation for 35 years or more, we must accept the very real possibility that they will not survive for more than 25 or 30 years. I would therefore recommend that the Commission evaluate the economics of STNP 2 based on no more than 30 years of operation. Given the historical trends in nuclear plant operating costs, 25 years would be a more prudent assumption.

Q: Should the depreciation rates for the STNP units be based on 25 year expected lives?

A: That would be reasonable from a technical viewpoint, but it is not necessary. Given the large rate increases likely to be associated with placing the units in ratebase, the Commission may initially prefer to use a longer expected life, producing lower depreciation rates. Depreciation rates can be increased later in the units' lives, if continued experience supports my projections. This approach would accomplish some of the goals of a phase-in of STNP costs, without formally deferring recovery.

2.6 Overheads

Q: **Are all of the expenses associated with operating a nuclear power plant recorded as plant O&M costs in the FERC form?**

A: No. Some of the costs related to owning and operating a nuclear power plant are recorded in other accounts. This is true for such costs as legal and regulatory expenses, insurance, payroll taxes, and employee benefits. Collectively, these expenses may be considered overhead costs.

Q: **How did you estimate these overheads?**

A: Table 2.16 displays the overhead expenses for Yankee Atomic, Connecticut Yankee, Vermont Yankee, and Maine Yankee during 1984 and 1985. The Yankee companies were chosen for this analysis because they have no other utility plant or operations besides the nuclear power plants. For other utilities, it would be very difficult to determine the portion of overheads attributable to the nuclear plant.

Line 7 of Table 2.16 shows the overhead expenses for each Yankee plant expressed as a percentage of total station non-fuel O&M. The percentages vary from 11.9% for Connecticut Yankee in 1984 to 57.6% for Maine Yankee in 1984. The average overhead expense for the four plants in this period was 27%. Thus, it is appropriate to add 27% to the STNP2 station O&M projection to reflect overheads. Table 2.17 shows the most optimistic O&M projection from historical results in Table 2.8 (column 13), grossed up for overheads.

3 STNP 2 CONSTRUCTION COST AND SCHEDULE

Q: **Are the current cost and schedule estimates for STNP 2 likely to be achieved?**

A: No. Nuclear cost and schedule estimates, including those prepared by Bechtel, have been notoriously unreliable and over-optimistic. In addition, the period allowed for the startup of STNP 2 (from fuel load to commercial operation) is much shorter than would be indicated by historical experience.

Q: **Please describe the historical reliability of nuclear power plant cost and schedule estimates.**

A: Appendix C summarizes the data available regarding the cost and schedule histories of the nuclear power plants which had entered commercial service by 1984. I have excluded from the cost analysis the turnkey plants, for which the manufacturers provided at least partial cost caps, and the reactors for which the federal government provided cost sharing. In addition, I have no detailed cost estimate data for either San Onofre 1 or Connecticut Yankee, and at the time this analysis was prepared, I had no information on the final cost of a few units which went commercial in 1984. For each available estimate, Appendix C lists the actual commercial operation date (COD), the actual construction cost, the date of the cost estimate and the estimated cost and COD for that estimate. The cost and schedule history data in Appendix C shows all of the changes in cost or schedule indicated in cost estimate history summaries provided by the Energy Information Administration (EIA). Those summaries are condensations of the Quarterly Construction Progress Reports (Form HQ-254 and Form EIA-254) filed by most nuclear utilities with the Atomic Energy Commission (AEC), and later with its successor agencies, the Energy Research and Development Administration (ERDA) and EIA. Where important data was missing from the HQ-254's, data from various published sources was used.[27] Final cost information is generally from reports to the FPC and the FERC, and the commercial operation date (COD) information is from NRC figures.

Q: **How have you summarized the reliability of these estimates?**

A: To quantify the extent of the errors in cost and schedule estimation, I have computed six statistics for each estimate:

- the projected years to COD (or "duration") at the time of the estimate,

- the ratio of final cost to the projected cost at the time of the estimate, in nominal terms (the "nominal cost ratio"),

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27. These sources included the AEC/ERDA annual **Nuclear Industry**, the **Nuclear News** World List of Nuclear Power Plants, and occasionally data from the utilities.

- the cost ratio expressed as a growth rate, annualized by the estimated time to completion, in nominal terms (the "nominal myopia factor"),

- the ratio of the initial cost estimate to the final cost, with the latter restated in the dollars of the initial COD estimate, to remove schedule-related inflation and AFUDC,

- the real cost ratio annualized by the actual duration,

- and the ratio of the actual remaining time until commercial operation to the projected time (the "duration ratio").

These terms are all fairly self-explanatory, except for myopia. The myopia factor is a measure of the widespread shortsightedness demonstrated by the nuclear industry in estimating construction costs. As the commercial operation dates for nuclear plants are pushed further into the future, utilities have more severely underestimated the cost of their construction. I have measured this effect with the following formula:

$$(\text{cost ratio})^{(1/\text{estimated duration})}$$

Table 3.1 summarizes the average values of each of these statistics, disaggregated by the estimated duration at the time of the cost estimate. For the 3-4 year estimated duration interval corresponding to the November 1985 estimate of a June 1989 in-service date for STNP 2 (an estimated duration of 3.58 years), the average myopia indicates that the actual cost of these units was typically 27% greater than the estimate, for each year that construction was expected to take. The average nominal cost ratio demonstrates that the average plant cost 2.39 times as much to complete as initially estimated, while the duration ratio indicates that the plants took almost twice (1.97 times) as long as was projected. In real terms, the average cost ratio was 1.84, and the average myopia was 18%.

Q: **What are the implications of these results for STNP 2?**

A: Unless there is some concrete reason to believe that the nuclear industry's ability to forecast costs has improved, it would be appropriate to apply the results of Table 3.1 to the most recent cost and schedule estimates of STNP 2 to produce revised or corrected estimates. Applying the historical experience to STNP 2 yields the following results:

- If the duration ratio for STNP 2 is 1.97, it would require 7.06 years to be completed, from November 1985, or until December 1992.

- If the nominal myopia factor is 27%, the final cost will be 2.35 times the November 1985 forecast, or $5.0 billion.

- If the nominal cost ratio is 2.39, the final cost will be 2.39 times the November 1985 forecast, $5.1 billion.

- If the real myopia factor is 18%, the final cost will be 1.81 times the November 1985 estimate, plus inflation during the schedule slippage. For inflation at 5.25%, 3.58 years of slippage would increase the cost 20.1%, bringing the total cost to 2.17 times the 11/85 estimate, or $4.7 billion.

- If the real cost ratio is 1.84, and the schedule slippage adds another 20.1% to the cost, the total cost would be 2.21 times the 11/85 estimate, or $4.7 billion.

Q: **These results are based on data through 1984. How do you expect that they would change if they were updated?**

A: The results for plants completed between 1984 and the present would probably be worse than the earlier data: the cost overruns would be higher and the schedule slippages would be greater. In general, the relatively trouble-free units were completed and placed in service early, with much smaller schedule slippages and cost overruns than were experienced by the units of the same vintage which entered service more recently, or are still under construction. For example, the 1984-87 data would include such problem plants as Diablo Canyon, Grand Gulf, and River Bend. Future data bases will include Shoreham, Seabrook, Watts Bar, and Nine Mile Point 2, assuming that all these units finally go commercial. None of these analyses would ever include the worst disasters of nuclear construction, the cancelled units such as WPPSS 4 and 5, Zimmer, Midland, and Marble Hill.

Q: **Does the fact that STNP 2 is a second unit offer any hope that its cost and schedule performance will be better than average?**

A: Yes, to some extent. Second units which significantly trail the first unit at a plant have often (but not always) encountered lower schedule slippage and lower cost escalation after the in-service date of the first unit. Therefore, it is reasonable to hope that the cost and schedule for STNP 2 will increase significantly near the commercial operation date (COD) of STNP 1 (an event which may occur late this year or early next year), and then increase relatively little in the remaining years of construction. If STNP 1 actually enters service in December 1987, as scheduled, and a new (and more reliable) estimate for STNP 2 appears at that time, 2.08 years of the 11/85 schedule would be subject to the higher slippage rates expected prior to the STNP 1 COD, and the remaining 1.5 years would be subject to whatever favorable effects the completion of STNP 1 would imply. If the slippage after STNP 1 COD is only 20% of the average,[28] the total slippage in STNP 2 cost and schedule might be expected to be about as much as would occur over 2.38 years (or about 66% of the estimated duration for STNP 2 at the time of the

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28. Note that the averages presented in Table 3.1 include the more favorable results of the lagging second units in the database.

11/85 estimate) for a unit without any trailing-unit advantages.

Applying the historical schedule overrun of 97% for 2.38 years worth of exposure produces 2.31 years (28 months) of slippage, bringing the expected STNP 2 COD to March of 1991. If the real cost overrun is equivalent to 2.38 years of myopia at 18%, the cost would increase 48%, plus delay-related inflation of 12.5%, for a total increase of 67%, to $3.6 billion.

Q: **One important consideration in determining the cost of completing STNP 2 is the federal income tax treatment of the unit, which depends on its in-service date. Based on historical experience, what is the likelihood that STNP 2 can be in service prior to December 1990?**

A: The chances are not very good. Table 3.2 displays all of the estimates in the 3-4 year duration range from Appendix C, sorted in order of the schedule overruns. Figure 3.1 shows the breakdown of overruns by interval, and Figure 3.2 shows the cumulative distribution of the overruns.

If the duration ratio for the 11/85 STNP 2 estimate exceeds 44%, the in-service date would slide past the end of 1990, and the favorable tax treatment under the transition rules of the Tax Reform Act of 1986 would be lost. In the historical data, 78.6% of the estimates showed slippage of more than 44%. Even if the slippage at STNP 2 is one third less than historical results, so that the critical figure for comparison is a 66% schedule overrun, 58.3% of the historical data shows duration ratios in excess of that figure.[29]

Q: **Have the STNP cost and schedule estimates been more stable than the industry average since the first estimate by Bechtel in August 1982?**

A: Yes. In that period, the direct cost estimate has remained constant, aided by the decline in inflation rates, and by the reduction of contingency. The STNP 1 schedule has slipped only six months,[30] and the STNP 2 schedule has not been changed. Total cost estimates for the plant would presumably be somewhat higher, due to the additional AFUDC on STNP 1. If the slippage remains at these low levels, STNP 2 would enter service prior to the December 1990 deadline, and at a cost closer to HL&P's estimate than to mine.

Q: **Do the relative levels of the estimated costs for STNP 1 and STNP 2 shed any light on the reliability of the STNP 2 cost estimate?**

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29. This analysis double-counts the advantages of trailing second units. The 58.3% figure is the fraction of estimates which showed schedule overruns of more than 66%, on the assumption that the status of STNP 2 as a trailing second unit will allow it to do a third better, and thus have only a 44% overrun if conditions were otherwise comparable to units without the trailing-second unit advantage. However, the data set for Table 3.2 includes trailing second units, such as TMI 2 and Hatch 2, and several of the estimates which fall under the 66% cut-off are for these trailing units.

30. Given the absence of an operating license in August 1987, four months prior to the scheduled commercial operation date, further slippage is very likely.

A: Yes. The cost estimate for STNP 2 is extremely low relative to that for STNP 1. Table 3.3 lists the relative direct costs (or cost estimates) for all the multiple units for which the TVA reports separate values, along with the temporal spacing between units. STNP 2 is projected to cost only 42% of the cost of STNP 1. This ratio is tied for lowest with Peach Bottom, where both units entered service in the same year. The next lowest value is 66%, and the average for units with 1-2 years separating is 91%. This fact certainly raises greater questions about the reliability of the STNP 2 cost estimate.

Q: **Have your myopia techniques been employed successfully in previous situations?**

A: Yes. In January 1980, PSNH estimated that Seabrook 1 and 2 would cost a total of $2.8 billion. A previous version of my myopia analysis predicted a cost of $5.9-11.5 billion. The last A/E estimate for the twin plant (prior to cancellation of Unit 2 in 1984) was for $10.1 billion. My numerous other predictions for Seabrook have also generally been borne out. For example, in 1984, PSNH predicted a COD of 8/86 for Unit 1, while I predicted 11/88. PSNH has now acknowledged that the plant is unlikely to be in operation by 7/88.

Myopia analysis was also the basis for my projecting in 1979 that the cost of Pilgrim 2 (then estimated by Boston Edison at $1.895 billion) would rise to $3.8-4.9 billion. In

September 1981, Edison announced a cost estimate of $4 billion, and cancelled the unit.

In October 1982, Commonwealth Edison predicted that the Braidwood plant would cost $2.74 billion. I predicted a cost of $4.78 to $5.45 billion, plus delay-related inflation. The final results are not yet in, since the two units are scheduled for operation later this year and in 9/88, but the utility estimate now stands at $5.05 billion, with a 21 month delay.

Myopia has also allowed me to produce (after the fact, but only using data available at the time) corrected versions of previous estimates for several nuclear plants, which were more accurate than the utilities' estimates at the time. On the other hand, these techniques did not anticipate the stability in the cost and schedule estimates for Millstone 3 (a unit at which construction was intentionally slowed down for a few years), after 1982.

Q: **Please expand on your previous statement that the period allowed for the start-up of STNP 2 (from fuel load to commercial operation) is much shorter than would be indicated by historical experience.**

A: Table 3.4 lists the startup intervals for all units in commercial operation which received their operating licenses since the beginning of 1978.[31] The shortest start-up period, 4 months, was that of St. Lucie 2, generally regarded as one of the great success stories of post-TMI nuclear construction. The intervals for the other units range up to 43 months, with a 34-plant average of 13 months.

Table 3.5 lists the dates of operating license issuance for units which are still in start-up. Perry, Fermi, and Shoreham will certainly increase the average start-up interval when they enter service.[32] All 6 units in Table 3.5 already have start-up periods in excess of six months.

Q: **What is HL&P's projection of the STNP 2 start-up interval?**

A: HL&P is currently projecting a start-up period of six months for each STNP unit, from fuel load to COD. Fuel load generally occurs immediately following the issuance of an operating license. This projection is considerably more optimistic than would be suggested by the historical experience. Only two of the units in Table 3.4 have beaten this projection, and five have tied it, out of the 34 units. If HL&P's projection of the fuel load date were correct, but

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31. Some utilities have reported different COD's for ratemaking and for other purposes. Whenever possible, I use the COD reported to the NRC.

32. Nine Mile Point 2 is scheduled for commercial operation in "early 88" according to the 8/3/87 Central Hudson quarterly report: if this estimate is correct, startup of Nine Mile Point 2 will require 15 months, further raising the average.

start-up required the 13 month average from Table 3.4, STNP 2 would go commercial in January 1990.

Q: **Why have nuclear cost and schedule estimates been subject to such persistent and significant overruns?**

A: Recent acknowledgements by the utilities themselves explain why the estimates have been incorrect. Many nuclear cost estimates were never intended to be predictions of the final cost of the plant: they were budget targets and cost-control documents. In the rapidly changing environment of nuclear construction, utilities and architect/engineers (A/Es) chose not to incorporate best estimates of the effects of evolving regulations. This issue is discussed at some length in Meyer (1984). Employees of Management Analysis Corporation (MAC), in testimony filed by Central Maine Power and Maine Public Service in their 1984 rate cases, summarize this practice with respect to Seabrook:

> PSNH established schedules that required superior effort. This strategy is generally appropriate because it demands the best possible performance from contractors. (Dittmar and Ward, 1984, page 25)

The MAC analysis further considered the tradeoffs between conservative and optimistic estimates, and explained the construction management advantages of intentionally optimistic estimates:

> If a budget is based on an overly conservative (high) estimate which establishes easily attained goals, a project's cost is likely to rise to fulfill the prediction. The use of aggressive targets is a management approach which, when reasonably applied, provides incentive for improving performance. If unrealistic cost or

> schedule targets are maintained too long, a project can be affected adversely. In such situations, it is difficult to hold people accountable for goals that they know are unrealistic. Morale problems may occur which could reduce productivity, cause delays or increase cost. A more serious consequence of managing to unrealistically aggressive targets may occur if activities are improperly sequenced such that work cannot be accomplished efficiently because of artificially induced constraints. (Ibid, page IV-6)

Southern California Edison, lead participant in the San Onofre plant, has reported that it actually kept two sets of cost estimates during much of the construction of San Onofre 2 and 3. One set was used for discussions with contractors and for other public purposes, while a higher set of estimates was used for top-level management purposes. The higher set included estimates of "possible future growth," because

> In late 1974, Edison project management recognized that due to the constantly changing nuclear industry regulatory and economic environment, in addition to the exposures due to specifically identifiable causes, the project costs would likely be impacted by many other unknowns. (Perla, et al., 1985)

In January 1975, when San Onofre 2 and 3 were scheduled to be complete in 5.5 and 6.75 years, respectively, SCE included "possible future growth" of about 50% of the total budget, in addition to conventional contingencies of about 8% in the public budget.

United Illuminating, a participant in both the Seabrook and Millstone 3 projects, has also acknowledged this practice, as demonstrated by the testimony of its President and other officials before the Connecticut Public Utilities Control Authority, filed 8/1/84:

> The project management estimate, used by the project manager to control construction of the facility, should be established as a challenging but achievable goal. Depending upon the degree of challenge desired, the project management estimate should have a probability of 10% to 30% of not being exceeded . . . [T]he project management estimate serves the need to maintain tight project controls . . .

Unfortunately, much less than 10% of nuclear cost estimates have been achieved, so the cost control function seems to have been overdone. It also appears that nuclear cost estimates routinely exclude effects of future, pending, and newly effective regulations which have not yet been reflected in the plant drawings, and of the other complications of building a nuclear plant.

Similar objectives and approaches have been apparent in the cost estimation procedures of other plants I have reviewed, including Midland, Marble Hill, and the WPPSS units.

It is important to remember that, throughout the period that utilities and A/Es were intentionally understating their estimates of the costs and construction schedules of nuclear units, they were describing those estimates to regulators, investors, and even other utilities as reliable, achievable predictions. It was common to see extensive discussions of why a new estimate was more reliable than previous estimates, and why the new estimate could be (and would be) achieved.[33] Therefore, assertions by HL&P and Bechtel that <u>this</u> estimate is correct should not be given particularly great weight.

Q: **How do the cost overruns you have estimated translate to annual construction costs?**

A: Results comparable to a 67% increase in total costs, with the commercial operation date delayed to early 1991, can be derived through any of a number of changes in the cash flows. Table 3.6 provides one such cash flow, based on scaling up HL&P's costs to the entire unit.

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33. By definition, each estimate occurs when design and construction are further advanced, and when more experience with nuclear construction is available. Nonetheless, there is no learning curve evident in the cost estimate histories of most units (normalized for projected time to completion), or of the industry as a whole.

4 POTENTIAL FOR CONSERVATION

Q: What was your basis for estimaing the potential for conservation of electricity in the service territories of the STNP owners?

A: I started with detailed estimates of the conservation potential for the Austin Electric Utility Department, as derived by a consultant to the Department. The report of the consultant, Rocky Mountain Institute (Lovins 1986), or RMI, provides the following estimated savings by customer class for technically and economically feasible improvements in electric energy use efficiency in existing facilities:

residential: 79%
commercial: 73%
large power: 51%
miscellaneous: 25%

Peak savings would be about the same, with commercial savings somewhat higher (due to the large savings available in cooling and in lighting, which is a major contributor to peak cooling loads) and residential savings somewhat lower. Savings in new construction were conservatively assumed to be the same as in existing buildings, except that a 90% reduction in energy usage was found to be feasible in new residential construction. A further 3% improvement in transmission and distribution efficiency was estimated.

These savings were very inexpensive, averaging less than one cent/kWh in 1986 dollars. They were also six times the size of the projected savings from Austin's existing conservation programs. Additional savings may become available as further technologies mature, and/or at higher prices.

Q: **How have you extrapolated the Austin results to the other STNP particiapants?**

A: Table 4.1 gives a disaggregation of the 1985 retail sales of the four participants into rate classes roughly comparable to those used in the Austin study. Table 4.2 shows the savings which would be achieved if each of the utilities experienced the same percentage savings by class as was estimated for Austin.

The Large Power class in Austin is primarily composed of electronics plants, which have different load characteristics than heavy process industries, such as oil refineries and chemicals. The Austin industrials have more of the loads typical of commercial customers, such as lighting and space conditioning, and less of the process drives (large electric motors) typical of industrial customers. Therefore, the Austin industrial conservation potential estimate is included as a "high" case, and an estimate by the same consultant (Lovins 1985) for a pulp-and-paper plant is included as a "low" case.[34]

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34. The percentage of savings given for the low case is the middle of the range presented in the conclusions to Lovins (1985). The range of savings estimates (17% to 36%) results largely from the mill's lack of detailed knowledge of the condition (or even the number) of motors in the plant.

Table 4.2 computes the total savings potential in each customer class for each utility, and then adds up the savings by class, by utility, and overall. Line 4 shows the ratio of the potential savings in 1985 to actual sales, and line 5 computes the number of years of growth at 4% which could be offset by savings of the estimated magnitude. Depending on the utility and the industrial savings fraction assumed, 18 to 33 years of load growth could be displaced by conservation.

Q: **Why did you compare the savings to load growth at 4%?**

A: I do not have load forecasts for the individual utilities. Overall, the ERCOT utilities project that their energy loads will to grow at 4% annually over the next decade.[35]

Q: **Is it reasonable to extrapolate Austin's conservation potential to the other STNP owners?**

A: It is quite reasonable. Each utility will have a different mix of conservation opportunities, depending on details of the building stock, end uses, and so on, but the total potential savings by class should not vary dramatically. For the class with the greatest heterogeneity, the industrials, I have included a range of estimates. In many cases, the values used in the Austin study would be conservative, either for such interior locations as Austin and San Antonio, or for the humid coastal cities served by CP&L and HL&P. Some of the values used by RMI were averages of Austin and coastal conditions,

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35. See NERC 1986.

while others were estimated directly for Austin and would show larger conservation potential in more humid conditions. There are obvious uncertainites in the extrapolations, but many of the variations tend to balance out (for example, evaporative cooling works better in Austin, but dehumidification saves more in cooling costs in Houston). The greatest uncertainties lie in categories of savings not included in RMI study, such as site-specific opportunities (such as shading, or industrial process changes) and in the development of new conservation technologies; therefore, the total conservation potential is likely to be higher than indicated in Table 4.2, rather than lower.

Of course, the estimates from the Austin study are not as useful to the other utilities in terms of conservation program design, and Table 4.2 is not a real substitute for detailed analysis of conservation potential by each utility. The Commission should be very wary of supporting any utility's power supply construction projects until the utility has completed an efficiency potential study equivalent in scope to the RMI study.

Q: Does this conclude your initial direct testimony?

A: Yes.

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TABLES AND FIGURES

TABLE 2.1: COMPARISON OF EQUIVALENT AVAILABILITY FACTORS TO CAPACITY FACTORS

	Calendar Year	1	2	3	4	5	6	7	8	9	10	11	12	13
San Onofre 1	EAF	33.8	69.3	81.0	87.5	74.6	60.3	83.5	86.2	69.0	62.1	78.4	89.1	21.6
	CF	33.8	69.3	81.0	87.5	74.6	60.3	83.5	86.2	65.6	62.1	71.2	89.1	21.6
	EAF-CF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	0.0	7.2	0.0	0.0
Connecticut Yankee	EAF	73.8	84.5	70.4	84.1	85.4	48.2	86.4	82.3	79.8	79.8	93.5	81.8	70.6
	CF	73.8	76.1	70.2	83.1	85.1	48.2	86.4	81.9	79.8	79.7	93.5	81.8	70.6
	EAF-CF	0.0	8.4	0.2	1.0	0.3	0.0	0.0	0.4	0.0	0.1	0.0	0.0	0.0
Ginna	EAF	64.9	82.0	56.0	59.5	66.9	56.5	64.9	66.6	69.1	81.5	72.6	60.8	66.0
	CF	64.9	82.0	55.9	59.5	66.9	56.5	64.9	66.6	68.7	80.9	72.6	60.7	66.0
	EAF-CF	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.4	0.6	0.0	0.1	0.0
Turkey Point 3	EAF	57.2	59.7	72.0	71.1	73.8	74.2	47.5	72.2	15.4	62.1			
	CF	54.5	59.7	72.0	71.0	73.7	74.2	47.5	72.2	15.4	62.1			
	EAF-CF	2.7	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0			
Turkey Point 4	EAF	64.7	62.8	72.3	53.7	70.4	65.2	74.7	73.0	71.5	9.2			
	CF	64.7	62.8	72.3	53.7	67.2	58.0	74.7	73.0	71.5	9.2			
	EAF-CF	0.0	0.0	0.0	0.0	3.2	7.2	0.0	0.0	0.0	0.0			
Indian Point 2	EAF	63.8	51.6	43.4	53.9	79.9	52.9	30.4	76.3	34.5				
	CF	63.8	51.6	43.4	53.9	79.8	52.9	30.4	76.3	31.2				
	EAF-CF	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	3.3				
Indian Point 3	EAF	75.7	47.1	88.8	30.1	35.9	26.4	0.0						
	CF	75.7	46.9	84.0	29.6	35.9	26.5	0.0						
	EAF-CF	0.0	0.2	4.8	0.5	0.0	-0.1	0.0						
Beaver Valley 1	EAF	50.2	29.9	26.8	11.9	57.7	44.1							
	CF	50.2	29.8	14.8	11.9	54.8	43.4							
	EAF-CF	0.0	0.1	12.0	0.0	2.9	0.7							
Salem 1	EAF	39.1	52.0	42.5	47.8	57.8	52.8							
	CF	39.1	51.7	42.5	43.4	54.8	52.8							
	EAF-CF	0.0	0.3	0.0	4.4	3.0	0.0							
Salem 2	EAF	82.1	74.1											
	CF	82.1	70.5											
	EAF-CF	0.0	3.6											

Source: Electric Power Research Institute, Nuclear Unit Operating Experience: 1980-1982 Update; April 1984, Appendix F (EPRI NP-3480)

TABLE 2.2: PWR CAPACITY FACTOR REGRESSIONS

	Equation 1		Equation 2	
	Coef	t-stat	Coef	t-stat
CONSTANT	73.19%	0.2	72.82%	24.5
MW600 [1]	-11.41%	-5.0	-14.72%	-8.0
AGE5 [2]	2.31%	3.8	2.31%	4.2
AGE_12 [3]	-10.89%	-3.2	--	--
OUT [4]	-10.01%	-5.2	-9.55%	-5.2
W44 [5]	-3.59%	-1.9	--	--
YR79_83[7]	-7.16%	-4.2	-7.03%	-4.4
CE [8]	--	--	7.43%	3.7
ADJUSTED R-SQ		0.176		0.228
F STATISTIC		16.9		25.8
OBSERVATIONS [8]		447		421

Notes: [1] MW600 = 1, if Design Electrical Rating (DER) > 600 MW; 0 otherwise.
[2] AGE5 = minimum of AGE (years from COD to middle of current year), and 5.
[3] AGE_12 = 1, if AGE >= 12; 0 otherwise.
[4] OUT = number of refuelings in year, including other single outages lasting more than 3 months (OUT usually equals 0 or 1).
[5] W44 = 1, if unit contains Westinghouse 44" turbine; 0 otherwise.
[6] Indicator = 1 in this year; 0 otherwise.
[7] YR79-83 = 1, if between 1978 and 1984; 0 otherwise.
[8] CE=1, if Combustion Engineering is the NSSS; 0 otherwise.
[9] Full calender years of PWR operation, 1973-85.

TABLE 2.3: PWR CAPACITY FACTOR PROJECTIONS FOR STNP2

YEAR	Value of REFUEL	Value of AGE5	Value of AGE_12	Equation 1: Pre-1979 Conds.	Equation 1: Avg. 1979-84 Conds.	Equation 2: Pre-1979 Conds.	Equation 2: Avg. 1979-84 Conds.	Average of four cases
				[1]	[2]	[3]	[4]	[5]
1990	0	0.5	0	59.35%	52.19%	59.25%	52.23%	55.75%
1991	1	1.5	0	51.65%	44.49%	52.02%	44.99%	48.28%
1992	1	2.5	0	53.96%	46.80%	54.33%	47.30%	50.59%
1993	1	3.5	0	56.27%	49.11%	56.63%	49.60%	52.90%
1994	1	4.5	0	58.58%	51.42%	58.94%	51.92%	55.21%
1995-2001	1	5	0	59.73%	52.57%	60.10%	53.07%	56.37%
2002-2024 [6]	1	5	1	48.84%	41.68%	60.10%	53.07%	50.92%
Average 1990-2024				52.03%	44.87%	59.55%	52.52%	

General note:

All coefficients are from equations in Table 6.2. Calculated for a 1250 MW unit with a Westinghouse turbine, and a COD of 12/31/89.

Column notes:

[1],[3] Assumes pre-1979 conditions exist in the projection years; therefore, all YR79_83 variable is set equal to 0.

[2],[4] Adjusts the projected capacity factor by the coefficient of the YR79_83 variable.

TABLE 2.4: COMPARISON OF CAPACITY FACTOR PREDICTIONS

Capacity Factor Predictions	Calendar Years of Experience							
	1 -[1]-	2	3	4	5	6	7-11	12 +
PLC [2]	55.8%	48.3%	50.6%	52.9%	55.2%	56.4%	56.4%	51.8%
HL&P Nominal [3]	58.7%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
HL&P Target [3]	70.5%	70.5%	70.5%	70.5%	71.6%	71.6%	71.6%	71.6%

As of: 30-Nov-86

	COD		Unit Years of Experience in each Calendar Year								Actual [4]	HL&P Nominal	HL&P Target	PLC [5]
											Predicted Capacity Factors			
Salem 1	30-Jun	77	0.51	1.00	1.00	1.00	1.00	1.00	3.93		52.6%	64.7%	71.2%	54.4%
Zion 1	31-Dec	73	0.00	1.00	1.00	1.00	1.00	1.00	5.00	2.94	56.6%	65.0%	71.3%	53.9%
Zion 2	17-Sep	74	0.29	1.00	1.00	1.00	1.00	1.00	5.00	1.92	60.3%	64.9%	71.3%	54.1%
Cook 1	27-Aug	75	0.35	1.00	1.00	1.00	1.00	1.00	5.00	0.93	59.3%	64.8%	71.3%	56.1%
Cook 2	01-Jul	78	0.50	1.00	1.00	1.00	1.00	1.00	2.92		60.0%	64.6%	71.1%	55.9%
Trojan	20-May	76	0.62	1.00	1.00	1.00	1.00	1.00	4.93		53.5%	64.6%	71.2%	56.4%
Sequoyah 1	01-Jul	81	0.50	1.00	1.00	1.00	1.00	0.91			45.7%	64.4%	70.9%	52.9%
Sequoyah 2	01-Jun	82	0.59	1.00	1.00	1.00	0.91				49.8%	64.2%	70.7%	52.2%
McGuire 1	01-Dec	81	0.08	1.00	1.00	1.00	1.00	0.91			51.2%	64.9%	70.9%	52.7%
Salem 2	13-Oct	81	0.22	1.00	1.00	1.00	1.00	0.91			47.4%	64.7%	70.9%	52.7%
Average [6]											55.1%	64.7%	71.2%	54.5%

Notes: [1] First partial year. No refueling assumed for PLC assumption.
[2] Projections from column [5] of Table 2-3.
[3] From "STPEGS Data", Revision 0, 6/26/87.
[4] Cumulative Net Elec. Energy/Cumulative Report Period Hours/DER; From NRC Gray Book, November 30, 1986.
[5] Cook 1 and 2, and Trojan do not have Westinghouse 44" turbines. Therefore, the value of the W44 coefficient is subtracted from the projected capacity factor for these plants, so they are 1.8% higher than otherwise.
[6] Weighted by experience.

TABLE 2.5: HISTORICAL CAPACITY FACTORS (DER), UNITS SIMILAR TO STNP2

UNIT	DER NET [1]	first year	CAPACITY FACTOR BY CALENDAR YEAR [2] 1	2	3	4	5	6	7	8	9	10	11	12
ZION 1	1050	74	37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%	51.0%	43.7%	61.7%	52.3%
ZION 2	1050	75	52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%	56.1%	67.2%	64.9%	55.6%	
COOK 1	1090	76	71.1%	50.1%	65.8%	59.3%	67.5%	71.0%	56.1%	55.4%	78.9%	22.2%		
TROJAN	1130	77	65.6%	16.8%	53.2%	61.2%	64.9%	48.5%	41.2%	47.7%	69.8%	65.7%		
SALEM 1	1090	78	47.4%	21.4%	59.4%	64.8%	42.9%	56.3%	22.2%	94.3%				
COOK 2	1100	79	61.8%	69.3%	66.3%	72.6%	72.8%	55.5%	59.0%					
SEQUOYAH 1	1148	82	48.8%	73.0%	60.5%	40.4%								
SALEM 2	1115	82	81.3%	7.5%	32.7%	51.4%								
MCGUIRE 1	1180	82	41.6%	44.8%	61.9%	65.6%								
SEQUOYAH 2	1148	83	66.5%	63.5%	55.8%									
AVERAGES: ALL UNITS [3]	1106		57.4%	57.8%	57.5%	60.4%	62.2%	58.1%	51.0%	64.2%	66.7%	49.1%	58.7%	52.3%

ADJUSTMENT FOR DEVIATIONS AT SALEM 1 AND TROJAN

ALL UNITS:

Salem/Trojan deviation [4]	127.6%
unit-years [5]	70
deviation/unit-year	1.8%

	1	2	3	4	5	6	7	8	9	10	11	12
ADJUSTED AVERAGE (all units)	55.6%	56.0%	55.7%	58.5%	60.4%	56.3%	49.2%	62.3%	64.9%	47.3%	56.8%	50.5%

all years	56.5%
>5 years	55.6%

Notes:
1. Original reported value.
2. Computed from NRC-reported net output and original DER; Grey Book, 1/85, various years.
3. Values for year 2 for Trojan, Salem 1, and Salem 2 are excluded from averages.
4. 3 * 57.8% - 16.8% - 21.4% - 7.5%.
5. Total number of full unit-years for these ten units, through 1985.

TABLE 2.6: RESULTS OF REGRESSIONS ON O&M DATA (All plants in dataset)

	Equation 1		Equation 2		Equation 3	
	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-2.12	-7.94	-2.12	-7.94	-2.19	-8.77
ln(MW) [2]	0.53	21.15	--	--	--	--
ln(UNITS)	0.03	0.56	0.56	12.27	0.70	15.34
YEAR [3]	0.11	28.62	0.11	28.62	0.11	31.24
ln(MW/unit)	--	--	0.53	21.15	0.48	20.23
NE [4]	--	--	--	--	0.28	8.78
Adjusted R-sq.		0.85		0.85		0.87
F statistic		1032.2		1032.2		904.3

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)
[2] MW = number of MegaWatt in MGN.
[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.
[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region).
NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 2.7: RESULTS OF REGRESSIONS ON O&M DATA (All plants > 300 MW)

	Equation 1		Equation 2		Equation 3	
	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-4.38	-9.43	-4.38	-9.43	-4.46	-10.30
ln(MW) [2]	0.62	10.13	--	--	--	--
ln(UNITS)	-0.07	-0.85	0.55	12.93	0.67	15.88
YEAR [3]	0.13	28.31	0.13	28.31	0.13	30.73
ln(MW/unit)	--	--	0.62	10.13	0.59	10.34
NE [4]	--	--	--	--	0.26	8.31
Adjusted R-sq.		0.77		0.77		0.80
F statistic		519.4		519.4		465.4

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)

[2] MW = number of MegaWatt in MGN.

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region).
NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 2.8: PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR STNP2 ($ million)

Year	HL&P	From Equation #3 (Table 2.7) [A]						From Equation #3 (Table 2.6) [B]					
		Compound Real Growth ($1983)				Linear Real Growth		Compound Real Growth ($1983)				Linear Real Growth	
	Nominal	$1983 (2 Units)	$1983 (1 Unit)	Difference (Unit 2)	Nominal	1983$	Nominal	$1983 (2 Units)	$1983 (1 Unit)	Difference (Unit 2)	Nominal	1983$	Nominal
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
1990	$71	$196	$123	$73	$94	$73	$94	$152	$94	$58	$75	$58	$75
1991	$75	$224	$140	$83	$113	$83	$113	$170	$105	$65	$88	$65	$88
1992	$80	$255	$160	$95	$136	$94	$134	$190	$117	$73	$104	$72	$103
1993	$84	$292	$183	$109	$163	$104	$157	$213	$131	$82	$123	$79	$119
1994	$89	$333	$209	$124	$196	$115	$181	$238	$147	$91	$145	$86	$136
1995	$95	$380	$238	$142	$236	$125	$208	$267	$165	$102	$170	$93	$155
1996	$100	$434	$272	$162	$284	$135	$237	$299	$184	$115	$201	$100	$175
1997	$106	$496	$311	$185	$341	$146	$269	$335	$206	$128	$237	$107	$197
1998	$113	$566	$355	$211	$410	$156	$303	$375	$231	$144	$279	$114	$221
1999	$120	$646	$405	$241	$492	$166	$340	$420	$259	$161	$329	$121	$247
2000	$127	$737	$462	$275	$591	$177	$380	$470	$290	$180	$387	$128	$275
2001	$134	$842	$528	$314	$711	$187	$423	$526	$325	$202	$456	$135	$305
2002	$142	$961	$603	$359	$854	$197	$470	$589	$363	$226	$538	$142	$337
2003	$151	$1,097	$688	$409	$1,026	$208	$521	$660	$407	$253	$634	$149	$373
2004	$160	$1,253	$786	$467	$1,233	$218	$576	$738	$456	$283	$747	$156	$410
2005	$170	$1,431	$897	$534	$1,482	$228	$635	$827	$510	$317	$880	$162	$451
2006	$180	$1,633	$1,024	$609	$1,781	$239	$698	$926	$571	$355	$1,037	$169	$495
2007	$191	$1,865	$1,169	$695	$2,140	$249	$767	$1,037	$639	$397	$1,222	$176	$543
2008	$202	$2,129	$1,335	$794	$2,571	$260	$840	$1,161	$716	$445	$1,440	$183	$594
2009	$214	$2,431	$1,524	$907	$3,090	$270	$920	$1,300	$802	$498	$1,697	$190	$649
2010	$227	$2,775	$1,740	$1,035	$3,713	$280	$1,005	$1,455	$898	$558	$2,000	$197	$708
2011	$241	$3,168	$1,987	$1,182	$4,461	$291	$1,097	$1,629	$1,005	$624	$2,357	$204	$771
2012	$255	$3,617	$2,268	$1,349	$5,361	$301	$1,196	$1,824	$1,125	$699	$2,778	$211	$839
2013	$270	$4,130	$2,590	$1,540	$6,442	$311	$1,302	$2,043	$1,260	$783	$3,273	$218	$912
2014	$287	$4,715	$2,956	$1,759	$7,741	$322	$1,416	$2,287	$1,411	$876	$3,858	$225	$991
2015	$304	$5,383	$3,375	$2,008	$9,302	$332	$1,538	$2,561	$1,580	$981	$4,546	$232	$1,075
2016	$322	$6,146	$3,854	$2,292	$11,178	$342	$1,670	$2,867	$1,769	$1,099	$5,357	$239	$1,165
2017	$341	$7,017	$4,400	$2,617	$13,432	$353	$1,810	$3,211	$1,980	$1,230	$6,314	$246	$1,262
2018	$362	$8,011	$5,023	$2,988	$16,140	$363	$1,961	$3,595	$2,217	$1,377	$7,440	$253	$1,366
2019	$383	$9,146	$5,735	$3,411	$19,395	$373	$2,123	$4,025	$2,483	$1,542	$8,768	$260	$1,477
2020	$406	$10,443	$6,548	$3,895	$23,305	$384	$2,297	$4,507	$2,780	$1,727	$10,333	$267	$1,597
2021	$431	$11,922	$7,476	$4,447	$28,005	$394	$2,482	$5,046	$3,113	$1,933	$12,177	$274	$1,724
2022	$457	$13,612	$8,535	$5,077	$33,652	$405	$2,681	$5,650	$3,485	$2,165	$14,350	$281	$1,861
2023	$484	$15,541	$9,745	$5,796	$40,437	$415	$2,895	$6,326	$3,902	$2,424	$16,912	$288	$2,007
2024	$513	$17,743	$11,125	$6,617	$48,591	$425	$3,123	$7,084	$4,370	$2,714	$19,930	$295	$2,164
2025	$544	$20,257	$12,702	$7,555	$58,389	$436	$3,367	$7,931	$4,892	$3,039	$23,486	$302	$2,331

Notes: [1] From STPEGS Capital Cost Data, 2/28/87. Inflated at 6% annually.

[2] ,[6] MW=1250 * 1.04, UNITS =2, NE=0.

[3], [5], [7], [9] Inflation rates are assumed to be 4%, 1986-90, 5.25% from 1990-2025. *From Tentative Assumptions.*

[4],[8] From 1992 on, projections increase by the difference between the 1990 & 1991 projections.

[A] Regressions originally performed on data from all plants > than 300 MW.

[B] Regressions originally performed on data from all plants in database.

TABLE 2.9: NUCLEAR CAPITAL ADDITIONS, 1972-1984

	Year	Averages by Year (in $/kw-yr): All plants	Single units, > 800 MW
All years before and including:	1972	$1.43	
	1973	$10.87	$38.90
	1974	$11.07	$26.82
	1975	$8.71	$19.72
	1976	$15.07	$2.98
	1977	$19.91	$12.78
	1978	$17.77	$25.94
	1979	$14.82	$16.75
	1980	$27.73	$27.97
	1981	$31.66	$28.33
	1982	$29.06	$24.80
	1983	$29.78	$26.42
	1984	$42.88	$34.45
Overall Average:		$20.74	$23.37
(# of obs.)		520	127
1978-1984 Average:		$27.69	$26.49
(# of obs.)		314	97
1980-1984 Average:		$32.29	$28.80
(# of obs.)		224	67

TABLE 2.10: PROJECTIONS OF ANNUAL CAPITAL ADDITIONS PER UNIT, FOR STNP2 ($ Thousand)

Regression Equation for Capital Additions per Unit

Constant	-31905	If80	11221
		If81	13131
ln(MW per unit)	6777	If82	11667
		If83	13508
ln(Units)	-12690	If84	22861
		Avg. 1980-84	14478

Real Cost Projections (1983 $)
for STNP2

	1 UNIT	2 UNITS
Per Unit	$31,163	$22,366
Total	$31,163	$44,733
Incremental	$31,163	$13,570

Nominal Cost Projections
(Incremental)

Year	1st Unit	2nd Unit	Total
1990	$44,188	$19,242	$63,430
1991	$47,126	$20,522	$67,648
1992	$50,260	$21,887	$72,146
1993	$53,602	$23,342	$76,944
1994	$57,167	$24,894	$82,061
1995	$60,968	$26,550	$87,518
1996	$65,023	$28,315	$93,338
1997	$69,347	$30,198	$99,545
1998	$73,958	$32,206	$106,165
1999	$78,876	$34,348	$113,225
2000	$84,122	$36,632	$120,754
2001	$89,716	$39,068	$128,784
2002	$95,682	$41,666	$137,348
2003	$102,045	$44,437	$146,482
2004	$108,831	$47,392	$156,223
2005	$116,068	$50,544	$166,612
2006	$123,786	$53,905	$177,691
2007	$132,018	$57,490	$189,508
2008	$140,797	$61,313	$202,110
2009	$150,161	$65,390	$215,551
2010	$160,146	$69,738	$229,885
2011	$170,796	$74,376	$245,172
2012	$182,154	$79,322	$261,476
2013	$194,267	$84,597	$278,864
2014	$207,186	$90,223	$297,409
2015	$220,964	$96,222	$317,186
2016	$235,658	$102,621	$338,279
2017	$251,329	$109,446	$360,775
2018	$268,042	$116,724	$384,766
2019	$285,867	$124,486	$410,353
2020	$304,877	$132,764	$437,642
2021	$325,152	$141,593	$466,745
2022	$346,774	$151,009	$497,783
2023	$369,835	$161,051	$530,886
2024	$394,429	$171,761	$566,190

Notes: [1] Real cost projections from the regression equation assume MW per unit =1250*1.04.
[2] Nominal Cost projections are calculated 1.4% above the GNP Inflator through 1986, and escalated by 5.4% from 1987-1990, and 6.65% thereafter.
[3] Regressions originally performed on data from all plants in database.

TABLE 2.11: PROJECTIONS OF CAPITAL ADDITIONS COSTS FOR STNP2 ($ Million)

	Year	HL&P Capital Additions Budget [1]	Extrapolation of Recent Historical Average [2]	Projections from Regression Analysis [3]
Capital Additions for the Plant in 1983 $:			$41.98	$13.57
	1990	$9.15	$59.52	$19.24
	1991	$13.00	$63.48	$20.52
	1992	$14.51	$67.70	$21.89
	1993	$15.27	$72.20	$23.34
	1994	$16.08	$77.01	$24.89
	1995	$16.92	$82.13	$26.55
	1996	$17.81	$87.59	$28.32
	1997	$18.74	$93.41	$30.20
	1998	$19.73	$99.62	$32.21
	1999	$20.76	$106.25	$34.35
	2000	$21.85	$113.31	$36.63
	2001	$23.00	$120.85	$39.07
	2002	$24.21	$128.89	$41.67
	2003	$25.48	$137.46	$44.44
	2004	$26.82	$146.60	$47.39
	2005	$28.22	$156.35	$50.54
	2006	$29.70	$166.74	$53.90
	2007	$31.26	$177.83	$57.49
	2008	$32.91	$189.66	$61.31
	2009	$34.63	$202.27	$65.39
	2010	$36.45	$215.72	$69.74
	2011	$38.37	$230.07	$74.38
	2012	$40.38	$245.37	$79.32
	2013	$42.50	$261.68	$84.60
	2014	$44.73	$279.09	$90.22
	2015	$47.08	$297.65	$96.22
	2016	$49.55	$317.44	$102.62
	2017	$52.15	$338.55	$109.45
	2018	$54.89	$361.06	$116.72
	2019	$57.77	$385.07	$124.49
	2020	$60.80	$410.68	$132.76
	2021	$64.00	$437.99	$141.59
	2022	$67.36	$467.12	$151.01
	2023	$70.89	$498.18	$161.05
	2024	$74.61	$531.31	$171.76

NOTES for Table 2.11:

[1] $13.1 ($1990) beginning in 1992, million escalated at 5.25% from 1991 through 2024. From STPEGS Capital Cost Data, 6/26/87, p 8.

[2] $32.29/kw escalated at 1.4% above the GNP inflator from 1983 to 1986, by 5.4% from 1986 to 1990, and at 6.65% from 1991 through 2024.

[3] Projections from regression analysis on capital additions, which is fully

TABLE 2.12: TLG DECOMMISSIONING ESTIMATES, CONSTANT DOLLARS

Plant/Station	Base Year	Estimated Cost/Unit (Base Year Dollars)	Estimated Cost/Unit ($1990, Millions)[2]	MW	PWR [3]	Twin [4]
Fermi 2	1978	67	126	1056	0	0
Monticello	1979	44	76	536	0	0
Prairie Island 1&2	1979	33	57	520	1	0.5
Brunswick 1	1979	48	83	790	0	0
Brunswick 2	1979	37	64	790	0	1
Robinson	1979	28	48	665	1	0
Summer	1981	52	75	900	1	0
Ginna	1982	108	146	490	1	0
Shoreham	1982	123	167	819	0	0
Callaway	1983	128	167	1150	1	0
Maine Yankee	1983	126	165	825	1	0
North Anna 1&2	1983	118	154	850	1	0.5
Spurry 1&2	1983	104	136	775	1	0.5
Wolf Creek	1983	109	142	1150	1	0
Waterford 3	1984	114	144	1104	1	0
Beaver Valley	1984	139	175	833	1	0
Kewaunee	1984	114	144	535	1	0
Davis Besse	1984	138	174	906	1	0
Diablo Canyon 1	1985	215	262	1084	1	1
Diablo Canyon 2	1985	256	311	1106	1	0
Shippingport	1985	98	119	150	1	0
Perry 1	1985	259	315	1205	0	0
Duane Arnold	1985	154	187	538	0	0
River Bend 1	1985	201	245	940	0	0
Chrystal River 3	1985	177	215	825	1	0
Nine Mile 2	1986	264	309	1085	0	0
Vogtle 1	1986	215	252	1100	1	0
Vogtle 2	1986	176	206	1100	1	1
Seabrook 1	1986	221	259	1150	1	0
Nine Mile 1	1986	212	248	610	0	0

Notes: [1] From Response to Interrogatory #AG-4-23, NMPSC 2004.
[2] Inflated at GNP.
[3] PWR = 1 if PWR.
[4] TWIN = 1 if cheaper twin, .5 if pair of units.

TABLE 2.13: REACTOR YEARS OF EXPERIENCE

Retired Units in Order of First Generation:

Unit	Years	1st Electric Generate	Shutdown Date
Dresden 1	18.54	15-Apr-60	31-Oct-78
Indian Point 1	12.12	16-Sep-62	31-Oct-74
Humboldt Bay	13.21	18-Apr-63	02-Jul-76
Hallam	1.26	29-May-63	01-Sep-64
Elk River	4.44	24-Aug-63	01-Feb-68
Piqua	2.16	04-Nov-63	01-Jan-66
CVTR	3.04	18-Dec-63	01-Jan-67
Bonus	3.8	14-Aug-64	01-Jun-68
Pathfinder	1.19	25-Jul-66	01-Oct-67
Fermi 1	6.32	05-Aug-66	29-Nov-72
Peach Bottom 1	7.76	27-Jan-67	01-Nov-74
Three Mile Island	0.93	21-Apr-78	28-Mar-79

Other Early Units:

Yankee-Rowe	26.76	10-Nov-60	
Big Rock Point	24.68	08-Dec-62	

Source: NRC Greybook.
[1] Years from first generation to shutdown - longer than commercial life.
[2] To 06-Aug-87 .

TABLE 2.14: REGRESSION RESULTS, TLG DECOMMISSIONING ESTIMATES

Regression Output:	
Constant	-11.7049
Std Err of Y Est	0.198324
R Squared	0.871725
No. of Observations	30
Degrees of Freedom	25

Y	b	c	d	f
LN(COST) ($1986)	LN(MW)	Year	PWR	T
X Coefficient(s)	0.3409	0.173984	-0.2110	-0.121
Std Err of Coef.	0.0894	0.015074	0.07932	0.1151

LN(COST) = a + b(ln(MW) + c(Year) + d(PWR) + f(T)

Cost = e^a * MW^b * (e^c)^Year * (e^d)^PWR * (e^f)^Twin

Cost = 8.25E-06 * MW^.3409 * 1.19^Year * .7987^PWR * .8917^Twin,
where Year = Base Year minus 1900.

Cost in millions of 1986 dollars. To convert to 1990 dollars, inflate at 4% annually.

TABLE 2.15: EXTRAPOLATION OF TRENDS IN DECOMMISSIONING COST ESTIMATES, TOTAL STNP2 ESTIMATE ($ 1990)

	Years Since 1986	Constant % Growth --[1]--	Linear Growth --[2]--
	-----		
1987	1	$200	$200
1988	2	$238	$233
1989	3	$283	$265
1990	4	$337	$297
1991	5	$401	$329
1992	6	$477	$362
1993	7	$568	$394
1994	8	$676	$426
1995	9	$805	$459
1996	10	$958	$491
1997	11	$1,140	$523
1998	12	$1,356	$555
1999	13	$1,614	$588
2000	14	$1,921	$620
2001	15	$2,285	$652
2002	16	$2,720	$685
2003	17	$3,237	$717
2004	18	$3,852	$749
2005	19	$4,584	$781
2006	20	$5,455	$814
2007	21	$6,491	$846
2008	22	$7,725	$878
2009	23	$9,193	$910
2010	24	$10,940	$943
2011	25	$13,019	$975

Notes: [1] Growth at exponent of .1758, or 19.2% annually, from Table 2.2.
[2] Linear growth at 19.2% of 1986 value.
1986 value from Economic Viability Study, Touche Ross Tentative Inputs.

TABLE 2.16: ANALYSIS OF OVERHEAD EXPENSE FOR YANKEE PLANTS ($ THOUSANDS)

	Yankee Atomic		Connecticut Yankee		Vermont Yankee		Maine Yankee		
	1984	1985	1934	1985	1984	1985	1984	1985	
1. Other O&M	2,553	2,871	6,370	6,776	8,777	10,226	17,934	19,289	
2. Employment Taxes:									
FICA	1,462	1,462	686	686	724	724	705	705	
Fed Unemp.	38	38	16	16	45	45	19	19	
State Unemp.	78	78	33	33	48	48	63	63	
3. Total Other	4,131	4,448	7,106	7,512	9,594	11,044	18,722	20,077	
4. Station O&M	38,113	43,895	86,320	86,492	64,652	67,187	67,574	71,454	
5. Fuel	11,691	7,301	26,432	40,941	21,449	20,771	35,079	35,694	
6. Non-fuel Station O&M	26,422	36,595	59,889	45,550	43,203	46,416	32,495	35,760	
7. Other as a % of Non-fuel Station O&M	15.63%	12.16%	11.87%	16.49%	22.21%	23.79%	57.61%	56.14%	Average: 26.99%

Source: 1985 FERC Forms of Yankee Atomic, Maine Yankee, Vermont Yankee, and Connecticut Yankee.

TABLE 2.17: PROJECTION OF TOTAL O&M EXPENSE

Year	Station O&M	Total O&M
----	-------	-----
	[1]	[2]
1990	$75	$95
1991	$88	$112
1992	$103	$131
1993	$119	$151
1994	$136	$173
1995	$155	$196
1996	$175	$222
1997	$197	$250
1998	$221	$281
1999	$247	$313
2000	$275	$349
2001	$305	$387
2002	$337	$428
2003	$373	$473
2004	$410	$521
2005	$451	$573
2006	$495	$629
2007	$543	$689
2008	$594	$754
2009	$649	$824
2010	$708	$899
2011	$771	$979
2012	$839	$1,066
2013	$912	$1,159
2014	$991	$1,258
2015	$1,075	$1,365
2016	$1,165	$1,480
2017	$1,262	$1,603
2018	$1,366	$1,735
2019	$1,477	$1,876
2020	$1,597	$2,028
2021	$1,724	$2,190
2022	$1,861	$2,363
2023	$2,007	$2,549
2024	$2,164	$2,748
2025	$2,331	$2,960

Notes: [1] From Table 2.8, Column 13.
[2] Column 1 multiplied by 1.27 (overhead percentage calculated in Table 2.16).

TABLE 3.1, PART 2: NOMINAL COSTOVERRUNS AND MYOPIA FACTORS

Estimated Time to Completion (years)	Number of Estimates	Average Cost Ratio	Average Myopia
1 - 1.99	188	1.39	25%
2 - 2.99	167	2.02	32%
3 - 3.99	91	2.39	27%
4 - 4.99	61	2.78	24%
5 +	82	3.63	22%

TABLE 3.1: HISTORICAL NUCLEAR DURATION MYOPIA

Estimated Time to Completion	Number of Estimates	Average Projected Time to Complete	Average Duration Ratio
(years)			
1 - 1.99	218	1.41	2.05
2 - 2.99	175	2.40	2.13
3 - 3.99	103	3.44	1.97
4 - 4.99	63	4.40	1.76
5 +	82	5.77	1.61

TABLE 3.1, PART 3: REAL COST OVERRUNS AND MYOPIA FACTORS

Estimated Time to Completion	Number of Estimates	Average Cost Ratio	Average Myopia
(years)			
1 - 1.99	188	1.25	19%
2 - 2.99	167	1.64	22%
3 - 3.99	91	1.84	18%
4 - 4.99	61	2.15	18%
5 +	82	2.69	17%

Unit	Actual COD	Date of Estimate	Estimated COD	Years to COD Estimated	Years to COD Actual	Ratio	Percentage Entering Service
----	--[1]--	---[2]---	---[3]---	---[4]---	--[5]--	-[6]-	----[7]---
Hatch 2	Sep-79	Sep-75	Apr-79	3.58	4.00	1.12	1.0%
Maine Yankee	Dec-72	Sep-68	May-72	3.66	4.25	1.16	1.9%
Three Mile Island 2	Dec-78	Sep-74	May-78	3.66	4.25	1.16	2.9%
Prairie Island 2	Dec-74	Sep-70	May-74	3.66	4.25	1.16	3.9%
Point Beach 1	Dec-70	Jun-66	Apr-70	3.83	4.50	1.17	4.9%
Point Beach 1	Dec-70	Sep-66	Apr-70	3.58	4.25	1.19	5.8%
Robinson 2	Mar-71	Jun-66	May-70	3.92	4.75	1.21	6.8%
Peach Bottom 3	Dec-74	Mar-71	Apr-74	3.09	3.75	1.22	7.8%
Monticello	Jun-71	Jun-66	May-70	3.92	5.00	1.28	8.7%
Ginna	Jul-70	Dec-65	Jun-69	3.50	4.58	1.31	9.7%
Ginna	Jul-70	Mar-66	Jun-69	3.25	4.33	1.33	10.7%
Trojan	Dec-75	Mar-71	Sep-74	3.50	4.75	1.36	11.7%
Surry 2	May-73	Dec-68	Mar-72	3.25	4.41	1.36	12.6%
Three Mile Point 1	Dec-69	Sep-64	Jul-68	3.83	5.25	1.37	13.6%
Pilgrim 1	Dec-72	Jun-68	Sep-71	3.25	4.50	1.39	14.6%
Duane Arnold	Feb-75	Dec-70	Dec-73	3.00	4.17	1.39	15.5%
Hatch 2	Sep-79	Sep-74	Apr-78	3.58	5.00	1.40	16.5%
Oconne 3	Dec-74	Sep-69	Jun-73	3.75	5.25	1.40	17.5%
Three Mile Island 2	Dec-78	Jun-73	May-77	3.92	5.50	1.40	18.4%
Brunswick 1	Mar-77	Dec-72	Dec-75	3.00	4.25	1.42	19.4%
Fort Calhoun 1	Sep-73	Mar-69	May-72	3.17	4.50	1.42	20.4%
Millstone 1	Mar-71	Dec-65	Aug-69	3.67	5.25	1.43	21.4%
Dresden 3	Nov-71	Mar-66	Feb-70	3.92	5.67	1.45	22.3%
Millstone 2	Dec-75	Dec-70	Apr-74	3.33	5.00	1.50	23.3%
Peach Bottom 3	Dec-74	Sep-69	Mar-73	3.50	5.25	1.50	24.3%
Brunswick 2	Nov-75	Dec-70	Mar-74	3.25	4.92	1.51	25.2%
Arkansas 1	Dec-74	Mar-69	Dec-72	3.75	5.75	1.53	26.2%
Brunswick 1	Mar-77	Jun-71	Mar-75	3.75	5.75	1.53	27.2%
Surry 1	Dec-72	Dec-67	Mar-71	3.25	5.00	1.54	28.2%
Peach Bottom 3	Dec-74	Dec-69	Mar-73	3.25	5.00	1.54	29.1%
Zion 1	Dec-73	Mar-69	Apr-72	3.09	4.75	1.54	30.1%
Oconee 1	Jul-73	Jun-67	May-71	3.92	6.08	1.55	31.1%
Arkansas 1	Dec-74	Jun-69	Dec-72	3.50	5.50	1.57	32.0%
St. Lucie 1	Jun-76	Dec-70	Jun-74	3.50	5.50	1.57	33.0%
Quad Cities 2	Mar-73	Sep-67	Mar-71	3.50	5.50	1.57	34.0%
Peach Bottom 3	Dec-74	Mar-70	Mar-73	3.00	4.75	1.58	35.0%
Oconee 1	Jul-73	Sep-67	May-71	3.66	5.83	1.59	35.9%
Calvert Cliffs 1	May-75	Mar-69	Jan-73	3.84	6.17	1.61	36.9%
Kewaunee	Jun-74	Mar-69	Jun-72	3.25	5.25	1.61	37.9%
Brunswick 1	Mar-77	Dec-71	Mar-75	3.25	5.25	1.62	38.8%
Fort Calhoun 1	Sep-73	Sep-67	May-71	3.66	6.00	1.64	39.8%
Oyster Creek 1	Dec-69	Jun-64	Oct-67	3.33	5.50	1.65	40.8%
Susquehanna 1	Jun-83	Dec-76	Nov-80	3.92	6.50	1.66	41.7%
St. Lucie 1	Jun-76	Jun-71	Jun-74	3.00	5.00	1.67	42.7%
Farley 2	Jul-81	Dec-75	Apr-79	3.33	5.58	1.68	43.7%
Three Mile Island 2	Dec-78	Aug-72	May-76	3.75	6.33	1.69	44.7%
Susquehanna 1	Jun-83	Mar-77	Nov-80	3.67	6.25	1.70	45.6%
Oconee 2	Sep-74	Mar-69	May-72	3.17	5.50	1.74	46.6%
Farley 1	Dec-77	Sep-71	Apr-75	3.58	6.25	1.75	47.6%
Hatch 1	Dec-75	Mar-70	Jun-73	3.25	5.75	1.77	48.5%
Quad Cities 1	Feb-73	Jun-66	Mar-70	3.75	6.67	1.78	49.5%
Hatch 1	Dec-75	Jun-70	Jun-73	3.00	5.50	1.83	50.5%

Unit	Actual COD	Date of Estimate	Estimated COD	Years to COD Estimated	Years to COD Actual	Ratio	Percentage Entering Service
----	--[1]--	---[2]---	---[3]---	---[4]---	--[5]--	-[6]-	----[7]---
St. Lucie 1	Jun-76	Sep-69	May-73	3.66	6.75	1.84	51.5%
Three Mile Island 1	Sep-74	Jun-67	May-71	3.92	7.25	1.85	52.4%
Salem 1	Jun-77	Sep-71	Oct-74	3.08	5.75	1.87	53.4%
Cook 1	Aug-75	Jun-69	Sep-72	3.25	6.17	1.90	54.4%
Beaver Valley 1	Oct-76	Dec-69	Jun-73	3.50	6.83	1.95	55.3%
Peach Bottom 2	Jul-74	Sep-67	Mar-71	3.50	6.83	1.95	56.3%
Calvert Cliffs 2	Apr-77	Sep-70	Jan-74	3.33	6.58	1.97	57.3%
Three Mile Island 1	Sep-74	Dec-67	May-71	3.41	6.75	1.98	58.3%
Three Mile Island 2	Dec-78	Sep-71	May-75	3.66	7.25	1.98	59.2%
Arkansas 2	Mar-80	Sep-73	Dec-76	3.25	6.50	2.00	60.2%
Brown's Ferry 1	Aug-74	Dec-66	Oct-70	3.83	7.67	2.00	61.2%
Browns Ferry 1	Aug-74	Sep-66	Aug-70	3.92	7.92	2.02	62.1%
Arkansas 2	Mar-80	Jun-73	Oct-76	3.33	6.75	2.02	63.1%
Summer 1	Jan-84	Dec-76	May-80	3.41	7.08	2.07	64.1%
Arkansas 2	Mar-80	Dec-73	Dec-76	3.00	6.25	2.08	65.0%
Browns Ferry 3	Mar-77	Sep-70	Oct-73	3.08	6.50	2.11	66.0%
Peach Bottom 2	Jul-74	Mar-68	Mar-71	3.00	6.33	2.11	67.0%
Arkansas 2	Mar-80	Dec-71	Oct-75	3.83	8.25	2.15	68.0%
McGuire 1	Dec-81	Sep-74	Jan-78	3.33	7.25	2.17	68.9%
Lasalle 1	Oct-82	Sep-75	Dec-78	3.25	7.08	2.18	69.9%
Cook 2	Jul-78	Sep-70	Mar-74	3.50	7.83	2.24	70.9%
Browns Ferry 1	Aug-74	Sep-67	Oct-70	3.08	6.92	2.24	71.8%
Three Mile Island 2	Dec-78	Sep-70	May-74	3.66	8.25	2.25	72.8%
Farley 2	Jul-81	Jun-73	Jan-77	3.59	8.08	2.25	73.8%
McGuire 1	Dec-81	Dec-74	Jan-78	3.09	7.00	2.27	74.8%
Chrystal River 3	Mar-77	Jun-68	Apr-72	3.83	8.75	2.28	75.7%
Indian Point 3	Aug-76	Sep-67	Jul-71	3.83	8.92	2.33	76.7%
Indian Point 2	Aug-73	Jun-66	Jun-69	3.00	7.17	2.39	77.7%
Farley 2	Jul-81	Dec-73	Jan-77	3.09	7.58	2.46	78.6%
North Anna 2	Dec-80	Sep-71	Jun-75	3.75	9.25	2.47	79.6%
Salem 1	Jun-77	Jun-67	May-71	3.92	10.00	2.55	80.6%
North Anna 2	Dec-80	Dec-71	Jun-75	3.50	9.00	2.57	81.6%
Sequoyah 2	Jun-82	Sep-74	Sep-77	3.00	7.75	2.58	82.5%
McGuire 1	Dec-81	Sep-73	Nov-76	3.17	8.25	2.60	83.5%
North Anna 2	Dec-80	Mar-72	Jul-75	3.33	8.75	2.63	84.5%
Summer 1	Jan-84	Jun-74	Jan-78	3.59	9.59	2.67	85.4%
Sequoyah 2	Jun-82	Dec-73	Feb-77	3.17	8.50	2.68	86.4%
Salem 2	Oct-81	Dec-72	Mar-76	3.25	8.83	2.72	87.4%
Salem 2	Oct-81	Sep-71	May-75	3.66	10.08	2.75	88.3%
McGuire 1	Dec-81	Dec-72	Mar-76	3.25	9.00	2.77	89.3%
Cook 2	Jul-78	Jun-69	Sep-72	3.25	9.08	2.79	90.3%
Sequoyah 2	Jun-82	Jun-73	Aug-76	3.17	9.00	2.84	91.3%
Sequoyah 1	Jul-81	Jun-70	Apr-74	3.83	11.08	2.89	92.2%
Salem 2	Oct-81	Jun-71	Dec-74	3.50	10.34	2.95	93.2%
Seqouyah 2	Jun-82	Jun-70	Apr-74	3.83	12.00	3.13	94.2%
Sequoyah 2	Jun-82	Dec-72	Dec-75	3.00	9.50	3.17	95.1%
Sequoyah 2	Jun-82	Dec-71	Mar-75	3.25	10.50	3.23	96.1%
Sequoyah 2	Jun-82	Jun-72	Jul-75	3.08	10.00	3.25	97.1%
Sequoyah 1	Jul-81	Mar-71	Apr-74	3.09	10.34	3.35	98.1%
Salem 2	Oct-81	Mar-71	Apr-74	3.09	10.59	3.43	99.0%
Salem 2	Oct-81	Mar-70	Jul-73	3.33	11.59	3.47	100.0%

Unit	Actual COD	Date of Estimate	Estimated COD	Years to COD Estimated	Years to COD Actual	Ratio	Percentage Entering Service
----	--[1]--	---[2]---	---[3]---	---[4]---	--[5]--	-[6]-	----[7]---

Notes: [1], [2], and [3] From Appendix C.
[4] [3] - [2].
[5] [1] - [2].
[6] [5]/[4].
[7] Percentage of units with duration ratios less than or equal to Column [6].

TABLE 3.3: RATIO OF SECOND UNIT DIRECT COST TO FIRST UNIT DIRECT COST

Plant Name	Cost Excluding AFUDC Unit 1	Cost Excluding AFUDC Unit 2	Commercial Operation Date Unit 1	Commercial Operation Date Unit 2	Ratio of Unit 2 to Unit 1 Cost [1]	Years Between CODs [2]
DRESDEN 2&3	$128	$131	Aug-70	Nov-71	102%	1.25
TURKEY POINT 3&4	$146	$124	Dec-72	Sep-73	85%	0.75
QUAD CITIES 1&2	$152	$132	Feb-73	Mar-73	87%	0.08
OCONEE 1&2	$135	$140	Jul-73	Sep-74	104%	1.17
PEACH BOTTOM 2&3	$537	$226 [5]	Jul-74	Dec-74	42%	0.42
SALEM 1&2	$671	$570	Jun-77	Oct-81	85%	4.33
POINT BEACH 1&2	$137	$151	Dec-70	Apr-73	110%	2.33
CALVERT CLIFFS 1&2	$415	$280	May-75	Apr-77	67%	1.92
ZION 1&2	$283	$186	Oct-73	Sep-74	66%	0.92
BEAVER VALLEY 1&2	$611	$3,295	Apr-77	Nov-87 [3]	539%	10.58
LIMERICK 1&2	$2,275	$1,800	Feb-86	Nov-90 [4]	79%	4.75
NORTH ANNA 1&2	$638	$405	Jun-78	Nov-80	63%	2.42
BRUNSWICK 1&2	$418	$333 [6]	Nov-75	Mar-77	80%	1.33
FARLEY 1&2	$706	$770	Dec-78	Jul-81	109%	2.58
SUSQUEHANNA 1&2	$1,298	$1,358	Jun-83	Feb-85	105%	1.67
SOUTH TEXAS 1&2	$2,906	$1,175	Dec-87	Jun-89	42%	1.50
Average:					115%	2.43

Source: Cost and COD data is from U.S. Nuclear Plants Cost Per Kilowatt Report, TVA, March, 1987.

Notes: [1] Unit 2 Cost divided by Unit 1 Cost.
[2] Unit 2 COD minus Unit 1 COD.
[3] Unit 2 listed as "late 87"; Unit 1 cost includes AFUDC.
[4] Unit 2 listed as "late 90".
[5] Costs include AFUDC.
[6] Unit 2 preceded Unit 1.
[7] Averages exclude STNP 1&2.

TABLE 3.4: RECENT EXPERIENCE IN START-UP INTERVALS

Unit ----	Date of Issuance, First Operating License [1] -------[1]-------	Commercial Operation Date ---[2]---	Start-up Interval (Months) ---[3]---
SHEARON HARRIS 1	Oct-86	May-87	6
HOPE CREEK 1	Apr-86	Dec-86	8
CATAWBA 2	Feb-86	Aug-86	6
DIABLO CANYON 2	Apr-85	Mar-86	11
MILLSTONE 3	Nov-85	Apr-86	5
PALO VERDE 2	Dec-85	Sep-86	9
RIVER BEND 1	Aug-85	Jun-86	9
WOLF CREEK	Mar-85	Sep-85	6
BYRON 1	Oct-84	Sep-85	11
CALLAWAY 1	Jun-84	Dec-84	6
CATAWBA 1	Dec-84	Jun-85	6
LIMERICK 1	Oct-84	Feb-86	15
PALO VERDE 1	Dec-84	Feb-86	14
SUSQUEHANNA 2	Mar-84	Feb-85	11
WATERFORD 3	Dec-84	Sep-85	9
LASALLE 2	Dec-83	Oct-84	10
WM MCGUIRE 2	Mar-83	Mar-84	11
ST LUCIE 2	Apr-83	Aug-83	4
WPPSS 2	Dec-83	Dec-84	12
GRAND GULF 1	Jun-82	Jul-85	36
LASALLE 1	Apr-82	Jan-84	21
SAN ONOFRE 2	Feb-82	Aug-83	17
SAN ONOFRE 3	Nov-82	Apr-84	16
SUMMER 1	Aug-82	Jan-84	16
SUSQUEHANNA 1	Jul-82	Jun-83	11
DIABLO CANYON 1	Sep-81	May-85	43
WM MCGUIRE 1	Jan-81	Dec-81	10
SEQUOYAH 2	Jun-81	Jun-82	11
JM FARLEY 2	Oct-80	Jul-81	9
NORTH ANNA 2	Apr-80	Dec-80	8
SALEM 2	Apr-80	Oct-81	18
SEQUOYAH 1	Feb-80	Jul-81	16
ARKANSAS 2	Sep-78	Mar-80	18
EDWIN I HATCH 2	Jun-78	Sep-79	14
Average:			13

Notes: [1] From Atomic Industrial Forum, January, 1987.
[2] From Nuclear News, February, 1987 and NRC.
[3] Column [2] - Column [3].

TABLE 3.5: UNITS IN STARTUP, JULY 1987

Unit	First Operating License [1]	Full Power License [2]	Months from First License to July 1987
Byron 2	Nov-86	Jan-87	8
Nine Mile Point 2	Oct-86	Jul-87	8
Clinton 1	Sep-86	Apr-87	10
Perry 1	Mar-86	Nov-86	16
Fermi 2	Mar-85	Jul-85	28
Shoreham	Dec-84		31

Notes: [1] From Atomic Industrial Forum, January, 1987.
[2] From NRC, Data as of July, 1987.

TABLE 3.6: CONVERSION OF 67% COST OVERRUN TO ANNUAL CASH FLOWS

	Direct	PTax	S&UTax	AFUDC	B&R Sett. &PC	Total	Cumulative	
	HL&P Share: HL&P Forecast [1]							
pre-87	361.7	7.0	1.3	103.1	-79.0	394.1	394.1	
87	78.4	2.2	0.6	41.5		122.7	516.8	
88	69.8	2.9	0.5	50.6		123.8	640.6	
89	1.4	6.0		28.6		36.0	676.6	
	HL&P Share: Revised Forecast [2]							
pre-87	361.7	7.0	1.3	103.1	-79.0	394.1	394.1	
87	85.0	2.2	0.7	41.5		129.4	523.5	
88	120.0	2.9	0.9	51.3		175.0	698.5	
89	110.0	6.5	0.8	69.8		187.2	885.7	
90	100.0	8.3	0.7	88.6		197.6	1083.3	
91	10.0	2.5		27.1		39.6	1122.9	1.66 [4]
	Total Plant: Revised Forecast [3]							
87	276.0	7.1	2.1					
88	389.6	9.5	2.8					
89	357.1	21.2	2.6					
90	324.7	26.9	2.3					
91	32.5	8.2						

Notes: [1] Costs from STPEGS Capital Cost Data, 6/26/87, pp 10-18.
[2] Direct selected so that [4] = 1.66.
PTax and AFUDC scaled on previous year's Cumulative Total.
S&UTax scaled on Direct.
AFUDC assumed to be 10% in 1990 and 1991.
PTax uses 1989 rate in 1990 and 1991.
1991 costs for 3 months.
[3] HL&P share divided by 30.8%.
[4] Ratio of Cumulative Total to HL&P Cumulative Total.

TABLE 4.1: MEGAWATTHOUR SALES

Sales	Houston L&P	Central P&L	Austin	San Antonio
Residential	14,981,112	4,469,884	2,171,000	3,491,415
Commercial	11,490,874	3,664,447	2,517,000	1,735,893
Industrial	27,418,046	5,985,326	452,000	3,617,943
Other Retail	103,808	346,524	144,000	75,565
Total Retail	53,993,840	14,466,181	5,284,000	8,920,816

Source: Financial Statistics of Selected Electric Utilities, 1985.
Lovins (1986).

TABLE 4.2: EFFICIENCY POTENTIAL

Class		Efficiency Savings Function	Fraction Left After Efficiency Improvements	1985 Sales With Efficiency [3] HL&P	CP&L	Austin	San Antonio	Total
		[1]	[2]					
Residual		79%	21%	3,146,034	938,676	455,910	733,197	5,273,816
Commercial		73%	27%	3,102,536	989,401	679,590	468,691	5,240,218
Industrial	Low	25%	75%	20,563,535	4,488,995	339,000	2,713,458	28,104,987
	High	50%	50%	13,709,023	2,992,663	226,000	1,808,972	18,736,658
Other		25%	75%	77,856	259,893	108,000	56,674	502,423
Total	Low			26,889,960	6,676,964	1,582,500	3,972,020	39,121,444
	High			20,035,449	5,180,632	1,469,500	3,067,534	29,753,115
% savings [4]	Low			50.2%	53.8%	70.1%	55.5%	
	High			62.9%	64.2%	72.2%	65.6%	
Years of Growth [5] Deferred at 4%	Low			17.8	19.7	30.7	20.6	
	High			25.3	26.2	32.6	27.2	

Notes: [1] From Lovins (1986), except "low industrial" from Lovins (1985).
[2] 1 - [1].
[3] [2] x 1985 Sales from Table 4.1.
[4] 1 - Total / (Table 4.1 Total).
[5] ln (1/(1-% savings)/ln(1.04) = -ln(1-% savings)/ln(1.04).

FIGURE 2.1: DIAGRAMMATIC DESCRIPTION OF AVAILABILITY FACTOR AND CAPACITY FACTOR

```
Region:            A                   B                  C          D
              !                  ! Unit operates at ! Unit not opera-! Unit is !
              ! Unit operates at ! less than full   ! ting, though   !   not   !
              ! full rated capacity ! rated capacity ! it could be   !operable !
         100   ________________________________________________________________!
              ! \\\\\\\\\\\\\\\\\\\\/\                ! !        !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\               !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\               !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\              !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\             !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\             !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\            !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\           !          !       !
    OUTPUT    ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\          !          !       !
     as %     ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\         !          !       !
   of rated   ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\         !          !       !
   capacity   ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\        !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\       !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\      !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\      !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\\     !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\\\    !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\\\\   !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\\\\\  !          !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\\\\\\\ !         !       !
              ! \\\\\\\\\\\\\\\\\\\\/\\\\\\\\\\\\\\\\\\\!        !       !
           0   ----------------------------------------------------------------!
              0                                                               100
                                     % of HOURS in period
```

1. CAPACITY FACTOR = AVERAGE OUTPUT / RATED CAPACITY
   (Shaded Area / Area of Rectangle)

2. AVAILABILITY FACTOR = POSSIBLE HOURS OF PRODUCTION / TOTAL HOURS
   (Sum of widths A,B,C & D)

FIGURE 2.2: CAPITAL ADDITIONS

(yearly avgs. in 1983 $/MW-yr)

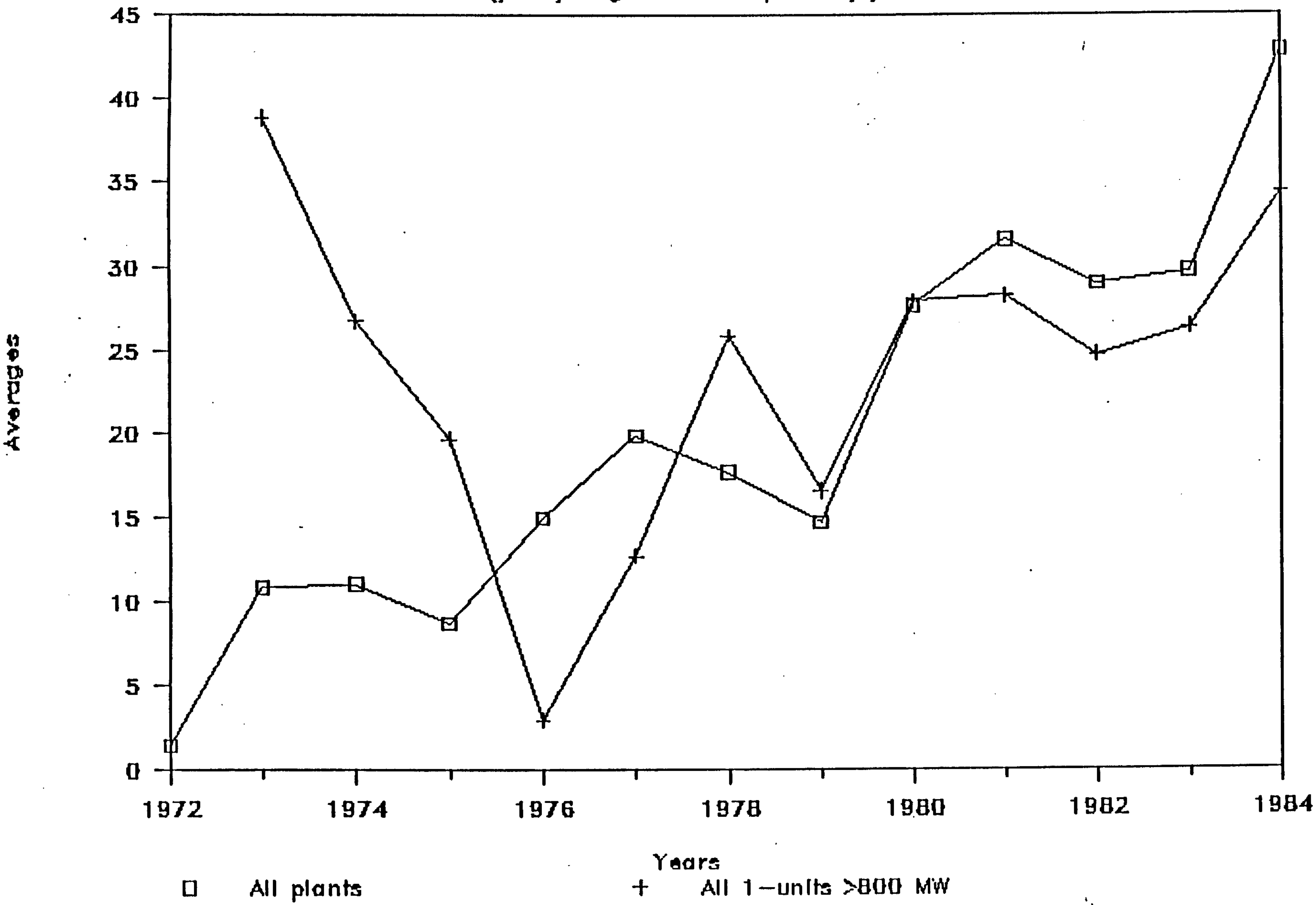


FIGURE 2.3: DECOMMISSIONING COSTS

Estimates Performed by TLG

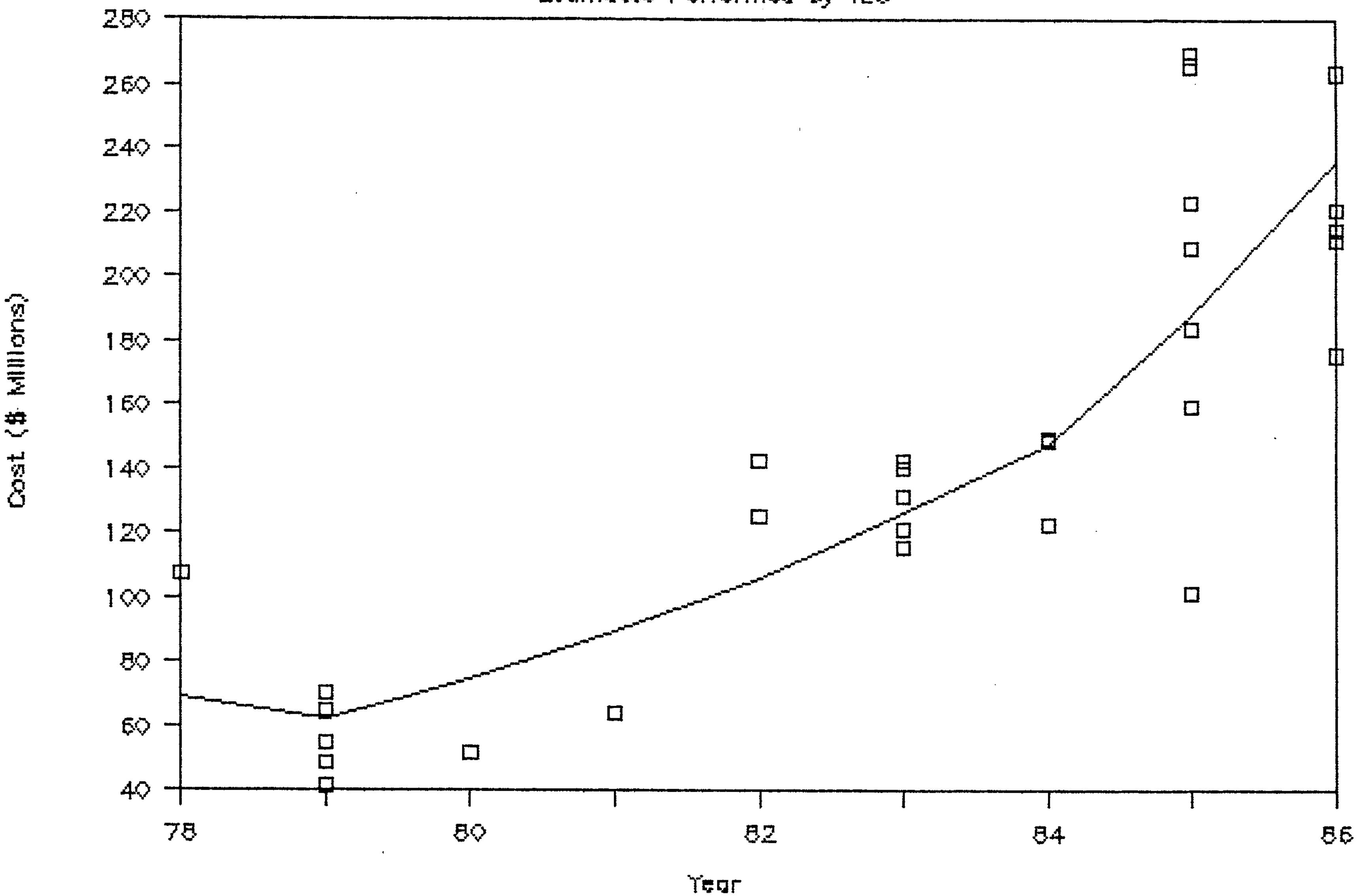


FIGURE 3.1: DURATION RATIOS DISTRIBUTED BY INTERVALS

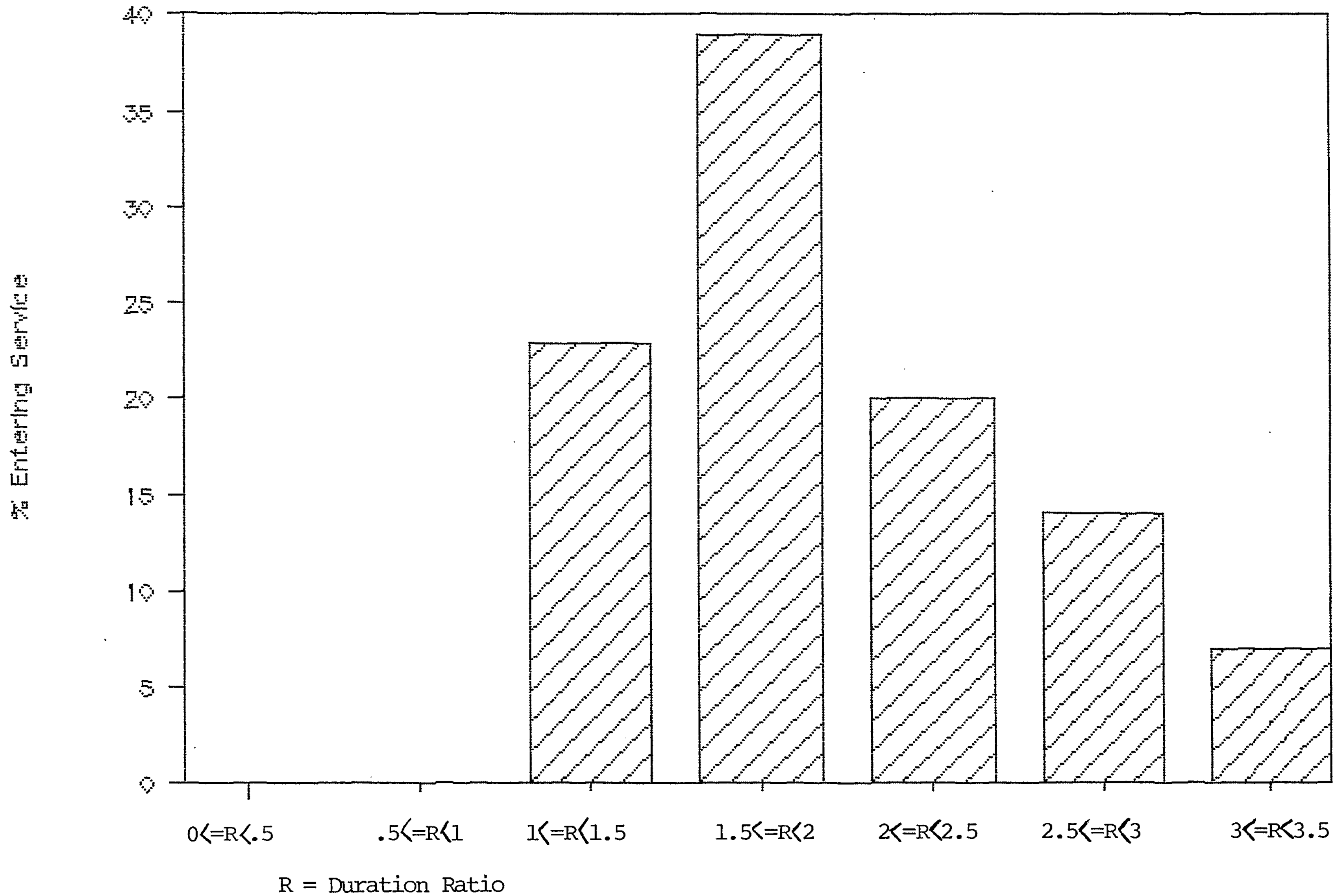
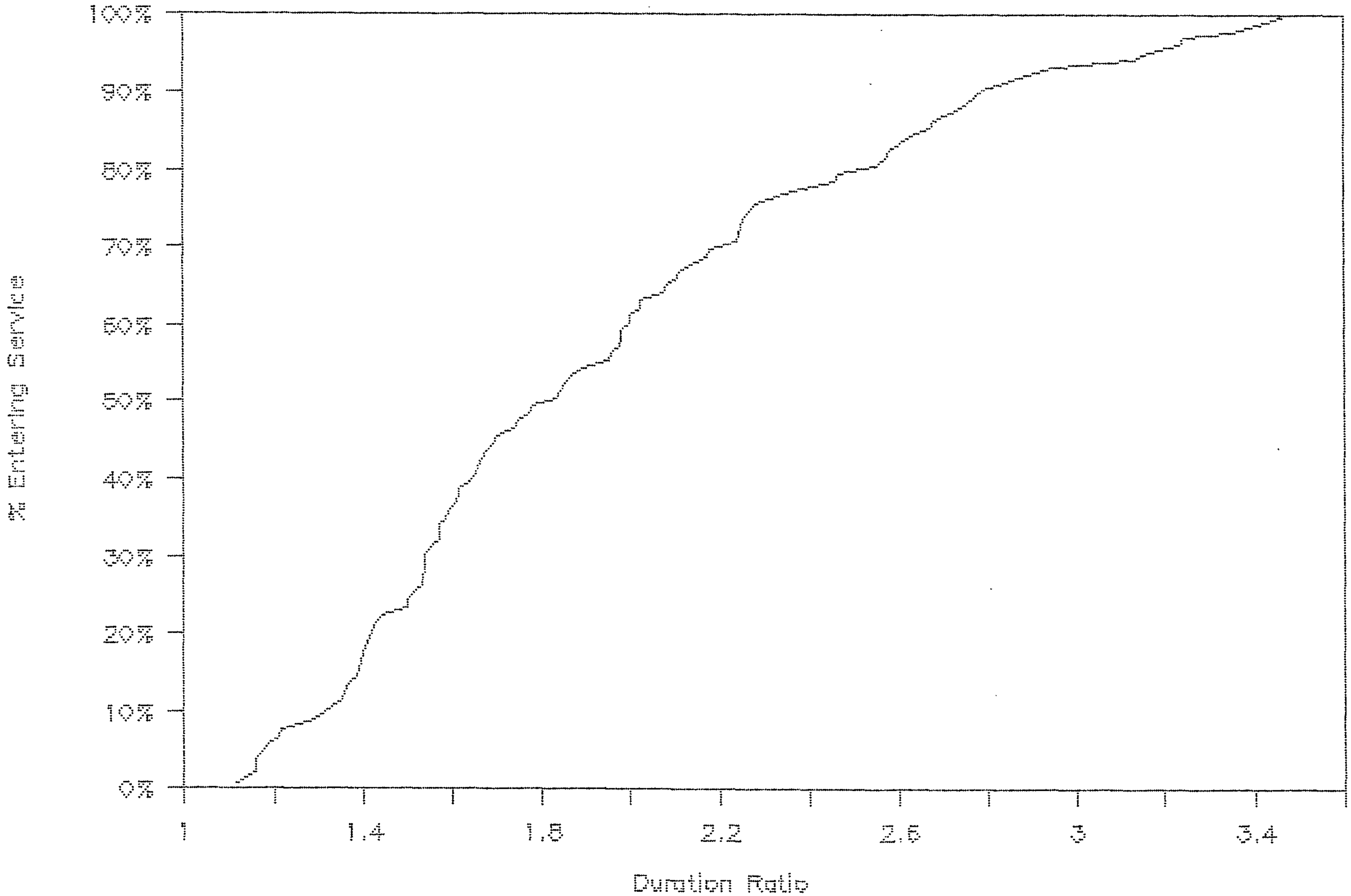


FIGURE 3.2: CUMULATIVE DISTRIBUTION OF DURATION RATIOS



APPENDIX B:

CAPACITY FACTOR DATA

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	B&W	T-G W40"	W44"	REFUEL	OUTAGE
San Onofre 1	1	450	68	1	68	1262	0.319	0.50	0	0	1	0	.	0.000
San Onofre 1	1	450	69	1	68	2607	0.661	1.50	0	0	1	0	.	0.000
San Onofre 1	1	450	70	1	68	3059	0.776	2.50	0	0	1	0	.	0.000
San Onofre 1	1	450	71	1	68	3303	0.838	3.50	0	0	1	0	.	0.000
San Onofre 1	1	450	72	1	68	2812	0.711	4.50	0	0	1	0	.	0.000
San Onofre 1	1	450	73	1	68	2267	0.575	5.50	0	0	1	0	1.000	0.000
San Onofre 1	1	450	74	1	68	3145	0.798	6.50	0	0	1	0	0.000	0.000
San Onofre 1	1	450	75	1	68	3245	0.823	7.50	0	0	1	0	1.000	0.000
San Onofre 1	1	450	76	1	68	2473	0.626	8.50	0	0	1	0	0.480	0.000
San Onofre 1	1	450	77	1	68	2333	0.592	9.50	0	0	1	0	0.520	0.000
San Onofre 1	1	450	78	1	68	2679	0.680	10.50	0	0	1	0	1.000	0.000
San Onofre 1	1	450	79	1	68	3356	0.851	11.50	0	0	1	0	0.000	0.000
San Onofre 1	1	450	80	1	68	817	0.207	12.50	0	0	1	0	1.000	0.000
San Onofre 1	1	450	81	1	68	779	0.198	13.50	0	0	1	0	0.000	1.000
San Onofre 1	1	450	82	1	68	510	0.129	14.50	0	0	1	0	0.000	1.000
San Onofre 1	1	450	83	1	68	-11.3	-0.003	15.50	0	0	1	0	0.000	1.000
San Onofre 1	1	450	84	1	68	262.6	0.067	16.50	0	0	1	0	0.000	1.000
San Onofre 1	1	450	85	1	68	2458	0.624	17.50	0	0	1	0	0.177	0.000
Conn Yankee	2	575	68	1	68	2995	0.593	0.50	0	0	0	1	.	0.000
Conn Yankee	2	575	69	1	68	3639	0.722	1.50	0	0	0	1	.	0.000
Conn Yankee	2	575	70	1	68	3538	0.702	2.50	0	0	0	1	.	0.000
Conn Yankee	2	575	71	1	68	4187	0.831	3.50	0	0	0	1	.	0.000
Conn Yankee	2	575	72	1	68	4300	0.851	4.50	0	0	0	1	.	0.000
Conn Yankee	2	575	73	1	68	2425	0.481	5.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	74	1	68	4351	0.864	6.50	0	0	0	1	0.000	0.000
Conn Yankee	2	575	75	1	68	4121	0.818	7.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	76	1	68	4028	0.797	8.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	77	1	68	4013	0.797	9.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	78	1	68	4708	0.935	10.50	0	0	0	1	0.000	0.000
Conn Yankee	2	575	79	1	68	4116	0.817	11.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	80	1	68	3563	0.705	12.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	81	1	68	4063	0.807	13.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	82	1	68	4538	0.901	14.50	0	0	0	1	0.000	0.000
Conn Yankee	2	575	83	1	68	3781	0.751	15.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	84	1	68	3362	0.667	16.50	0	0	0	1	1.000	0.000
Conn Yankee	2	575	85	1	68	4638	0.921	17.50	0	0	0	1	0.000	0.000
Ginna	3	490	71	7	70	2705	0.630	1.00	0	0	1	0	.	0.000
Ginna	3	490	72	7	70	2356	0.547	2.00	0	0	1	0	.	0.000
Ginna	3	490	73	7	70	3396	0.791	3.00	0	0	1	0	0.000	0.000
Ginna	3	490	74	7	70	2097	0.489	4.00	0	0	1	0	1.000	0.000
Ginna	3	490	75	7	70	3041	0.708	5.00	0	0	1	0	1.000	0.000
Ginna	3	490	76	7	70	2061	0.479	6.00	0	0	1	0	1.000	0.000
Ginna	3	490	77	7	70	3028	0.705	7.00	0	0	1	0	1.000	0.000
Ginna	3	490	78	7	70	3219	0.750	8.00	0	0	1	0	1.000	0.000
Ginna	3	490	79	7	70	2961	0.690	9.00	0	0	1	0	1.000	0.000
Ginna	3	490	80	7	70	3094	0.719	10.00	0	0	1	0	1.000	0.000
Ginna	3	490	81	7	70	3323	0.774	11.00	0	0	1	0	1.000	0.000
Ginna	3	490	82	7	70	2408	0.561	12.00	0	0	1	0	1.000	0.000
Ginna	3	490	83	7	70	3040	0.708	13.00	0	0	1	0	1.000	0.000
Ginna	3	490	84	7	70	3157	0.735	14.00	0	0	1	0	1.000	0.000

				Comm. Op. Date					Reactor		T-G			
Unit Name	ID#	MW (DER)	Data year	mn	yr	GWH	CF = GWH/DER/8.76	AGE	CE	B&W	W40"	W44"	REFUEL	OUTAGE
Ginna	3	490	85	7	70	3620	0.843	15.00	0	0	1	0	1.000	0.000
Point Beach 1	4	497	71	12	70	3274	0.752	0.58	0	0	1	0	.	0.000
Point Beach 1	4	497	72	12	70	2925	0.670	1.58	0	0	1	0	.	0.000
Point Beach 1	4	497	73	12	70	2743	0.630	2.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	74	12	70	3142	0.722	3.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	75	12	70	2922	0.671	4.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	76	12	70	3404	0.780	5.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	77	12	70	3687	0.847	6.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	78	12	70	3795	0.872	7.58	0	0	1	0	0.000	0.000
Point Beach 1	4	497	79	12	70	3055	0.702	8.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	80	12	70	2477	0.567	9.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	81	12	70	2615	0.601	10.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	82	12	70	2702	0.621	11.58	0	0	1	0	1.000	0.000
Point Beach 1	4	497	83	12	70	2384	0.548	12.58	0	0	1	0	0.481	0.000
Point Beach 1	4	497	84	12	70	3109	0.714	13.58	0	0	1	0	0.519	0.000
Point Beach 1	4	497	85	12	70	3354	0.770	14.58	0	0	1	0	1.000	0.000
Robinson 2	5	707	72	3	71	4829	0.778	1.33	0	0	0	1	.	0.000
Robinson 2	5	707	73	3	71	3764	0.608	2.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	74	3	71	4813	0.777	3.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	75	3	71	4171	0.673	4.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	76	3	71	4874	0.785	5.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	77	3	71	4230	0.683	6.33	0	0	0	1	0.000	0.000
Robinson 2	5	707	78	3	71	3980	0.643	7.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	79	3	71	4005	0.647	8.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	80	3	71	3211	0.517	9.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	81	3	71	3504	0.566	10.33	0	0	0	1	0.000	0.000
Robinson 2	5	707	82	3	71	2252	0.364	11.33	0	0	0	1	1.000	0.000
Robinson 2	5	707	83	3	71	3347	0.540	12.33	0	0	0	1	0.000	0.000
Robinson 2	5	707	84	3	71	190	0.031	13.33	0	0	0	1	0.977	0.000
Robinson 2	5	707	85	3	71	5240	0.846	14.33	0	0	0	1	0.023	0.000
Palisades	6	821	72	12	71	1765	0.245	0.58	1	0	0	1	.	0.000
Palisades	6	821	73	12	71	2411	0.335	1.58	1	0	0	1	0.201	0.000
Palisades	6	821	74	12	71	78	0.011	2.58	1	0	0	1	1.000	0.000
Palisades	6	821	75	12	71	2428	0.338	3.58	1	0	0	1	0.160	0.000
Palisades	6	821	76	12	71	2847	0.395	4.58	1	0	0	1	0.840	0.000
Palisades	6	821	77	12	71	5085	0.707	5.58	1	0	0	1	0.000	0.000
Palisades	6	821	78	12	71	2624	0.365	6.58	1	0	0	1	1.000	0.000
Palisades	6	821	79	12	71	3433	0.477	7.58	1	0	0	1	0.437	0.000
Palisades	6	821	80	12	71	2380	0.330	8.58	1	0	0	1	0.563	0.000
Palisades	6	821	81	12	71	3463	0.482	9.58	1	0	0	1	1.000	0.000
Palisades	6	821	82	12	71	3345	0.465	10.58	1	0	0	1	0.000	0.000
Palisades	6	821	83	12	71	3769	0.524	11.58	1	0	0	1	0.400	0.000
Palisades	6	821	84	12	71	811.5	0.113	12.58	1	0	0	1	0.600	0.000
Palisades	6	821	85	12	71	5302	0.737	13.58	1	0	0	1	0.435	0.000
Point Beach 2	7	497	73	10	72	3004	0.690	0.75	0	0	1	0	0.000	0.000
Point Beach 2	7	497	74	10	72	3178	0.730	1.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	75	10	72	3741	0.859	2.75	0	0	1	0	0.000	0.000
Point Beach 2	7	497	76	10	72	3762	0.862	3.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	77	10	72	3622	0.832	4.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	78	10	72	3859	0.886	5.75	0	0	1	0	0.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40"	T-G W44"	REFUEL	OUTAGE
Point Beach 2	7	497	79	10	72	3707	0.851	6.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	80	10	72	3588	0.822	7.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	81	10	72	3720	0.854	8.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	82	10	72	3606	0.828	9.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	83	10	72	3016	0.693	10.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	84	10	72	3512	0.807	11.75	0	0	1	0	1.000	0.000
Point Beach 2	7	497	85	10	72	3603	0.828	12.75	0	0	1	0	1.000	0.000
Surry 1	8	823	73	12	72	3461	0.480	0.58	0	0	0	1	0.000	0.000
Surry 1	8	823	74	12	72	3318	0.460	1.58	0	0	0	1	0.678	0.000
Surry 1	8	823	75	12	72	3917	0.543	2.58	0	0	0	1	0.322	0.000
Surry 1	8	823	76	12	72	4397	0.608	3.58	0	0	0	1	0.767	0.000
Surry 1	8	823	77	12	72	5024	0.697	4.58	0	0	0	1	0.233	0.000
Surry 1	8	823	78	12	72	4704	0.652	5.58	0	0	0	1	1.000	0.000
Surry 1	8	823	79	12	72	2255	0.313	6.58	0	0	0	1	0.000	1.000
Surry 1	8	823	80	12	72	2473	0.342	7.58	0	0	0	1	0.000	1.000
Surry 1	8	823	81	12	72	2377	0.330	8.58	0	0	0	1	0.000	1.000
Surry 1	8	823	82	12	72	5483	0.761	9.58	0	0	0	1	0.000	0.000
Surry 1	8	823	83	12	72	4086	0.567	10.58	0	0	0	1	1.000	0.000
Surry 1	8	823	84	12	72	3334	0.462	11.58	0	0	0	1	1.000	0.000
Surry 1	8	823	85	12	72	5618	0.779	12.58	0	0	0	1	0.000	0.000
Turkey Point 3	9	745	73	12	72	3328	0.510	0.58	0	0	0	1	0.000	0.000
Turkey Point 3	9	745	74	12	72	3624	0.555	1.58	0	0	0	1	1.000	0.000
Turkey Point 3	9	745	75	12	72	4375	0.670	2.58	0	0	0	1	1.000	0.000
Turkey Point 3	9	745	76	12	72	4320	0.660	3.58	0	0	0	1	0.722	0.000
Turkey Point 3	9	745	77	12	72	4471	0.685	4.58	0	0	0	1	0.721	0.000
Turkey Point 3	9	745	78	12	72	4501	0.690	5.58	0	0	0	1	0.557	0.000
Turkey Point 3	9	745	79	12	72	2875	0.441	6.58	0	0	0	1	0.458	0.000
Turkey Point 3	9	745	80	12	72	4387	0.670	7.58	0	0	0	1	0.542	0.000
Turkey Point 3	9	745	81	12	72	912	0.140	8.58	0	0	0	1	1.000	0.000
Turkey Point 3	9	745	82	12	72	3766	0.577	9.58	0	0	0	1	0.000	0.000
Turkey Point 3	9	745	83	12	72	4325	0.663	10.58	0	0	0	1	0.930	0.000
Turkey Point 3	9	745	84	12	72	4784	0.733	11.58	0	0	0	1	0.070	0.000
Turkey Point 3	9	745	85	12	72	3412	0.523	12.58	0	0	0	1	1.000	0.000
Maine Yankee	10	790	73	12	72	3351	0.484	0.58	1	0	0	1	0.000	0.000
Maine Yankee	10	790	74	12	72	3574	0.516	1.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	75	12	72	4502	0.651	2.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	76	12	72	5929	0.854	3.58	1	0	0	1	0.000	0.000
Maine Yankee	10	790	77	12	72	5145	0.743	4.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	78	12	72	5355	0.774	5.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	79	12	72	4539	0.656	6.58	1	0	0	1	0.000	0.000
Maine Yankee	10	790	80	12	72	4404	0.635	7.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	81	12	72	5212	0.753	8.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	82	12	72	4524	0.654	9.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	83	12	72	4634	0.670	10.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	84	12	72	5134	0.742	11.58	1	0	0	1	1.000	0.000
Maine Yankee	10	790	85	12	72	5354	0.774	12.58	1	0	0	1	1.000	0.000
Surry 2	11	823	74	5	73	2635	0.365	1.17	0	0	0	1	0.000	1.000
Surry 2	11	823	75	5	73	5053	0.701	2.17	0	0	0	1	1.000	0.000
Surry 2	11	823	76	5	73	3343	0.462	3.17	0	0	0	1	1.000	0.000
Surry 2	11	823	77	5	73	4457	0.618	4.17	0	0	0	1	1.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40"	T-G W44"	REFUEL	OUTAGE
Surry 2	11	823	78	5	73	5372	0.745	5.17	0	0	0	1	0.000	0.000
Surry 2	11	823	79	5	73	612	0.085	6.17	0	0	0	1	0.846	0.000
Surry 2	11	823	80	5	73	2242	0.310	7.17	0	0	0	1	0.154	0.000
Surry 2	11	823	81	5	73	5150	0.714	8.17	0	0	0	1	1.000	0.000
Surry 2	11	823	82	5	73	5492	0.762	9.17	0	0	0	1	0.000	0.000
Surry 2	11	823	83	5	73	4086	0.567	10.17	0	0	0	1	1.000	0.000
Surry 2	11	823	84	5	73	5209	0.723	11.17	0	0	0	1	0.000	0.000
Surry 2	11	823	85	5	73	4072	0.565	12.17	0	0	0	1	1.000	0.000
Oconee 1	12	886	74	7	73	3998	0.515	1.00	0	1	0	0	0.702	0.000
Oconee 1	12	886	75	7	73	5286	0.681	2.00	0	1	0	0	0.298	0.000
Oconee 1	12	886	76	7	73	3994	0.513	3.00	0	1	0	0	1.000	0.000
Oconee 1	12	886	77	7	73	3944	0.508	4.00	0	1	0	0	1.000	0.000
Oconee 1	12	886	78	7	73	5054	0.651	5.00	0	1	0	0	1.000	0.000
Oconee 1	12	886	79	7	73	5000	0.644	6.00	0	1	0	0	0.720	0.000
Oconee 1	12	886	80	7	73	5117	0.657	7.00	0	1	0	0	0.280	0.000
Oconee 1	12	886	81	7	73	2996	0.386	8.00	0	1	0	0	1.000	0.000
Oconee 1	12	886	82	7	73	5153	0.664	9.00	0	1	0	0	0.000	0.000
Oconee 1	12	886	83	7	73	5141	0.662	10.00	0	1	0	0	1.000	0.000
Oconee 1	12	886	84	7	73	6167	0.795	11.00	0	1	0	0	1.000	0.000
Oconee 1	12	886	85	7	73	7066	0.910	12.00	0	1	0	0	0.000	0.000
Indian Point 2	13	873	74	8	73	3324	0.435	0.92	0	0	0	1	0.000	0.000
Indian Point 2	13	873	75	8	73	4885	0.639	1.92	0	0	0	1	0.000	0.000
Indian Point 2	13	873	76	8	73	2268	0.296	2.92	0	0	0	1	1.000	0.000
Indian Point 2	13	873	77	8	73	5210	0.681	3.92	0	0	0	1	0.000	0.000
Indian Point 2	13	873	78	8	73	4369	0.571	4.92	0	0	0	1	1.000	0.000
Indian Point 2	13	873	79	8	73	4805	0.628	5.92	0	0	0	1	1.000	0.000
Indian Point 2	13	873	80	8	73	4264	0.556	6.92	0	0	0	1	0.332	0.000
Indian Point 2	13	873	81	8	73	3055	0.399	7.92	0	0	0	1	0.668	0.000
Indian Point 2	13	873	82	8	73	4447	0.581	8.92	0	0	0	1	1.000	0.000
Indian Point 2	13	873	83	8	73	60.73	0.008	9.92	0	0	0	1	0.427	0.000
Indian Point 2	13	873	84	8	73	2887	0.378	10.92	0	0	0	1	0.573	0.000
Indian Point 2	13	873	85	8	73	6665	0.872	11.92	0	0	0	1	0.000	0.000
Turkey Point 4	14	745	74	9	73	4293	0.658	0.83	0	0	0	1	0.000	0.000
Turkey Point 4	14	745	75	9	73	3990	0.611	1.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	76	9	73	3772	0.576	2.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	77	9	73	3666	0.562	3.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	78	9	73	3788	0.580	4.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	79	9	73	3845	0.589	5.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	80	9	73	3854	0.589	6.83	0	0	0	1	0.797	0.000
Turkey Point 4	14	745	81	9	73	4505	0.690	7.83	0	0	0	1	0.203	0.000
Turkey Point 4	14	745	82	9	73	3845	0.589	8.83	0	0	0	1	0.000	0.000
Turkey Point 4	14	745	83	9	73	2973	0.456	9.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	84	9	73	3079	0.472	10.83	0	0	0	1	1.000	0.000
Turkey Point 4	14	745	85	9	73	5178	0.793	11.83	0	0	0	1	0.000	0.000
Fort Calhoun	15	457	74	9	73	2416	0.603	0.83	1	0	0	0	0.000	0.000
Fort Calhoun	15	457	75	9	73	2081	0.520	1.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	76	9	73	2195	0.547	2.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	77	9	73	2993	0.748	3.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	78	9	73	2849	0.712	4.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	79	9	73	3666	0.916	5.83	1	0	0	0	0.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40"	T-G W44"	REFUEL	OUTAGE
Fort Calhoun	15	457	80	9	73	2011	0.501	6.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	81	9	73	2150	0.537	7.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	82	9	73	3482	0.870	8.83	1	0	0	0	0.209	0.000
Fort Calhoun	15	457	83	9	73	0.07	0.000	9.83	1	0	0	0	0.791	0.000
Fort Calhoun	15	457	84	9	73	2332	0.583	10.83	1	0	0	0	1.000	0.000
Fort Calhoun	15	457	85	9	73	3066	0.766	11.83	1	0	0	0	0.753	0.000
Prairie Island 1	16	530	74	12	73	1433	0.309	0.58	0	0	1	0	0.000	0.000
Prairie Island 1	16	530	75	12	73	3694	0.796	1.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	76	12	73	3269	0.702	2.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	77	12	73	3715	0.800	3.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	78	12	73	3811	0.821	4.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	79	12	73	2911	0.627	5.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	80	12	73	3106	0.667	6.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	81	12	73	3839	0.827	7.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	82	12	73	3918	0.844	8.58	0	0	1	0	1.000	0.000
Prairie Island 1	16	530	83	12	73	3888	0.837	9.58	0	0	1	0	0.916	0.000
Prairie Island 1	16	530	84	12	73	4159	0.896	10.58	0	0	1	0	0.084	0.000
Prairie Island 1	16	530	85	12	73	3677	0.792	11.58	0	0	1	0	1.000	0.000
Zion 1	17	1050	74	12	73	3478	0.378	0.58	0	0	0	1	0.000	1.000
Zion 1	17	1050	75	12	73	4909	0.534	1.58	0	0	0	1	0.000	0.000
Zion 1	17	1050	76	12	73	4757	0.516	2.58	0	0	0	1	1.000	0.000
Zion 1	17	1050	77	12	73	5034	0.547	3.58	0	0	0	1	1.000	0.000
Zion 1	17	1050	78	12	73	6770	0.736	4.58	0	0	0	1	1.000	0.000
Zion 1	17	1050	79	12	73	5537	0.602	5.58	0	0	0	1	1.000	0.000
Zion 1	17	1050	80	12	73	6515	0.706	6.58	0	0	0	1	0.000	0.000
Zion 1	17	1050	81	12	73	6193	0.673	7.58	0	0	0	1	1.000	0.000
Zion 1	17	1050	82	12	73	4695	0.510	8.58	0	0	0	1	1.000	0.000
Zion 1	17	1050	83	12	73	4016	0.437	9.58	0	0	0	1	0.855	0.000
Zion 1	17	1050	84	12	73	5692	0.619	10.58	0	0	0	1	0.145	0.000
Zion 1	17	1050	85	12	73	4814	0.523	11.58	0	0	0	1	1.000	0.000
Kewaunee	18	560	75	6	74	3341	0.681	1.08	0	0	1	0	0.000	0.000
Kewaunee	18	560	76	6	74	3383	0.688	2.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	77	6	74	3546	0.723	3.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	78	6	74	3890	0.793	4.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	79	6	74	3439	0.701	5.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	80	6	74	3632	0.738	6.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	81	6	74	3769	0.768	7.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	82	6	74	3825	0.780	8.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	83	6	74	3706	0.755	9.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	84	6	74	3810	0.777	10.08	0	0	1	0	1.000	0.000
Kewaunee	18	560	85	6	74	3699	0.754	11.08	0	0	1	0	1.000	0.000
Oconee 2	19	886	75	9	74	4968	0.640	0.83	0	1	0	0	0.000	0.000
Oconee 2	19	886	76	9	74	4229	0.543	1.83	0	1	0	0	1.000	0.000
Oconee 2	19	886	77	9	74	3825	0.493	2.83	0	1	0	0	1.000	0.000
Oconee 2	19	886	78	9	74	4786	0.617	3.83	0	1	0	0	1.000	0.000
Oconee 2	19	886	79	9	74	5968	0.769	4.83	0	1	0	0	0.000	0.000
Oconee 2	19	886	80	9	74	3879	0.498	5.83	0	1	0	0	1.000	0.000
Oconee 2	19	886	81	9	74	5190	0.669	6.83	0	1	0	0	0.045	0.000
Oconee 2	19	886	82	9	74	3437	0.443	7.83	0	1	0	0	0.955	0.000
Oconee 2	19	886	83	9	74	5141	0.662	8.83	0	1	0	0	1.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40*	T-G W44*	REFUEL	OUTAGE
Oconee 2	19	886	84	9	74	7298	0.940	9.83	0	1	0	0	0.000	0.000
Oconee 2	19	886	85	9	74	5058	0.652	10.83	0	1	0	0	1.000	0.000
TMI 1	20	819	75	9	74	5542	0.772	0.83	0	1	0	0	0.000	0.000
TMI 1	20	819	76	9	74	4336	0.603	1.83	0	1	0	0	1.000	0.000
TMI 1	20	819	77	9	74	5463	0.761	2.83	0	1	0	0	1.000	0.000
TMI 1	20	819	78	9	74	5674	0.791	3.83	0	1	0	0	1.000	0.000
Zion 2	21	1050	75	9	74	4829	0.525	0.83	0	0	0	1	0.000	0.000
Zion 2	21	1050	76	9	74	4641	0.503	1.83	0	0	0	1	0.000	0.000
Zion 2	21	1050	77	9	74	6275	0.682	2.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	78	9	74	6732	0.732	3.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	79	9	74	4760	0.518	4.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	80	9	74	5279	0.572	5.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	81	9	74	5257	0.572	6.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	82	9	74	5158	0.561	7.83	0	0	0	1	0.000	0.000
Zion 2	21	1050	83	9	74	6181	0.672	8.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	84	9	74	5986	0.651	9.83	0	0	0	1	1.000	0.000
Zion 2	21	1050	85	9	74	5114	0.556	10.83	0	0	0	1	0.894	0.000
Oconee 3	22	986	75	12	74	5037	0.583	0.58	0	1	0	0	0.000	0.000
Oconee 3	22	986	76	12	74	4735	0.549	1.58	0	1	0	0	1.000	0.000
Oconee 3	22	986	77	12	74	5239	0.607	2.58	0	1	0	0	1.000	0.000
Oconee 3	22	986	78	12	74	6064	0.702	3.58	0	1	0	0	1.000	0.000
Oconee 3	22	986	79	12	74	3260	0.377	4.58	0	1	0	0	1.000	0.000
Oconee 3	22	986	80	12	74	5218	0.602	5.58	0	1	0	0	0.264	0.000
Oconee 3	22	886	81	12	74	~~5637~~	~~0.726~~	~~6.58~~	~~0~~	~~1~~	~~0~~	~~0~~	~~0.736~~	~~0.000~~
Oconee 3	22	986	82	12	74	2117	0.245	7.58	0	1	0	0	1.000	0.000
Oconee 3	22	986	83	12	74	7099	0.822	8.58	0	1	0	0	0.000	0.000
Oconee 3	22	986	84	12	74	5354	0.620	9.58	0	1	0	0	1.000	0.000
Oconee 3	22	986	85	12	74	4858	0.562	10.58	0	1	0	0	1.000	0.000
Arkansas 1	23	850	75	12	74	4880	0.655	0.58	0	1	0	1	0.000	0.000
Arkansas 1	23	850	76	12	74	3888	0.521	1.58	0	1	0	1	0.000	0.000
Arkansas 1	23	850	77	12	74	5103	0.685	2.58	0	1	0	1	1.000	0.000
Arkansas 1	23	850	78	12	74	5250	0.705	3.58	0	1	0	1	1.000	0.000
Arkansas 1	23	850	79	12	74	3323	0.446	4.58	0	1	0	1	1.000	0.000
Arkansas 1	23	850	80	12	74	3782	0.507	5.58	0	1	0	1	0.000	0.000
Arkansas 1	23	850	81	12	74	4901	0.658	6.58	0	1	0	1	1.000	0.000
Arkansas 1	23	850	82	12	74	3721	0.500	7.58	0	1	0	1	0.369	0.000
Arkansas 1	23	850	83	12	74	3220	0.432	8.58	0	1	0	1	0.631	0.000
Arkansas 1	23	850	84	12	74	4604	0.618	9.58	0	1	0	1	0.763	0.000
Arkansas 1	23	850	85	12	74	5190	0.697	10.58	0	1	0	1	0.237	0.000
Prairie Island 2	24	530	75	12	74	3176	0.684	0.58	0	0	1	0	0.000	0.000
Prairie Island 2	24	530	76	12	74	2661	0.572	1.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	77	12	74	3882	0.836	2.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	78	12	74	3924	0.845	3.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	79	12	74	4193	0.903	4.58	0	0	1	0	0.000	0.000
Prairie Island 2	24	530	80	12	74	3469	0.745	5.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	81	12	74	3093	0.666	6.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	82	12	74	3858	0.831	7.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	83	12	74	3716	0.800	8.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	84	12	74	3906	0.841	9.58	0	0	1	0	1.000	0.000
Prairie Island 2	24	530	85	12	74	3608	0.777	10.58	0	0	1	0	1.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40"	T-G W44"	REFUEL	OUTAGE
Rancho Seco	25	913	76	4	75	2205	0.275	1.25	0	1	0	1	0.000	1.000
Rancho Seco	25	913	77	4	75	5880	0.735	2.25	0	1	0	1	1.000	0.000
Rancho Seco	25	913	78	4	75	4988	0.624	3.25	0	1	0	1	1.000	0.000
Rancho Seco	25	913	79	4	75	5712	0.714	4.25	0	1	0	1	0.000	0.000
Rancho Seco	25	913	80	4	75	4415	0.551	5.25	0	1	0	1	1.000	0.000
Rancho Seco	25	913	81	4	75	2631	0.329	6.25	0	1	0	1	1.000	0.000
Rancho Seco	25	913	82	4	75	3367	0.421	7.25	0	1	0	1	0.000	0.000
Rancho Seco	25	913	83	4	75	2850	0.356	8.25	0	1	0	1	1.000	0.000
Rancho Seco	25	913	84	4	75	3768	0.471	9.25	0	1	0	1	0.000	0.000
Rancho Seco	25	913	85	4	75	1936	0.242	10.25	0	1	0	1	1.000	0.000
Calvert Cliffs 1	26	845	76	5	75	6304	0.849	1.17	1	0	0	0	0.001	0.000
Calvert Cliffs 1	26	845	77	5	75	4882	0.660	2.17	1	0	0	0	0.999	0.000
Calvert Cliffs 1	26	845	78	5	75	4676	0.632	3.17	1	0	0	0	1.000	0.000
Calvert Cliffs 1	26	845	79	5	75	4194	0.567	4.17	1	0	0	0	1.000	0.000
Calvert Cliffs 1	26	845	80	5	75	4534	0.611	5.17	1	0	0	0	0.000	0.000
Calvert Cliffs 1	26	845	81	5	75	6110	0.825	6.17	1	0	0	0	1.000	0.000
Calvert Cliffs 1	26	845	82	5	75	5362	0.724	7.17	1	0	0	0	1.000	0.000
Calvert Cliffs 1	26	845	83	5	75	5570	0.752	8.17	1	0	0	0	1.000	0.000
Calvert Cliffs 1	26	845	84	5	75	6222	0.841	9.17	1	0	0	0	0.000	0.000
Calvert Cliffs 1	26	845	85	5	75	4360	0.589	10.17	1	0	0	0	1.000	0.000
Cook 1	27	1090	76	8	75	6805	0.711	0.92	0	0	0	0	0.130	0.000
Cook 1	27	1090	77	8	75	4786	0.501	1.92	0	0	0	0	0.870	0.000
Cook 1	27	1090	78	8	75	6287	0.658	2.92	0	0	0	0	1.000	0.000
Cook 1	27	1090	79	8	75	5660	0.593	3.92	0	0	0	0	1.000	0.000
Cook 1	27	1090	80	8	75	6462	0.675	4.92	0	0	0	0	1.000	0.000
Cook 1	27	1090	81	8	75	6782	0.710	5.92	0	0	0	0	1.000	0.000
Cook 1	27	1090	82	8	75	5353	0.561	6.92	0	0	0	0	1.000	0.000
Cook 1	27	1090	83	8	75	5286	0.554	7.92	0	0	0	0	1.000	0.000
Cook 1	27	1090	84	8	75	7551	0.791	8.92	0	0	0	0	0.000	0.000
Cook 1	27	1090	85	8	75	2116	0.222	9.92	0	0	0	0	1.000	0.000
Millstone 2	28	828	76	12	75	4539	0.624	0.58	1	0	0	0	0.000	0.000
Millstone 2	28	828	77	12	75	4343	0.599	1.58	1	0	0	0	0.326	0.000
Millstone 2	28	828	78	12	75	4500	0.620	2.58	1	0	0	0	0.674	0.000
Millstone 2	28	828	79	12	75	4364	0.602	3.58	1	0	0	0	1.000	0.000
Millstone 2	28	828	80	12	75	4882	0.671	4.58	1	0	0	0	1.000	0.000
Millstone 2	28	828	81	12	75	6092	0.840	5.58	1	0	0	0	0.267	0.000
Millstone 2	28	828	82	12	75	5009	0.691	6.58	1	0	0	0	0.733	0.000
Millstone 2	28	828	83	12	75	2453	0.338	7.58	1	0	0	0	0.954	0.000
Millstone 2	28	828	84	12	75	6608	0.911	8.58	1	0	0	0	0.046	0.000
Millstone 2	28	828	85	12	75	3498	0.482	9.58	1	0	0	0	1.000	0.000
Trojan	29	1130	77	5	76	6492	0.656	1.17	0	0	0	0	0.000	0.000
Trojan	29	1130	78	5	76	1666	0.168	2.17	0	0	0	0	1.000	0.000
Trojan	29	1130	79	5	76	5267	0.532	3.17	0	0	0	0	0.000	0.000
Trojan	29	1130	80	5	76	6073	0.612	4.17	0	0	0	0	1.000	0.000
Trojan	29	1130	81	5	76	6424	0.649	5.17	0	0	0	0	1.000	0.000
Trojan	29	1130	82	5	76	4802	0.485	6.17	0	0	0	0	1.000	0.000
Trojan	29	1130	83	5	76	4081	0.412	7.17	0	0	0	0	1.000	0.000
Trojan	29	1130	84	5	76	4736	0.478	8.17	0	0	0	0	1.000	0.000
Trojan	29	1130	85	5	76	6911	0.698	9.17	0	0	0	0	1.000	0.000
Indian Point 3	30	873	77	8	76	5518	0.722	0.92	0	0	0	1	0.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40"	T-G W44"	REFUEL	OUTAGE
Indian Point 3	30	873	78	8	76	5457	0.714	1.92	0	0	0	1	1.000	0.000
Indian Point 3	30	873	79	8	76	4795	0.627	2.92	0	0	0	1	0.721	0.000
Indian Point 3	30	873	80	8	76	3071	0.400	3.92	0	0	0	1	0.279	0.000
Indian Point 3	30	873	81	8	76	3033	0.397	4.92	0	0	0	1	0.000	0.000
Indian Point 3	30	873	82	8	76	1436	0.188	5.92	0	0	0	1	0.640	0.000
Indian Point 3	30	873	83	8	76	60.74	0.008	6.92	0	0	0	1	0.360	0.000
Indian Point 3	30	873	84	8	76	6042	0.790	7.92	0	0	0	1	0.000	0.000
Indian Point 3	30	873	85	8	76	4729	0.618	8.92	0	0	0	1	1.000	0.000
Beaver Valley 1	31	852	77	10	76	2970	0.398	0.75	0	0	0	1	0.000	0.000
Beaver Valley 1	31	852	78	10	76	2480	0.332	1.75	0	0	0	1	0.000	1.000
Beaver Valley 1	31	852	79	10	76	1778	0.238	2.75	0	0	0	1	0.087	0.000
Beaver Valley 1	31	852	80	10	76	301	0.040	3.75	0	0	0	1	0.913	0.000
Beaver Valley 1	31	852	81	10	76	4662	0.625	4.75	0	0	0	1	1.000	0.000
Beaver Valley 1	31	852	82	10	76	2688	0.360	5.75	0	0	0	1	1.000	0.000
Beaver Valley 1	31	852	83	10	76	4676	0.627	6.75	0	0	0	1	1.000	0.000
Beaver Valley 1	31	852	84	10	76	4746	0.636	7.75	0	0	0	1	0.958	0.000
Beaver Valley 1	31	852	85	10	76	5901	0.791	8.75	0	0	0	1	0.042	0.000
St. Lucie 1	32	802	77	12	76	5344	0.761	0.58	1	0	0	1	0.000	0.000
St. Lucie 1	32	802	78	12	76	5000	0.712	1.58	1	0	0	1	1.000	0.000
St. Lucie 1	32	802	79	12	76	4885	0.695	2.58	1	0	0	1	1.000	0.000
St. Lucie 1	32	802	80	12	76	5200	0.738	3.58	1	0	0	1	1.000	0.000
St. Lucie 1	32	802	81	12	76	4947	0.704	4.58	1	0	0	1	1.000	0.000
St. Lucie 1	32	802	82	12	76	6785	0.966	5.58	1	0	0	1	0.000	0.000
St. Lucie 1	32	802	83	12	76	1070	0.152	6.58	1	0	0	1	0.693	0.000
St. Lucie 1	32	802	84	12	76	4228	0.602	7.58	1	0	0	1	0.307	0.000
St. Lucie 1	32	802	85	12	76	5866	0.835	8.58	1	0	0	1	1.000	0.000
Crystal River 3	33	825	78	3	77	2592	0.359	1.33	0	1	0	1	0.000	1.000
Crystal River 3	33	825	79	3	77	3762	0.521	2.33	0	1	0	1	1.000	0.000
Crystal River 3	33	825	80	3	77	3354	0.463	3.33	0	1	0	1	1.000	0.000
Crystal River 3	33	825	81	3	77	4084	0.565	4.33	0	1	0	1	1.000	0.000
Crystal River 3	33	825	82	3	77	4916	0.680	5.33	0	1	0	1	0.000	0.000
Crystal River 3	33	825	83	3	77	3772	0.522	6.33	0	1	0	1	1.000	0.000
Crystal River 3	33	825	84	3	77	6479	0.896	7.33	0	1	0	1	0.000	0.000
Crystal River 3	33	825	85	3	77	2849	0.394	8.33	0	1	0	1	1.000	0.000
Calvert Cliffs 2	34	845	78	4	77	5227	0.706	1.25	1	0	1	0	1.000	0.000
Calvert Cliffs 2	34	845	79	4	77	5489	0.742	2.25	1	0	1	0	1.000	0.000
Calvert Cliffs 2	34	845	80	4	77	6413	0.364	3.25	1	0	1	0	0.000	0.000
Calvert Cliffs 2	34	845	81	4	77	5416	0.732	4.25	1	0	1	0	1.000	0.000
Calvert Cliffs 2	34	845	82	4	77	5005	0.676	5.25	1	0	1	0	0.500	0.000
Calvert Cliffs 2	34	845	83	4	77	6113	0.826	6.25	1	0	1	0	0.000	0.000
Calvert Cliffs 2	34	845	84	4	77	5338	0.721	7.25	1	0	1	0	1.000	0.000
Calvert Cliffs 2	34	845	85	4	77	5608	0.758	8.25	1	0	1	0	1.000	0.000
Salem 1	35	1090	78	6	77	4529	0.474	1.08	0	0	0	1	0.000	0.000
Salem 1	35	1090	79	6	77	2043	0.214	2.08	0	0	0	1	1.000	0.000
Salem 1	35	1090	80	6	77	5684	0.594	3.08	0	0	0	1	1.000	0.000
Salem 1	35	1090	81	6	77	6191	0.648	4.08	0	0	0	1	0.000	0.000
Salem 1	35	1090	82	6	77	4095	0.429	5.08	0	0	0	1	1.000	0.000
Salem 1	35	1090	83	6	77	5376	0.563	6.08	0	0	0	1	0.000	0.000
Salem 1	35	1090	84	6	77	2127	0.223	7.08	0	0	0	1	1.000	0.000
Salem 1	35	1090	85	6	77	9008	0.943	8.08	0	0	0	1	0.000	0.000

Unit Name	ID#	MW (DER)	Data year	Comm. Op. Date mn	Comm. Op. Date yr	GWH	CF = GWH/DER/8.76	AGE	Reactor CE	Reactor B&W	T-G W40"	T-G W44"	REFUEL	OUTAGE
Davis-Besse 1	36	906	78	11	77	2612	0.329	0.67	0	1	0	0	0.000	0.000
Davis-Besse 1	36	906	79	11	77	3129	0.394	1.67	0	1	0	0	0.000	0.000
Davis-Besse 1	36	906	80	11	77	2094	0.263	2.67	0	1	0	0	1.000	0.000
Davis-Besse 1	36	906	81	11	77	4363	0.550	3.67	0	1	0	0	0.000	0.000
Davis-Besse 1	36	906	82	11	77	3218	0.405	4.67	0	1	0	0	1.000	0.000
Davis-Besse 1	36	906	83	11	77	4883	0.615	5.67	0	1	0	0	1.000	0.000
Davis-Besse 1	36	906	84	11	77	4292	0.541	6.67	0	1	0	0	0.857	0.000
Davis-Besse 1	36	906	85	11	77	1943	0.245	7.67	0	1	0	0	0.143	0.000
Farley 1	37	829	78	12	77	5920	0.815	0.58	0	0	0	1	0.000	0.000
Farley 1	37	829	79	12	77	1744	0.240	1.58	0	0	0	1	1.000	0.000
Farley 1	37	829	80	12	77	4604	0.632	2.58	0	0	0	1	0.392	0.000
Farley 1	37	829	81	12	77	2616	0.360	3.58	0	0	0	1	1.234	0.000
Farley 1	37	829	82	12	77	5216	0.718	4.58	0	0	0	1	0.374	0.000
Farley 1	37	829	83	12	77	5983	0.824	5.58	0	0	0	1	1.000	0.000
Farley 1	37	829	84	12	77	5428	0.747	6.58	0	0	0	1	1.000	0.000
Farley 1	37	829	85	12	77	5869	0.808	7.58	0	0	0	1	1.000	0.000
Cook 2	38	1100	79	3	78	5953	0.618	1.33	0	0	0	0	0.789	0.000
Cook 2	38	1100	80	3	78	6692	0.693	2.33	0	0	0	0	0.211	0.000
Cook 2	38	1100	81	3	78	6385	0.663	3.33	0	0	0	0	1.000	0.000
Cook 2	38	1100	82	3	78	6996	0.726	4.33	0	0	0	0	0.649	0.000
Cook 2	38	1100	83	3	78	7013	0.728	5.33	0	0	0	0	0.351	0.000
Cook 2	38	1100	84	3	78	5364	0.557	6.33	0	0	0	0	1.000	0.000
Cook 2	38	1100	85	3	78	5684	0.590	7.33	0	0	0	0	0.000	0.000
North Anna 1	39	907	79	6	78	4189	0.527	1.08	0	0	0	1	0.821	0.000
North Anna 1	39	907	80	6	78	5632	0.707	2.08	0	0	0	1	0.179	0.000
North Anna 1	39	907	81	6	78	4638	0.584	3.08	0	0	0	1	0.029	0.000
North Anna 1	39	907	82	6	78	2398	0.302	4.08	0	0	0	1	0.971	0.000
North Anna 1	39	907	83	6	78	5310	0.668	5.08	0	0	0	1	0.000	0.000
North Anna 1	39	907	84	6	78	3785	0.476	6.08	0	0	0	1	1.000	0.000
North Anna 1	39	907	85	6	78	5799	0.730	7.08	0	0	0	1	1.000	0.000
Arkansas 2	40	912	81	3	80	4324	0.541	1.33	1	0	0	1	1.000	0.000
Arkansas 2	40	912	82	3	80	3807	0.477	2.33	1	0	0	1	1.000	0.000
Arkansas 2	40	912	83	3	80	4427	0.554	3.33	1	0	0	1	0.736	0.000
Arkansas 2	40	912	84	3	80	6204	0.777	4.33	1	0	0	1	0.264	0.000
Arkansas 2	40	912	85	3	80	4699	0.588	5.33	1	0	0	1	1.000	0.000
North Anna 2	41	907	81	12	80	5653	0.711	0.58	0	0	0	1	0.000	0.000
North Anna 2	41	907	82	12	80	4047	0.509	1.58	0	0	0	1	1.000	0.000
North Anna 2	41	907	83	12	80	5802	0.730	2.58	0	0	0	1	1.000	0.000
North Anna 2	41	907	84	12	80	4717	0.594	3.58	0	0	0	1	1.000	0.000
North Anna 2	41	907	85	12	80	6814	0.858	4.58	0	0	0	1	0.000	0.000
Sequoyah 1	43	1128	82	7	81	4909	0.497	1.00	0	0	0	1	1.000	0.000
Sequoyah 1	43	1128	83	7	81	7340	0.743	2.00	0	0	0	1	1.000	0.000
Sequoyah 1	43	1128	84	7	81	6105	0.618	3.00	0	0	0	1	1.000	0.000
Sequoyah 1	43	1128	85	7	81	4061	0.411	4.00	0	0	0	1	1.000	0.000
Salem 2	44	1115	82	10	81	7942	0.813	0.75	0	0	0	1	0.000	0.000
Salem 2	44	1115	83	10	81	743.6	0.076	1.75	0	0	0	1	1.000	0.000
Salem 2	44	1115	84	10	81	3201	0.328	2.75	0	0	0	1	0.000	1.000
Salem 2	44	1115	85	10	81	5017	0.514	3.75	0	0	0	1	0.000	1.000
McGuire 1	45	1180	82	12	81	4302	0.416	0.58	0	0	0	1	0.000	0.000
McGuire 1	45	1180	83	12	81	4634	0.448	1.58	0	0	0	1	0.000	0.000

				Comm. Op. Date					Reactor		T-G			
Unit Name	ID#	MW (DER)	Data year	mn	yr	GWH	CF = GWH/DER/8.76	AGE	CE	B&W	W40"	W44"	REFUEL	OUTAGE
McGuire 1	45	1180	84	12	81	6419	0.621	2.58	0	0	0	1	1.000	0.000
McGuire 1	45	1180	85	12	81	6777	0.656	3.58	0	0	0	1	1.000	0.000
Sequoyah 2	46	1148	83	6	82	6691	0.665	1.08	0	0	0	1	1.000	0.000
Sequoyah 2	46	1148	84	6	82	6403	0.637	2.08	0	0	0	1	1.000	0.000
Sequoyah 2	46	1148	85	6	82	5611	0.558	3.08	0	0	0	1	0.000	0.000
Summer 1	46	900	84	1	84	4197	0.532	0.50	0	0	0	0	1.000	0.000
Summer 1	46	900	85	1	84	5231	0.663	1.50	0	0	0	0	1.000	0.000
San Onofre 2	47	1070	84	8	83	5267	0.562	0.92	1	0	0	0	0.404	0.000
San Onofre 2	47	1070	85	8	83	5154	0.550	1.92	1	0	0	0	0.596	0.000
St. Lucie 2	48	804	84	8	83	5565	0.790	0.92	1	0	0	1	1.000	0.000
St. Lucie 2	48	804	85	8	83	6109	0.867	1.92	1	0	0	1	0.000	0.000
San Onofre 3	49	1080	85	4	84	3707	0.392	1.25	1	0	0	0	0.900	0.000
Callaway 1	50	1171	85	12	84	8046	0.784	0.58	0	0	0	0	0.000	0.000

APPENDIX C:

NUCLEAR CONSTRUCTION COST AND SCHEDULE DATA

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Nine Mile Point 1	162	Dec-69	186.9	Jun-68	134	Jun-69	154.4	1.00	1.21	1.211	1.21	1.211	1.50
Nine Mile Point 1	162	Dec-69	186.9	Dec-68	134	Dec-69	154.4	1.00	1.21	1.211	1.21	1.211	1.00
Surry 2	155	May-73	146.9	Mar-72	147	Mar-73	139.0	1.00	1.06	1.057	1.06	1.057	1.17
Kewaunee	203	Jun-74	176.7	Mar-72	134	Mar-73	126.7	1.00	1.52	1.518	1.39	1.395	2.25
Kewaunee	203	Jun-74	176.7	Jun-72	158	Jun-73	149.4	1.00	1.29	1.287	1.18	1.183	2.00
Kewaunee	203	Jun-74	176.7	Sep-72	163	Sep-73	154.1	1.00	1.25	1.248	1.15	1.147	1.75
Peach Bottom 3	223	Dec-74	194.1	Dec-73	284	Dec-74	246.8	1.00	0.79	0.786	0.79	0.786	1.00
Arkansas 1	239	Dec-74	207.5	Mar-73	200	Mar-74	173.8	1.00	1.19	1.194	1.19	1.194	1.75
Fitzpatrick	419	Jul-75	333.1	Jun-73	301	Jun-74	261.6	1.00	1.39	1.392	1.27	1.274	2.08
St. Lucie 1	486	Jun-76	367.4	Dec-74	401	Dec-75	318.8	1.00	1.21	1.213	1.15	1.153	1.50
Beaver Valley 1	599	Oct-76	452.4	Jun-74	419	Jun-75	333.1	1.00	1.43	1.429	1.36	1.358	2.34
Beaver Valley 1	599	Oct-76	452.4	Dec-74	451	Dec-75	358.5	1.00	1.33	1.328	1.26	1.262	1.84
Crystal River 3	419	Mar-77	299.2	Mar-74	283	Mar-75	225.0	1.00	1.48	1.481	1.33	1.330	3.00
Farley 1	727	Dec-77	519.4	Jun-76	614	Jun-77	438.4	1.00	1.18	1.185	1.18	1.185	1.50
North Anna 2	542	Dec-80	303.8	Mar-78	467	Mar-79	285.8	1.00	1.16	1.161	1.06	1.063	2.76
Lasalle 1	1367	Oct-82	660.8	Jun-80	1107	Jun-81	567.3	1.00	1.23	1.235	1.16	1.165	2.33
Summer 1	1283	Jan-84	579.4	Jun-82	1174	Jun-83	544.5	1.00	1.09	1.093	1.06	1.064	1.59
Turkey Point 4	127	Sep-73	119.9	Jun-71	96	Jun-72	96.0	1.00	1.32	1.320	1.25	1.248	2.25
Turkey Point 4	127	Sep-73	119.9	Dec-71	126	Dec-72	126.0	1.00	1.01	1.006	0.95	0.952	1.75
Prairie Isl 1	233	Dec-73	220.5	Dec-71	190	Dec-72	190.5	1.00	1.22	1.224	1.16	1.158	2.00
Browns Ferry 3	334	Mar-77	238.2	Jun-75	246	Jun-76	185.9	1.00	1.36	1.355	1.28	1.281	1.75
Farley 2	750	Jul-81	384.3	Sep-79	684	Sep-80	383.4	1.00	1.10	1.096	1.00	1.003	1.83
Sequoyah 1	984	Jul-81	504.0	Jun-79	632	Jun-80	354.2	1.00	1.56	1.555	1.42	1.422	2.08
Lasalle 1	1367	Oct-82	660.8	Mar-79	808	Mar-80	452.9	1.00	1.69	1.690	1.46	1.458	3.58
Lasalle 1	1367	Oct-82	660.8	Dec-79	1003	Dec-80	562.2	1.00	1.36	1.362	1.18	1.175	2.83
Prairie Isl 1	233	Dec-73	220.5	Sep-72	210	Oct-73	198.9	1.08	1.11	1.100	1.11	1.100	1.15
Cooper	269	Jul-74	234.0	Jun-72	207	Jul-73	195.7	1.08	1.30	1.275	1.20	1.179	1.92
Arkansas 1	239	Dec-74	207.5	Sep-72	185	Oct-73	174.9	1.08	1.29	1.266	1.19	1.171	2.08
Rancho Seco	344	Apr-75	273.2	Sep-73	328	Oct-74	285.0	1.08	1.05	1.044	0.96	0.961	1.46
Trojan	452	Dec-75	359.3	Sep-74	366	Oct-75	291.0	1.08	1.23	1.215	1.23	1.215	1.15
Indian Point 3	570	Aug-76	430.7	Sep-73	400	Oct-74	347.6	1.08	1.43	1.387	1.24	1.219	2.73
Beaver Valley 1	599	Oct-76	452.4	Sep-74	451	Oct-75	358.5	1.08	1.33	1.300	1.26	1.240	1.93
Sequoyah 1	984	Jul-81	504.0	Sep-78	632	Oct-79	386.7	1.08	1.56	1.505	1.30	1.278	2.62
Summer 1	1283	Jan-84	579.4	Sep-82	1174	Oct-83	544.5	1.08	1.09	1.086	1.06	1.059	1.23
Browns Ferry 1	276	Aug-74	240.0	Sep-71	185	Oct-72	185.1	1.08	1.49	1.447	1.30	1.271	2.69
Brunswick 2	389	Nov-75	309.3	Dec-73	339	Jan-75	269.5	1.08	1.15	1.136	1.15	1.136	1.77
Browns Ferry 3	334	Mar-77	238.2	Dec-74	149	Jan-76	112.6	1.08	2.24	2.102	2.11	1.995	2.07
North Anna 1	782	Jun-78	519.7	Mar-76	567	Apr-77	404.9	1.08	1.38	1.345	1.28	1.259	2.08
Nine Mile Point 1	162	Dec-69	186.9	Dec-67	134	Jan-69	154.4	1.09	1.21	1.192	1.21	1.192	1.84
Calvert Cliffs 2	335	Apr-77	239.4	Dec-75	251	Jan-77	179.2	1.09	1.34	1.305	1.34	1.305	1.23
Three Mile I. 1	401	Sep-74	348.4	Jun-73	393	Aug-74	341.5	1.17	1.02	1.017	1.02	1.017	1.07
Zion 2	292	Sep-74	253.7	Mar-72	235	May-73	222.2	1.17	1.24	1.205	1.14	1.120	2.15
Beaver Valley 1	599	Oct-76	452.4	Mar-74	419	May-75	333.1	1.17	1.43	1.358	1.36	1.300	2.22
Salem 2	820	Oct-81	420.2	Mar-78	619	May-79	378.8	1.17	1.32	1.273	1.11	1.093	3.08
Surry 1	247	Dec-72	246.7	Dec-70	189	Feb-72	189.0	1.17	1.31	1.256	1.31	1.256	1.71
Zion 1	276	Dec-73	261.0	Jun-71	232	Aug-72	232.0	1.17	1.19	1.160	1.12	1.106	2.14
Browns Ferry 1	276	Aug-74	240.0	Mar-71	185	May-72	185.1	1.17	1.49	1.408	1.30	1.249	2.93
McGuire 1	906	Dec-81	464.1	Dec-78	549	Feb-80	307.7	1.17	1.65	1.534	1.51	1.421	2.57
Surry 2	155	May-73	146.9	Dec-71	145	Mar-73	137.1	1.25	1.07	1.057	1.07	1.057	1.13
Peach Bottom 3	223	Dec-74	194.1	Sep-73	316	Dec-74	274.6	1.25	0.71	0.757	0.71	0.757	1.00
Brunswick 2	389	Nov-75	309.3	Sep-73	309	Dec-74	268.5	1.25	1.26	1.203	1.15	1.120	1.73
Brunswick 1	318	Mar-77	227.4	Dec-75	329	Mar-77	234.9	1.25	0.97	0.974	0.97	0.974	1.00

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Brunswick 1	318	Mar-77	227.4	Dec-74	281	Mar-76	212.3	1.25	1.13	1.105	1.07	1.056	1.80
Davis-Besse 1	672	Nov-77	480.2	Dec-75	533	Mar-77	380.6	1.25	1.26	1.205	1.26	1.205	1.54
Summer 1	1283	Jan-84	579.4	Sep-80	827	Dec-81	423.8	1.25	1.55	1.422	1.37	1.285	2.67
Turkey Point 3	109	Dec-72	108.7	Mar-70	111	Jun-71	115.6	1.25	0.98	0.983	0.94	0.952	2.20
Surry 2	155	May-73	146.9	Sep-71	141	Dec-72	141.0	1.25	1.10	1.081	1.04	1.034	1.33
Prairie Isl 1	233	Dec-73	220.5	Sep-71	148	Dec-72	147.8	1.25	1.58	1.440	1.49	1.377	1.80
Kewaunee	203	Jun-74	176.7	Sep-71	134	Dec-72	134.0	1.25	1.52	1.396	1.32	1.248	2.20
Peach Bottom 2	531	Jul-74	461.1	Jun-72	352	Sep-73	332.9	1.25	1.51	1.388	1.39	1.298	1.66
Oconee 3	160	Dec-74	139.4	Mar-73	137	Jun-74	119.0	1.25	1.17	1.134	1.17	1.134	1.40
Rancho Seco	344	Apr-75	273.2	Mar-73	327	Jun-74	284.2	1.25	1.05	1.040	0.96	0.969	1.67
San Onofre 2	2502	Aug-83	1160.3	Mar-81	2010	Jun-82	971.6	1.25	1.24	1.191	1.19	1.152	1.93
Summer 1	1283	Jan-84	579.4	Mar-80	827	Jun-81	423.8	1.25	1.55	1.420	1.37	1.284	3.07
Turkey Point 4	127	Sep-73	119.9	Mar-71	83	Jun-72	83.0	1.25	1.53	1.402	1.44	1.341	2.00
Crystal River 3	419	Mar-77	299.2	Jun-75	420	Sep-76	317.4	1.25	1.00	0.998	0.94	0.954	1.40
Brunswick 1	318	Mar-77	227.4	Mar-75	281	Jun-76	212.3	1.25	1.13	1.105	1.07	1.056	1.60
Davis-Besse 1	672	Nov-77	480.2	Jun-75	461	Sep-76	348.3	1.25	1.46	1.351	1.38	1.292	1.93
Farley 2	750	Jul-81	384.3	Jun-79	687	Sep-80	385.0	1.25	1.09	1.072	1.00	0.999	1.66
Cook 1	545	Aug-75	433.0	Dec-73	427	Apr-75	339.5	1.33	1.28	1.201	1.28	1.201	1.25
Hatch 1	390	Dec-75	310.4	Dec-72	282	Apr-74	245.0	1.33	1.38	1.277	1.27	1.194	2.25
Lasalle 1	1367	Oct-82	660.8	Dec-80	1184	Apr-82	572.3	1.33	1.15	1.114	1.15	1.114	1.38
Vermont Yankee	184	Nov-72	184.5	Mar-70	133	Jul-71	138.5	1.33	1.39	1.278	1.33	1.240	2.00
Surry 1	247	Dec-72	246.7	Jun-70	189	Oct-71	196.9	1.33	1.31	1.221	1.25	1.184	1.88
Three Mile I. 1	401	Sep-74	348.4	Mar-73	373	Jul-74	324.1	1.33	1.07	1.056	1.07	1.056	1.13
Duane Arnold	280	Feb-75	222.5	Sep-72	192	Jan-74	166.8	1.33	1.46	1.327	1.33	1.241	1.81
Browns Ferry 2	276	Mar-75	219.6	Mar-73	149	Jul-74	129.5	1.33	1.85	1.588	1.69	1.486	1.50
Rancho Seco	344	Apr-75	273.2	Jun-72	264	Oct-73	249.6	1.33	1.30	1.219	1.09	1.070	2.12
Calvert Cliffs 1	431	May-75	342.4	Jun-72	250	Oct-73	236.4	1.33	1.72	1.504	1.45	1.320	2.18
Fitzpatrick	419	Jul-75	333.1	Jun-72	301	Oct-73	284.6	1.33	1.39	1.282	1.17	1.125	2.31
Cook 1	545	Aug-75	433.0	Jun-72	416	Oct-73	393.4	1.33	1.31	1.224	1.10	1.075	2.37
Cook 1	545	Aug-75	433.0	Jun-73	427	Oct-74	371.0	1.33	1.28	1.200	1.17	1.123	1.62
Indian Point 3	570	Aug-76	430.7	Mar-73	317	Jul-74	275.5	1.33	1.80	1.553	1.56	1.398	2.60
Browns Ferry 3	334	Mar-77	238.2	Jun-69	149	Oct-70	163.0	1.33	2.24	1.830	1.46	1.329	5.81
North Anna 1	782	Jun-78	519.7	Dec-75	536	Apr-77	382.7	1.33	1.46	1.327	1.36	1.258	1.87
Sequoyah 1	984	Jul-81	504.0	Mar-78	535	Jul-79	327.1	1.33	1.84	1.580	1.54	1.383	2.50
McGuire 1	906	Dec-81	464.1	Mar-78	549	Jul-79	335.9	1.33	1.65	1.456	1.38	1.274	2.82
Susquehanna 1	1947	Jun-83	902.9	Sep-80	1841	Jan-82	889.7	1.33	1.06	1.043	1.01	1.011	2.06
Surry 2	155	May-73	146.9	Jun-71	139	Oct-72	139.0	1.34	1.12	1.087	1.06	1.042	1.43
Farley 1	727	Dec-77	519.4	Jun-75	487	Oct-76	368.0	1.34	1.49	1.350	1.41	1.294	1.87
Millstone 2	426	Dec-75	338.9	Dec-73	380	May-75	302.1	1.41	1.12	1.085	1.12	1.085	1.41
Susquehanna 1	1947	Jun-83	902.9	Dec-81	2292	May-83	1062.9	1.41	0.85	0.891	0.85	0.891	1.06
Fort Calhoun 1	176	Sep-73	166.2	Dec-71	159	May-73	150.4	1.42	1.11	1.074	1.11	1.074	1.24
Zion 1	276	Dec-73	261.0	Dec-70	232	May-72	232.0	1.42	1.19	1.131	1.12	1.087	2.12
Palisades	147	Dec-71	152.8	Mar-69	110	Aug-70	120.3	1.42	1.33	1.225	1.27	1.184	1.94
Three Mile I. 1	401	Sep-74	348.4	Jun-72	328	Nov-73	310.2	1.42	1.22	1.152	1.12	1.085	1.59
Rancho Seco	344	Apr-75	273.2	Sep-72	300	Feb-74	260.7	1.42	1.15	1.100	1.05	1.034	1.82
Calvert Cliffs 1	431	May-75	342.4	Sep-72	250	Feb-74	217.2	1.42	1.72	1.467	1.58	1.378	1.88
Farley 1	727	Dec-77	519.4	Sep-74	456	Feb-76	344.6	1.42	1.60	1.390	1.51	1.336	2.29
North Anna 2	542	Dec-80	303.8	Mar-77	426	Aug-78	283.2	1.42	1.27	1.185	1.07	1.051	2.65
Oconee 2	160	Sep-74	139.4	Sep-71	137	Feb-73	129.6	1.42	1.17	1.117	1.08	1.053	2.11
Hatch 1	390	Dec-75	310.4	Sep-72	184	Mar-74	159.9	1.49	2.12	1.654	1.94	1.558	2.17
North Anna 2	542	Dec-80	303.8	Sep-77	426	Mar-79	260.7	1.49	1.27	1.175	1.17	1.108	2.17
Surry 1	247	Dec-72	246.7	Dec-69	189	Jun-71	196.9	1.50	1.31	1.195	1.25	1.163	2.00
Cook 1	545	Aug-75	433.0	Dec-72	427	Jun-74	371.0	1.50	1.28	1.176	1.17	1.109	1.78

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Cook 2	452	Jul-78	300.2	Dec-76	437	Jun-78	290.5	1.50	1.03	1.022	1.03	1.022	1.05
Summer 1	1283	Jan-84	579.4	Dec-80	1032	Jun-82	498.8	1.50	1.24	1.156	1.16	1.105	2.06
Turkey Point 4	127	Sep-73	119.9	Dec-70	81	Jun-72	81.0	1.50	1.57	1.348	1.48	1.299	1.83
Calvert Cliffs 1	431	May-75	342.4	Dec-71	210	Jun-73	198.6	1.50	2.05	1.614	1.72	1.438	2.28
St. Lucie 1	486	Jun-76	367.4	Jun-74	366	Dec-75	291.0	1.50	1.33	1.208	1.26	1.168	1.33
Crystal River 3	419	Mar-77	299.2	Jun-73	283	Dec-74	245.9	1.50	1.48	1.299	1.22	1.140	2.50
Calvert Cliffs 2	335	Apr-77	239.4	Jun-74	273	Dec-75	217.0	1.50	1.23	1.147	1.10	1.068	1.89
Farley 1	727	Dec-77	519.4	Dec-75	589	Jun-77	420.6	1.50	1.24	1.151	1.24	1.151	1.33
Arkansas 1	239	Dec-74	207.5	Mar-72	175	Sep-73	165.5	1.50	1.36	1.230	1.25	1.162	1.83
Browns Ferry 3	334	Mar-77	238.2	Mar-74	149	Sep-75	118.5	1.50	2.24	1.709	2.01	1.591	2.00
Calvert Cliffs 2	335	Apr-77	239.4	Mar-74	273	Sep-75	217.0	1.50	1.23	1.147	1.10	1.068	2.05
Sequoyah 1	984	Jul-81	504.0	Mar-77	475	Sep-78	315.5	1.50	2.07	1.624	1.60	1.366	2.88
Lasalle 1	1367	Oct-82	660.8	Jun-79	918	Dec-80	514.5	1.50	1.49	1.303	1.28	1.181	2.22
Salem 1	850	Jun-77	607.2	Mar-75	678	Sep-76	512.3	1.51	1.25	1.162	1.19	1.119	1.50
Davis-Besse 1	672	Nov-77	480.2	Mar-75	434	Sep-76	327.9	1.51	1.55	1.337	1.46	1.288	1.77
Sequoyah 2	623	Jun-82	301.3	Mar-79	632	Sep-80	354.2	1.51	0.99	0.991	0.85	0.898	2.16
Millstone 2	426	Dec-75	338.9	Sep-72	282	Apr-74	245.0	1.58	1.51	1.299	1.38	1.228	2.06
Browns Ferry 3	334	Mar-77	238.2	Sep-73	149	Apr-75	118.5	1.58	2.24	1.665	2.01	1.556	2.21
Sequoyah 2	623	Jun-82	301.3	Dec-80	1094	Jul-82	528.8	1.58	0.57	0.700	0.57	0.700	0.95
Farley 1	727	Dec-77	519.4	Dec-74	456	Jul-76	344.6	1.58	1.60	1.343	1.51	1.296	1.90
Farley 2	750	Jul-81	384.3	Sep-78	652	Apr-80	365.4	1.58	1.15	1.093	1.05	1.032	1.79
Browns Ferry 2	276	Mar-75	219.6	Jun-72	149	Jan-74	129.5	1.59	1.85	1.476	1.69	1.395	1.73
Rancho Seco	344	Apr-75	273.2	Mar-72	215	Oct-73	203.3	1.59	1.60	1.344	1.34	1.205	1.94
Calvert Cliffs 1	431	May-75	342.4	Mar-72	210	Oct-73	198.6	1.59	2.05	1.573	1.72	1.410	2.00
Surry 2	155	May-73	146.9	Mar-71	138	Oct-72	138.0	1.59	1.13	1.078	1.06	1.040	1.37
Oconee 1	156	Jul-73	147.1	Sep-69	109	May-71	113.8	1.66	1.42	1.237	1.29	1.167	2.30
Three Mile I. 1	401	Sep-74	348.4	Sep-72	363	May-74	315.4	1.66	1.10	1.062	1.10	1.062	1.20
Beaver Valley 1	599	Oct-76	452.4	Sep-73	409	May-75	325.1	1.66	1.46	1.258	1.39	1.220	1.86
North Anna 2	542	Dec-80	303.8	Sep-76	363	May-78	241.3	1.66	1.49	1.273	1.26	1.149	2.56
Sequoyah 1	984	Jul-81	504.0	Sep-76	475	May-78	315.5	1.66	2.07	1.551	1.60	1.326	2.91
Pilgrim 1	239	Dec-72	239.3	Jan-70	153	Sep-71	159.6	1.66	1.56	1.307	1.50	1.276	1.75
Surry 2	155	May-73	146.9	Sep-70	138	May-72	138.0	1.66	1.13	1.074	1.06	1.038	1.60
Fort Calhoun 1	176	Sep-73	166.2	Sep-71	125	May-73	118.2	1.66	1.41	1.227	1.41	1.227	1.20
Calvert Cliffs 2	335	Apr-77	239.4	Dec-73	243	Aug-75	193.2	1.66	1.38	1.213	1.24	1.138	2.00
North Anna 2	542	Dec-80	303.8	Dec-76	381	Aug-78	253.3	1.66	1.42	1.236	1.20	1.115	2.40
Vermont Yankee	184	Nov-72	184.5	Jul-70	154	Mar-72	154.0	1.67	1.20	1.114	1.20	1.114	1.40
Three Mile I. 1	401	Sep-74	348.4	Mar-72	206	Nov-73	194.8	1.67	1.95	1.490	1.79	1.416	1.50
Farley 1	727	Dec-77	519.4	Jun-74	415	Feb-76	313.6	1.67	1.75	1.399	1.66	1.353	2.10
North Anna 2	542	Dec-80	303.8	Mar-76	311	Nov-77	222.1	1.67	1.74	1.395	1.37	1.206	2.85
Three Mile I. 1	401	Sep-74	348.4	Mar-71	261	Nov-72	261.0	1.67	1.54	1.293	1.33	1.188	2.09
Susquehanna 1	1947	Jun-83	902.9	Jun-79	1285	Feb-81	658.3	1.67	1.52	1.282	1.37	1.208	2.39
Turkey Point 3	109	Dec-72	108.7	Sep-69	99	Jun-71	103.1	1.75	1.10	1.055	1.05	1.031	1.86
Surry 1	247	Dec-72	246.7	Sep-69	165	Jun-71	171.9	1.75	1.50	1.259	1.44	1.230	1.86
Calvert Cliffs 2	335	Apr-77	239.4	Sep-73	243	Jun-75	193.2	1.75	1.38	1.202	1.24	1.131	2.05
Three Mile I. 2	715	Dec-78	475.6	Aug-76	637	May-78	423.5	1.75	1.12	1.069	1.12	1.069	1.32
Peach Bottom 2	531	Jul-74	461.1	Jun-71	288	Mar-73	272.3	1.75	1.84	1.418	1.69	1.351	1.76
Cook 1	545	Aug-75	433.0	Jun-71	356	Mar-73	336.6	1.75	1.53	1.275	1.29	1.155	2.38
Brunswick 1	318	Mar-77	227.4	Jun-75	328	Mar-77	234.2	1.75	0.97	0.983	0.97	0.983	1.00
Salem 1	850	Jun-77	607.2	Dec-73	497	Sep-75	394.7	1.75	1.71	1.360	1.54	1.279	2.00
Davis-Besse 1	672	Nov-77	480.2	Sep-74	434	Jun-76	327.9	1.75	1.55	1.284	1.46	1.243	1.81
Sequoyah 2	623	Jun-82	301.3	Sep-78	632	Jun-80	354.2	1.75	0.99	0.992	0.85	0.912	2.14
Sequoyah 2	623	Jun-82	301.3	Sep-79	442	Jun-81	226.5	1.75	1.41	1.217	1.33	1.177	1.57
Duane Arnold	280	Feb-75	222.5	Mar-72	177	Dec-73	167.4	1.75	1.58	1.299	1.33	1.177	1.67

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Millstone 2	426	Dec-75	338.9	Mar-73	341	Dec-74	296.3	1.75	1.25	1.136	1.14	1.080	1.57
Crystal River 3	419	Mar-77	299.2	Dec-74	375	Sep-76	283.4	1.75	1.12	1.065	1.06	1.032	1.28
Browns Ferry 3	334	Mar-77	238.2	Mar-73	149	Dec-74	129.5	1.75	2.24	1.584	1.84	1.416	2.28
Sequoyah 1	984	Jul-81	504.0	Dec-75	364	Sep-77	259.6	1.75	2.71	1.765	1.94	1.460	3.19
San Onofre 2	2502	Aug-83	1160.3	Mar-80	1824	Dec-81	934.7	1.75	1.37	1.198	1.24	1.131	1.95
Oconee 2	160	Sep-74	139.4	Mar-71	109	Dec-72	109.0	1.75	1.47	1.246	1.28	1.150	2.00
Summer 1	1283	Jan-84	579.4	Mar-79	756	Dec-80	423.7	1.75	1.70	1.352	1.37	1.195	2.76
Vermont Yankee	184	Nov-72	184.5	Sep-69	120	Jul-71	125.0	1.83	1.54	1.265	1.48	1.237	1.73
Trojan	452	Dec-75	359.3	Sep-73	334	Jul-75	265.5	1.83	1.35	1.180	1.35	1.180	1.23
McGuire 1	906	Dec-81	464.1	Sep-77	466	Jul-79	285.2	1.83	1.94	1.438	1.63	1.305	2.32
Surry 1	247	Dec-72	246.7	Jun-69	165	Apr-71	171.9	1.83	1.50	1.246	1.44	1.218	1.91
Oconee 2	160	Sep-74	139.4	Sep-70	109	Jul-72	109.0	1.83	1.47	1.235	1.28	1.144	2.18
Browns Ferry 2	276	Mar-75	219.6	Sep-71	149	Jul-73	141.0	1.83	1.85	1.400	1.56	1.274	1.91
Beaver Valley 1	599	Oct-76	452.4	Dec-72	340	Oct-74	295.4	1.83	1.76	1.362	1.53	1.262	2.09
Zion 1	276	Dec-73	261.0	Jun-70	232	Apr-72	232.0	1.83	1.19	1.099	1.12	1.066	1.91
Browns Ferry 1	276	Aug-74	240.0	Jun-70	149	Apr-72	149.1	1.83	1.85	1.400	1.61	1.296	2.27
Three Mile I. 1	401	Sep-74	348.4	Dec-70	262	Oct-72	262.0	1.83	1.53	1.261	1.33	1.168	2.04
Browns Ferry 2	276	Mar-75	219.6	Jun-70	149	Apr-72	149.1	1.83	1.85	1.400	1.47	1.235	2.59
Browns Ferry 3	334	Mar-77	238.2	Jun-70	149	Apr-72	149.1	1.83	2.24	1.551	1.60	1.291	3.68
San Onofre 2	2502	Aug-83	1160.3	Dec-79	1740	Oct-81	891.7	1.83	1.44	1.219	1.30	1.154	2.00
McGuire 1	906	Dec-81	464.1	Mar-77	466	Jan-79	285.2	1.84	1.94	1.436	1.63	1.304	2.59
Calvert Cliffs 2	335	Apr-77	239.4	Mar-75	253	Jan-77	180.6	1.84	1.33	1.165	1.33	1.165	1.13
North Anna 1	782	Jun-78	519.7	Mar-75	536	Jan-77	382.7	1.84	1.46	1.228	1.36	1.181	1.77
Fort Calhoun 1	176	Sep-73	166.2	Jun-69	92	May-71	95.8	1.91	1.91	1.403	1.73	1.334	2.22
Sequoyah 1	984	Jul-81	504.0	Jun-76	364	May-78	241.7	1.91	2.71	1.682	2.09	1.468	2.66
McGuire 1	906	Dec-81	464.1	Jun-76	384	May-78	255.3	1.91	2.36	1.566	1.82	1.367	2.87
Rancho Seco	344	Apr-75	273.2	Jun-71	215	May-73	203.3	1.92	1.60	1.277	1.34	1.167	2.00
Crystal River 3	419	Mar-77	299.2	Dec-72	283	Nov-74	245.9	1.92	1.48	1.227	1.22	1.108	2.22
North Anna 1	782	Jun-78	519.7	Dec-73	431	Nov-75	342.6	1.92	1.81	1.364	1.52	1.243	2.35
Fort Calhoun 1	176	Sep-73	166.2	Dec-70	125	Nov-72	125.0	1.92	1.41	1.194	1.33	1.160	1.43
North Anna 2	542	Dec-80	303.8	Dec-75	301	Nov-77	214.9	1.92	1.80	1.359	1.41	1.198	2.61
Calvert Cliffs 2	335	Apr-77	239.4	Mar-73	204	Feb-75	162.2	1.92	1.64	1.295	1.48	1.225	2.13
Millstone 1	97	Mar-71		Mar-69		Mar-70		1.00					2.000
Point Beach 1	74	Dec-70		Dec-69		Dec-70		1.00					1.000
Point Beach 2	71	Oct-72		Sep-70		Sep-71		1.00					2.085
Indian Point 2	206	Aug-73		Dec-70		Dec-71		1.00					2.668
Ginna	83	Jul-70		Sep-68		Oct-69		1.08					1.691
Millstone 1	97	Mar-71		Sep-69		Oct-70		1.08					1.382
Quad Cities 1	100	Feb-73		Jun-70		Jul-71		1.08					2.471
Dresden 2	83	Jul-70		Dec-68		Jan-70		1.08					1.457
Millstone 1	97	Mar-71		Dec-68		Jan-70		1.08					2.071
Oyster Creek 1	90	Dec-69		Mar-67		Apr-68		1.09					2.534
Indian Point 2	206	Aug-73		Mar-69		May-70		1.17					3.789
Quad Cities 2	100	Mar-73		Mar-71		May-72		1.17					1.712
Dresden 3	104	Nov-71		Mar-70		Jun-71		1.25					1.335
Oyster Creek 1	90	Dec-69		Sep-66		Jan-68		1.33					2.437
Indian Point 2	206	Aug-73		Jun-69		Oct-70		1.33					3.125
Quad Cities 1	100	Feb-73		Mar-70		Jul-71		1.33					2.193
Indian Point 2	206	Aug-73		Dec-69		May-71		1.41					2.595
Dresden 3	104	Nov-71		Mar-69		Aug-70		1.42					1.882
Point Beach 1	74	Dec-70		Mar-69		Aug-70		1.42					1.236
Point Beach 2	71	Oct-72		Mar-70		Aug-71		1.42					1.824

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Oyster Creek 1	90	Dec-69		Jun-66		Dec-67		1.50					2.334
Dresden 3	104	Nov-71		Jun-69		Dec-70		1.50					1.611
Indian Point 2	206	Aug-73		Sep-68		Apr-70		1.58					3.111
Dresden 2	83	Jul-70		Sep-67		Apr-69		1.58					1.789
Quad Cities 1	100	Feb-73		Jun-69		Jan-71		1.59					2.316
Dresden 3	104	Nov-71		Dec-68		Aug-70		1.66					1.752
Oyster Creek 1	90	Dec-69		Mar-66		Dec-67		1.75					2.142
Quad Cities 1	100	Feb-73		Dec-68		Oct-70		1.83					2.277
Point Beach 2	71	Oct-72		Sep-69		Aug-71		1.91					1.611
Millstone 1	97	Mar-71		Sep-67		Aug-69		1.92					1.824
For: 1 <= t < 2													
No. of data points:								220	190	190	190	190	220
Average								1.417	1.428	1.271	1.293	1.190	1.983
Standard Deviation:								0.288	0.343	0.194	0.248	0.154	0.592
Fort Calhoun 1	176	Sep-73	166.2	Sep-69	92	Sep-71	95.8	2.00	1.91	1.383	1.73	1.317	2.00
Brunswick 2	389	Nov-75	309.3	Dec-72	256	Dec-74	222.5	2.00	1.52	1.233	1.39	1.179	1.46
Trojan	452	Dec-75	359.3	Sep-72	243	Sep-74	211.2	2.00	1.86	1.364	1.70	1.305	1.62
St. Lucie 1	486	Jun-76	367.4	Dec-73	318	Dec-75	252.8	2.00	1.53	1.237	1.45	1.206	1.25
Brunswick 1	318	Mar-77	227.4	Dec-73	269	Dec-75	213.8	2.00	1.18	1.088	1.06	1.031	1.62
Browns Ferry 3	334	Mar-77	238.2	Aug-72	149	Aug-74	129.5	2.00	2.24	1.496	1.84	1.356	2.29
Calvert Cliffs 2	335	Apr-77	239.4	Jun-72	204	Jun-74	177.3	2.00	1.64	1.282	1.35	1.162	2.42
Farley 1	727	Dec-77	519.4	Dec-73	395	Dec-75	314.0	2.00	1.84	1.357	1.65	1.286	2.00
North Anna 1	782	Jun-78	519.7	Dec-72	407	Dec-74	353.7	2.00	1.92	1.386	1.47	1.212	2.75
Lasalle 1	1367	Oct-82	660.8	Sep-77	675	Sep-79	413.0	2.00	2.03	1.423	1.60	1.265	2.54
Kewaunee	203	Jun-74	176.7	Jun-70	123	Jun-72	123.0	2.00	1.65	1.286	1.44	1.199	2.00
Kewaunee	203	Jun-74	176.7	Sep-70	123	Sep-72	123.0	2.00	1.65	1.286	1.44	1.199	1.87
Peach Bottom 2	531	Jul-74	461.1	Mar-71	277	Mar-73	261.9	2.00	1.92	1.384	1.76	1.327	1.67
Peach Bottom 2	531	Jul-74	461.1	Dec-70	230	Dec-72	230.0	2.00	2.31	1.519	2.00	1.416	1.79
Crystal River 3	419	Mar-77	299.2	Sep-71	190	Sep-73	179.7	2.00	2.21	1.485	1.67	1.290	2.75
Sequoyah 1	984	Jul-81	504.0	Sep-75	324	Sep-77	231.3	2.00	3.04	1.742	2.18	1.476	2.91
Sequoyah 2	623	Jun-82	301.3	Mar-78	535	Mar-80	299.6	2.00	1.17	1.080	1.01	1.003	2.12
Browns Ferry 1	276	Aug-74	240.0	Sep-69	149	Oct-71	155.3	2.08	1.85	1.345	1.55	1.233	2.36
Prairie Isl 2	177	Dec-74	153.8	Sep-72	160	Oct-74	138.7	2.08	1.11	1.051	1.11	1.051	1.08
Browns Ferry 2	276	Mar-75	219.6	Sep-69	149	Oct-71	155.3	2.08	1.85	1.345	1.41	1.181	2.64
Beaver Valley 1	599	Oct-76	452.4	Sep-72	342	Oct-74	297.2	2.08	1.75	1.309	1.52	1.224	1.96
Browns Ferry 3	334	Mar-77	238.2	Sep-72	149	Oct-74	129.5	2.08	2.24	1.473	1.84	1.340	2.16
Browns Ferry 3	334	Mar-77	238.2	Sep-69	149	Oct-71	155.3	2.08	2.24	1.473	1.53	1.228	3.60
Prairie Isl 1	233	Dec-73	220.5	Sep-70	148	Oct-72	147.8	2.08	1.58	1.245	1.49	1.212	1.56
Three Mile I. 1	401	Sep-74	348.4	Jun-70	184	Jul-72	184.0	2.08	2.18	1.453	1.89	1.359	2.04
Three Mile I. 1	401	Sep-74	348.4	Sep-70	197	Oct-72	197.0	2.08	2.04	1.406	1.77	1.315	1.92
Cook 1	545	Aug-75	433.0	Sep-71	356	Oct-73	336.6	2.08	1.53	1.226	1.29	1.128	1.88
Farley 1	727	Dec-77	519.4	Mar-73	294	Apr-75	233.7	2.08	2.47	1.545	2.22	1.467	2.29
North Anna 1	782	Jun-78	519.7	Mar-73	407	Apr-75	323.6	2.08	1.92	1.368	1.61	1.255	2.52
Farley 2	750	Jul-81	384.3	Mar-77	689	Apr-79	421.6	2.08	1.09	1.042	0.91	0.957	2.08
Surry 2	155	May-73	146.9	Mar-70	138	Apr-72	138.0	2.09	1.13	1.059	1.06	1.031	1.52
Browns Ferry 2	276	Mar-75	219.6	Mar-71	149	Apr-73	141.0	2.09	1.85	1.344	1.56	1.237	1.92
Calvert Cliffs 2	335	Apr-77	239.4	Dec-71	168	Jan-74	146.0	2.09	2.00	1.393	1.64	1.268	2.56
North Anna 1	782	Jun-78	519.7	Dec-74	504	Jan-77	359.9	2.09	1.55	1.234	1.44	1.193	1.68

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Sequoyah 1	984	Jul-81	504.0	Dec-74	324	Jan-77	231.3	2.09	3.04	1.703	2.18	1.452	3.15
Farley 2	750	Jul-81	384.3	Mar-78	635	Apr-80	355.9	2.09	1.18	1.083	1.08	1.038	1.60
Palisades	147	Dec-71	152.8	Mar-68	89	May-70	97.3	2.17	1.65	1.260	1.57	1.232	1.73
Beaver Valley 1	599	Oct-76	452.4	Mar-73	340	May-75	270.3	2.17	1.76	1.299	1.67	1.269	1.66
North Anna 1	782	Jun-78	519.7	Sep-73	407	Nov-75	323.6	2.17	1.92	1.352	1.61	1.245	2.19
Sequoyah 2	623	Jun-82	301.3	Mar-77	475	May-79	290.4	2.17	1.31	1.134	1.04	1.017	2.42
Susquehanna 1	1947	Jun-83	902.9	Mar-81	2276	May-83	1055.3	2.17	0.86	0.931	0.86	0.931	1.04
Maine Yankee	219	Dec-72	219.2	Mar-70	181	May-72	181.0	2.17	1.21	1.092	1.21	1.092	1.27
Peach Bottom 2	531	Jul-74	461.1	Mar-70	230	May-72	230.0	2.17	2.31	1.470	2.00	1.378	2.00
Three Mile I. 1	401	Sep-74	348.4	Sep-71	296	Nov-73	279.9	2.17	1.35	1.150	1.24	1.106	1.38
Three Mile I. 1	401	Sep-74	348.4	Mar-70	184	May-72	184.0	2.17	2.18	1.432	1.89	1.342	2.08
Oconee 3	160	Dec-74	139.4	Sep-71	137	Nov-73	129.6	2.17	1.17	1.075	1.08	1.034	1.50
North Anna 1	782	Jun-78	519.7	Mar-74	446	May-76	337.0	2.17	1.75	1.295	1.54	1.221	1.96
Sequoyah 1	984	Jul-81	504.0	Jun-74	313	Aug-76	236.1	2.17	3.15	1.697	2.13	1.419	3.27
McGuire 1	906	Dec-81	464.1	Dec-76	384	Feb-79	235.0	2.17	2.36	1.485	1.97	1.369	2.31
Summer 1	1283	Jan-84	579.4	Mar-78	675	May-80	378.3	2.17	1.90	1.345	1.53	1.217	2.69
Surry 1	247	Dec-72	246.7	Dec-68	165	Mar-71	171.9	2.25	1.50	1.196	1.44	1.175	1.78
Salem 1	850	Jun-77	607.2	Dec-72	425	Mar-75	337.9	2.25	2.00	1.362	1.80	1.298	2.00
Surry 2	155	May-73	146.9	Dec-69	138	Mar-72	138.0	2.25	1.13	1.054	1.06	1.028	1.52
Peach Bottom 2	531	Jul-74	461.1	Dec-69	218	Mar-72	218.0	2.25	2.43	1.486	2.12	1.396	2.04
Brunswick 2	389	Nov-75	309.3	Dec-71	210	Mar-74	182.5	2.25	1.85	1.316	1.70	1.265	1.74
Brunswick 1	318	Mar-77	227.4	Sep-73	251	Dec-75	199.5	2.25	1.27	1.112	1.14	1.060	1.56
North Anna 1	782	Jun-78	519.7	Sep-72	360	Dec-74	312.8	2.25	2.17	1.412	1.66	1.253	2.56
Arkansas 2	640	Mar-80	358.7	Dec-75	393	Mar-78	261.3	2.25	1.63	1.242	1.37	1.151	1.89
Three Mile I. 1	401	Sep-74	348.4	Jun-69	162	Sep-71	168.7	2.25	2.47	1.496	2.06	1.380	2.33
Peach Bottom 3	223	Dec-74	194.1	Jun-72	316	Sep-74	274.6	2.25	0.71	0.857	0.71	0.857	1.11
St. Lucie 1	486	Jun-76	367.4	Mar-72	235	Jun-74	204.2	2.25	2.07	1.381	1.80	1.298	1.89
St. Lucie 1	486	Jun-76	367.4	Mar-73	318	Jun-75	252.8	2.25	1.53	1.208	1.45	1.181	1.45
Beaver Valley 1	599	Oct-76	452.4	Sep-71	286	Dec-73	270.4	2.25	2.09	1.389	1.67	1.257	2.26
Calvert Cliffs 2	335	Apr-77	239.4	Mar-72	168	Jun-74	146.0	2.25	2.00	1.359	1.64	1.246	2.26
Salem 1	850	Jun-77	607.2	Sep-74	678	Dec-76	512.3	2.25	1.25	1.106	1.19	1.078	1.22
Summer 1	1283	Jan-84	579.4	Sep-78	675	Dec-80	378.3	2.25	1.90	1.330	1.53	1.208	2.37
Fort Calhoun 1	176	Sep-73	166.2	Mar-70	125	Jun-72	125.0	2.25	1.41	1.163	1.33	1.135	1.56
Turkey Point 4	127	Sep-73	119.9	Mar-70	80	Jun-72	80.0	2.25	1.58	1.227	1.50	1.197	1.56
Kewaunee	203	Jun-74	176.7	Mar-70	121	Jun-72	121.0	2.25	1.68	1.259	1.46	1.183	1.89
Arkansas 2	640	Mar-80	358.7	Mar-75	339	Jun-77	242.1	2.25	1.89	1.326	1.48	1.191	2.22
Farley 2	750	Jul-81	384.3	Jun-75	365	Sep-77	260.6	2.25	2.05	1.377	1.47	1.188	2.70
Sequoyah 1	984	Jul-81	504.0	Mar-74	313	Jun-76	236.1	2.25	3.15	1.663	2.13	1.400	3.26
Farley 2	750	Jul-81	384.3	Dec-76	572	Apr-79	350.0	2.33	1.31	1.123	1.10	1.041	1.97
Sequoyah 1	984	Jul-81	504.0	Dec-72	225	Apr-75	178.5	2.33	4.38	1.885	2.82	1.561	3.68
Cooper	269	Jul-74	234.0	Dec-70	207	Apr-73	195.7	2.33	1.30	1.119	1.20	1.080	1.54
Beaver Valley 1	599	Oct-76	452.4	Jun-72	311	Oct-74	270.2	2.33	1.93	1.324	1.67	1.247	1.86
Calvert Cliffs 2	335	Apr-77	239.4	Sep-72	204	Jan-75	162.2	2.33	1.64	1.237	1.48	1.182	1.96
Salem 1	850	Jun-77	607.2	Dec-70	237	Apr-73	224.1	2.33	3.59	1.729	2.71	1.533	2.79
Farley 2	750	Jul-81	384.3	Dec-77	662	Apr-80	371.0	2.33	1.13	1.055	1.04	1.015	1.54
Browns Ferry 2	276	Mar-75	219.6	Sep-70	149	Jan-73	141.0	2.34	1.85	1.302	1.56	1.209	1.92
Calvert Cliffs 1	431	May-75	342.4	Sep-70	170	Jan-73	160.8	2.34	2.53	1.489	2.13	1.382	2.00
Indian Point 3	570	Aug-76	430.7	Mar-71	256	Jul-73	242.1	2.34	2.23	1.409	1.78	1.280	2.34
Calvert Cliffs 2	335	Apr-77	239.4	Sep-74	256	Jan-77	182.8	2.34	1.31	1.123	1.31	1.123	1.11
Arkansas 2	640	Mar-80	358.7	Jun-75	339	Oct-77	242.1	2.34	1.89	1.313	1.48	1.183	2.03
Arkansas 2	640	Mar-80	358.7	Sep-75	369	Jan-78	245.3	2.34	1.73	1.266	1.46	1.177	1.93
Sequoyah 1	984	Jul-81	504.0	Sep-74	313	Jan-77	223.1	2.34	3.15	1.634	2.26	1.418	2.92
Farley 2	750	Jul-81	384.3	Sep-74	363	Jan-77	259.2	2.34	2.07	1.364	1.48	1.184	2.92

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Susquehanna 1	1947	Jun-83	902.9	Sep-79	1607	Jan-82	776.7	2.34	1.21	1.086	1.16	1.067	1.60
St. Lucie 1	486	Jun-76	367.4	Dec-72	318	May-75	252.8	2.41	1.53	1.192	1.45	1.168	1.45
Davis-Besse 1	672	Nov-77	480.2	Dec-72	349	May-75	277.4	2.41	1.93	1.312	1.73	1.255	2.04
Three Mile I. 1	401	Sep-74	348.4	Dec-69	180	May-72	180.0	2.41	2.23	1.393	1.94	1.315	1.97
Prairie Isl 2	177	Dec-74	153.8	Dec-71	145	May-74	125.6	2.41	1.22	1.087	1.22	1.087	1.24
Davis-Besse 1	672	Nov-77	480.2	Sep-73	409	Feb-76	309.1	2.42	1.64	1.228	1.55	1.200	1.72
Sequoyah 1	984	Jul-81	504.0	Jun-72	213	Nov-74	184.7	2.42	4.63	1.885	2.73	1.515	3.76
Nine Mile Point 1	162	Dec-69	186.9	Jun-66	88	Nov-68	106.6	2.42	1.84	1.288	1.75	1.261	1.45
Browns Ferry 2	276	Mar-75	219.6	Sep-67	124	Feb-70	136.0	2.42	2.22	1.390	1.61	1.219	3.10
Browns Ferry 3	334	Mar-77	238.2	Sep-71	149	Feb-74	129.5	2.42	2.24	1.395	1.84	1.286	2.27
Susquehanna 1	1947	Jun-83	902.9	Sep-78	1293	Feb-81	662.5	2.42	1.51	1.184	1.36	1.136	1.96
Peach Bottom 2	531	Jul-74	461.1	Sep-69	206	Mar-72	206.0	2.50	2.58	1.461	2.24	1.381	1.93
Cook 1	545	Aug-75	433.0	Sep-70	339	Mar-73	320.6	2.50	1.61	1.209	1.35	1.128	1.97
St. Lucie 1	486	Jun-76	367.4	Dec-71	218	Jun-74	189.4	2.50	2.23	1.378	1.94	1.303	1.80
Beaver Valley 1	599	Oct-76	452.4	Dec-71	286	Jun-74	248.5	2.50	2.09	1.344	1.82	1.271	1.93
Davis-Besse 1	672	Nov-77	480.2	Jun-72	304	Dec-74	264.2	2.50	2.21	1.374	1.82	1.270	2.17
Farley 1	727	Dec-77	519.4	Jun-73	294	Dec-75	233.7	2.50	2.47	1.437	2.22	1.376	1.80
North Anna 1	782	Jun-78	519.7	Dec-71	344	Jun-74	298.9	2.50	2.27	1.389	1.74	1.248	2.60
Sequoyah 1	984	Jul-81	504.0	Jun-73	225	Dec-75	178.5	2.50	4.38	1.806	2.82	1.515	3.23
Sequoyah 1	984	Jul-81	504.0	Dec-73	225	Jun-76	169.6	2.50	4.38	1.806	2.97	1.546	3.03
Farley 2	750	Jul-81	384.3	Dec-74	363	Jun-77	259.2	2.50	2.07	1.337	1.48	1.171	2.63
Trojan	452	Dec-75	359.3	Mar-72	233	Sep-74	202.5	2.50	1.94	1.303	1.77	1.258	1.50
Beaver Valley 1	599	Oct-76	452.4	Jun-71	219	Dec-73	207.1	2.50	2.73	1.495	2.18	1.367	2.13
Salem 1	850	Jun-77	607.2	Jun-71	237	Dec-73	224.1	2.50	3.59	1.666	2.71	1.489	2.40
North Anna 2	542	Dec-80	303.8	Mar-75	301	Sep-77	214.9	2.51	1.80	1.265	1.41	1.148	2.30
Salem 2	820	Oct-81	420.2	Mar-74	496	Sep-76	374.8	2.51	1.65	1.222	1.12	1.047	3.03
Trojan	452	Dec-75	359.3	Dec-72	284	Jul-75	225.8	2.58	1.59	1.197	1.59	1.197	1.16
North Anna 2	542	Dec-80	303.8	Dec-72	227	Jul-75	180.5	2.58	2.39	1.401	1.68	1.224	3.10
Farley 2	750	Jul-81	384.3	Sep-76	499	Apr-79	305.3	2.58	1.50	1.171	1.26	1.093	1.87
Millstone 2	426	Dec-75	338.9	Sep-71	252	Apr-74	219.0	2.58	1.69	1.226	1.55	1.184	1.65
Hatch 1	390	Dec-75	310.4	Sep-70	184	Apr-73	174.0	2.58	2.12	1.338	1.78	1.251	2.03
Cook 2	452	Jul-78	300.2	Sep-75	437	Apr-78	290.5	2.58	1.03	1.013	1.03	1.013	1.10
Sequoyah 1	984	Jul-81	504.0	Dec-71	213	Jul-74	184.7	2.58	4.63	1.810	2.73	1.475	3.71
Browns Ferry 2	276	Mar-75	219.6	Mar-68	124	Oct-70	136.0	2.58	2.22	1.362	1.61	1.204	2.71
Beaver Valley 1	599	Oct-76	452.4	Mar-72	309	Oct-74	268.5	2.58	1.94	1.292	1.68	1.224	1.77
Browns Ferry 3	334	Mar-77	238.2	Mar-68	124	Oct-70	136.0	2.58	2.68	1.465	1.75	1.242	3.48
Salem 1	850	Jun-77	607.2	Mar-72	336	Oct-74	291.5	2.58	2.53	1.433	2.08	1.328	2.03
North Anna 2	542	Dec-80	303.8	Mar-73	227	Oct-75	180.5	2.58	2.39	1.400	1.68	1.223	3.00
Sequoyah 2	623	Jun-82	301.3	Jun-76	364	Jan-79	222.4	2.58	1.71	1.232	1.35	1.125	2.32
Farley 2	750	Jul-81	384.3	Jun-74	338	Jan-77	241.3	2.59	2.22	1.361	1.59	1.197	2.74
Fort Calhoun 1	176	Sep-73	166.2	Sep-68	92	May-71	95.9	2.66	1.91	1.275	1.73	1.230	1.88
Lasalle 1	1367	Oct-82	660.8	Sep-76	585	May-79	358.0	2.66	2.34	1.376	1.85	1.259	2.28
Three Mile I. 1	401	Sep-74	348.4	Sep-69	162	May-72	162.0	2.66	2.47	1.405	2.15	1.333	1.88
Oconee 2	160	Sep-74	139.4	Sep-69	109	May-72	109.2	2.66	1.47	1.155	1.28	1.096	1.88
North Anna 2	542	Dec-80	303.8	Sep-73	227	May-76	171.5	2.66	2.39	1.386	1.77	1.239	2.72
Sequoyah 2	623	Jun-82	301.3	Sep-75	324	May-78	215.4	2.66	1.92	1.278	1.40	1.134	2.53
Arkansas 2	640	Mar-80	358.7	Jun-74	318	Feb-77	227.1	2.67	2.01	1.299	1.58	1.187	2.15
North Anna 2	542	Dec-80	303.8	Mar-74	240	Nov-76	181.4	2.67	2.26	1.356	1.68	1.213	2.53
Turkey Point 4	127	Sep-73	119.9	Sep-69	41	Jun-72	41.0	2.75	3.09	1.508	2.92	1.478	1.46
Three Mile I. 1	401	Sep-74	348.4	Dec-68	150	Sep-71	156.2	2.75	2.67	1.430	2.23	1.339	2.09
Beaver Valley 1	599	Oct-76	452.4	Sep-70	219	Jun-73	207.1	2.75	2.73	1.442	2.18	1.329	2.21
North Anna 1	782	Jun-78	519.7	Sep-71	310	Jun-74	269.4	2.75	2.52	1.400	1.93	1.270	2.46
North Anna 1	782	Jun-78	519.7	Jun-71	308	Mar-74	267.6	2.75	2.54	1.403	1.94	1.273	2.55

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Arkansas 2	640	Mar-80	358.7	Sep-74	318	Jun-77	227.1	2.75	2.01	1.290	1.58	1.181	2.00
Lasalle 1	1367	Oct-82	660.8	Dec-76	585	Sep-79	358.0	2.75	2.34	1.362	1.85	1.250	2.12
North Anna 1	782	Jun-78	519.7	Mar-72	344	Dec-74	298.9	2.75	2.27	1.348	1.74	1.223	2.27
North Anna 2	542	Dec-80	303.8	Dec-74	264	Sep-77	188.5	2.75	2.05	1.299	1.61	1.189	2.18
Salem 2	820	Oct-81	420.2	Dec-73	497	Sep-76	375.2	2.75	1.65	1.200	1.12	1.042	2.85
Salem 1	850	Jun-77	607.2	Mar-70	237	Dec-72	237.0	2.75	3.59	1.590	2.56	1.407	2.63
Indian Point 3	570	Aug-76	430.7	Sep-68	156	Jul-71	162.5	2.83	3.65	1.581	2.65	1.412	2.81
North Anna 2	542	Dec-80	303.8	Sep-72	208	Jul-75	165.4	2.83	2.61	1.403	1.84	1.240	2.92
Oconee 3	160	Dec-74	139.4	Sep-70	109	Jul-73	103.1	2.83	1.47	1.146	1.35	1.113	1.50
Indian Point 3	570	Aug-76	430.7	Sep-69	156	Jul-72	156.0	2.83	3.65	1.580	2.76	1.432	2.46
Indian Point 3	570	Aug-76	430.7	Sep-70	218	Jul-73	206.1	2.83	2.61	1.404	2.09	1.297	2.10
Hatch 2	515	Sep-79	315.1	Jun-76	512	Apr-79	313.3	2.83	1.01	1.002	1.01	1.002	1.15
Peach Bottom 3	223	Dec-74	194.1	Dec-70	221	Oct-73	209.0	2.83	1.01	1.004	0.93	0.974	1.41
Crystal River 3	419	Mar-77	299.2	Jun-69	148	Apr-72	148.0	2.83	2.83	1.444	2.02	1.282	2.73
North Anna 2	542	Dec-80	303.8	Jun-73	227	Apr-76	171.5	2.83	2.39	1.360	1.77	1.223	2.65
Farley 2	750	Jul-81	384.3	Jun-77	689	Apr-80	386.2	2.83	1.09	1.030	1.00	0.998	1.44
McGuire 1	906	Dec-81	464.1	Jun-74	220	Apr-77	157.1	2.83	4.12	1.648	2.95	1.466	2.65
Sequoyah 2	623	Jun-82	301.3	Jun-74	313	Apr-77	223.1	2.83	1.99	1.276	1.35	1.112	2.82
Browns Ferry 3	334	Mar-77	238.2	Mar-71	149	Jan-74	129.5	2.84	2.24	1.328	1.84	1.239	2.11
St. Lucie 1	486	Jun-76	367.4	Jun-72	269	May-75	213.8	2.91	1.81	1.225	1.72	1.204	1.37
St. Lucie 2	1430	Aug-83	663.2	Jun-80	1100	May-83	510.1	2.91	1.30	1.094	1.30	1.094	1.09
Summer 1	1283	Jan-84	579.4	Jun-76	493	May-79	301.7	2.91	2.60	1.389	1.92	1.251	2.60
Zion 2	292	Sep-74	253.7	Jun-70	213	May-73	201.4	2.92	1.37	1.114	1.26	1.082	1.46
Three Mile I. 2	715	Dec-78	475.6	Jun-75	630	May-78	418.8	2.92	1.14	1.045	1.14	1.045	1.19
Browns Ferry 2	276	Mar-75	219.6	Mar-67	117	Feb-70	128.3	2.92	2.35	1.340	1.71	1.202	2.74
Arkansas 2	640	Mar-80	358.7	Mar-74	273	Feb-77	194.9	2.92	2.34	1.338	1.84	1.232	2.05
Susquehanna 1	1947	Jun-83	902.9	Mar-78	1195	Feb-81	612.6	2.92	1.63	1.182	1.47	1.142	1.80
Point Beach 2	71	Oct-72		Dec-69		Dec-71		2.00					1.418
Oyster Creek 1	90	Dec-69		Sep-65		Nov-67		2.17					1.962
Quad Cities 2	100	Mar-73		Mar-70		May-72		2.17					1.384
Quad Cities 2	100	Mar-73		Dec-68		Apr-71		2.33					1.823
Millstone 1	97	Mar-71		Mar-67		Aug-69		2.42					1.653
Quad Cities 1	100	Feb-73		Sep-67		Mar-70		2.50					2.171
Quad Cities 2	100	Mar-73		Jun-69		Jan-72		2.58					1.450
Dresden 2	83	Jul-70		Mar-66		Feb-69		2.92					1.482

For: 2 <= t < 3	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
No. of data points:	175	167	167	167	167	175
Average	2.397	2.055	1.331	1.669	1.228	2.100
Standard Deviation:	0.279	0.734	0.183	0.449	0.132	0.585

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Peach Bottom 2	531	Jul-74	461.1	Mar-68	163	Mar-71	169.8	3.00	3.26	1.482	2.72	1.396	2.11
Brunswick 1	318	Mar-77	227.4	Dec-72	214	Dec-75	170.1	3.00	1.49	1.142	1.34	1.102	1.42
Sequoyah 2	623	Jun-82	301.3	Dec-72	225	Dec-75	178.5	3.00	2.78	1.406	1.69	1.191	3.17
Peach Bottom 3	223	Dec-74	194.1	Mar-70	221	Mar-73	209.0	3.00	1.01	1.003	0.93	0.976	1.58
Duane Arnold	280	Feb-75	222.5	Dec-70	148	Dec-73	140.0	3.00	1.89	1.237	1.59	1.167	1.39
Hatch 1	390	Dec-75	310.4	Jun-70	184	Jun-73	174.0	3.00	2.12	1.285	1.78	1.213	1.83
St. Lucie 1	486	Jun-76	367.4	Jun-71	203	Jun-74	176.4	3.00	2.40	1.338	2.08	1.277	1.67
Arkansas 2	640	Mar-80	358.7	Dec-73	273	Dec-76	206.3	3.00	2.34	1.328	1.74	1.202	2.08
Sequoyah 2	623	Jun-82	301.3	Sep-74	313	Sep-77	223.1	3.00	1.99	1.259	1.35	1.105	2.58
Sequoyah 2	623	Jun-82	301.3	Jun-72	213	Jul-75	168.9	3.08	2.93	1.418	1.78	1.207	3.25
Browns Ferry 1	276	Aug-74	240.0	Sep-67	124	Oct-70	136.0	3.08	2.22	1.295	1.76	1.202	2.24
Browns Ferry 3	334	Mar-77	238.2	Sep-70	149	Oct-73	141.0	3.08	2.24	1.299	1.69	1.186	2.11
Salem 1	850	Jun-77	607.2	Sep-71	308	Oct-74	267.6	3.08	2.76	1.390	2.27	1.304	1.87
Zion 1	276	Dec-73	261.0	Mar-69	205	Apr-72	205.0	3.09	1.35	1.101	1.27	1.081	1.54
Peach Bottom 3	223	Dec-74	194.1	Mar-71	263	Apr-74	228.5	3.09	0.85	0.948	0.85	0.948	1.22
Farley 2	750	Jul-81	384.3	Dec-73	329	Jan-77	234.9	3.09	2.28	1.306	1.64	1.173	2.46
Sequoyah 1	984	Jul-81	504.0	Mar-71	213	Apr-74	184.7	3.09	4.63	1.643	2.73	1.385	3.35
Salem 2	820	Oct-81	420.2	Mar-71	237	Apr-74	205.9	3.09	3.46	1.495	2.04	1.260	3.43
McGuire 1	906	Dec-81	464.1	Dec-74	384	Jan-78	255.3	3.09	2.36	1.321	1.82	1.214	2.27
Fort Calhoun 1	176	Sep-73	166.2	Mar-69	92	May-72	92.0	3.17	1.91	1.227	1.81	1.205	1.42
Oconee 2	160	Sep-74	139.4	Mar-69	93	May-72	92.6	3.17	1.73	1.189	1.51	1.138	1.74
McGuire 1	906	Dec-81	464.1	Sep-73	220	Nov-76	166.2	3.17	4.12	1.563	2.79	1.383	2.60
Sequoyah 2	623	Jun-82	301.3	Jun-73	225	Aug-76	169.6	3.17	2.78	1.380	1.78	1.199	2.84
Sequoyah 2	623	Jun-82	301.3	Dec-73	225	Feb-77	160.3	3.17	2.78	1.380	1.88	1.220	2.68
Surry 1	247	Dec-72	246.7	Dec-67	144	Mar-71	150.0	3.25	1.71	1.180	1.64	1.166	1.54
Surry 2	155	May-73	146.9	Dec-68	123	Mar-72	123.0	3.25	1.26	1.075	1.19	1.056	1.36
Peach Bottom 3	223	Dec-74	194.1	Dec-69	203	Mar-73	192.0	3.25	1.10	1.030	1.01	1.003	1.54
Brunswick 2	389	Nov-75	309.3	Dec-70	195	Mar-74	169.4	3.25	2.00	1.237	1.83	1.204	1.51
Brunswick 1	318	Mar-77	227.4	Dec-71	181	Mar-75	143.9	3.25	1.76	1.190	1.58	1.151	1.62
Salem 2	820	Oct-81	420.2	Dec-72	425	Mar-76	321.1	3.25	1.93	1.224	1.31	1.086	2.72
McGuire 1	906	Dec-81	464.1	Dec-72	220	Mar-76	166.2	3.25	4.12	1.546	2.79	1.372	2.77
Sequoyah 2	623	Jun-82	301.3	Dec-71	213	Mar-75	168.9	3.25	2.93	1.393	1.78	1.195	3.23
Pilgrim 1	239	Dec-72	239.3	Jun-68	122	Sep-71	127.4	3.25	1.96	1.229	1.88	1.214	1.39
Arkansas 2	640	Mar-80	358.7	Sep-73	275	Dec-76	207.8	3.25	2.33	1.297	1.73	1.183	2.00
Lasalle 1	1367	Oct-82	660.8	Sep-75	498	Dec-78	331.1	3.25	2.74	1.364	2.00	1.237	2.18
Kewaunee	203	Jun-74	176.7	Mar-69	109	Jun-72	109.0	3.25	1.87	1.211	1.62	1.160	1.61
Cook 1	545	Aug-75	433.0	Jun-69	235	Sep-72	235.0	3.25	2.32	1.295	1.84	1.207	1.90
Hatch 1	390	Dec-75	310.4	Mar-70	185	Jun-73	174.9	3.25	2.11	1.258	1.77	1.193	1.77
Cook 2	452	Jul-78	300.2	Jun-69	235	Sep-72	235.0	3.25	1.92	1.222	1.28	1.078	2.79
Millstone 2	426	Dec-75	338.9	Dec-70	239	Apr-74	207.7	3.33	1.78	1.190	1.63	1.158	1.50
North Anna 2	542	Dec-80	303.8	Mar-72	198	Jul-75	157.4	3.33	2.74	1.353	1.93	1.218	2.63
Farley 2	750	Jul-81	384.3	Dec-75	477	Apr-79	291.9	3.33	1.57	1.145	1.32	1.086	1.68
Calvert Cliffs 2	335	Apr-77	239.4	Sep-70	128	Jan-74	111.2	3.33	2.62	1.335	2.15	1.258	1.97
Arkansas 2	640	Mar-80	358.7	Jun-73	275	Oct-76	207.8	3.33	2.33	1.288	1.73	1.178	2.02
Salem 2	820	Oct-81	420.2	Mar-70	237	Jul-73	224.1	3.33	3.46	1.451	1.87	1.207	3.47
McGuire 1	906	Dec-81	464.1	Sep-74	365	Jan-78	242.7	3.33	2.48	1.313	1.91	1.215	2.17
Three Mile I. 1	401	Sep-74	348.4	Dec-67	124	May-71	129.2	3.41	3.23	1.410	2.70	1.337	1.98
Summer 1	1283	Jan-84	579.4	Dec-76	635	May-80	355.9	3.41	2.02	1.229	1.63	1.153	2.07
Peach Bottom 2	531	Jul-74	461.1	Sep-67	163	Mar-71	169.8	3.50	3.26	1.402	2.72	1.331	1.95
Peach Bottom 3	223	Dec-74	194.1	Sep-69	193	Mar-73	182.5	3.50	1.16	1.043	1.06	1.018	1.50
Cook 2	452	Jul-78	300.2	Sep-70	339	Mar-74	294.6	3.50	1.33	1.085	1.02	1.005	2.24
St. Lucie 1	486	Jun-76	367.4	Dec-70	200	Jun-74	173.8	3.50	2.43	1.289	2.11	1.239	1.57
Beaver Valley 1	599	Oct-76	452.4	Dec-69	192	Jun-73	181.6	3.50	3.12	1.384	2.49	1.298	1.95

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
North Anna 2	542	Dec-80	303.8	Dec-71	198	Jun-75	157.4	3.50	2.74	1.333	1.93	1.207	2.57
Arkansas 1	239	Dec-74	207.5	Jun-69	132	Dec-72	132.0	3.50	1.81	1.184	1.57	1.138	1.57
Salem 2	820	Oct-81	420.2	Jun-71	237	Dec-74	205.9	3.50	3.46	1.425	2.04	1.226	2.95
Trojan	452	Dec-75	359.3	Mar-71	228	Sep-74	198.1	3.50	1.98	1.216	1.81	1.185	1.36
Farley 1	727	Dec-77	519.4	Sep-71	259	Apr-75	205.9	3.58	2.81	1.334	2.52	1.295	1.75
Hatch 2	515	Sep-79	315.1	Sep-75	513	Apr-79	313.9	3.58	1.00	1.001	1.00	1.001	1.12
Hatch 2	515	Sep-79	315.1	Sep-74	513	Apr-78	341.0	3.58	1.00	1.001	0.92	0.978	1.40
Farley 2	750	Jul-81	384.3	Jun-73	268	Jan-77	191.4	3.59	2.80	1.332	2.01	1.215	2.25
Summer 1	1283	Jan-84	579.4	Jun-74	355	Jan-78	236.0	3.59	3.61	1.431	2.45	1.285	2.67
Maine Yankee	219	Dec-72	219.2	Sep-68	131	May-72	131.0	3.66	1.67	1.151	1.67	1.151	1.16
Oconee 1	156	Jul-73	147.1	Sep-67	93	May-71	96.5	3.66	1.68	1.152	1.53	1.122	1.59
Fort Calhoun 1	176	Sep-73	166.2	Sep-67	70	May-71	72.9	3.66	2.51	1.286	2.28	1.252	1.64
Prairie Isl 2	177	Dec-74	153.8	Sep-70	112	May-74	97.5	3.66	1.58	1.133	1.58	1.133	1.16
St. Lucie 1	486	Jun-76	367.4	Sep-69	123	May-73	116.3	3.66	3.95	1.455	3.16	1.369	1.84
Three Mile I. 2	715	Dec-78	475.6	Sep-70	285	May-74	247.7	3.66	2.51	1.286	1.92	1.195	2.24
Three Mile I. 2	715	Dec-78	475.6	Sep-71	345	May-75	274.3	3.66	2.07	1.220	1.73	1.162	1.97
Three Mile I. 2	715	Dec-78	475.6	Sep-74	580	May-78	385.6	3.66	1.23	1.059	1.23	1.059	1.15
Salem 2	820	Oct-81	420.2	Sep-71	308	May-75	244.9	3.66	2.66	1.306	1.72	1.159	2.75
Susquehanna 1	1947	Jun-83	902.9	Mar-77	1097	Nov-80	615.0	3.67	1.77	1.169	1.47	1.110	1.70
Oconee 3	160	Dec-74	139.4	Sep-69	109	Jun-73	103.3	3.75	1.47	1.108	1.35	1.083	1.40
Brunswick 1	318	Mar-77	227.4	Jun-71	182	Mar-75	144.7	3.75	1.75	1.161	1.57	1.128	1.53
Three Mile I. 2	715	Dec-78	475.6	Aug-72	465	May-76	351.4	3.75	1.54	1.122	1.35	1.084	1.68
North Anna 2	542	Dec-80	303.8	Sep-71	191	Jun-75	151.8	3.75	2.84	1.321	2.00	1.203	2.47
Arkansas 1	239	Dec-74	207.5	Mar-69	138	Dec-72	138.0	3.75	1.73	1.157	1.50	1.115	1.53
Nine Mile Point 1	162	Dec-69	186.9	Sep-64	68	Jul-68	82.4	3.83	2.39	1.255	2.27	1.239	1.37
Indian Point 3	570	Aug-76	430.7	Sep-67	154	Jul-71	160.4	3.83	3.70	1.407	2.69	1.294	2.34
Browns Ferry 1	276	Aug-74	240.0	Dec-66	117	Oct-70	128.3	3.83	2.35	1.250	1.87	1.178	2.00
Crystal River 3	419	Mar-77	299.2	Jun-68	113	Apr-72	113.0	3.83	3.71	1.408	2.65	1.289	2.28
Arkansas 2	640	Mar-80	358.7	Dec-71	200	Oct-75	159.0	3.83	3.20	1.355	2.26	1.236	2.15
Sequoyah 1	984	Jul-81	504.0	Jun-70	187	Apr-74	162.1	3.83	5.27	1.543	3.11	1.344	2.89
Sequoyah 2	623	Jun-82	301.3	Jun-70	187	Apr-74	162.1	3.83	3.34	1.370	1.86	1.176	3.13
Calvert Cliffs 1	431	May-75	342.4	Mar-69	124	Jan-73	117.3	3.84	3.47	1.383	2.92	1.322	1.61
Oconee 1	156	Jul-73	147.1	Jun-67	86	May-71	89.3	3.92	1.81	1.164	1.65	1.136	1.55
Browns Ferry 1	276	Aug-74	240.0	Sep-66	117	Aug-70	128.3	3.92	2.35	1.244	1.87	1.174	2.02
Three Mile I. 1	401	Sep-74	348.4	Jun-67	106	May-71	110.4	3.92	3.78	1.405	3.16	1.341	1.85
Salem 1	850	Jun-77	607.2	Jun-67	149	May-71	155.2	3.92	5.71	1.560	3.91	1.417	2.55
Three Mile I. 2	715	Dec-78	475.6	Jun-73	525	May-77	374.9	3.92	1.36	1.082	1.27	1.063	1.40
Susquehanna 1	1947	Jun-83	902.9	Dec-76	1032	Nov-80	578.2	3.92	1.89	1.176	1.56	1.121	1.66
Indian Point 2	206	Aug-73		Jun-66		Jun-69		3.00					2.389
Ginna	83	Jul-70		Mar-66		Jun-69		3.25					1.332
Oyster Creek 1	90	Dec-69		Jun-64		Oct-67		3.33					1.651
Quad Cities 2	100	Mar-73		Sep-67		Mar-71		3.50					1.572
Ginna	83	Jul-70		Dec-65		Jun-69		3.50					1.309
Point Beach 1	74	Dec-70		Sep-66		Apr-70		3.58					1.187
Millstone 1	97	Mar-71		Dec-65		Aug-69		3.67					1.431
Quad Cities 1	100	Feb-73		Jun-66		Mar-70		3.75					1.780
Point Beach 1	74	Dec-70		Jun-66		Apr-70		3.83					1.174
Monticello	105	Jun-71		Jun-66		May-70		3.92					1.277
Robinson 2	78	Mar-71		Jun-66		May-70		3.92					1.213
Dresden 3	104	Nov-71		Mar-66		Feb-70		3.92					1.445

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Salem 2	820	Oct-81	420.2	Sep-74	496	May-79	303.5	4.66	1.65	1.114	1.38	1.072	1.52
St. Lucie 2	1430	Aug-83	663.2	Sep-78	845	May-83	391.9	4.66	1.69	1.119	1.69	1.119	1.05
Maine Yankee	219	Dec-72	219.2	Sep-67	100	May-72	100.0	4.67	2.19	1.183	2.19	1.183	1.13
Nine Mile Point 1	162	Dec-69	186.9	Mar-64	68	Nov-68	82.4	4.67	2.39	1.205	2.27	1.192	1.23
Susquehanna 1	1947	Jun-83	902.9	Mar-76	1047	Nov-80	586.8	4.67	1.86	1.142	1.54	1.097	1.55
Salem 1	850	Jun-77	607.2	Sep-66	139	May-71	144.8	4.70	6.12	1.470	4.19	1.356	2.29
Three Mile I. 2	715	Dec-78	475.6	Aug-69	214	May-74	186.0	4.75	3.34	1.289	2.56	1.219	1.96
Trojan	452	Dec-75	359.3	Dec-69	227	Sep-74	197.3	4.75	1.99	1.156	1.82	1.135	1.26
Farley 1	727	Dec-77	519.4	Jun-70	203	Apr-75	161.4	4.83	3.58	1.302	3.22	1.274	1.55
Arkansas 2	640	Mar-80	358.7	Dec-70	183	Oct-75	145.5	4.83	3.50	1.296	2.47	1.205	1.91
Sequoyah 2	623	Jun-82	301.3	Dec-68	161	Oct-73	152.2	4.83	3.87	1.323	1.98	1.152	2.79
Peach Bottom 3	223	Dec-74	194.1	Mar-68	145	Jan-73	137.1	4.84	1.54	1.093	1.42	1.074	1.40
Calvert Cliffs 1	431	May-75	342.4	Mar-68	125	Jan-73	118.2	4.84	3.45	1.291	2.90	1.246	1.48
Calvert Cliffs 2	335	Apr-77	239.4	Mar-69	105	Jan-74	91.2	4.84	3.19	1.271	2.62	1.221	1.67
Oconee 2	160	Sep-74	139.4	Jun-67	86	May-72	85.8	4.92	1.87	1.136	1.63	1.104	1.47
Point Beach 2	71	Oct-72		Mar-67		Apr-71		4.08					1.368
Quad Cities 2	100	Mar-73		Sep-66		Mar-71		4.50					1.445

For: 4 <= t < 5

	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
No. of data points:	63	61	61	61	61	63
Average	4.398	2.827	1.251	2.193	1.186	1.752
Standard Deviation:	0.256	1.186	0.117	0.715	0.085	0.481

Oconee 3	160	Dec-74	139.4	Jun-68	88	Jun-73	83.1	5.00	1.83	1.128	1.68	1.109	1.30
Duane Arnold	280	Feb-75	222.5	Dec-68	107	Dec-73	101.2	5.00	2.62	1.212	2.20	1.171	1.23
Hatch 1	390	Dec-75	310.4	Jun-68	160	Jun-73	151.3	5.00	2.44	1.195	2.05	1.155	1.50
North Anna 1	782	Jun-78	519.7	Mar-69	185	Mar-74	160.8	5.00	4.23	1.334	3.23	1.265	1.85
St. Lucie 2	1430	Aug-83	663.2	Dec-74	537	Dec-79	328.6	5.00	2.66	1.216	2.02	1.151	1.73
Arkansas 1	239	Dec-74	207.5	Dec-67	132	Dec-72	132.0	5.00	1.81	1.126	1.57	1.095	1.40
St. Lucie 2	1430	Aug-83	663.2	Dec-75	620	Dec-80	347.5	5.00	2.31	1.182	1.91	1.138	1.53
Sequoyah 1	984	Jul-81	504.0	Sep-68	161	Oct-73	152.2	5.08	6.11	1.428	3.31	1.266	2.52
Zion 1	276	Dec-73	261.0	Mar-67	164	Apr-72	164.0	5.09	1.68	1.108	1.59	1.096	1.33
Calvert Cliffs 1	431	May-75	342.4	Dec-67	123	Jan-73	116.3	5.09	3.50	1.279	2.94	1.236	1.46
Crystal River 3	419	Mar-77	299.2	Mar-67	110	Apr-72	110.0	5.09	3.81	1.301	2.72	1.217	1.97
Fitzpatrick	419	Jul-75	333.1	Mar-68	224	May-73	211.8	5.17	1.87	1.129	1.57	1.092	1.42
McGuire 1	906	Dec-81	464.1	Sep-70	179	Nov-75	142.3	5.17	5.06	1.369	3.26	1.257	2.18
Lasalle 1	1367	Oct-82	660.8	Mar-73	407	May-78	270.6	5.17	3.36	1.264	2.44	1.189	1.86
Prairie Isl 1	233	Dec-73	220.5	Mar-67	100	May-72	100.0	5.17	2.33	1.178	2.21	1.165	1.31
Surry 2	155	May-73	146.9	Dec-66	108	Mar-72	108.0	5.25	1.44	1.072	1.36	1.060	1.22
Brunswick 1	318	Mar-77	227.4	Dec-70	194	Mar-76	146.6	5.25	1.64	1.099	1.55	1.087	1.19
Davis-Besse 1	672	Nov-77	480.2	Sep-69	201	Dec-74	174.7	5.25	3.35	1.259	2.75	1.212	1.56
Salem 2	820	Oct-81	420.2	Dec-67	128	Mar-73	121.0	5.25	6.41	1.425	3.47	1.268	2.64
Lasalle 1	1367	Oct-82	660.8	Sep-72	407	Dec-77	290.6	5.25	3.36	1.260	2.27	1.169	1.92
Lasalle 1	1367	Oct-82	660.8	Sep-73	430	Dec-78	285.9	5.25	3.18	1.247	2.31	1.173	1.73
Beaver Valley 1	599	Oct-76	452.4	Mar-68	150	Jun-73	141.8	5.25	3.99	1.302	3.19	1.247	1.64
San Onofre 2	2502	Aug-83	1160.3	Mar-74	655	Jun-79	400.8	5.25	3.82	1.291	2.89	1.224	1.79
St. Lucie 2	1430	Aug-83	663.2	Sep-75	537	Dec-80	301.0	5.25	2.66	1.205	2.20	1.162	1.51
Millstone 2	426	Dec-75	338.9	Dec-68	179	Apr-74	155.5	5.33	2.38	1.177	2.18	1.157	1.31
Hatch 2	515	Sep-79	315.1	Dec-72	330	Apr-78	219.4	5.33	1.56	1.087	1.44	1.070	1.27

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Lasalle 1	1367	Oct-82	660.8	Jun-73	407	Oct-78	270.6	5.33	3.36	1.255	2.44	1.182	1.75
Lasalle 1	1367	Oct-82	660.8	Jun-70	360	Oct-75	286.2	5.33	3.80	1.284	2.31	1.170	2.31
San Onofre 2	2502	Aug-83	1160.3	Jun-76	1210	Oct-81	620.1	5.33	2.07	1.146	1.87	1.125	1.34
Peach Bottom 3	223	Dec-74	194.1	Sep-67	145	Jan-73	137.1	5.34	1.54	1.084	1.42	1.067	1.36
Rancho Seco	344	Apr-75	273.2	Dec-67	134	May-73	126.7	5.42	2.56	1.190	2.16	1.152	1.35
Oconee 3	160	Dec-74	139.4	Dec-67	93	Jun-73	87.6	5.50	1.73	1.105	1.59	1.088	1.27
Duane Arnold	280	Feb-75	222.5	Jun-68	103	Dec-73	97.4	5.50	2.72	1.199	2.28	1.162	1.21
St. Lucie 2	1430	Aug-83	663.2	Jun-74	360	Dec-79	220.3	5.50	3.97	1.285	3.01	1.222	1.67
Trojan	452	Dec-75	359.3	Mar-69	197	Sep-74	171.2	5.50	2.29	1.163	2.10	1.144	1.23
Farley 1	727	Dec-77	519.4	Sep-69	164	Apr-75	130.4	5.58	4.44	1.306	3.98	1.281	1.48
Beaver Valley 1	599	Oct-76	452.4	Dec-67	150	Jul-73	141.8	5.58	3.99	1.281	3.19	1.231	1.58
Farley 2	750	Jul-81	384.3	Sep-71	233	Apr-77	166.4	5.58	3.22	1.233	2.31	1.162	1.76
Calvert Cliffs 1	431	May-75	342.4	Jun-67	118	Jan-73	111.6	5.59	3.65	1.261	3.07	1.222	1.42
Susquehanna 1	1947	Jun-83	902.9	Sep-73	810	May-79	495.7	5.66	2.40	1.168	1.82	1.112	1.72
Oconee 2	160	Sep-74	139.4	Sep-66	75	May-72	75.4	5.66	2.13	1.143	1.85	1.115	1.41
Salem 2	820	Oct-81	420.2	Sep-67	128	May-73	121.0	5.66	6.41	1.388	3.47	1.246	2.49
Lasalle 1	1367	Oct-82	660.8	Sep-71	360	May-77	257.1	5.66	3.80	1.266	2.57	1.181	1.96
Trojan	452	Dec-75	359.3	Dec-68	196	Sep-74	170.3	5.75	2.31	1.156	2.11	1.139	1.22
St. Lucie 2	1430	Aug-83	663.2	Dec-72	360	Oct-78	239.3	5.83	3.97	1.267	2.77	1.191	1.83
Calvert Cliffs 2	335	Apr-77	239.4	Mar-68	106	Jan-74	92.1	5.84	3.16	1.218	2.60	1.178	1.56
Summer 1	1283	Jan-84	579.4	Mar-71	234	Jan-77	167.1	5.84	5.48	1.338	3.47	1.237	2.20
Hatch 2	515	Sep-79	315.1	Jun-70	189	Apr-76	142.8	5.88	2.72	1.186	2.21	1.144	1.57
St. Lucie 2	1430	Aug-83	663.2	Jun-77	850	May-83	394.2	5.91	1.68	1.092	1.68	1.092	1.04
Zion 2	292	Sep-74	253.7	Jun-67	153	May-73	144.7	5.92	1.91	1.115	1.75	1.100	1.23
Susquehanna 1	1947	Jun-83	902.9	Dec-74	945	Nov-80	529.6	5.92	2.06	1.130	1.70	1.094	1.44
Pilgrim 1	239	Dec-72	239.3	Jul-65	70	Jul-71	72.9	6.00	3.42	1.227	3.28	1.219	1.24
Davis-Besse 1	672	Nov-77	480.2	Dec-68	180	Dec-74	156.4	6.00	3.74	1.246	3.07	1.206	1.49
Susquehanna 1	1947	Jun-83	902.9	Jun-69	150	27560	119.2	6.00	12.98	1.533	7.57	1.401	2.33
San Onofre 2	2502	Aug-83	1160.3	Jun-73	655	Jun-79	400.8	6.00	3.82	1.250	2.89	1.194	1.69
St. Lucie 2	1430	Aug-83	663.2	Dec-76	850	Dec-82	410.9	6.00	1.68	1.091	1.61	1.083	1.11
Oconee 3	160	Dec-74	139.4	Jun-67	92	Jun-73	87.1	6.00	1.74	1.097	1.60	1.082	1.25
Lasalle 1	1367	Oct-82	660.8	Dec-71	360	Dec-77	257.1	6.00	3.80	1.249	2.57	1.170	1.81
San Onofre 2	2502	Aug-83	1160.3	Jun-70	213	Jun-76	160.9	6.00	11.75	1.508	7.21	1.390	2.19
Millstone 2	426	Dec-75	338.9	Mar-68	146	Apr-74	126.9	6.08	2.92	1.193	2.67	1.175	1.27
San Onofre 2	2502	Aug-83	1160.3	Sep-75	1142	Oct-81	585.2	6.08	2.19	1.138	1.98	1.119	1.30
Peach Bottom 3	223	Dec-74	194.1	Dec-66	125	Jan-73	118.2	6.09	1.79	1.100	1.64	1.085	1.31
Calvert Cliffs 2	335	Apr-77	239.4	Dec-67	107	Jan-74	93.0	6.09	3.13	1.206	2.58	1.168	1.53
Susquehanna 1	1947	Jun-83	902.9	Sep-74	810	Nov-80	454.0	6.17	2.40	1.153	1.99	1.118	1.42
St. Lucie 2	1430	Aug-83	663.2	Sep-76	620	Dec-82	299.7	6.25	2.31	1.143	2.21	1.136	1.11
San Onofre 2	2502	Aug-83	1160.3	Mar-70	189	Jun-76	142.8	6.25	13.24	1.511	8.12	1.398	2.15
Millstone 2	426	Dec-75	338.9	Dec-67	150	Apr-74	130.3	6.33	2.84	1.179	2.60	1.163	1.26
San Onofre 2	2502	Aug-83	1160.3	Mar-75	1142	Jul-81	585.2	6.34	2.19	1.132	1.98	1.114	1.33
Susquehanna 1	1947	Jun-83	902.9	Dec-72	703	May-79	430.2	6.41	2.77	1.172	2.10	1.123	1.64
Prairie Isl 2	177	Dec-74	153.8	Dec-67	80	May-74	69.3	6.41	2.22	1.132	2.22	1.132	1.09
San Onofre 2	2502	Aug-83	1160.3	Dec-71	409	Jun-78	271.9	6.50	6.12	1.321	4.27	1.250	1.79
Farley 2	750	Jul-81	384.3	Sep-70	183	Apr-77	130.7	6.58	4.10	1.239	2.94	1.178	1.65
San Onofre 2	2502	Aug-83	1160.3	Dec-74	893	Jul-81	457.6	6.58	2.80	1.169	2.54	1.152	1.32
Calvert Cliffs 2	335	Apr-77	239.4	Jun-67	105	Jan-74	91.2	6.59	3.19	1.193	2.62	1.158	1.49
Susquehanna 1	1947	Jun-83	902.9	Sep-69	150	Jun-76	113.3	6.75	12.98	1.462	7.97	1.360	2.04
San Onofre 2	2502	Aug-83	1160.3	Sep-71	363	Jun-78	241.3	6.75	6.89	1.331	4.81	1.262	1.77
St. Lucie 2	1430	Aug-83	663.2	Mar-73	360	Dec-79	220.3	6.75	3.97	1.227	3.01	1.177	1.54
St. Lucie 2	1430	Aug-83	663.2	Mar-74	360	Dec-80	201.8	6.75	3.97	1.227	3.29	1.193	1.39
Susquehanna 1	1947	Jun-83	902.9	Jun-71	373	Jun-78	247.9	7.00	5.22	1.266	3.64	1.203	1.71

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Susquehanna 1	1947	Jun-83	902.9	Mar-72	645	May-79	394.4	7.16	3.02	1.167	2.29	1.123	1.57
Susquehanna 1	1947	Jun-83	902.9	Dec-71	526	May-79	322.1	7.41	3.70	1.193	2.80	1.149	1.55
Susquehanna 1	1947	Jun-83	902.9	Dec-70	250	Jun-78	166.2	7.50	7.79	1.315	5.43	1.253	1.67
For: 5 <= t													
No. of data points:								82	82	82	82	82	82
Average								5.773	3.676	1.226	2.751	1.176	1.582
Standard Deviation:								0.607	2.441	0.102	1.357	0.073	0.350

APPENDIX D:

OPERATIONS AND MAINTENANCE

AND

CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Arkansas 1	74	902	233027	.	.	.	.	.	4	1
Arkansas 1	75	902	238751	5724	10407	4109	7034	11.54	4	1
Arkansas 1	76	902	242204	3453	5962	6015	9787	6.61	4	1
Arkansas 1	77	902	247069	4865	7997	8379	12883	8.87	4	1
Arkansas 1	78	902	253994	6925	10259	12125	17358	11.37	4	1
Arkansas 1	79	902	268130	14136	18641	18923	24935	20.67	4	1
Arkansas 1	80	NA	NA	.	.	.	.	.	4	1
Arkansas 1&2	81	1845	916567	.	.	.	.	.	4	2
Arkansas 1&2	82	1845	927141	10574	11034	54496	56588	5.98	4	2
Arkansas 1&2	83	1845	935827	8686	8686	66173	66173	4.71	4	2
Arkansas 1&2	84	1845	1017607	81780	80091	75818	73098	43.41	4	2
Beaver Valley	76	923	599697	.	.	.	.	.	1	1
Beaver Valley	77	923	598716	-981	-1525	14692	22590	-1.65	1	1
Beaver Valley	78	923	582408	-16308	-23883	22681	32470	-25.88	1	1
Beaver Valley	79	923	576367	-6041	-8067	22907	30185	-8.74	1	1
Beaver Valley	80	923	647575	71208	87849	34771	41966	95.18	1	1
Beaver Valley	81	924	671283	23708	26909	35838	39455	29.12	1	1
Beaver Valley	82	923	748515	77232	80791	49144	51030	87.53	1	1
Beaver Valley	83	905	829685	81170	81170	68156	68156	89.69	1	1
Beaver Valley	84	924	878844	49159	47244	71835	69249	51.12	1	1
Big Rock Point	63	54	14412	.	.	.	.	.	3	1
Big Rock Point	64	54	14349	-63	-221	666	1971	-4.10	3	1
Big Rock Point	65	75	13750	-599	-2106	715	2071	-28.07	3	1
Big Rock Point	66	75	13793	43	149	763	2140	1.99	3	1
Big Rock Point	67	75	13837	44	146	1086	2958	1.94	3	1
Big Rock Point	68	75	13926	89	287	865	2257	3.82	3	1
Big Rock Point	69	75	13958	32	96	933	2315	1.29	3	1
Big Rock Point	70	75	14324	366	1023	1062	2501	13.64	3	1
Big Rock Point	71	75	14554	230	593	1266	2840	7.91	3	1
Big Rock Point	72	75	14731	177	432	1412	3041	5.76	3	1
Big Rock Point	73	75	14815	84	195	1586	3230	2.60	3	1
Big Rock Point	74	75	16012	1197	2415	2263	4235	32.20	3	1
Big Rock Point	75	75	16587	575	1034	2584	4424	13.79	3	1
Big Rock Point	76	75	22907	6320	10702	3183	5179	142.70	3	1
Big Rock Point	77	75	23971	1064	1668	5125	7880	22.24	3	1
Big Rock Point	78	75	24409	438	639	3645	5218	8.52	3	1
Big Rock Point	79	75	27014	2605	3473	9232	12165	46.31	3	1
Big Rock Point	80	75	27262	248	304	8409	10149	4.06	3	1
Big Rock Point	81	75	33356	6094	6863	12970	14279	91.51	3	1
Big Rock Point	82	75	37068	3712	3862	15513	16108	51.49	3	1
Big Rock Point	83	75	39382	2314	2314	16561	16561	30.85	3	1
Big Rock Point	84	75	40105	723	701	12246	11805	9.35	3	1
Browns Ferry 1&2	75	2304	512653	.	.	.	.	.	2	2
Browns Ferry 1&2	76	2304	552357	39704	66749	16104	26204	28.97	2	2
Browns Ferry 1,2,3	77	3456	853325	.	.	.	.	.	2	3
Browns Ferry 1,2,3	78	3456	885991	32666	47072	45921	65740	13.62	2	3
Browns Ferry 1,2,3	79	3456	888350	2359	3092	55588	73249	0.89	2	3
Browns Ferry 1,2,3	80	3456	890428	2078	2485	66969	80827	0.72	2	3
Browns Ferry 1,2,3	81	3456	892715	2287	2503	85469	94095	0.72	2	3
Browns Ferry 1,2,3	82	3456	915514	22799	23404	92271	95813	6.77	2	3
Browns Ferry 1,2,3	83	3456	929490	13976	13976	108946	108946	4.04	2	3
Browns Ferry 1,2,3	84	3456	1037790	108300	106449	129996	125317	30.80	2	3
Brunswick 2	75	866	382246	.	.	.	.	.	2	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Brunswick 2	76	866	389118	6872	11553	10518	17115	13.34	2	1
Brunswick 2&1	77	1733	707560	.	.	.	.	.	2	2
Brunswick 2&1	78	1733	714928	7368	10617	26633	38128	6.13	2	2
Brunswick 2&1	79	1733	750828	35900	47055	34206	45074	27.15	2	2
Brunswick 2&1	80	1733	776989	26161	31285	57516	63418	18.05	2	2
Brunswick 2&1	81	1733	803535	26546	29050	73150	80532	16.76	2	2
Brunswick 2&1	82	1755	805771	2236	2295	112235	116543	1.31	2	2
Brunswick 2&1	83	1733	893322	87551	87551	109814	109814	50.52	2	2
Brunswick 2&1	84	1733	1020910	127588	125407	103362	99642	72.36	2	2
Calvert Cliffs 1	75	918	428747	.	.	.	.	.	1	1
Calvert Cliffs 1	76	918	430674	1927	3216	8984	14613	3.50	1	1
Calvert Cliffs 1&2	77	1828	765995	.	.	.	.	.	1	2
Calvert Cliffs 1&2	78	1828	777711	11716	17158	25997	37217	9.39	1	2
Calvert Cliffs 1&2	79	1828	780095	2384	3183	36397	47961	1.74	1	2
Calvert Cliffs 1&2	80	1828	790988	10893	13439	41628	50242	7.35	1	2
Calvert Cliffs 1&2	81	1828	820215	29227	33173	50409	55496	18.15	1	2
Calvert Cliffs 1&2	82	1828	852313	32098	33577	61969	64348	18.37	1	2
Calvert Cliffs 1&2	83	1828	903868	51555	51555	52772	52772	28.20	1	2
Calvert Cliffs 1&2	84	1828	942111	38243	36753	62345	60099	20.11	1	2
Connecticut Yankee	68	600	91801	.	.	2047	5340	.	1	1
Connecticut Yankee	69	600	91841	40	121	2067	5129	0.20	1	1
Connecticut Yankee	70	600	93516	1675	4694	4479	10547	7.82	1	1
Connecticut Yankee	71	600	93669	153	395	3279	7354	0.66	1	1
Connecticut Yankee	72	600	93814	145	346	3749	8073	0.58	1	1
Connecticut Yankee	73	600	94016	202	459	6352	12935	0.76	1	1
Connecticut Yankee	74	600	106212	12196	24285	4935	9234	40.48	1	1
Connecticut Yankee	75	600	108921	2709	4842	9381	16059	8.07	1	1
Connecticut Yankee	76	600	114503	5582	9317	9419	15326	15.53	1	1
Connecticut Yankee	77	600	117238	2735	4252	9448	14527	7.09	1	1
Connecticut Yankee	78	600	121288	4050	5931	8736	12506	9.89	1	1
Connecticut Yankee	79	600	123037	1749	2335	18923	24935	3.89	1	1
Connecticut Yankee	80	600	137644	14607	18021	35155	42430	30.03	1	1
Connecticut Yankee	81	600	152552	14908	16921	37488	41271	28.20	1	1
Connecticut Yankee	82	600	167878	15326	16032	35723	37094	26.72	1	1
Connecticut Yankee	83	600	182739	14861	14861	48672	48672	24.77	1	1
Connecticut Yankee	84	600	191277	8538	8206	59889	57733	13.68	1	1
Cook 1	75	1089	538611	.	.	.	.	.	3	1
Cook 1	76	1089	544650	6039	10227	7047	11467	9.39	3	1
Cook 1	77	1089	552238	7588	11895	10012	15594	10.92	3	1
Cook 1&2	78	2200	996177	.	.	.	.	.	3	2
Cook 1&2	79	2285	1025829	29652	39536	26750	35249	17.30	3	2
Cook 1&2	80	2250	1074584	48755	59847	32409	39115	26.60	3	2
Cook 1&2	81	2285	1096310	21726	24468	37967	41799	10.71	3	2
Cook 1&2	82	2285	1118610	22300	23200	50859	52811	10.15	3	2
Cook 1&2	83	2285	1145590	26980	26980	59519	59519	11.81	3	2
Cook 1&2	84	2285	1169784	24194	23470	80435	77540	10.27	3	2
Cooper	74	835	246268	.	.	.	.	.	3	1
Cooper	75	835	269297	23019	41399	7386	12644	49.58	3	1
Cooper	76	835	269287	0	0	10211	16615	0.00	3	1
Cooper	77	835	302382	33095	51879	10218	15711	62.13	3	1
Cooper	78	836	384630	82248	120010	8306	11891	143.55	3	1
Cooper	79	836	384570	-60	-80	10232	13483	-0.10	3	1
Cooper	80	836	384569	-1	-1	19004	22936	0.00	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Cooper	81	778	383748	-821	-925	20455	22519	-1.19	3	1
Cooper	82	836	384358	610	635	23492	24383	0.76	3	1
Cooper	83	836	383509	-749	-749	30893	30893	-0.90	3	1
Cooper	84	836	383511	-98	-95	25639	24774	-0.11	3	1
Crystal River	77	801	365535	.	.	.	.	.	2	1
Crystal River	78	890	415173	49633	71528	15613	22351	80.37	2	1
Crystal River	79	890	419131	3958	5188	23992	31614	5.83	2	1
Crystal River	80	898	421055	1924	2301	39841	48085	2.59	2	1
Crystal River	81	801	384011	-37044	-40559	42313	46583	-50.61	2	1
Crystal River	82	801	385759	1748	1794	46736	48592	2.24	2	1
Crystal River	83	801	396620	10861	10861	67548	67548	13.55	2	1
Crystal River	84	890	452274	55654	54703	84681	81633	61.43	2	1
Davis-Besse	77	960	557966	.	.	.	.	.	3	1
Davis-Besse	78	906	635147	77181	112617	14096	20180	124.30	3	1
Davis-Besse	79	906	671140	35993	47991	21737	28643	52.97	3	1
Davis-Besse	80	962	738544	67404	82739	44630	53865	86.31	3	1
Davis-Besse	81	962	786437	47893	53938	41413	45592	56.07	3	1
Davis-Besse	82	962	846126	59689	62099	59955	62256	64.55	3	1
Davis-Besse	83	962	882523	36397	36397	49328	49328	37.33	3	1
Davis-Besse	84	963	1003254	120731	117119	60802	58614	121.67	3	1
Dresden 1	62	208	34180	.	.	.	.	.	3	1
Dresden 1	63	208	34442	262	921	1266	3804	4.43	3	1
Dresden 1	64	208	34468	26	91	1071	3169	0.44	3	1
Dresden 1	65	208	34451	-17	-60	1264	3660	-0.29	3	1
Dresden 1	66	208	34352	-99	-343	1163	3263	-1.65	3	1
Dresden 1	67	208	34366	14	46	1912	5208	0.22	3	1
Dresden 1	68	208	33467	-899	-2897	1673	4365	-13.93	3	1
Dresden 1	69	208	33968	501	1510	1788	4436	7.26	3	1
Dresden 1&2	70	1018	116609	.	.	.	.	.	3	2
Dresden 1,2,3	71	1828	220380	.	.	.	.	.	3	3
Dresden 1,2,3	72	1865	241479	21099	51526	9142	19686	27.63	3	3
Dresden 1,2,3	73	1865	235397	-6082	-14110	9050	18429	-7.57	3	3
Dresden 1,2,3	74	1865	237303	1906	3845	16731	31307	2.06	3	3
Dresden 1,2,3	75	1865	249177	11874	21355	32895	56313	11.45	3	3
Dresden 1,2,3	76	1865	256493	7316	12389	30092	48965	6.64	3	3
Dresden 1,2,3	77	1865	258522	2029	3181	26999	41513	1.71	3	3
Dresden 1,2,3	78	1865	276887	18365	26797	33932	48577	14.37	3	3
Dresden 1,2,3	79	1865	290785	13898	18531	44579	58742	9.94	3	3
Dresden 1,2,3	80	1865	303201	12416	15241	38130	46020	8.17	3	3
Dresden 1,2,3	81	1865	307054	3853	4339	40361	44434	2.33	3	3
Dresden 1,2,3	82	1865	331590	24536	25526	43740	45419	13.69	3	3
Dresden 1,2,3	83	1865	340169	8579	8579	47134	47134	4.60	3	3
Dresden 1,2,3	84	1865	472538	132369	128409	65921	63548	68.85	3	3
Duane Arnold	74	565	288821	.	.	.	.	.	3	1
Duane Arnold	75	565	279730	-9091	-16350	3839	6572	-28.94	3	1
Duane Arnold	76	565	279928	198	335	7050	11472	0.59	3	1
Duane Arnold	77	565	287561	7633	11966	7508	11544	21.18	3	1
Duane Arnold	78	597	282345	-5216	-7611	11916	17059	-12.75	3	1
Duane Arnold	79	597	306768	24423	32564	9528	12555	54.55	3	1
Duane Arnold	80	597	324186	17418	21381	18398	22205	35.91	3	1
Duane Arnold	81	597	339460	15274	17202	21956	24172	28.91	3	1
Duane Arnold	82	597	365309	25849	26892	29239	30361	45.05	3	1
Duane Arnold	83	597	397117	31808	31808	45949	45949	53.28	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Duane Arnold	84	597	412435	15318	14860	34587	33342	24.89	3	1
Farley 1	77	888	727426	.	.	.	.	.	2	1
Farley 1	78	888	734519	7093	10221	12207	17475	11.51	2	1
Farley 1	79	888	751634	17115	22433	22545	29708	25.25	2	1
Farley 1	80	888	761329	9695	11594	25734	31059	13.06	2	1
Farley 1&2	81	1776	1541981	.	.	.	.	.	2	2
Farley 1&2	82	1777	1611172	69191	71028	52488	54503	39.97	2	2
Farley 1&2	83	1777	1642869	31697	31697	60275	60275	17.84	2	2
Farley 1&2	84	1777	1664849	21980	21604	76822	74057	12.16	2	2
Fitzpatrick	75	849	NA	.	.	.	.	.	1	1
Fitzpatrick	76	849	NA	.	.	10700	17411	.	1	1
Fitzpatrick	77	849	NA	.	.	17383	26728	.	1	1
Fitzpatrick	78	883	NA	.	.	19045	27265	.	1	1
Fitzpatrick	79	883	NA	.	.	25131	33115	.	1	1
Fitzpatrick	80	883	NA	.	.	33303	40194	.	1	1
Fitzpatrick	81	883	367141	.	.	36678	40380	.	1	1
Fitzpatrick	82	883	344597	-22544	-23583	31504	32713	-26.71	1	1
Fitzpatrick	83	883	373346	28749	28749	43170	43170	32.56	1	1
Fitzpatrick	84	883	429948	56602	54397	53796	51860	61.60	1	1
Fort Calhoun	73	481	173870	.	.	.	.	.	3	1
Fort Calhoun	74	481	175800	1930	3894	3413	6386	8.09	3	1
Fort Calhoun	75	481	178572	2772	4985	5962	10206	10.36	3	1
Fort Calhoun	76	481	178896	324	549	7449	12121	1.14	3	1
Fort Calhoun	77	481	179994	1098	1721	8493	13059	3.58	3	1
Fort Calhoun	78	481	180328	334	487	8116	11619	1.01	3	1
Fort Calhoun	79	481	180830	502	669	8504	11206	1.39	3	1
Fort Calhoun	80	481	192700	11870	14571	14332	17298	30.29	3	1
Fort Calhoun	81	481	198544	5844	6582	11472	12630	13.68	3	1
Fort Calhoun	82	481	211041	12497	13001	18934	19661	27.03	3	1
Fort Calhoun	83	481	221514	10473	10473	23860	23860	21.77	3	1
Fort Calhoun	84	502	230358	8844	8580	25239	24331	17.09	3	1
Ginna	70	517	83175	.	.	.	.	.	1	1
Ginna	71	517	83075	-100	-258	4391	9849	-0.50	1	1
Ginna	72	517	83982	907	2167	4082	8790	4.19	1	1
Ginna	73	517	85004	1022	2320	3556	7200	4.49	1	1
Ginna	74	517	87668	2664	5305	5391	10088	10.26	1	1
Ginna	75	517	89750	2082	3721	6597	11293	7.20	1	1
Ginna	76	517	93308	3558	5939	7356	11969	11.49	1	1
Ginna	77	517	114141	20833	32391	7942	12212	62.65	1	1
Ginna	78	517	121860	7719	11305	9819	14057	21.87	1	1
Ginna	79	517	129112	7252	9684	12819	16892	18.73	1	1
Ginna	80	517	136138	7026	8668	18924	22840	16.77	1	1
Ginna	81	517	159487	23349	26501	22482	24751	51.26	1	1
Ginna	82	517	182754	23267	24339	29570	30705	47.08	1	1
Ginna	83	517	214985	32231	32231	26956	26956	62.33	1	1
Ginna	84	517	236071	21086	20264	32679	31503	39.19	1	1
Hatch 1	76	850	390393	.	.	.	.	.	2	1
Hatch 1	77	850	396799	6406	9842	9799	15066	11.58	2	1
Hatch 1	78	850	409113	12314	17744	12268	17563	20.88	2	1
Hatch 1&2	79	1702	918419	.	.	.	.	.	2	2
Hatch 1&2	80	1700	947147	28728	34355	38486	46450	20.21	2	2
Hatch 1&2	81	1704	969365	22218	24314	62010	68268	14.27	2	2
Hatch 1&2	82	1704	1004824	35459	36400	67689	70287	21.36	2	2

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Hatch 1&2	83	1701	1134116	129291	129291	107802	107802	76.03	2	2
Hatch 1&2	84	1701	1260053	125937	123785	139787	134756	72.79	2	2
Humboldt	63	60	24471	.	.	.	.	.	6	1
Humboldt	64	60	23786	-685	-2566	525	1554	-42.77	6	1
Humboldt	65	60	24176	390	1461	629	1822	24.35	6	1
Humboldt	66	60	22224	-1952	-7101	562	1577	-118.35	6	1
Humboldt	67	60	22480	256	892	630	1716	14.87	6	1
Humboldt	68	60	22619	139	465	582	1518	7.75	6	1
Humboldt	69	60	22688	69	222	646	1603	3.70	6	1
Humboldt	70	60	22764	76	230	619	1458	3.83	6	1
Humboldt	71	60	22850	86	243	926	2077	4.04	6	1
Humboldt	72	60	22947	97	256	897	1932	4.27	6	1
Humboldt	73	65	22998	51	128	915	1863	1.97	6	1
Humboldt	74	65	23171	173	381	1070	2002	5.86	6	1
Humboldt	75	65	24031	860	1648	1221	2090	25.35	6	1
Humboldt	76	65	24543	512	905	1980	3222	13.92	6	1
Humboldt	77	65	26726	2183	3535	3081	4737	54.39	6	1
Humboldt	78	65	28506	1780	2675	1655	2341	41.16	6	1
Humboldt	79	65	28567	61	83	1485	1957	1.27	6	1
Indian Point 1	63	275	126218	.	.	.	.	.	1	1
Indian Point 1	64	275	126255	37	131	2894	8564	0.48	1	1
Indian Point 1	65	275	126330	75	266	2626	7605	0.97	1	1
Indian Point 1	66	275	128891	2561	8808	2929	8217	32.03	1	1
Indian Point 1	67	275	128821	-70	-230	3184	8672	-0.84	1	1
Indian Point 1	68	275	128818	-3	-10	2831	7386	-0.03	1	1
Indian Point 1	69	275	127914	-904	-2736	2713	6731	-9.95	1	1
Indian Point 1	70	275	128083	169	474	3498	8237	1.72	1	1
Indian Point 1	71	275	128175	92	237	3962	8886	0.86	1	1
Indian Point 1	72	275	128938	763	1823	6950	14956	6.63	1	1
Indian Point 1&2	73	1288	334963	.	.	.	.	.	1	2
Indian Point 1&2	74	1288	340188	5225	10404	12737	23834	8.08	1	2
Indian Point 1&2	75	1288	348218	8030	14353	13195	22589	11.14	1	2
Indian Point 1&2	76	1288	359410	11192	18681	18285	29753	14.50	1	2
Indian Point 1&2	77	1288	370637	11227	17456	16525	25409	13.55	1	2
Indian Point 1&2	78	1288	377573	6936	10158	28167	40324	7.89	1	2
Indian Point 1&2	79	1288	379966	2393	3195	32643	43014	2.48	1	2
Indian Point 2	80	1013	329445	.	.	.	.	.	1	1
Indian Point 2	81	1013	398037	68592	77852	54506	60007	76.85	1	1
Indian Point 2	82	1013	461010	62973	65875	68664	71300	65.03	1	1
Indian Point 2	83	1013	477418	16408	16408	49910	49910	16.20	1	1
Indian Point 2	84	1013	503852	26434	25404	96839	93354	25.08	1	1
Indian Point 3	76	1125	NA	.	.	.	.	.	1	1
Indian Point 3	77	1125	NA	.	.	12654	19457	.	1	1
Indian Point 3	78	1068	NA	.	.	23318	33382	.	1	1
Indian Point 3	79	1068	NA	.	.	28884	38061	.	1	1
Indian Point 3	80	1013	NA	.	.	50357	60777	.	1	1
Indian Point 3	81	1013	493018	.	.	58174	64045	.	1	1
Indian Point 3	82	1013	522350	29332	30684	82542	85710	30.29	1	1
Indian Point 3	83	1013	538949	16599	16599	48682	48682	16.39	1	1
Indian Point 3	84	1013	560398	21449	20613	55982	53967	20.35	1	1
Kewaunee	74	535	202193	.	.	.	.	.	3	1
Kewaunee	75	535	203389	1196	2151	8945	15313	4.02	3	1
Kewaunee	76	535	205351	1962	3323	10727	17455	6.21	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -fuel 1983 $	/MW-yr	Region	# of Units
Kewaunee	77	535	205892	541	848	10924	16797	1.59	3	1
Kewaunee	78	535	209748	3856	5626	10430	14931	10.52	3	1
Kewaunee	79	535	213289	3541	4721	11323	14920	8.82	3	1
Kewaunee	80	535	214696	1407	1727	14843	17914	3.23	3	1
Kewaunee	81	535	227413	12717	14322	19334	21295	26.77	3	1
Kewaunee	82	535	236500	9087	9454	21978	22822	17.67	3	1
Kewaunee	83	535	252451	15951	15951	23926	23926	29.81	3	1
Kewaunee	84	535	259757	7306	7087	27829	26827	13.25	3	1
LaSalle	82	1078	1336166	.	.	.	.	.	3	1
LaSalle	83	1170	1344053	7887	7887	35379	35379	6.74	3	1
LaSalle 1&2	84	2341	2417914	.	.	.	.	.	3	1
Lacrosse	78	60	22991	.	.	.	.	.	3	1
Lacrosse	79	50	23132	141	188	3041	4007	3.76	3	1
Lacrosse	80	50	25987	2855	3505	3318	4005	70.09	3	1
Lacrosse	81	50	26237	250	282	3955	4354	5.63	3	1
Lacrosse	82	.	.	.	.	.	.	.	3	1
Lacrosse	83	.	.	.	.	.	.	.	3	1
Lacrosse	84	.	.	.	.	.	.	.	3	1
Maine Yankee	73	830	219225	.	.	.	.	.	1	1
Maine Yankee	74	830	221074	1849	3682	5232	9790	4.44	1	1
Maine Yankee	75	830	233710	12636	22586	6301	10787	27.21	1	1
Maine Yankee	76	830	235069	1359	2268	5261	8561	2.73	1	1
Maine Yankee	77	830	236454	1385	2153	8418	12943	2.59	1	1
Maine Yankee	78	864	237810	1356	1986	10817	15486	2.30	1	1
Maine Yankee	79	864	239987	2177	2907	9971	13139	3.36	1	1
Maine Yankee	80	864	246847	6860	8463	14028	16931	9.80	1	1
Maine Yankee	81	864	262240	15393	17471	20576	22653	20.22	1	1
Maine Yankee	82	864	269738	7498	7844	28554	29650	9.08	1	1
Maine Yankee	83	864	275713	5975	5975	21557	21557	6.92	1	1
Maine Yankee	84	864	295412	19699	18932	32495	31325	21.91	1	1
McGuire 1	81	1220	905601	.	.	.	.	.	1	1
McGuire 1	82	1220	909146	3545	3708	37258	38688	3.04	1	1
McGuire 1	83	1220	903347	-5799	-5799	56030	56030	-4.75	1	2
McGuire 1&2	84	2441	1935269	.	.	.	.	.	1	2
Millstone 1	71	661	96819	.	.	.	.	.	1	1
Millstone 1	72	661	97343	524	1252	7677	16532	1.89	1	1
Millstone 1	73	661	98837	1494	3391	7655	15547	5.13	1	1
Millstone 1	74	661	98745	-92	-183	9808	18353	-0.28	1	1
Millstone 1	75	661	99244	499	892	12065	20654	1.35	1	1
Millstone 1	76	661	125141	25897	43225	14040	22846	65.39	1	1
Millstone 1	77	661	127476	2335	3630	12637	19431	5.49	1	1
Millstone 1	78	661	139783	12307	18024	16448	23547	27.27	1	1
Millstone 1	79	661	153135	13352	17829	23060	30386	26.97	1	1
Millstone 1	80	661	167438	14303	17646	24784	29912	26.70	1	1
Millstone 1	81	661	247250	79812	90587	33270	36628	137.04	1	1
Millstone 1	82	661	275880	28630	29949	33465	34750	45.31	1	1
Millstone 1	83	662	282531	6651	6651	43569	43569	10.05	1	1
Millstone 1	84	662	300248	17717	17027	36867	35540	25.74	1	1
Millstone 2	75	909	418372	.	.	.	.	.	1	1
Millstone 2	76	909	426271	7899	13184	10929	17783	14.50	1	1
Millstone 2	77	909	448751	22480	34952	17377	26719	38.45	1	1
Millstone 2	78	909	463638	14887	21802	22288	31907	23.99	1	1
Millstone 2	79	909	464674	1036	1383	21931	28899	1.52	1	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Millstone 2	80	909	477586	12912	15929	30163	36405	17.52	1	1
Millstone 2	81	909	495610	18024	20457	28877	31791	22.51	1	1
Millstone 2	82	909	529017	33407	34946	45248	46985	38.44	1	1
Millstone 2	83	909	557377	28960	28960	56452	56452	31.86	1	1
Millstone 2	84	910	566560	8583	8248	49539	47756	9.07	1	1
Monticello	71	568	105011	.	.	.	.	.	3	1
Monticello	72	568	104937	-74	-181	2567	5528	-0.32	3	1
Monticello	73	568	106869	1932	4482	5006	10194	7.89	3	1
Monticello	74	568	117996	11127	22448	5179	9691	39.52	3	1
Monticello	75	568	122106	4110	7392	8729	14943	13.01	3	1
Monticello	76	568	123362	1256	2127	6609	10754	3.74	3	1
Monticello	77	568	124390	1028	1611	11109	17081	2.84	3	1
Monticello	78	568	126488	2098	3061	9136	13079	5.39	3	1
Monticello	79	568	134937	8449	11265	10584	13947	19.83	3	1
Monticello	80	568	139725	4788	5877	21413	25844	10.35	3	1
Monticello	81	568	150407	10682	12030	18261	20104	21.18	3	1
Monticello	82	568	171425	21018	21866	30799	31981	38.50	3	1
Monticello	83	569	227698	56273	56273	22628	22628	98.93	3	1
Monticello	84	569	354921	127223	123417	43203	41648	216.98	3	1
Nine Mile Point	70	620	162235	.	.	.	.	.	1	1
Nine Mile Point	71	641	164492	2257	5822	2753	6188	9.08	1	1
Nine Mile Point	72	641	162416	-2076	-4961	3575	7698	-7.74	1	1
Nine Mile Point	73	641	163212	796	1807	4524	9212	2.82	1	1
Nine Mile Point	74	641	163389	177	352	6251	11697	0.55	1	1
Nine Mile Point	75	641	164189	800	1430	5810	9946	2.23	1	1
Nine Mile Point	76	641	181200	17011	28393	5330	8673	44.30	1	1
Nine Mile Point	77	641	188087	6887	10708	9743	14991	16.70	1	1
Nine Mile Point	78	641	187086	-1001	-1466	6382	9136	-2.29	1	1
Nine Mile Point	79	641	204080	16994	22692	11663	15368	35.40	1	1
Nine Mile Point	80	641	217371	13291	16397	32964	39785	25.58	1	1
Nine Mile Point	81	642	265015	47644	54076	26744	29443	84.23	1	1
Nine Mile Point	82	620	281922	16907	17686	21480	22304	28.53	1	1
Nine Mile Point	83	642	367746	85824	85824	25517	25517	133.68	1	1
Nine Mile Point	84	642	460273	92527	88922	26788	25824	138.51	1	1
North Anna 1	78	979	781739	.	.	.	.	.	2	1
North Anna 1	79	979	783864	2125	2785	19519	25720	2.85	2	1
North Anna 1&2	80	1959	1315869	.	.	.	.	.	2	2
North Anna 1&2	81	1959	1368195	52326	57262	28857	31769	29.23	2	2
North Anna 1&2	82	1959	1416217	48022	49297	43493	45162	25.16	2	2
North Anna 1&2	83	1959	1302075	-114142	-114142	40110	40110	-58.27	2	2
North Anna 1&2	84	1959	1312555	10480	10301	59187	57056	5.26	2	2
Oconee 1	73	886	155612	.	.	.	.	.	2	1
Oconee 1,2,3	74	2660	476443	.	.	.	.	.	2	3
Oconee 1,2,3	75	2660	476691	248	446	12449	21311	0.17	2	3
Oconee 1,2,3	76	2660	478793	2102	3534	16735	27231	1.33	2	3
Oconee 1,2,3	77	2660	490724	11931	18331	25038	38498	6.89	2	3
Oconee 1,2,3	78	2661	492689	1965	2832	29600	42375	1.06	2	3
Oconee 1,2,3	79	2661	498935	6246	8187	40177	52942	3.08	2	3
Oconee 1,2,3	80	2661	509438	10503	12560	52003	62764	4.72	2	3
Oconee 1,2,3	81	2666	520036	10598	11598	58789	64722	4.35	2	3
Oconee 1,2,3	82	2666	532168	12132	12454	88016	91394	4.57	2	3
Oconee 1,2,3	83	2667	539959	7791	7791	82851	82851	2.92	2	3
Oconee 1,2,3	84	2667	559053	19094	18768	93024	89676	7.04	2	3

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Oyster Creek	70	550	89893	.	.	.	.	.	1	1
Oyster Creek	71	550	92121	2238	5773	3097	6946	10.50	1	1
Oyster Creek	72	550	92637	516	1233	3877	8349	2.24	1	1
Oyster Creek	73	550	92766	129	293	6311	12851	0.53	1	1
Oyster Creek	74	550	92198	-568	-1131	10678	19981	-2.06	1	1
Oyster Creek	75	550	97151	4953	8853	12310	21073	16.10	1	1
Oyster Creek	76	550	108545	11394	19018	10399	16921	34.58	1	1
Oyster Creek	77	550	112583	4038	6278	14833	22807	11.42	1	1
Oyster Creek	78	550	150459	37876	55470	15898	22759	100.85	1	1
Oyster Creek	79	550	161745	11286	15070	13055	17203	27.40	1	1
Oyster Creek	80	550	200255	38510	47510	37530	45296	86.38	1	1
Oyster Creek	81	550	222963	22708	25774	45254	49921	46.86	1	1
Oyster Creek	82	550	256407	33444	34985	60812	63146	63.61	1	1
Oyster Creek	83	550	331441	75034	75034	73246	73246	136.43	1	1
Oyster Creek	84	550	393346	61905	59493	83789	80774	108.17	1	1
Palisades	72	811	146687	.	.	.	.	.	3	1
Palisades	73	811	160284	13597	31545	3160	6435	38.90	3	1
Palisades	74	811	180063	19779	39902	11778	22039	49.20	3	1
Palisades	75	811	182297	2234	4018	9601	16436	4.95	3	1
Palisades	76	811	185272	2975	5038	9848	16024	6.21	3	1
Palisades	77	811	182068	-3204	-5022	6569	10100	-6.19	3	1
Palisades	78	811	199643	17575	25644	15393	22036	31.62	3	1
Palisades	79	811	194651	-4992	-6656	26344	34714	-8.21	3	1
Palisades	80	811	211505	16854	20689	19251	23235	25.51	3	1
Palisades	81	811	255491	43986	49538	44140	48595	61.08	3	1
Palisades	82	811	282667	27176	28273	38452	39929	34.86	3	1
Palisades	83	812	375573	92906	92906	57030	57030	114.46	3	1
Palisades	84	812	393781	18208	17663	51568	49712	21.76	3	1
Peach Bottom 2,3	74	2304	742158	.	.	.	.	.	1	2
Peach Bottom 2,3	75	2304	753981	11823	21132	12619	21602	9.17	1	2
Peach Bottom 2,3	76	2304	761722	7741	12921	30601	49793	5.61	1	2
Peach Bottom 2,3	77	2304	794094	32372	50332	46674	71766	21.85	1	2
Peach Bottom 2,3	78	2304	807496	13402	19627	39306	56270	8.52	1	2
Peach Bottom 2,3	79	2304	813792	6296	8407	40004	52714	3.65	1	2
Peach Bottom 2,3	80	2304	836708	22916	28271	56875	68644	12.27	1	2
Peach Bottom 2,3	81	2304	902169	65461	74298	72615	79943	32.25	1	2
Peach Bottom 2,3	82	2304	953400	51231	53592	81669	84804	23.26	1	2
Peach Bottom 2,3	83	2304	993310	39910	39910	105284	105284	17.32	1	2
Peach Bottom 2,3	84	2304	1047496	54186	52075	105513	101715	22.60	1	2
Pilgrim	72	655	321540	.	.	.	.	.	1	1
Pilgrim	73	655	239329	.	.	.	.	.	1	1
Pilgrim	74	655	235982	-3347	-6665	9527	17827	-10.18	1	1
Pilgrim	75	655	236464	482	862	7340	12565	1.32	1	1
Pilgrim	76	655	241440	4976	8306	16633	27065	12.68	1	1
Pilgrim	77	655	257579	16139	25093	15320	23556	38.31	1	1
Pilgrim	78	687	261758	4179	6120	14187	20310	8.91	1	1
Pilgrim	79	687	270429	8670	11577	18387	24229	16.85	1	1
Pilgrim	80	687	337986	67558	83346	27785	33534	121.32	1	1
Pilgrim	81	687	358680	20694	23488	34994	38526	34.19	1	1
Pilgrim	82	687	430711	72031	75350	42437	44066	109.68	1	1
Pilgrim	83	687	472831	42120	42120	47276	47276	61.31	1	1
Pilgrim	84	687	639225	166394	159911	57854	55772	232.77	1	1
Point Beach 1	71	523	73959	.	.	.	.	.	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Point Beach 1&2	72	1047	145348	.	.	.	.	.	3	2
Point Beach 1&2	73	1047	161632	16284	37779	3647	7426	36.08	3	2
Point Beach 1&2	74	1047	161436	-196	-395	5229	9785	-0.38	3	2
Point Beach 1&2	75	1047	164224	2788	5014	6159	10544	4.79	3	2
Point Beach 1&2	76	1047	167125	2901	4913	6592	10726	4.69	3	2
Point Beach 1&2	77	1047	167699	574	900	8014	12322	0.86	3	2
Point Beach 1&2	78	1047	171189	3490	5093	7395	10587	4.86	3	2
Point Beach 1&2	79	1047	170668	-521	-695	12461	16420	-0.66	3	2
Point Beach 1&2	80	1047	172472	1804	2214	17904	21609	2.12	3	2
Point Beach 1&2	81	1047	188495	16023	18045	26820	29527	17.24	3	2
Point Beach 1&2	82	1047	192297	3802	3955	31951	33177	3.78	3	2
Point Beach 1&2	83	1048	194910	2613	2613	36667	36667	2.49	3	2
Point Beach 1&2	84	1048	224646	29736	28847	42054	40540	27.54	3	2
Prairie Isl. 1	73	593	233234	.	.	.	.	.	3	1
Prairie Isl. 1&2	74	1186	405374	.	.	.	.	.	3	2
Prairie Isl. 1&2	75	1186	410207	4833	8692	7261	12430	7.33	3	2
Prairie Isl. 1&2	76	1186	413087	2880	4877	15574	25342	4.11	3	2
Prairie Isl. 1&2	77	1186	423966	10879	17054	17090	26277	14.38	3	2
Prairie Isl. 1&2	78	1186	425182	1216	1774	14214	20349	1.50	3	2
Prairie Isl. 1&2	79	1186	433659	8477	11303	15346	20222	9.53	3	2
Prairie Isl. 1&2	80	1186	444766	11107	13634	23175	27971	11.50	3	2
Prairie Isl. 1&2	81	1186	457082	12316	13870	26791	29495	11.70	3	2
Prairie Isl. 1&2	82	1186	478688	21606	22478	28169	29250	18.95	3	2
Prairie Isl. 1&2	83	1186	499848	21160	21160	31251	31251	17.84	3	2
Prairie Isl. 1&2	84	1186	539237	39389	38211	33299	32100	32.21	3	2
Quad Cities 1&2	72	1656	200149	.	.	.	.	.	3	2
Quad Cities 1&2	73	1656	211539	11390	26425	6290	12808	15.96	3	2
Quad Cities 1&2	74	1656	223882	12343	24901	9210	17234	15.04	3	2
Quad Cities 1&2	75	1656	237227	13345	24000	14777	25297	14.49	3	2
Quad Cities 1&2	76	1656	241480	4253	7202	16723	27211	4.35	3	2
Quad Cities 1&2	77	1656	247194	5714	8957	17756	27302	5.41	3	2
Quad Cities 1&2	78	1656	252951	5757	8400	22168	31736	5.07	3	2
Quad Cities 1&2	79	1656	263741	10790	14387	23420	30861	8.69	3	2
Quad Cities 1&2	80	1656	273075	9334	11457	38686	46691	6.92	3	2
Quad Cities 1&2	81	1656	278524	5449	6137	37272	41033	3.71	3	2
Quad Cities 1&2	82	1656	311157	32633	33950	42185	43805	20.50	3	2
Quad Cities 1&2	83	1657	327125	15968	15968	44940	44940	9.64	3	2
Quad Cities 1&2	84	1656	314168	-12957	-12569	53179	51265	-7.59	3	2
Rancho Seco	75	928	343620	.	.	.	.	.	6	1
Rancho Seco	76	928	343438	-182	-322	7193	11704	-0.35	6	1
Rancho Seco	77	928	336050	-7388	-11964	14000	21526	-12.89	6	1
Rancho Seco	78	928	338792	2742	4121	11834	16941	4.44	6	1
Rancho Seco	79	928	339538	746	1012	13720	18079	1.09	6	1
Rancho Seco	80	928	353574	14036	17441	28408	34296	18.79	6	1
Rancho Seco	81	928	365651	12077	13716	35542	39129	14.78	6	1
Rancho Seco	82	928	369225	3574	3722	36330	37724	4.01	6	1
Rancho Seco	83	929	372144	2919	2919	52588	52588	3.14	6	1
Rancho Seco	84	929	447331	75187	73115	57961	55875	78.75	6	1
Robinson	71	768	77753	.	.	.	.	.	2	1
Robinson	72	768	81999	4246	10369	1780	3833	13.50	2	1
Robinson	73	768	82113	114	264	4609	9385	0.34	2	1
Robinson	74	768	83272	1159	2359	4780	8944	3.07	2	1
Robinson	75	768	84982	1710	3075	6360	10888	4.00	2	1

Plant	Yr	Rating	Total Construction Cost	[illegible]	1983 $	O&M Fuel	O&M Fuel 1983 $	$/kW-yr	Region	# of Units
Robinson	76	768	85231	52	324	5903	7605	9.55	2	1
Robinson	77	768	855[illegible]	4306	5676	6859	10516	8.61	2	1
Robinson	78	768	93412	370	2577	14355	20550	7.26	2	1
Robinson	79	768	101[illegible]	7383	10230	15142	19953	13.39	2	1
Robinson	80	768	110[illegible]	3782	[illegible]	22095	26553	13.56	2	1
Robinson	81	769	[illegible]	[illegible]	[illegible]	21798	22987	5.45	2	1
Robinson	82	769	125[illegible]	12323	12939	43164	44821	16.05	2	1
Robinson	83	769	128045	2162	2158	38174	38174	2.92	2	1
Robinson	84	769	[illegible]	[illegible]	134319	56077	53898	174.57	2	1
Salem 1	77	1120	35831[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1
Salem 1	78	1170	350[illegible]	[illegible]	975	22311	31940	0.83	1	1
Salem 1	79	1165	[illegible]	[illegible]	[illegible]	1230[illegible]	56058	9.32	1	1
Salem 1	80	1174	3387[illegible]	[illegible]107	[illegible]	59684	72038	42.29	1	1
Salem 1&2	81	2343	17531[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	2
Salem 1&2	82	2343	18063[illegible]	[illegible]823	[illegible]	156625	162625	21.49	1	2
Salem 1&2	83	2344	18977[illegible]	20879	[illegible]	1755[illegible]	17555[illegible]	[illegible]	1	2
Salem 1&2	84	2345	175019[illegible]	[illegible]	[illegible]	[illegible]	177102	[illegible]	1	2
San Onofre 1	68	450	[illegible]	[illegible]	[illegible]	1981	3864	[illegible]	6	1
San Onofre 1	69	450	[illegible]	[illegible]	[illegible]	1975	4900	25.53	6	1
San Onofre 1	70	450	[illegible]	[illegible]	[illegible]	2236	5265	6.35	6	1
San Onofre 1	71	450	85563	655	1847	2412	5410	7.10	6	1
San Onofre 1	72	450	85517	778	1970	3518	7576	1.95	6	1
San Onofre 1	73	450	85823	771	[illegible]	5839	11890	1.55	6	1
San Onofre 1	74	450	8624[illegible]	423	831	5553	10402	2.07	6	1
San Onofre 1	75	450	86433	496	872	8668	14833	0.83	6	1
San Onofre 1	76	450	85196	2053	1507	10498	17869	35.33	6	1
San Onofre 1	77	450	[illegible]	[illegible]	[illegible]	3125	[illegible]	[illegible]	6	1
San Onofre 1	78	450	1816[illegible]	2325	2874	14517	20782	53.38	6	1
San Onofre 1	79	450	[illegible]	[illegible]	[illegible]	11661	15578	[illegible]	6	1
San Onofre 1	80	450	[illegible]	[illegible]	[illegible]	31085	37522	[illegible]	6	1
San Onofre 1	81	450	[illegible]	[illegible]	[illegible]	24396	26858	100.39	6	1
San Onofre 1	82	456	[illegible]	37342	39306	36838	38249	108.13	6	1
San Onofre 1&2	83	1577	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6	1
San Onofre 1,2,3	84	2704	3[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6	1
Sequoyah 1	81	1220	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	1
Sequoyah 1&2	82	2441	1585[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	2
Sequoyah 1&2	83	2441	164[illegible]	30075	30075	68588	68588	23.73	2	2
Sequoyah 1&2	84	2441	1677[illegible]	12379	12167	767[illegible]	73993	4.98	2	2
St. Lucie 1	76	850	3702[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	1
St. Lucie 1	77	850	[illegible]	26007	[illegible]	[illegible]	[illegible]	38.93	2	1
St. Lucie 1	78	850	4950[illegible]	3808	[illegible]	15814	22533	14.93	2	1
St. Lucie 1	79	850	4995[illegible]	5661	5582	14[illegible]	18954	7.04	2	1
St. Lucie 1	80	850	50[illegible]	568[illegible]	6799	[illegible]	[illegible]	8.00	2	1
St. Lucie 1	81	850	51[illegible]	8355	9149	[illegible]	255[illegible]	10.75	2	1
St. Lucie 1	82	850	52[illegible]	16251	16682	[illegible]	226[illegible]	19.63	2	1
St. Lucie 1&2	83	1573	181[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	2
St. Lucie 1&2	84	1573	188[illegible]	67328	66169	[illegible]	56[illegible]	42.05	2	2
Sumner 1	84	636	866[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	1
Surry 1	72	847	2460[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	1
Surry 1&2	73	1695	39[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	2
Surry 1&2	74	1695	40[illegible]	[illegible]	[illegible]655	[illegible]	[illegible]	[illegible]	2	2
Surry 1&2	75	1695	[illegible]	[illegible]	[illegible]757	[illegible]	[illegible]	[illegible]	2	2
Surry 1&2	76	1695	40[illegible]	2107	[illegible]	[illegible]	2[illegible]	[illegible]	2	2

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Surry 1&2	77	1695	412235	3720	5715	15977	24566	3.37	2	2
Surry 1&2	78	1695	419952	7716	11119	19323	27663	6.56	2	2
Surry 1&2	79	1695	409703	-10249	-13434	23313	30720	-7.93	2	2
Surry 1&2	80	1695	556083	146380	175052	29458	35554	103.28	2	2
Surry 1&2	81	1695	750969	194886	213271	31185	34332	125.32	2	2
Surry 1&2	82	1695	783058	32089	32941	33088	34358	19.43	2	2
Surry 1&2	83	1695	805393	22335	22335	57158	57158	13.18	2	2
Surry 1&2	84	1695	822239	16846	16558	59146	57017	9.77	2	2
Susquehanna 1	84	1037	1774663	.	.	.	.	.	2	1
Three Mile Isl. 1	74	871	398337	.	.	.	.	.	1	1
Three Mile Isl. 1	75	871	400928	2591	4631	14225	24354	5.32	1	1
Three Mile Isl. 1	76	871	399425	-1503	-2509	17840	29029	-2.88	1	1
Three Mile Isl. 1	77	871	398895	-530	-824	13287	20430	-0.95	1	1
Three Mile Isl. 1	78	871	361902	-36993	-54177	17954	25703	-62.20	1	1
Three Mile Isl. 1	79	871	407936	46034	61469	11842	15604	70.57	1	1
Three Mile Isl. 1	80	NA	NA	.	.	NA	NA	.	1	1
Three Mile Isl. 1	81	870	441596	.	.	54048	59503	.	1	1
Trojan	76	1216	451978	.	.	.	.	.	6	1
Trojan	77	1216	460666	8688	14069	13628	20954	11.57	6	1
Trojan	78	1216	466419	5753	8647	15204	21766	7.11	6	1
Trojan	79	1216	486705	20286	27523	16957	22344	22.63	6	1
Trojan	80	1216	503279	16574	20594	25790	31127	16.94	6	1
Trojan	81	1216	548765	45486	51661	32205	35455	42.48	6	1
Trojan	82	1216	565576	16811	17509	30629	31805	14.40	6	1
Trojan	83	1216	573894	8318	8318	30345	30345	6.84	6	1
Trojan	84	1216	581283	7389	7185	46089	44430	5.91	6	1
Turkey Point 3	72	760	108709	.	.	.	.	.	2	1
Turkey Point 3&4	73	1519	231239	.	.	.	.	.	2	2
Turkey Point 3&4	74	1519	235496	4257	8663	9660	18076	5.70	2	2
Turkey Point 3&4	75	1519	244256	8760	15754	15493	26522	10.37	2	2
Turkey Point 3&4	76	1519	255705	11449	19248	18602	30263	12.67	2	2
Turkey Point 3&4	77	1519	267648	11943	18350	15109	23232	12.08	2	2
Turkey Point 3&4	78	1519	273441	5793	8348	18602	26630	5.50	2	2
Turkey Point 3&4	79	1519	284431	10990	14405	22511	29663	9.49	2	2
Turkey Point 3&4	80	1519	293554	9223	11030	30830	37210	7.26	2	2
Turkey Point 3&4	81	1519	305503	11849	12967	30274	33329	8.54	2	2
Turkey Point 3&4	82	1519	417224	111721	114687	32066	33297	75.50	2	2
Turkey Point 3&4	83	1520	527224	110000	110000	47776	47776	72.37	2	2
Turkey Point 3&4	84	1520	585304	58080	57087	60054	57892	37.56	2	2
Vermont Yankee	72	514	172042	.	.	.	.	.	1	1
Vermont Yankee	73	563	184481	12439	28237	4957	10094	50.15	1	1
Vermont Yankee	74	563	185158	677	1348	5692	10651	2.39	1	1
Vermont Yankee	75	563	185739	581	1038	7682	13151	1.84	1	1
Vermont Yankee	76	563	193886	8147	13598	7912	12874	24.15	1	1
Vermont Yankee	77	563	196331	2445	3801	9775	15030	6.75	1	1
Vermont Yankee	78	563	198837	2506	3670	11191	16021	6.52	1	1
Vermont Yankee	79	563	200835	1998	2668	14208	18722	4.74	1	1
Vermont Yankee	80	563	217575	16740	20652	22586	27260	36.68	1	1
Vermont Yankee	81	563	226115	8540	9693	26795	29499	17.22	1	1
Vermont Yankee	82	563	231880	5765	6031	33764	35060	10.71	1	1
Vermont Yankee	83	563	255209	23329	23329	46312	46312	41.44	1	1
Vermont Yankee	84	563	259856	4647	4466	43203	41648	7.93	1	1
Yankee-Rowe	62	152	38162	.	.	.	.	.	1	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Yankee-Rowe	63	185	38398	236	837	1312	3942	4.52	1	1
Yankee-Rowe	64	185	38622	224	795	1121	3317	4.29	1	1
Yankee-Rowe	65	185	38766	144	511	1403	4063	2.76	1	1
Yankee-Rowe	66	185	39390	624	2146	1505	4222	11.60	1	1
Yankee-Rowe	67	185	39560	170	553	1307	3560	3.02	1	1
Yankee-Rowe	68	185	39572	12	38	1501	3916	0.21	1	1
Yankee-Rowe	69	185	39623	51	154	1602	3975	0.33	1	1
Yankee-Rowe	70	185	39636	13	36	1558	3669	0.20	1	1
Yankee-Rowe	71	185	40271	635	1638	1745	3914	8.85	1	1
Yankee-Rowe	72	185	41500	1229	2937	2912	6271	15.37	1	1
Yankee-Rowe	73	185	42507	1007	2286	2437	4962	12.36	1	1
Yankee-Rowe	74	185	44473	1966	3915	3950	7391	21.16	1	1
Yankee-Rowe	75	185	46101	1628	2910	4557	7801	15.73	1	1
Yankee-Rowe	76	185	46566	465	776	4976	8097	4.20	1	1
Yankee-Rowe	77	185	48332	1766	2745	6966	10711	14.84	1	1
Yankee-Rowe	78	185	48912	580	849	7653	10956	4.59	1	1
Yankee-Rowe	79	185	52192	3280	4380	10150	13375	23.67	1	1
Yankee-Rowe	80	185	55285	3093	3816	22250	26854	20.63	1	1
Yankee-Rowe	81	185	63717	8432	9570	22069	24296	51.73	1	1
Yankee-Rowe	82	185	72149	8432	8821	24320	25253	47.68	1	1
Yankee-Rowe	83	185	72503	354	354	18987	18987	1.91	1	1
Yankee-Rowe	84	185	75554	3051	2933	26422	25471	15.85	1	1
Zion 1	73	1098	275989	.	.	.	.	.	3	1
Zion 1&2	74	2196	565819	.	.	.	.	.	3	2
Zion 1&2	75	2196	567987	2168	3899	12735	21801	1.78	3	2
Zion 1&2	76	2196	571762	3775	6393	18268	29725	2.91	3	2
Zion 1&2	77	2196	577903	6141	9626	18104	27837	4.38	3	2
Zion 1&2	78	2196	586396	8493	12392	20383	29180	5.64	3	2
Zion 1&2	79	2196	594941	8545	11393	26954	35518	5.19	3	2
Zion 1&2	80	2196	625788	30847	37865	37655	45447	17.24	3	2
Zion 1&2	81	2196	639723	13935	15694	44864	49392	7.15	3	2
Zion 1&2	82	2196	650175	10452	10874	52617	54637	4.95	3	2
Zion 1&2	83	2196	680259	30084	30084	48670	48670	13.70	3	2
Zion 1&2	84	2196	689803	9544	9259	56860	54814	4.22	3	2

APPENDIX E:

CAPACITY FACTOR ANALYSIS

REGRESSION ANALYSIS OF PWR CAPACITY FACTORS

MAY 1986

By Anne Edwards and Paul Chernick

Table of Contents

1 Introduction

This analysis builds on previous work, which was based on data through 1983. Since then, the database regarding capacity factors of PWR nuclear power plants has grown a great deal with the addition of data through 1984 and again with data through 1985. With the increased number of observations, a better representation of nuclear power plant experience, we can be more confident about the results which are generated by our analyses. The analysis which is described here includes plots, correlations, and regressions, and results in an equation for predicting capacity factors into the future.

2 Data and Sources

The variables in Table 1 were originally entered into or calculated within the capacity factor database. The database has a separate observation for each unit of each plant, because there are no economies of scale in capacity factors. The printout of the complete database is included as Appendix B.

TABLE 1: Variables used in Regression Analysis of PWR Capacity Factors

Variable	Description	Source
NAME	Separate name for each unit	[1]
ID	Identification number for each unit; index based on chronological order of commercial operation date	
MW	Design Electrical Rating (DER)	[1]
YEAR	Datapoint year	[1]
COD	Month and year of commercial operation date	[1]
GWH	Annual Net Electric Energy output (MWH), divided by 1000.	[1]
CF	CF = Capacity Factor = MWH/DER/8760	Calculated
AGE	Years from commercial operation to middle of current year	Calculated
CE	Dummy variable indicating NSSS is Combustion Engineering	[2]
BW	Dummy variable indicating NSSS is Babcock and Wilcox	[2]
W40	Dummy variable indicating unit contains Westinghouse turbine generator with 40" blade	[2,3]
W44	Dummy variable indicating unit contains Westinghouse turbine generator with 44" blade	[2,3]
REFUEL	Number of full refuelings which occurred during the year. Usually 0 or 1, but may be partial or slightly greater than one if the unit was out over the new year.	[1]

Table 1 Sources:

[1] NRC "Green Books," Nuclear Power Plant Operating Experience, NUREG/CR-3430, for data 1973-1982. NRC "Gray Books," Licensed Operating Reactors, Status Summary Report, NUREG-0020, up to September 1985.
[2] Electrical World, "Annual Generation Construction Surveys," annual.
[3] Electric Power Research Institute, Nuclear Unit Operating Experience: 1980 Through 1982 Update, (EPRI NP-3480), April 1984, Appendix C. Westinghouse turbines entering service after 1978 assumed to have 44" blade.

Other variables were created during the course of our analyses, but they are defined in the text which follows. To complete the list of all variables used in this analysis, the new variables are: AFT78, YR79_83, OUT, AGE5, and AGE_12.

3 Preliminary Analyses

Before running regressions, it may be helpful to see what the data looks like in its simplest form. Plots of the raw data, and correlations between the variables, are helpful in determining the variables which have a strong effect on capacity factors. This is easily done by plotting capacity factors on other variables, one at a time. If there is a clear trend in any one plot, then that variable may explain some part of the variability. Attachment 1 contains all of the plots run for this analysis.

The first three plots display all capacity factor data plotted first on AGE, then on MW, then on YEAR. When compared with AGE, capacity factors do appear to increase in the first few years. The existence of very low capacity factors in later years suggests not only that capacity factors level off after five years, but also that they appear to decrease as age increases past ten or twelve years. It is not clear from the plot whether the low capacity factors in later years will be explained by variables other than age.

At first sight, there appears to be a strong negative trend when capacity factor is compared to MW. However, the distribution of datapoints on size leads one to visually separate the units into groups. There is a gap around 600-700 MW, to the left of which the capacity factors are higher. Once the small plants are distinguished from the larger plants, the size trend does not appear to be smooth at all, but rather there appears to be a sharp drop which occurs at the 600-700 MW gap.

When compared with YEAR, capacity factors do decrease on average, and the majority of seriously low capacity factors occur after 1978. The plot of CF on YEAR suggests that the regulatory reaction to the TMI accident in 1979 had a profound effect on the performance of nuclear power plants. To test this, we created a variable called AFT78, (AFT78 = 1 if 1979 or later, and 0 otherwise), and looked at plots of all data where AFT78=1, and then where AFT78=0, separately.[1] These plots are included in Attachment 1, with the plots of earlier data first.

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1. Note that the dataset was once divided at the end of 1979, but the division at the beginning of 1979 has more significance.

The age effect, when we compare the plots from the two time periods, is more strongly positive before 1979 than after. The size effect (MW) is strongly negative before 1979, but in the later years the negative trend is more vague and could be considered to be positive. Because the difference in time periods does influence the relationship between other variables, we decided to include the AFT78 variable in our regressions.

The effect of refuelings appears to be negative in both time periods. The plots of CF on REFUEL show extremely low capacity factors in years with no refuelings. Further research indicated that many of those low capacity factors were caused by extended outages for reasons other than refueling. We created another variable called OUTAGE to indicate each plant-year during which the NRC reports a single-purpose, non-refueling outage lasting more than three months. The value of OUTAGE, like REFUEL, is usually and in this case always equal to 0 or 1. Table 2 below is a list of observations for which OUTAGE = 1.

All further analyses used OUT in place of REFUEL, where OUT = REFUEL + OUTAGE.

TABLE 2: Major Outages Other Than Refuelings

Plant name	Year	Portion of outage within year
Surry 2	1974	1.00
Zion 1	1974	1.00
Rancho Seco	1976	1.00
Beaver Valley 1	1978	1.00
Crystal River 3	1978	1.00
Surry 1	1979	1.00
Surry 1	1980	1.00
San Onofre 1	1981	1.00
Surry 1	1981	1.00
San Onofre 1	1982	1.00
San Onofre 1	1983	1.00
San Onofre 1	1984	1.00
Salem 2	1984	1.00

Source: NRC "Green Books," Nuclear Power Plant Operating Experience, NUREG/CR-3430, for data 1973-1982. NRC "Gray Books," Licensed Operating Reactors, Status Summary Report, NUREG-0020, up to September 1985.

For comparison, plots of CF on REFUEL and CF on OUT are included in Attachment 1, for both time periods. Note that when each plot of CF on REFUEL is compared with the plot of CF on OUT for the same time period, the low capacity factors at REFUEL=0 have shifted to OUT=1. As would be expected, major outages do on average cause lower annual capacity factors.

Another helpful step in determining which variables to include in the regressions is a correlation matrix. Each correlation in the matrix demonstrates the relationship between two variables in the dataset (see page 1 of Attachment 2). When two variables are highly correlated, due to factors other than the effect we are trying to measure, the correlation can confound the results of a regression which includes both variables. For example, YEAR and AGE are highly correlated because age increases with time directly. We must expect that the effects of these two variables will be difficult to distinguish in the regression equations. The calculated effect of one could hide the true effect of the other. Likewise, problems may arise from using the Westinghouse turbine variables in a regression with MW, because of the fact that Westinghouse 44" turbines were generally installed in later, larger plants, while Westinghouse 40" turbines were installed in the smallest units.

The second page of Attachment 2 is the correlation matrix which includes most of the variables which were ultimately used in our analyses. This was a helpful reference tool when specifying the regression equations.

4 Regressions

Our first regressions duplicate those which appeared in an early A&I PWR capacity factor analysis, using data through 1982 (Tables 3.16 and 3.17, Testimony of Paul Chernick, State of New Hampshire before the Public Utilities Commission, Docket #84-200). These are simple regressions, but they indicate the bottom line effects of age and size on capacity factors. With the added data for 1983 through 1985, the size trend has not changed much at all, and the age effect has decreased. (See also Attachment 3, pp. 1-2)

4.1 Outage Effects

The outage indicator, as we have already seen, is an extremely important explanatory variable. OUT is included for all but the simplest regressions in this analysis, and remains significant throughout.

4.2 Age Effects

First in the simple regressions, and then in all regressions that followed, we included AGE5, which is the minimum value of AGE and 5. This version of the age variable represents the fact that the typical unit's performance improves over the first five years of its life (more or less), and then levels off. Other analyses have also indicated that there is a maturation level at the age of 5 (see Easterling, Statistical Analysis of Power Plant Capacity Factors through 1979, NUREG/CR-1881). We tested other ages as level-off points, but reconfirmed that the upward trend continues most notably until age 5, and loses significance when the level-off age is later. (See Attachment 3, pp. 3-4)

4.3 Turbine Effects

The next variables added to the regression were the Westinghouse turbine indicators, W40 and W44. These seemed to improve the equations (see Attachment 3, pp. 4-6), but two things indicated that the coefficients were not representing their true effects. First of all, the Westinghouse 44" turbine appeared to have a negative effect, while the 40" turbine had an even stronger positive effect. Other sources on past experience indicate that the opposite is true: 44" turbines have actually performed better than 40" turbines, and neither should have a positive effect on capacity factors (see Attachment 4).[2]

It is likely that the turbine ~~variables are~~ picking up the size effect in the regression. When MW is introduced into the equation which contains turbine variables, it is not significant. However, when MW is in the equation without turbine variables, as we have seen, it is very significant (Attachment 3, pp. 6-7). The size effect is better established than the turbine effect, and demonstrates the expected sign, so we chose to omit the Westinghouse variable from the estimation equation at this point.

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2. All of the units in our database have either Westinghouse or General Electric turbines, with the two exceptions of Cook 2 which has a Brown-Boveri turbine, and San Onofre 2 which has a GEC turbine (General Electric Company, U.K.).

4.4 Year Effects

The transformation of the age variable to AGE5 leaves it less correlated with time, which allows us greater flexibility in introducing time-related variables into the equation. As we learned from our preliminary analyses, the YEAR variable is highly correlated with other variables in its raw form. With data through 1984 in our earlier regresssions, the variable AFT78 explained a large part of the variability in the data. With the addition of 1985 data, AFT78 explains less of the variability, suggesting that nuclear power plant performance has improved over the last couple of years.

To determine a more detailed time pattern of PWR performance in the post-TMI period, we created a dummy variable for each year, 1979 and after. The separate year dummies are not highly correlated with age variables (see page 2 of Attachment 2), presumably because in any one year there is a large variety of ages among the plants. For that reason, we could add them to our regressions without the fear of confounding the results we had already discovered.

The results on the separate year variables including 1985, begin on page 14 of Attachment 3, and indicate the definite improvement in performance in 1984 and 1985. Some years, namely 1981, 1984, and 1985, do not have a significant effect, so the overall equation loses some significance when the separate year dummies are used (see Attachment 3, pp. 14, 15, and intermittently thereafter).

For our latest analysis we introduced one more variable (YR79_83) to distinguish the post-TMI years from pre-1979 and post-1983 time periods, The significant results of equations including this variable (Attachment 3, pages 15+), indicate that the years 1979-83 were distinctly worse than other years. Whether this is a cyclical change or a one-time event has yet to be determined.

4.5 Size Effects

Previous analyses of PWR capacity factors have consistently indicated strong negative correlations between size and capacity factor. Consistent with common practice, we have previously represented size with the continuous variable MW, assuming that the size effect is roughly linear over the range of interest (400-1200 MW). However, inspection of the plots in Attachment 2, and the regressions in Attachment 3, page 8, indicates that increased size beyond 600 MW has little, if any, effect on capacity factors. The trend which had been detected in the size effect may be better modeled as a downward shift at MW=600.[3] The new variable MW600, a dummy variable to indicate plants larger

3. No units have original DER's between 575 MW and 707 MW.

than 600 MW, was created and added to our regressions. (See Attachment 3, pp. 11+)

4.6 More Age Effects

Once we had a good regression (Attachment 3, page 8, bottom), we plotted the residuals on size (MW) and age (AGE) to see if there was remaining variability which could be attributed to either of those variables (Attachment 3, pp. 9 and 10). Indeed, we discovered that although we had adequately modelled the trend in the maturation years with AGE5, there also exists a downward trend in the later years of a unit's life. At first we defined a variable which, in effect, was the opposite of AGE5. AGE_12 equaled the maximum value of AGE and 12. This variable was a significant addition to the regression, but indicated a very rapid downward trend. A more appropriate definition, given the small amount of datapoints for plants greater than 12 years old, was to make AGE_12 a dummy variable (AGE_12 = 1 if AGE is greater than or equal to 12, and 0 otherwise). The coefficient then indicates the inefficiency of a plant 12 or more years old (Attachment 4, pp. 11+).

For the sake of completeness, we also tried AGE_10 and AGE_11 dummy variables in the equation. AGE_12 was the most significant break-off point (Attachment 3, pp. 11-12).

4.7 More Turbine Effects

The last variable to be added, or rather added again, was W44. The correlation between W44 and MW600 is still high (see page 2 of Attachment 2), which is one reason for the lower F-statistic when W44 is added. However, it is an additional variable which explains some variability, so the adjusted R^2 increases, and the coefficient is significant (Attachment 3, pages 13 and 17).

5 Results

The results from our "best" regression on the full database (Attachment 3, page 17) are recorded as Equation 1 in Table 6.2, and projections from that equation are calculated in Table 6.3.

Three things should be noted when considering these results. First, all results reported here are based on data from 1973 to 1985. We have data for the majority of the variables back to 1968, but we have no source of refueling data before 1973. Therefore, because REFUEL and OUT are missing for all observations before 1973, those observations are excluded when a regression is run. In order to be able to include those observations, we tried to assign average values for the years 1973-1978, to the earlier years. When the regressions were run on this hypothetical data, however, none of the effects were particular strengthened. In any case, there are only 16 of those "missing" observations, and they represent the experience of only the earliest and smallest plants (only Robinson 2 and Palisades, which both entered commercial operation in 1972, are larger than 600 MW).

Second, the second unit of the Farley nuclear plant was inadvertantly left out of the database. It has only been operating since 1981, and would not be expected to change the results.

Finally, the DER of Sequoyah 1 is incorrectly reported in Appendix B, the capacity factor database, as 1128 MW. The DER is actually 1148, which means that the capacity factors for Sequoyah 1 are calculated to be slightly lower than the true capacity factors.

6 Regressions on Reduced Dataset

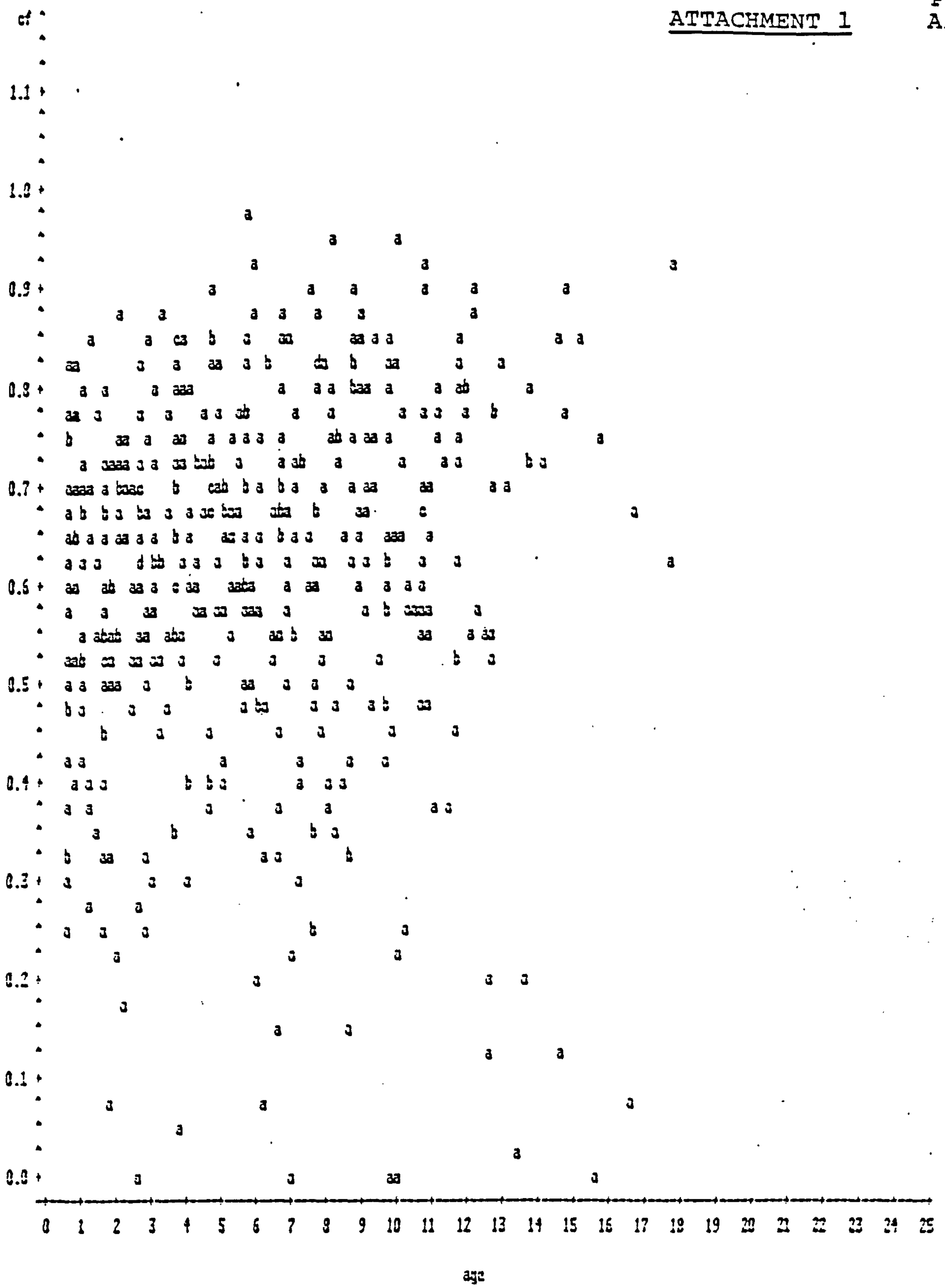
32 observations were deleted from the database in order to test a couple of hypotheses of particular interest to Palo Verde. First, San Onofre 1 was deleted, because it is a unit which has performed extremely poorly since its twelfth year in operation. Second, Palisades was deleted, because it is the only Combustion Engineering plant which has had particularly low capacity factors.

After running various regressions on this dataset, beginning with Equation 1, the preferred composition of the equation changed. Once San Onofre is removed, the AGE_12 variable loses its significance (Attachment 3, page 18), and is taken out. When

Palisades is removed, the dummy variable CE is added to the equation and found to be significant (Attachment 3, page 19). Combustion Engineering units have generally had good experience, with the exception of Palisades, which is unusual in several respects. Palo Verde is a Combustion Engineering plant, so a positive coefficient on the CE variable increases the capacity factors projected for Palo Verde.

Finally, during the course of these changes, the W44 variable loses significance and is removed. The best results from this reduced dataset (Attachment 3, page 23) are reported as Equation 2 in Table 6.2, and projections from that equation are calculated in Table 6.3.

plot of cf*age   legend: a = 1 obs, b = 2 obs, etc.



plot of cf*year   legend: a = 1 obs, b = 2 obs, etc.

cf

year

All data

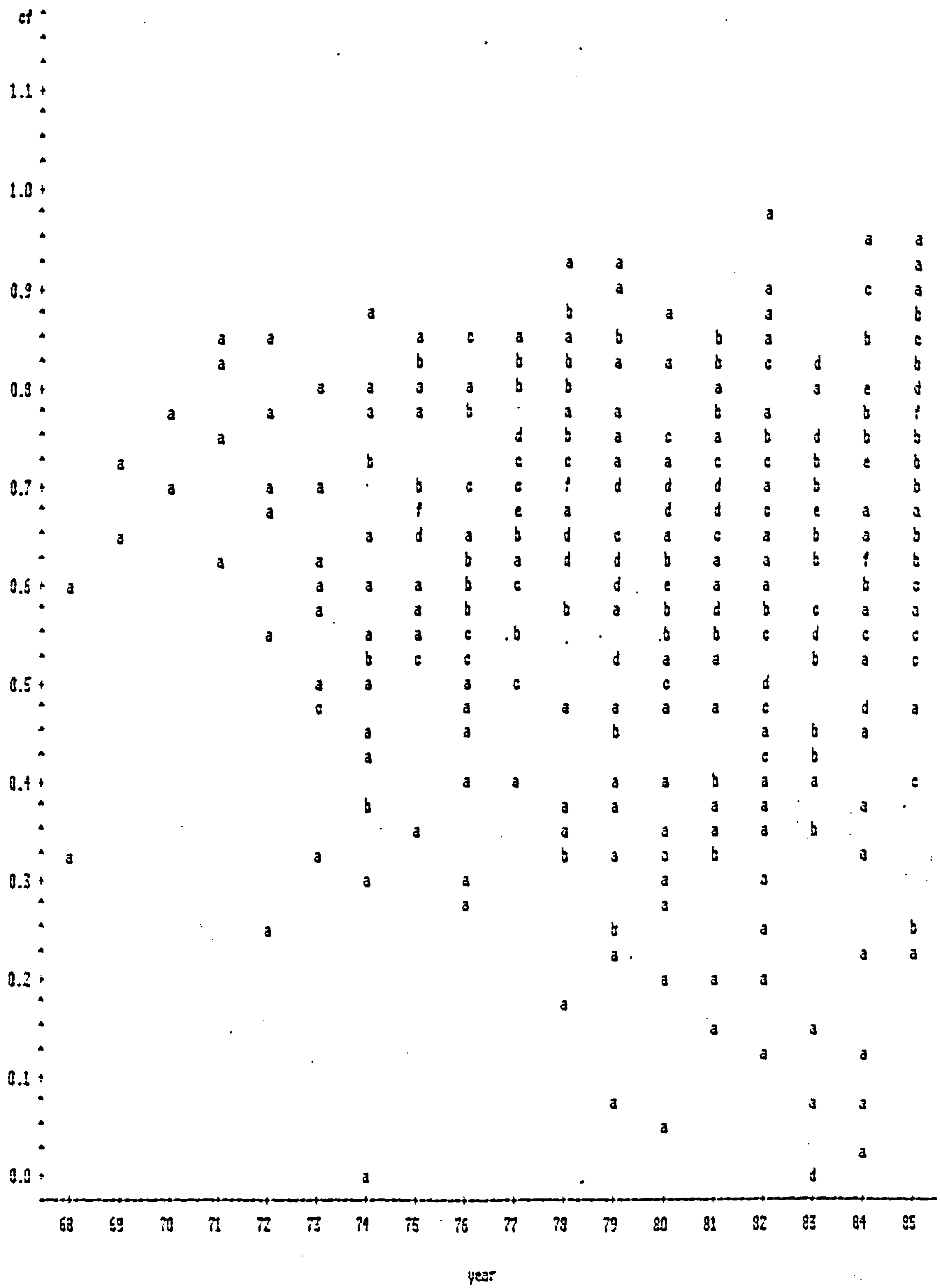
sas

plot of cf*ms legend: a = 1 obs, b = 2 obs, etc.

* the procedure plot used 0.12 seconds and 554k and printed pages 1 to 3.

*-1 sf*age ms bs cc u40 u44 year cut;

plot of cf*year legend: a = 1 obs, b = 2 obs, etc.



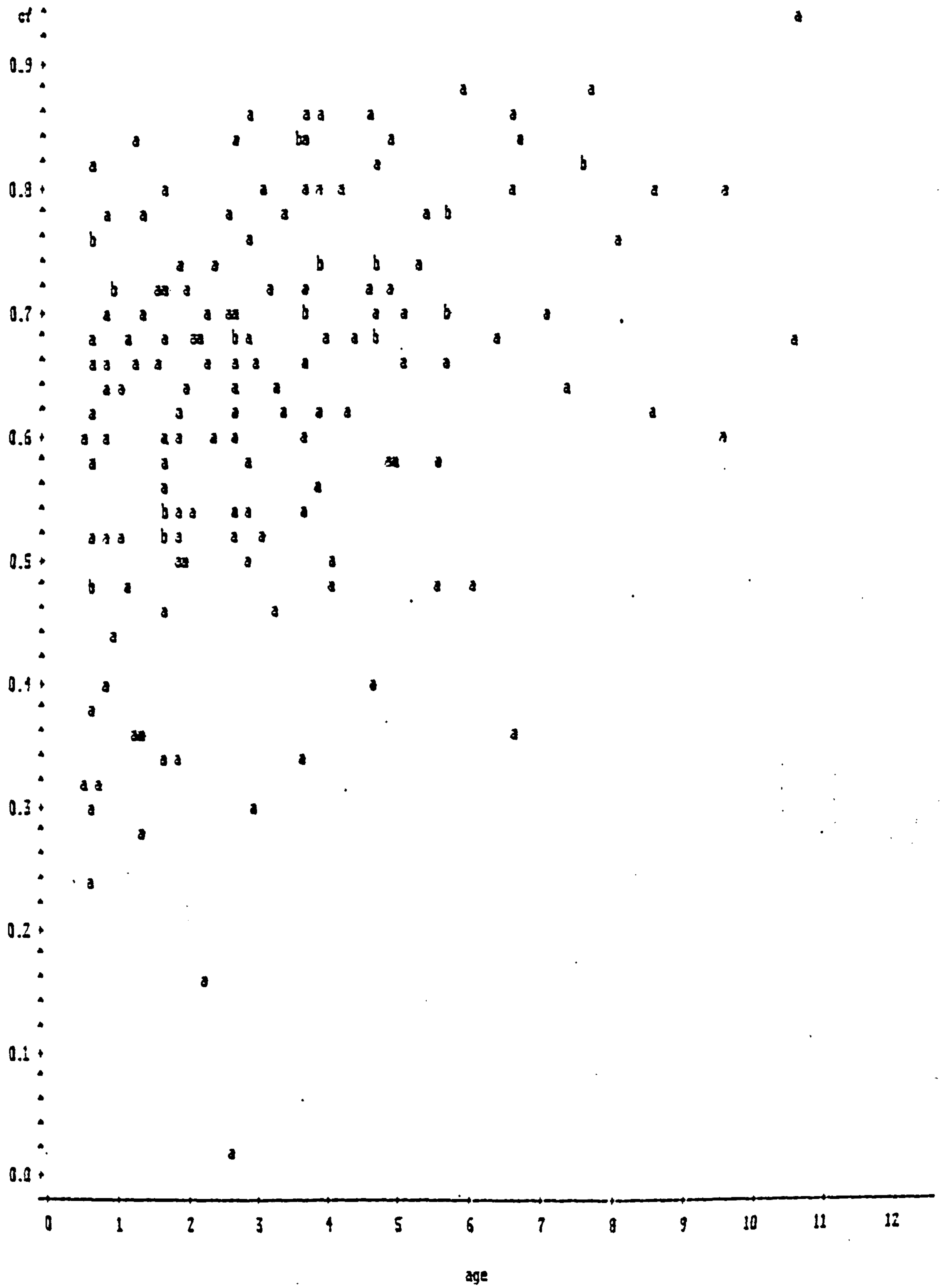
plot of cf*... legend: a = 1 obs, b = 2 obs, etc.

421 proc plot; plot cf*age cf*reruel cf*mu;

Pre-1975

sas 13:08 tuesday, january 21, 1986 5

plot of cf*age legend: a = 1 obs, b = 2 obs, etc.



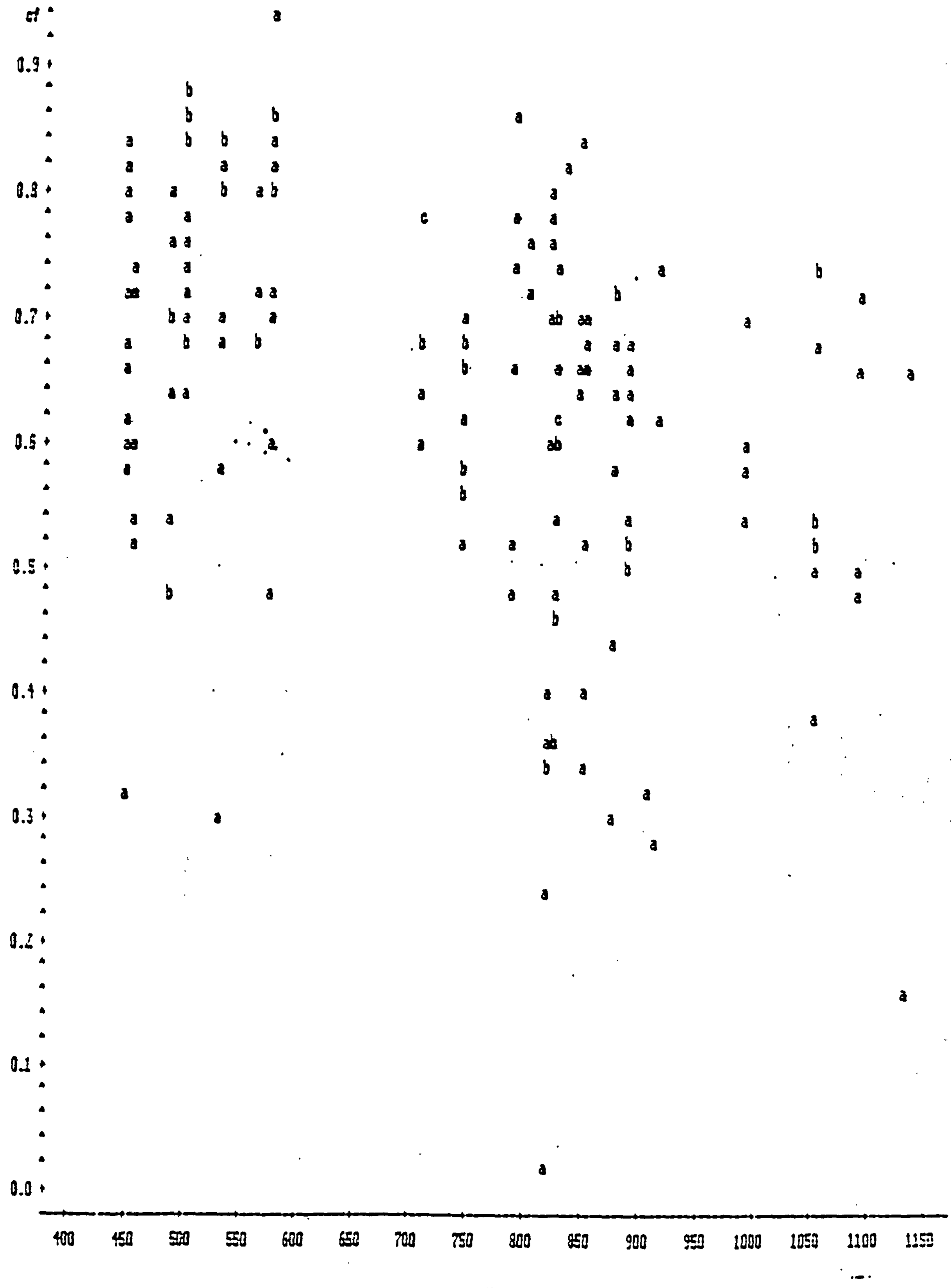
sas 13:08 tuesday, january 21, 1986 5

plot of cf*refuel legend: a = 1 obs, b = 2 obs, etc.

note: 16 obs had missing values

sas 13:08 tuesday, january 21, 1996 7

plot of cf*mw legend: a = 1 obs, b = 2 obs, etc.



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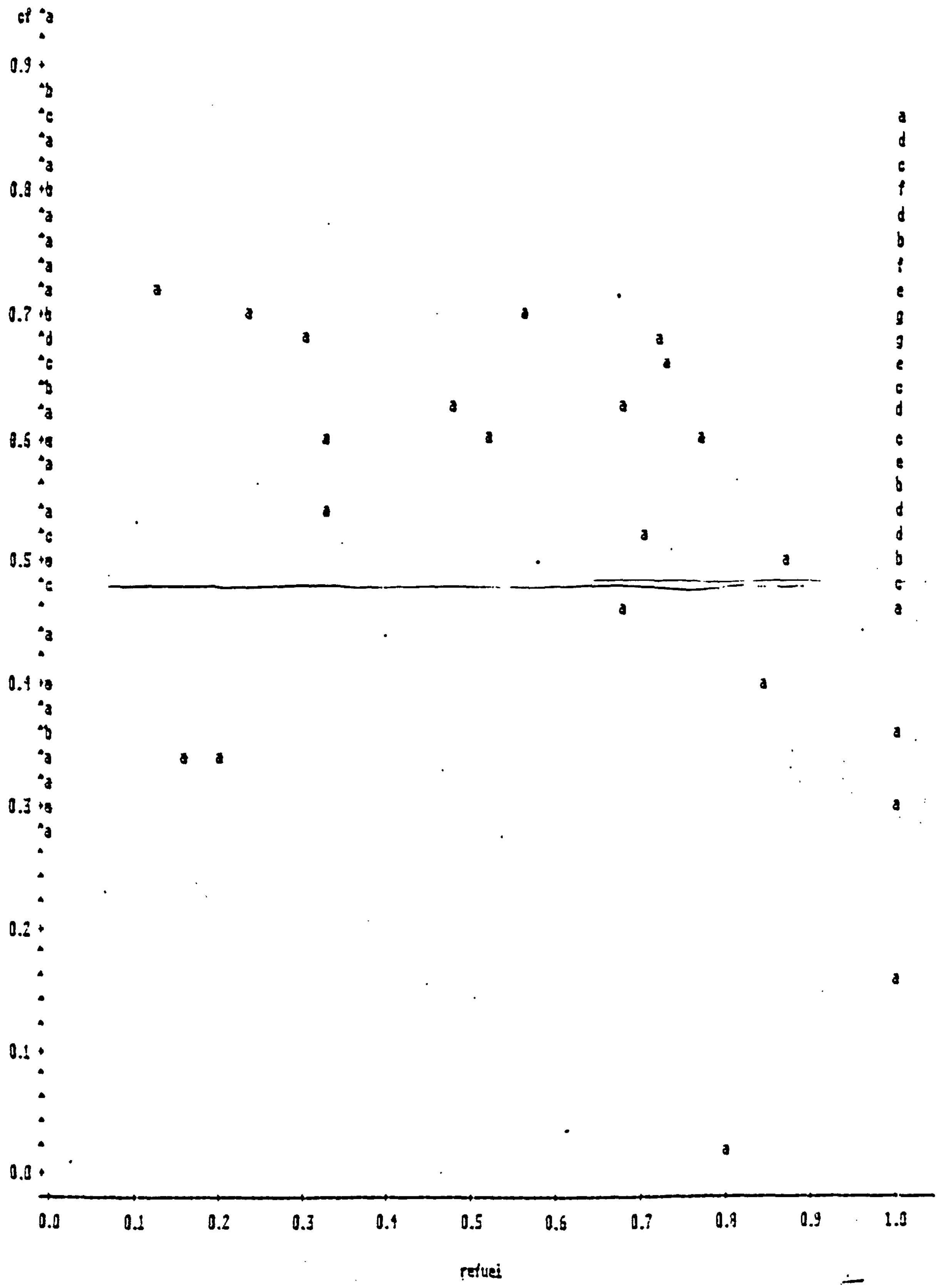
age

Pre-1979

sas 13:08 tuesday, january 21, 1986 6

plot of cf*refuel legend: a = 1 obs, b = 2 obs, etc.



note: 16 obs had missing values

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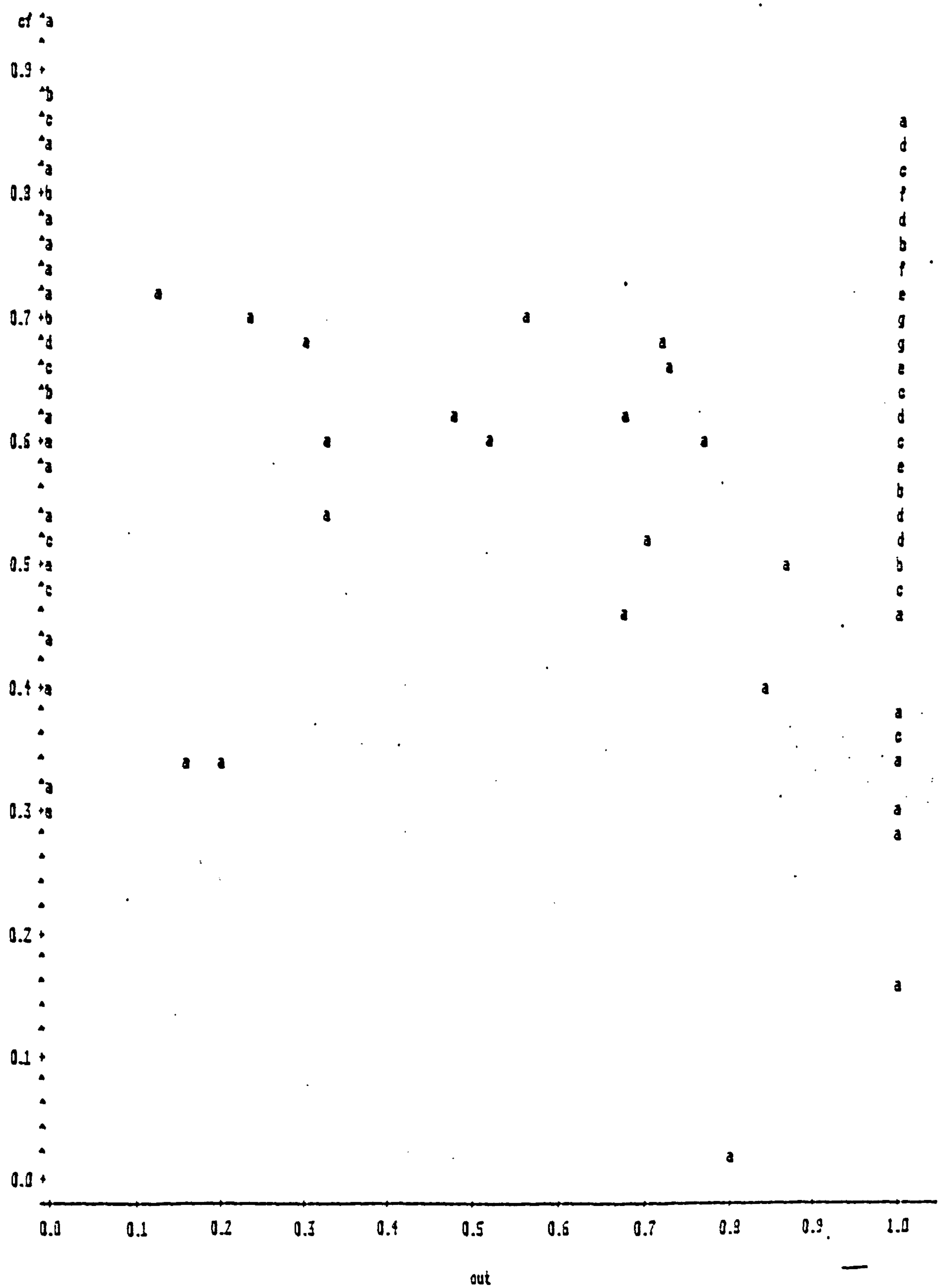
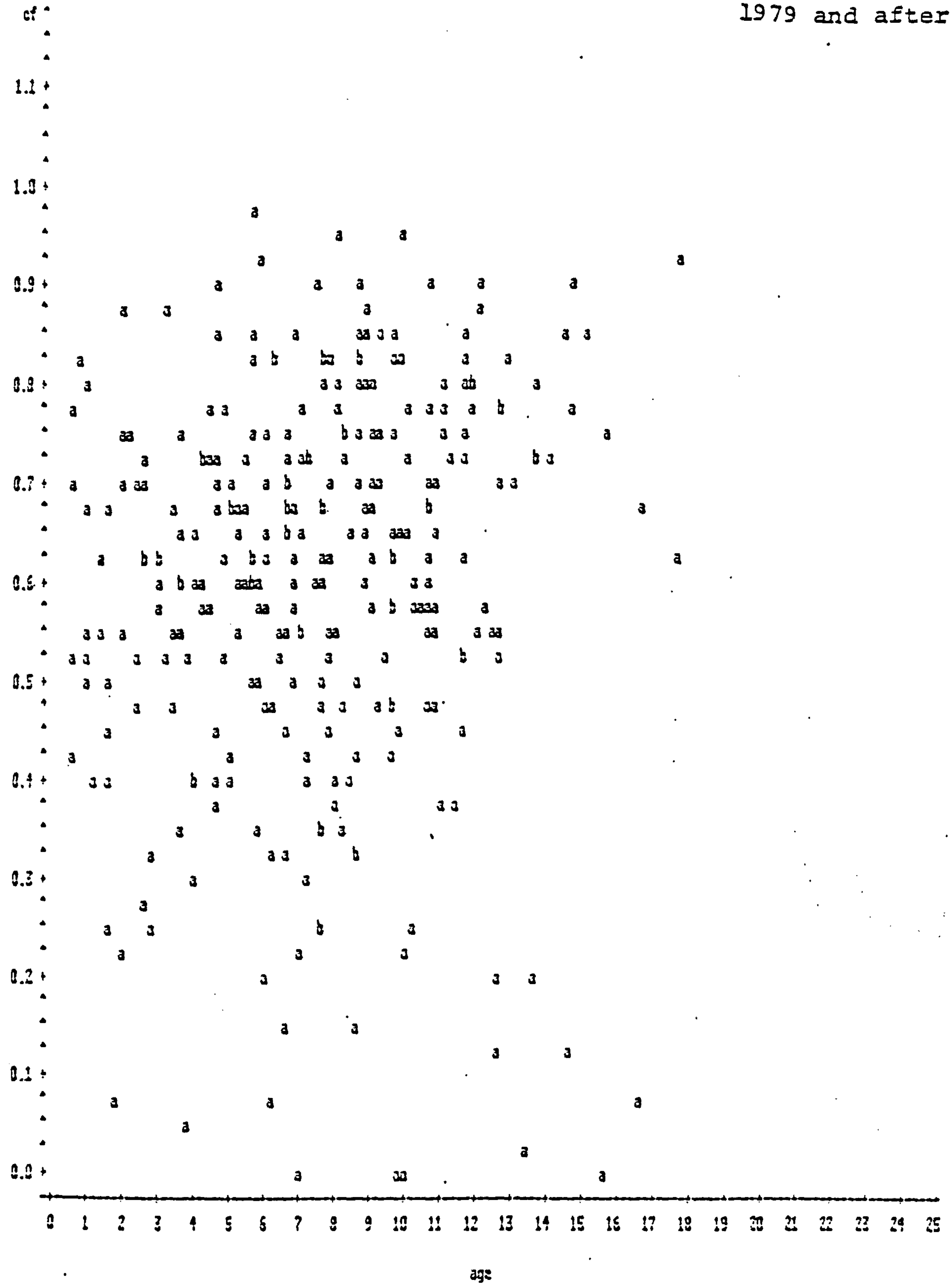
plot of cf*out legend: a = 1 obs. b = 2 obs, etc.



note: 16 obs had missing values

plot of cf*age   legend: a = 1 obs, b = 2 obs, etc.

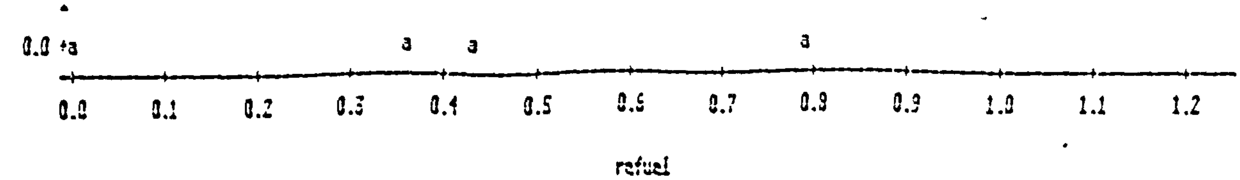
1979 and after



sas   17:10 thursday, april 7, 1995   4

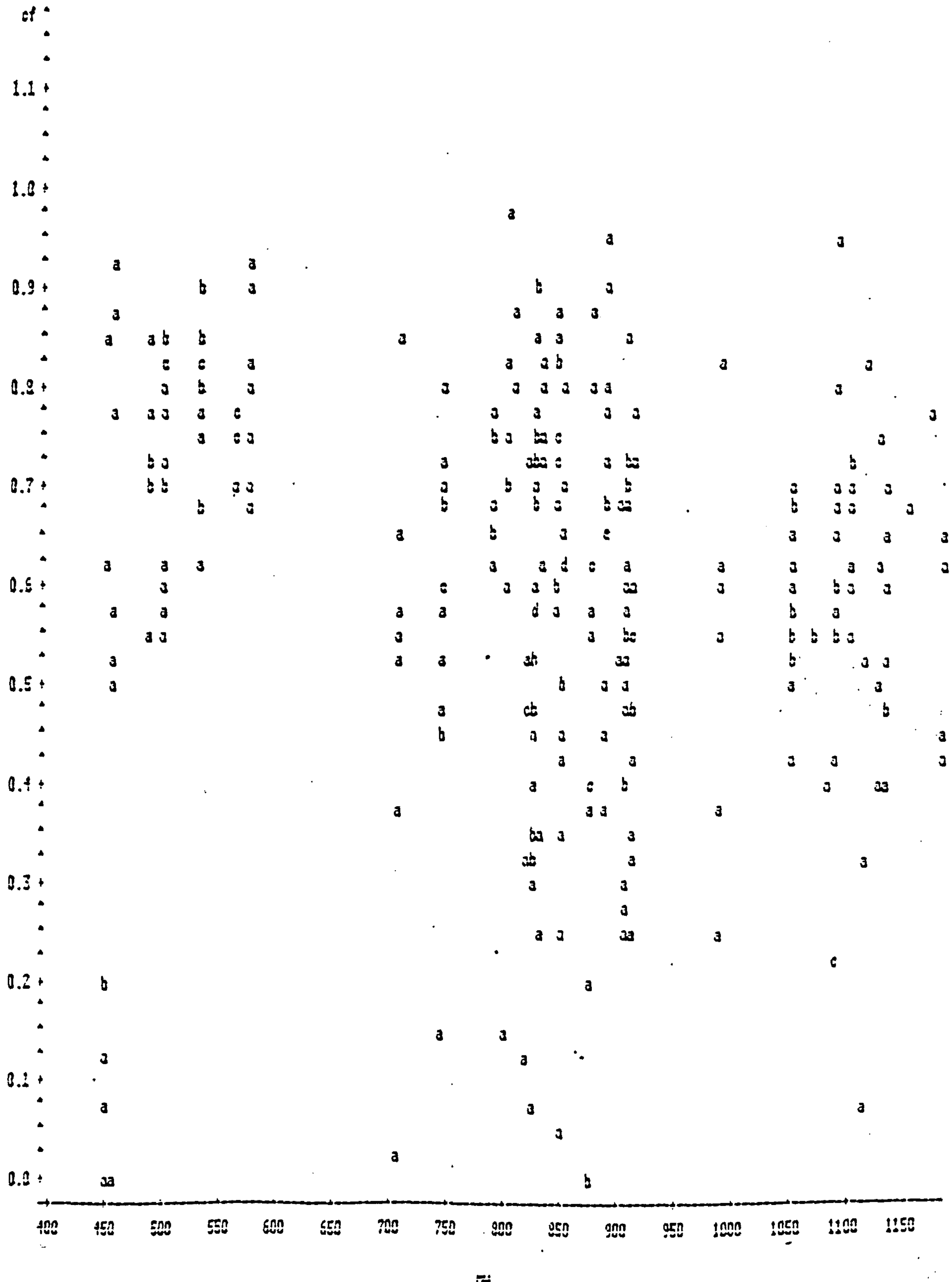
plot of cf*refuel   legend: a = 1 obs, b = 2 obs, etc.

cf

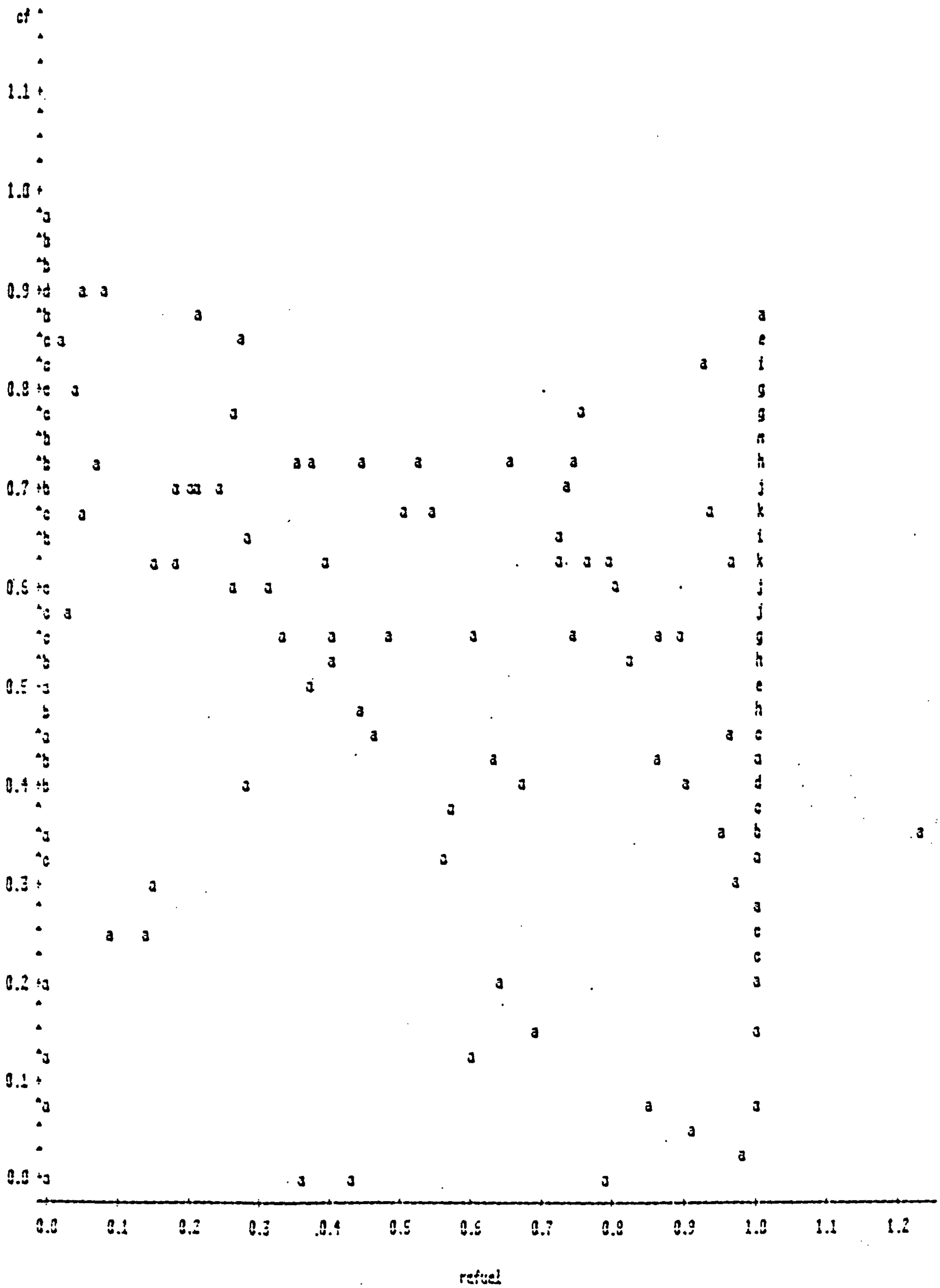


1979 and after

plot of cf*mi legend: a = 1 obs, b = 2 obs, etc.



plot of cf*refuel legend: a = 1 obs, b = 2 obs, etc.

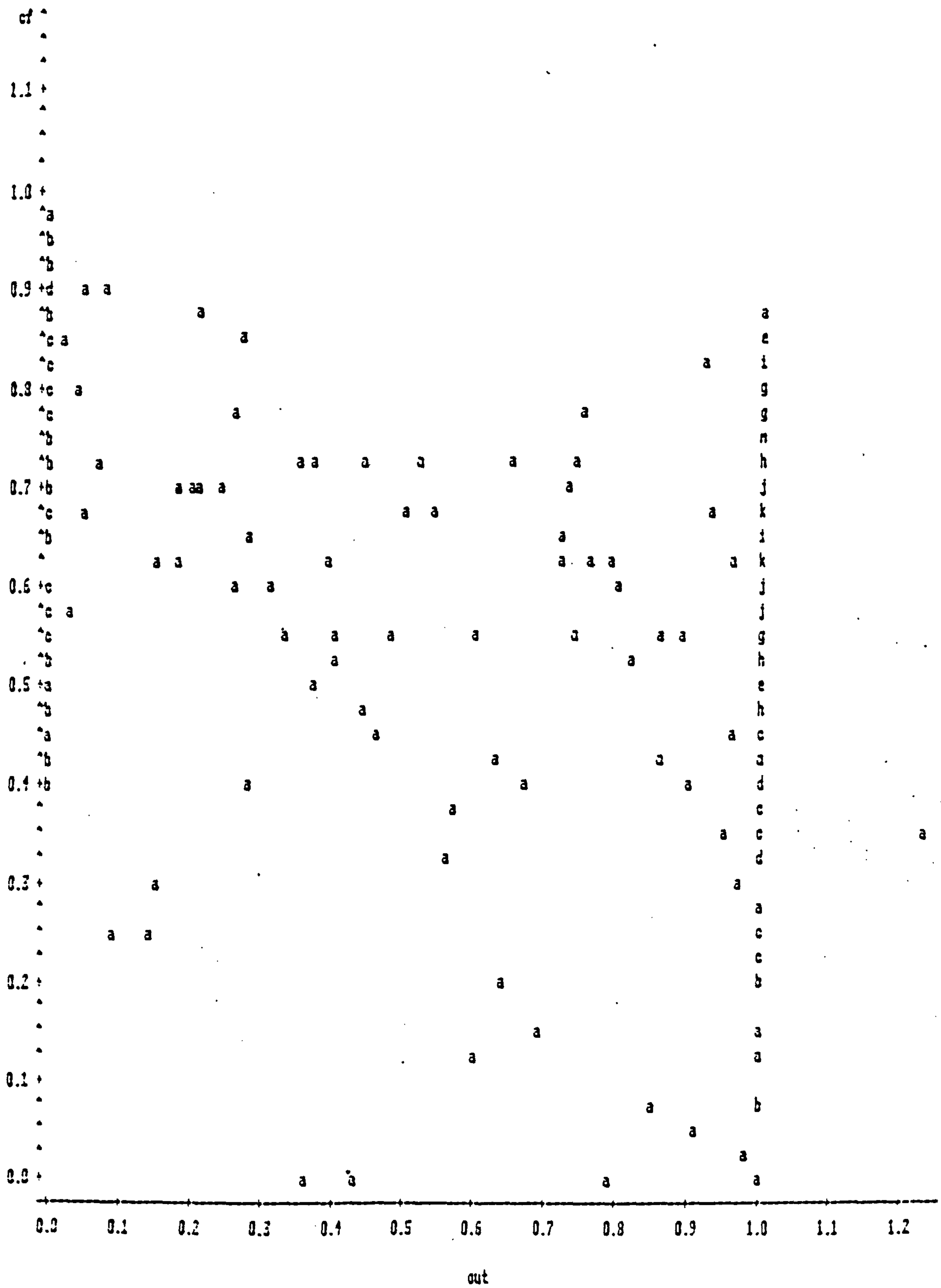


sas

aft78=1

1979 and after

plot of cf*out   Legend: a = 1 obs, b = 2 obs, etc.



note: the procedure plot used 0.09 seconds and 554k and printed pages 4 to 5.
note: sas used 1466k memory.

note: sas institute inc.
sas circle
po box 8000
cary, n.c 27511-8000

474 proc corr; var cf age ms u40 u44 bu ce year out;

ATTACHMENT 2

sas

variable	n	mean	std dev	sum	minimum	maximum
cf	461	0.6108	0.1967	281.6	-0.0030	0.966
age	461	5.9251	3.7594	2731.9	0.5000	17.500
ms	461	790.0304	201.3740	364204.0	450.0000	1190.000
u40	460	0.2239	0.4173	103.0	0.0000	1.000
u44	460	0.5370	0.4992	247.0	0.0000	1.000
bu	461	0.1627	0.3695	75.0	0.0000	1.000
ce	461	0.1866	0.3900	86.0	0.0000	1.000
year	461	79.9255	3.7856	36800.0	68.0000	85.000
out	445	0.6918	0.4241	307.9	0.0000	1.234

pearson correlation coefficients / prob > \|r\| under h0:rho=0 / number of observations

	cf	age	ms	u40	u44	bu	ce	year	out
cf	1.00000	0.06400	-0.25990	0.25998	-0.20454	-0.09754	0.02737	-0.01716	-0.15539
	0.0000	0.1701	0.0001	0.0001	0.0001	0.0363	0.5578	0.7133	0.0010
	461	461	461	460	460	461	461	461	445
age	0.06400	1.00000	-0.29425	0.15453	-0.02966	-0.06377	-0.05742	0.62153	0.09078
	0.1701	0.0000	0.0001	0.0009	0.5257	0.1717	0.2195	0.0001	0.0557
	461	461	461	460	460	461	461	461	445
ms	-0.25990	-0.29425	1.00000	-0.69687	0.32178	0.21942	-0.01657	0.29734	-0.11502
	0.0001	0.0001	0.0000	0.0001	0.0001	0.0001	0.7227	0.0001	0.0152
	461	461	461	460	460	461	461	461	445
u40	0.25998	0.15453	-0.69687	1.00000	-0.57842	-0.23707	-0.15057	-0.15360	0.15233
	0.0001	0.0009	0.0001	0.0000	0.0001	0.0001	0.0012	0.0009	0.0013
	460	460	460	460	460	460	460	460	444
u44	-0.20454	-0.02966	0.32178	-0.57842	1.00000	-0.13303	-0.03554	0.04560	-0.11025
	0.0001	0.5257	0.0001	0.0001	0.0000	0.0043	0.4470	0.3291	0.0201
	460	460	460	460	460	460	460	460	444
bu	-0.09754	-0.06377	0.21942	-0.23707	-0.13303	1.00000	-0.21109	0.03422	-0.04090
	0.0363	0.1717	0.0001	0.0001	0.0043	0.0000	0.0001	0.4636	0.3894
	461	461	461	460	460	461	461	461	445
ce	0.02737	-0.05742	-0.01657	-0.15057	-0.03554	-0.21109	1.00000	0.06468	-0.01371
	0.5578	0.2195	0.7227	0.0012	0.4470	0.0001	0.0000	0.1656	0.7731
	461	461	461	460	460	461	461	461	445
year	-0.01716	0.62153	0.29734	-0.15360	0.04560	0.03422	0.06468	1.00000	0.05563
	0.7133	0.0001	0.0001	0.0009	0.3291	0.4636	0.1656	0.0000	0.2415
	461	461	461	460	460	461	461	461	445
out	-0.15539	0.09078	-0.11502	0.15233	-0.11025	-0.04090	-0.01371	0.05563	1.00000
	0.0010	0.0557	0.0152	0.0013	0.0201	0.3894	0.7731	0.2415	0.0000
	445	445	445	444	444	445	445	445	445

note: the procedure corr used 0.10 seconds and 554k and printed page 1.

475 proc reg; model cf=age ms;

476 * Simple Regression 31;

pearson correlation coefficients / prob > |r| under h0:rho=0 / number of observations

	cf	aft78	age5	age_12	out	nw600	u44	if79	if80	if81	if82	if83	if84
cf	1.00000	-0.09357	0.10844	-0.03896	-0.15539	-0.29027	-0.20454	-0.04813	-0.06496	-0.00870	-0.04724	-0.11658	0.01507
	0.0000	0.0447	0.0199	0.4039	0.0010	0.0001	0.0001	0.3024	0.1638	0.8521	0.3115	0.0122	0.7469
	461	461	461	461	445	461	460	461	461	461	461	461	461
aft78	-0.09357	1.00000	0.51617	0.19605	0.03590	0.17869	0.04607	0.22272	0.22272	0.22905	0.23834	0.24139	0.24740
	0.0447	0.0000	0.0001	0.0001	0.4500	0.0001	0.3242	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
	461	461	461	461	445	461	460	461	461	461	461	461	461
age5	0.10844	0.51617	1.00000	0.19396	0.17420	-0.11459	-0.01922	0.02697	0.11167	0.13700	0.13134	0.15219	0.14197
	0.0199	0.0001	0.0000	0.0001	0.0002	0.0139	0.6810	0.5635	0.0165	0.0032	0.0047	0.0010	0.0023
	461	461	461	461	445	461	460	461	461	461	461	461	461
age_12	-0.03896	0.19605	0.19396	1.00000	0.00968	-0.23473	-0.01958	-0.07908	-0.01512	-0.01994	0.00610	0.06395	0.08822
	0.4039	0.0001	0.0001	0.0000	0.8387	0.0001	0.6754	0.0899	0.7461	0.6866	0.8961	0.1705	0.0584
	461	461	461	461	445	461	460	461	461	461	461	461	461
out	-0.15539	0.03590	0.17420	0.00968	1.00000	-0.14980	-0.11025	0.01120	0.01171	0.06508	-0.06011	0.05482	-0.00447
	0.0010	0.4500	0.0002	0.8387	0.0000	0.0016	0.0201	0.8139	0.8055	0.1705	0.2056	0.2485	0.9250
	445	445	445	445	445	445	444	445	445	445	445	445	445
nw600	-0.29027	0.17869	-0.11459	-0.23473	-0.14980	1.00000	0.48139	0.02313	0.02313	0.03200	0.04462	0.04967	0.05654
	0.0001	0.0001	0.0139	0.0001	0.0016	0.0000	0.0001	0.6204	0.6204	0.4931	0.3391	0.2871	0.2255
	461	461	461	461	445	461	460	461	461	461	461	461	461
u44	-0.20454	0.04607	-0.01922	-0.01958	-0.11025	0.48139	1.00000	-0.00640	-0.00640	0.00807	0.02862	0.02862	0.01889
	0.0001	0.3242	0.6810	0.6754	0.0201	0.0001	0.0000	0.8911	0.8911	0.8629	0.5404	0.5404	0.6861
	460	460	460	460	444	460	460	460	460	460	460	460	460
if79	-0.04813	0.22272	0.02697	-0.07908	0.01120	0.02313	-0.00640	1.00000	-0.08983	-0.09239	-0.09613	-0.09735	-0.09979
	0.3024	0.0001	0.5635	0.0899	0.8139	0.6204	0.8911	0.0000	0.0539	0.0474	0.0391	0.0366	0.0322
	461	461	461	461	445	461	460	461	461	461	461	461	461
if80	-0.06496	0.22272	0.11167	-0.01512	0.01171	0.02313	-0.00640	-0.08983	1.00000	-0.09239	-0.09613	-0.09735	-0.09979
	0.1638	0.0001	0.0165	0.7461	0.8055	0.6204	0.8911	0.0539	0.0000	0.0474	0.0391	0.0366	0.0322
	461	461	461	461	445	461	460	461	461	461	461	461	461
if81	-0.00870	0.22905	0.13700	-0.01994	0.06508	0.03200	0.00807	-0.09239	-0.09239	1.00000	-0.09886	-0.10013	-0.10262
	0.8521	0.0001	0.0032	0.6866	0.1705	0.4931	0.8629	0.0474	0.0474	0.0000	0.0338	0.0316	0.0275
	461	461	461	461	445	461	460	461	461	461	461	461	461
if82	-0.04724	0.23834	0.13134	0.00610	-0.06011	0.04462	0.02862	-0.09613	-0.09613	-0.09886	1.00000	-0.10419	-0.10578
	0.3115	0.0001	0.0047	0.8961	0.2056	0.3391	0.5404	0.0391	0.0391	0.0338	0.0000	0.0253	0.0218
	461	461	461	461	445	461	460	461	461	461	461	461	461
if83	-0.11658	0.24139	0.15219	0.06395	0.05482	0.04967	0.02862	-0.09735	-0.09735	-0.10013	-0.10419	1.00000	-0.10815
	0.0122	0.0001	0.0010	0.1705	0.2485	0.2871	0.5404	0.0366	0.0366	0.0316	0.0253	0.0000	0.0202
	461	461	461	461	445	461	460	461	461	461	461	461	461
if84	0.01507	0.24740	0.14197	0.08822	-0.00447	0.05654	0.01889	-0.09979	-0.09979	-0.10262	-0.10578	-0.10815	1.00000
	0.7469	0.0001	0.0023	0.0584	0.9250	0.2255	0.6861	0.0322	0.0322	0.0275	0.0218	0.0202	0.0000
	461	461	461	461	445	461	460	461	461	461	461	461	461

note: the procedure corr used 0.11 seconds and 554k and printed pages 1 to 2.

478 proc plot; plot cf*out;

ATTACHMENT 3

Regression Results for

PWR Capacity Factor Analysis

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	2	1.07630263	0.53815131	16.479	0.0001
error	458	14.95662681	0.03265617		
c total	460	16.03292944			

root mse	0.1807102	r-square	0.0671
dep mean	0.6108416	adj r-sq	0.0631
c.v.	29.5838		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.80571440	0.04150917	19.411	0.0001
age	1	-0.000519222	0.002337650	-0.222	0.8247
mu	1	-0.000242778	0.000043641	-5.563	0.0001

note: the procedure reg used 0.07 seconds and 768k and printed page 2.

477 proc reg; model cf=age5 mu;
478 * Simple Regression #2;

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	2	1.14529159	0.57264580	17.617	0.0001
error	458	14.88763785	0.03250554		
c total	460	16.03292944			

root mse	0.1802929	r-square	0.0714
dep mean	0.6108416	adj r-sq	0.0674
c.v.	29.51549		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.75996494	0.04379751	17.353	0.0001
age5	1	0.008329819	0.005651592	1.474	0.1413
mu	1	-0.000229664	0.000042332	-5.425	0.0001

note: the procedure reg used 0.07 seconds and 768k and printed page 3.

479 proc reg; model cf=age5 mu aft78;
480 * PUR Regression with dummy for 1979 and after;

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	3	1.12558081	0.37519360	11.481	0.0001
error	441	14.41223774	0.03268081		
c total	444	15.53781855			

root mse	0.1807783	r-square	0.0724
dep mean	0.6089258	adj r-sq	0.0661
c.v.	29.68807		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > *t*
intercep	1	0.59769219	0.02669007	22.394	0.0001
aft78	1	-0.07732379	0.02092970	-3.694	0.0002
age5	1	0.03052096	0.006815964	4.478	0.0001
out	1	-0.08387789	0.02057770	-4.076	0.0001

note: the procedure reg used 0.08 seconds and 768k and printed page 1.

477 proc reg; model cf=aft78 age7 out;

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	3	1.01091233	0.33697078	10.230	0.0001
error	441	14.52690622	0.03294083		
c total	444	15.53781855			

root mse	0.1814961	r-square	0.0651
dep mean	0.6089258	adj r-sq	0.0587
c.v.	29.80594		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > *t*
intercep	1	0.62408152	0.02395184	26.056	0.0001
aft78	1	-0.07883943	0.02174973	-3.625	0.0003
age7	1	0.01870108	0.004616220	4.051	0.0001
out	1	-0.07855791	0.02051140	-3.830	0.0001

note: the procedure reg used 0.07 seconds and 768k and printed page 2.

478 proc reg; model cf=aft78 age9 out;
479

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	3	1.12559081	0.37519360	11.481	0.0001
error	441	14.41223774	0.03268081		
c total	444	15.53781855			

root mse	0.1807733	r-square	0.0724
dep mean	0.6089258	adj r-sq	0.0661
c.v.	29.68807		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.59769219	0.02669007	22.394	0.0001
aft78	1	-0.07732373	0.02092970	-3.694	0.0002
age5	1	0.03052096	0.006815364	4.478	0.0001
out	1	-0.08387789	0.02057770	-4.076	0.0001

note: the procedure reg used 0.08 seconds and 768k and printed page 1.

477 proc reg; model cf=aft78 age7 out;

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	3	1.01091233	0.33697078	10.230	0.0001
error	441	14.52690622	0.03294083		
c total	444	15.53781855			

root mse	0.1814961	r-square	0.0651
dep mean	0.6089258	adj r-sq	0.0587
c.v.	29.80594		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.62408152	0.02395184	26.056	0.0001
aft78	1	-0.07883943	0.02174973	-3.625	0.0003
age7	1	0.01870108	0.004616220	4.051	0.0001
out	1	-0.07855731	0.02051140	-3.830	0.0001

note: the procedure reg used 0.07 seconds and 768k and printed page 2.

478 proc reg; model cf=aft78 age9 out;
479

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	3	0.97935115	0.32645038	9.889	0.0001
error	441	14.55846740	0.03301240		
c total	444	15.53781855			

root mse	0.1816931	r-square	0.0630
dep mean	0.6089258	adj r-sq	0.0567
c.v.	29.8383		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.63591934	0.02267773	28.042	0.0001
aft78	1	-0.07805142	0.02186046	-3.570	0.0004
age9	1	0.01411208	0.003593719	3.927	0.0001
out	1	-0.07635002	0.02047446	-3.729	0.0002

note: the procedure reg used 0.07 seconds and 768k and printed page 3.

480 proc reg; model cf=aft78 age5 out u40 u44;

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	5	2.31111879	0.46222376	15.310	0.0001
error	438	13.22354837	0.03019075		
c total	443	15.53466716			

root mse	0.1737549	r-square	0.1488
dep mean	0.6087995	adj r-sq	0.1391
c.v.	28.54057		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.62144093	0.02881707	21.565	0.0001
aft78	1	-0.06202135	0.02049548	-3.026	0.0026
age5	1	0.02565436	0.006734791	3.809	0.0002
out	1	-0.10114299	0.01997932	-5.062	0.0001
u40	1	0.09189799	0.02505311	3.666	0.0003
u44	1	-0.04182441	0.02006919	-2.084	0.0377

note: the procedure reg used 0.08 seconds and 768k and printed page 4.

481 proc reg; model cf=aft78 age5 out u;

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	4	1.16547816	0.29136954	8.902	0.0001
error	439	14.36918900	0.03273164		
c total	443	15.53466716			

root mse	0.1809189	r-square	0.0750
dep mean	0.6087995	adj r-sq	0.0666
c.v.	29.71731		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.60011620	0.02978793	20.146	0.0001
aft78	1	-0.08014071	0.02112066	-3.794	0.0002
age5	1	0.03192196	0.006934547	4.589	0.0001
out	1	-0.08520758	0.02062797	-4.131	0.0001
u	1	-0.006949971	0.02004799	-0.347	0.7290

note: the procedure reg used 0.08 seconds and 768k and printed page 5.

492 proc reg; model cf=if79 if80 if81 if82 if83 if84 age5 out u40 u44;
483

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	10	2.74126765	0.27412677	9.278	0.0001
error	433	12.79339951	0.02954596		
c total	443	15.53466716			

root mse	0.1718894	r-square	0.1765
dep mean	0.6087995	adj r-sq	0.1574
c.v.	28.23415		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.61935375	0.02959755	21.565	0.0001
if79	1	-0.07132371	0.03079929	-2.317	0.0210
if80	1	-0.09279926	0.03127563	-2.967	0.0032
if81	1	-0.05138326	0.03093386	-1.666	0.0963
if82	1	-0.09617138	0.02997857	-2.974	0.0042
if83	1	-0.11867727	0.03019829	-3.931	0.0001
if84	1	-0.04320723	0.02921481	-1.479	0.1399
age5	1	0.02597936	0.006255447	4.153	0.0001
out	1	-0.09974451	0.01983461	-5.029	0.0001
u40	1	0.09392396	0.02461103	3.816	0.0002
u44	1	-0.03999498	0.01984363	-2.010	0.0450

note: the procedure reg used 0.09 seconds and 768k and printed page 5.

494 proc reg; model cf=aft78 age5 out u40 u44 [illegible]

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	6	2.35339095	0.39223183	13.004	0.0001
error	437	13.18127621	0.03016310		
c total	443	15.53466716			

root mse	0.1736753	r-square	0.1515
dep mean	0.6087995	adj r-sq	0.1398
c.v.	28.5275		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.59221155	0.05635853	10.431	0.0001
aft78	1	-0.05378946	0.02163501	-2.486	0.0133
age5	1	0.02290058	0.007122255	3.215	0.0014
out	1	-0.10058102	0.01997532	-5.035	0.0001
u48	1	0.06733059	0.03252536	2.070	0.0390
u44	1	-0.04438687	0.02017644	-2.200	0.0283
mu	1	-0.000074086	0.000062531	-1.184	0.2371

note: the procedure reg used 0.07 seconds and 768k and printed page 7.

485 proc reg; model cf=aft78 age5 out mu;

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	4	1.76045603	0.44011401	14.056	0.0001
error	440	13.77736252	0.03131219		
c total	444	15.53781855			

root mse	0.1769525	r-square	0.1133
dep mean	0.6089258	adj r-sq	0.1052
c.v.	29.05978		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.79328022	0.05068733	15.650	0.0001
aft78	1	-0.04305257	0.02185485	-1.970	0.0495
age5	1	0.01870022	0.007169611	2.608	0.0094
out	1	-0.08940160	0.02017953	-4.430	0.0001
mu	1	-0.000210033	0.000046645	-4.503	0.0001

note: the procedure reg used 0.08 seconds and 768k and printed page 8.

2 sas(r) log os sas 5.08 vs2/mvs job ext73704 step 16:34 thursday, april 3, 1995

```
2        sas(r) log   os sas 5.08          vs2/mvs job ext/strt step                    [illegible]

486        proc reg; model cf=if79 if80 if81 if82 if83 if84 age5 out mu;

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dep variable: cf
analysis of variance

                     sum of          mean
source    df        squares        square       f value      prob>f

model      9     2.17086654    0.24120739       7.850       0.0001
error    435    13.36695201    0.03072863
c total  444    15.53781855

     root mse      0.1752958     r-square      0.1397
     dep mean      0.6089258     adj r-sq      0.1219
     c.v.           28.78771

parameter estimates

                      parameter        standard      t for h0:
variable  df          estimate           error     parameter=0     prob > |t|
[illegible]         0.0000205115                        -4.571          0.0001
intercep   1        0.78947130      0.04935741          15.995          0.0001
if79       1       -0.06460087      0.03149190          -2.052          0.0408
if80       1       -0.08376858      0.03202340          -2.615          0.0092
if81       1       -0.04393817      0.03163594          -1.390          0.1652
if82       1       -0.07437531      0.03086335          -2.410          0.0164
if83       1       -0.10112594      0.03076303          -3.287          0.0011
if84       1       -0.03133746      0.03012837          -1.040          0.2989
age5       1        0.02056536     0.006541122           3.144          0.0018
out        1        .06432403                           -4.396          .0001
```

The end!

dep mean 0.6089258 adj r-sq 0.1219
c.v. 28.78771

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.78947130	0.04935741	15.995	0.0001
if79	1	-0.06460087	0.03149180	-2.052	0.0408
if80	1	-0.08375858	0.03202840	-2.615	0.0092
if81	1	-0.04393817	0.03160594	-1.390	0.1652
if82	1	-0.07437531	0.03085335	-2.410	0.0164
if83	1	-0.10112594	0.03076303	-3.287	0.0011
if84	1	-0.03133746	0.03012937	-1.040	0.2989
age5	1	0.02056586	0.006541122	3.144	0.0018
out	1	-0.08824043	0.02007089	-4.396	0.0001
mu	1	-0.000205119	0.000044674	-4.591	0.0001

note: the procedure reg used 0.09 seconds and 768k and printed page 1.

475 proc reg; model cf=aft78 age5 out mu;
476 output out=two r=resid;

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	4	1.76045603	0.44011401	14.056	0.0001
error	440	13.77736252	0.03131219		
c total	444	15.53781855			

root mse 0.1769525 r-square 0.1133
dep mean 0.6089258 adj r-sq 0.1052
c.v. 29.05978

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.79328022	0.05058793	15.650	0.0001
aft78	1	-0.04305257	0.02185485	-1.970	0.0495
age5	1	0.01870021	0.007169611	2.608	0.0094
out	1	-0.08940160	0.02017953	-4.430	0.0001

note: the data set work.two has 461 observations and 23 variables. 101 obs/trk.

mu	1	-0.000210033	0.000046645	-4.503	0.0001

note: the procedure reg used 0.13 seconds and 768k and printed page 2.

477 proc sort; by u40 u44 year;

note: data set work.two has 461 observations and 23 variables. 101 obs/trk.
note: the procedure sort used 0.12 seconds and 1466k.

478 proc means; var resid; by u40 u44;

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variable label n mean standard minimum maximum std error sum variance c.v.

479 proc plot: plot resid*mw='*' resid*age='*';
480

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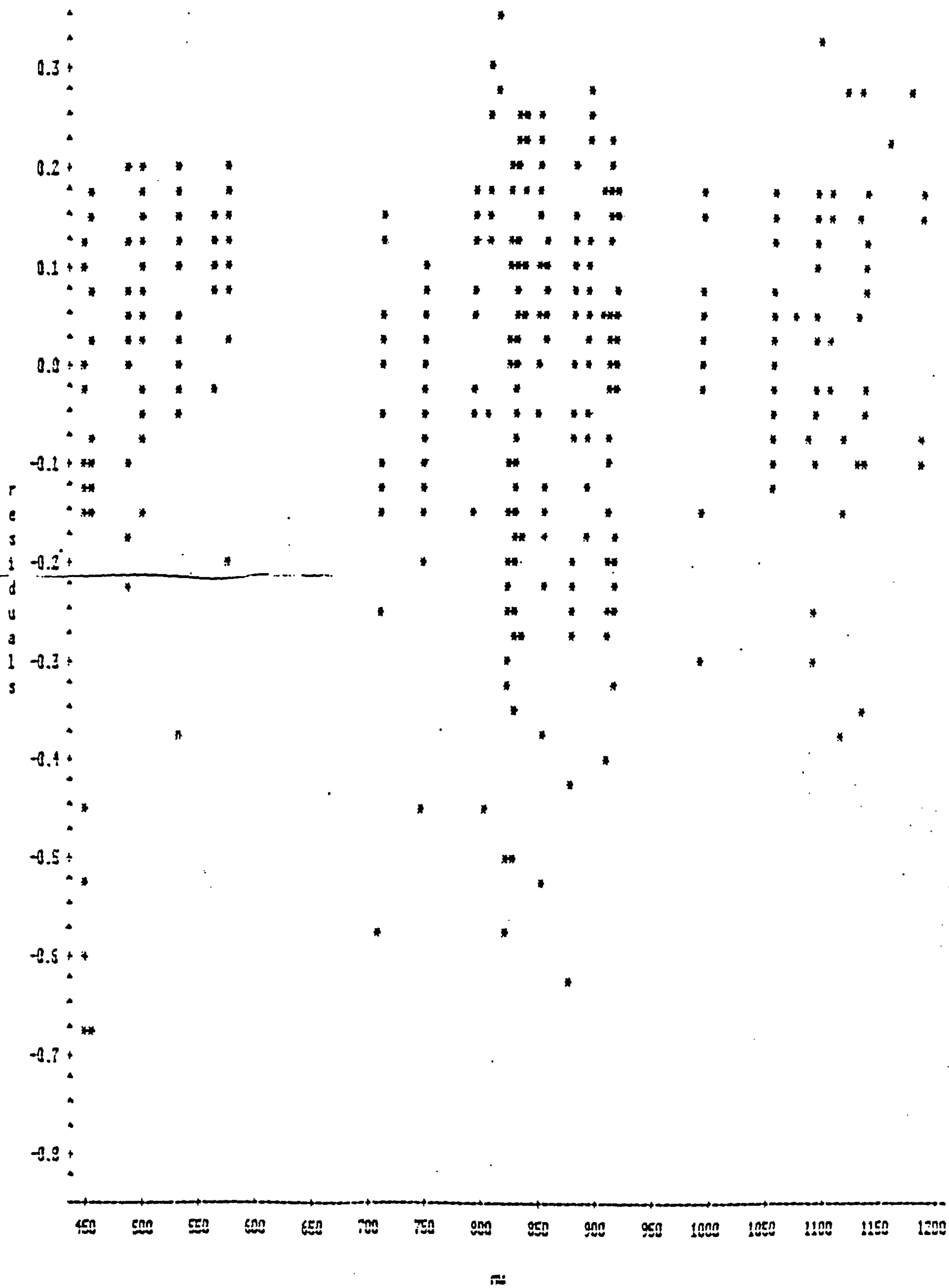
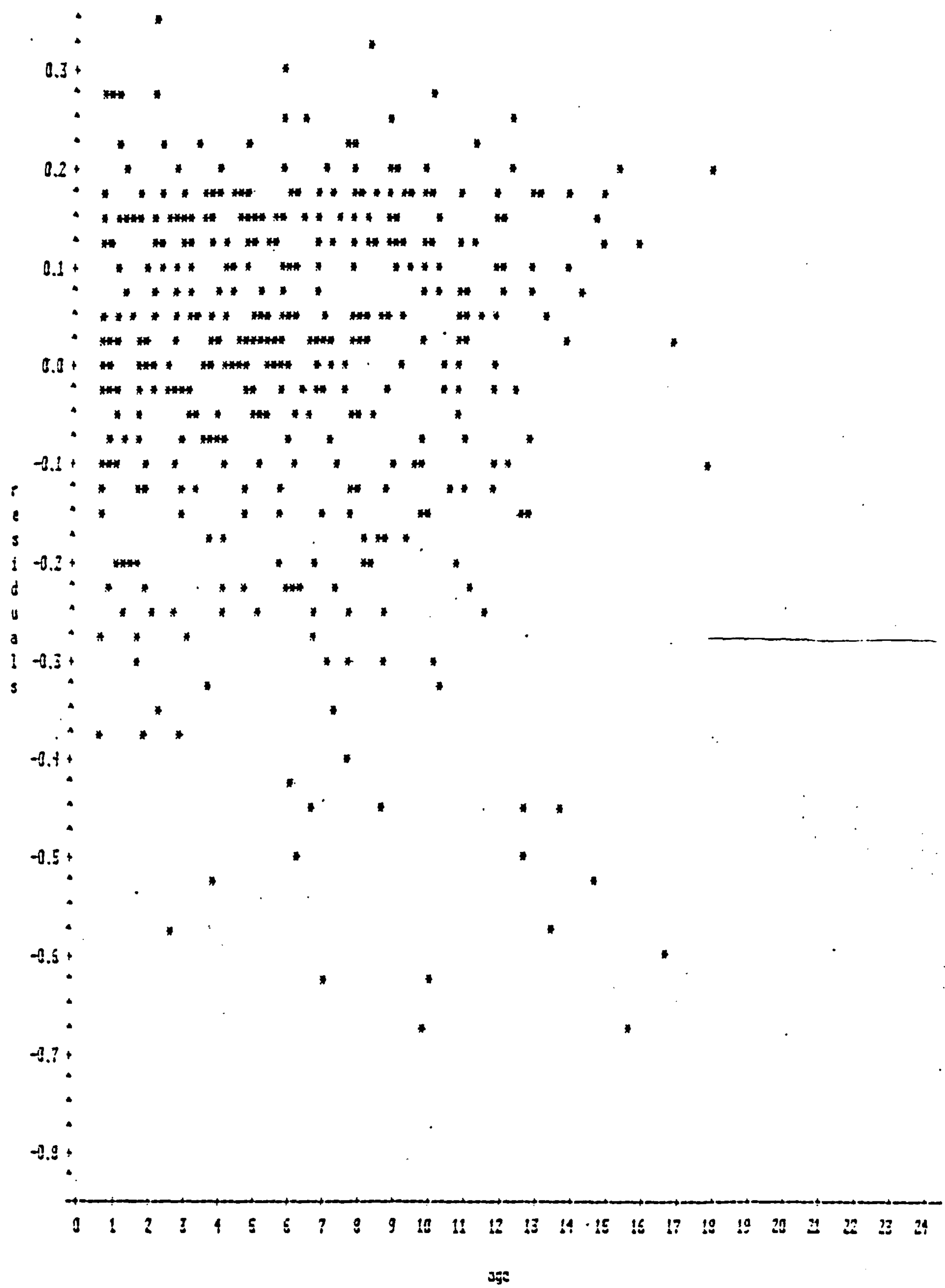
plot of resid*mw symbol used is *



note: 16 obs had missing values 157 obs hidden plot of resid*age symbol used is *



note: 16 obs had missing values 65 obs hidden
note: the procedure plot used 0.09 seconds and 554k and printed pages 4 to 5.

```
491        data three; set one;
492          age_12=max(age,12);
```

analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	5	2.17779752	0.43555152	14.373	0.0001
error	441	13.36344135	0.03030259		
c total	446	15.54119999			

root mse	0.1740764	r-square	0.1401
dep mean	0.6099747	adj r-sq	0.1304
c.v.	28.59995		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > *t*
intercep	1	0.71950177	0.03279632	21.945	0.0001
aft79	1	-0.04210059	0.02125225	-1.981	0.0482
age5	1	0.02050673	0.006835513	3.000	0.0029
out	1	-0.09648270	0.01999999	-4.951	0.0001
mu600	1	-0.12377959	0.02097422	-5.901	0.0001
age_10	1	-0.02352923	0.02473735	-0.951	0.3421

note: the procedure reg used 0.07 seconds and 759k and printed page 3.

497 proc reg; model of=aft79 age5 out mu600 age_11;

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dep variables: of
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	5	2.18593099	0.43718619	14.435	0.0001
error	441	13.35526909	0.03028405		
c total	446	15.54119999			

root mse	0.1740231	r-square	0.1407
dep mean	0.6099747	adj r-sq	0.1309
c.v.	28.53111		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > *t*
intercep	1	0.72114063	0.03288753	21.931	0.0001
aft79	1	-0.04169522	0.02119997	-1.967	0.0499
age5	1	0.02017959	0.006789137	2.973	0.0031
out	1	-0.09690077	0.01999916	-4.970	0.0001
mu600	1	-0.12493425	0.02104256	-5.932	0.0001
age_11	1	-0.03141027	0.02897605	-1.084	0.2790

note: the procedure reg used 0.08 seconds and 759k and printed page 4.

499 proc reg; model of=aft79 age5 out mu600 age_12;

sas 11:41 tuesday, april 9, 1995 5

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	5	2.37601495	0.47520299	15.918	0.0001
error	441	13.16518403	0.02985303		
c total	446	15.54119999			

root mse	0.1727803	r-square	0.1529
dep mean	0.6099747	adj r-sq	0.1433
c.v.	28.37698		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.72750412	0.03267523	22.264	0.0001
af479	1	-0.03533306	0.02099791	-1.742	0.0822
age5	1	0.02039219	0.006725329	3.032	0.0026
out	1	-0.09814605	0.01973775	-4.973	0.0001
mu600	1	-0.13394490	0.02080402	-6.438	0.0001
age_12	1	-0.09573794	0.03482100	-2.749	0.0062

note: the procedure reg used 0.07 seconds and 768k and printed page 5.

2 sas(r) log os sas 5.08 vs2/mvs job ext73704 step 11:41 tuesday, april 8, 1986

489 proc reg; model cf=af479 age5 out mu600 age_10 age_11 age_12;

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	7	2.43612053	0.34801722	11.559	0.0001
error	439	13.10507946	0.02985211		
c total	446	15.54119999			

root mse	0.1727776	r-square	0.1568
dep mean	0.6099747	adj r-sq	0.1432
c.v.	28.37655		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.72593940	0.03269618	22.203	0.0001
af479	1	-0.03958124	0.02115561	-1.871	0.0620
age5	1	0.01994254	0.006791034	2.937	0.0035
out	1	-0.09695567	0.01975712	-4.907	0.0001
mu600	1	-0.13067742	0.02106364	-6.204	0.0001
age_10	1	-0.008929313	0.03669126	-0.243	0.8079
age_11	1	0.06757259	0.05350865	1.263	0.2073
age_12	1	-0.14930137	0.05172133	-2.887	0.0041

dep variables: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	6	2.49416555	0.41569442	14.019	0.0001
error	440	13.04703244	0.02965235		
c total	446	15.54119999			

root mse	0.1721995	r-square	0.1605
dep mean	0.6099747	adj r-sq	0.1490
c.v.	28.29144		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.72969976	0.03257179	22.372	0.0001
aft79	1	-0.04001571	0.02089599	-1.915	0.0562
age5	1	0.02157221	0.006729703	3.206	0.0014
out	1	-0.10004109	0.01969419	-5.080	0.0001
age_12	1	-0.08681256	0.03499063	-2.481	0.0135
mu600	1	-0.11007573	0.02393497	-4.599	0.0001
u44	1	-0.03800979	0.01904163	-1.996	0.0465

note: the procedure reg used 0.08 seconds and 768k and printed page 7.

```
491         proc means; var aft79 age5 out age_12 mu600 u44 if79 if80 if81 if82 if83
492           if84 if85;
```

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variable	n	mean	standard deviation	minimum value	maximum value	std error of mean	sum	variance	c.v.
aft79	463	0.64578834	0.47879106	0.00000000	1.00000000	0.02225131	299.0000000	0.22924089	74.141
age5	463	3.88665227	1.50799972	0.50000000	5.00000000	0.07007759	1799.5200000	2.27373141	38.797
out	447	0.69096197	0.42467999	0.00000000	1.27400000	0.02008667	308.8600000	0.18035309	61.462
age_12	463	0.06479482	0.24642972	0.00000000	1.00000000	0.01145255	30.0000000	0.06072761	380.323
mu600	463	0.73002160	0.44442847	0.00000000	1.00000000	0.02065434	338.0000000	0.19751667	60.879
u44	463	0.53995680	0.49994000	0.00000000	1.00000000	0.02318771	250.0000000	0.24994112	92.404
if79	463	0.08207343	0.27477346	0.00000000	1.00000000	0.01276991	38.0000000	0.07550045	334.790
if80	463	0.08207343	0.27477346	0.00000000	1.00000000	0.01276991	38.0000000	0.07550045	334.790
if81	463	0.08639309	0.28124752	0.00000000	1.00000000	0.01307058	40.0000000	0.07910017	325.544
if82	463	0.09287257	0.29056774	0.00000000	1.00000000	0.01350393	43.0000000	0.08442961	312.867
if83	463	0.09503240	0.29357599	0.00000000	1.00000000	0.01364369	44.0000000	0.08618739	308.923
if84	463	0.10151188	0.30233200	0.00000000	1.00000000	0.01405055	47.0000000	0.09140464	297.829
if85	463	0.10583153	0.30795462	0.00000000	1.00000000	0.01431187	49.0000000	0.09483605	290.996

note: the procedure means used 0.11 seconds and 554k and printed page 8.

```
493         proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12 mu600 u44;
494         output out=four r=resid;
495
```

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dep variables: cf
analysis of variance

```
493       proc reg; model cf=if79 if80 if81 if82 if83
494       output out=four r=resid;
495
```


sas   11:41 tuesday, april 8, 1986   9

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	12	3.04210744	0.25359229	8.806	0.0001
error	434	12.49809154	0.02879745		
c total	446	15.54119899			

root mse	0.1696991	r-square	0.1958
dep mean	0.6089747	adj r-sq	0.1735
c.v.	27.87077		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.73422583	0.03231742	22.719	0.0001
if79	1	-0.05839150	0.03187573	-1.831	0.0677
if80	1	-0.07134498	0.03276482	-2.177	0.0300
if81	1	-0.02953652	0.03244454	-0.910	0.3631
if82	1	-0.06153637	0.03171194	-1.940	0.0530
if83	1	-0.08219503	0.03181037	-2.584	0.0101
if84	1	-0.009069730	0.03103425	-0.260	0.7950
if85	1	0.04869744	0.03181068	1.531	0.1265
age5	1	0.02097643	0.006675643	3.127	0.0019
out	1	-0.09799465	0.01950422	-5.024	0.0001
age_12	1	-0.12026337	0.03593362	-3.356	0.0009
mu600	1	-0.12049804	0.02379692	-5.064	0.0001

note: the data set work.four has 463 observations and 28 variables. 83 obs/trk.

u44	1	-0.03376270	0.01879735	-1.796	0.0732

note: the procedure reg used 0.15 seconds and 768k and printed page 9.

```
496       data five; set four; if hr=1;
```

note: data set work.five has 75 observations and 28 variables. 83 obs/trk.
note: the data statement used 0.04 seconds and 438k.

```
497       proc plot; plot resid*year='*';
```

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plot of resid*year   symbol used is *

```
    |
0.4 +
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```

root mse [illegible] r-square [illegible]
dep mean 0.6088747 adj r-sq 0.1694
c.v. 27.94069

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.72917317	0.03195540	22.818	0.0001
yr79_93	1	-0.07055141	0.01710900	-4.124	0.0001
age5	1	0.02239370	0.006027097	3.716	0.0002
out	1	-0.09684035	0.01943102	-4.984	0.0001
mu600	1	-0.13584276	0.01976003	-6.875	0.0001
age_12	1	-0.11586360	0.03380731	-3.427	0.0007

note: the procedure reg used 0.08 seconds and 780k and printed page 8.

532 proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12 mu600;

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dep variable: cf
analysis of variance

EQUATION 1

source	df	sum of squares	mean square	f value	prob>f
model	11	2.95020335	0.26820031	9.266	0.0001
error	435	12.59099562	0.02894482		
c total	446	15.54119898			

root mse 0.1701318 r-square 0.1898
dep mean 0.6088747 adj r-sq 0.1693
c.v. 27.942

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.73331328	0.03239600	22.636	0.0001
if79	1	-0.05584313	0.03192677	-1.749	0.0810
if80	1	-0.06789194	0.03279195	-2.070	0.0390
if81	1	-0.02666134	0.03249793	-0.821	0.4123
if82	1	-0.05998051	0.03176086	-1.857	0.0640
if83	1	-0.07962558	0.03185965	-2.499	0.0129
if84	1	-0.004555665	0.03105171	-0.147	0.8834
if85	1	0.05428410	0.03173861	1.710	0.0879
age5	1	0.01981053	0.006666205	2.972	0.0031
out	1	-0.09624960	0.01953005	-4.928	0.0001
age_12	1	-0.12904227	0.03559944	-3.626	0.0003
mu600	1	-0.14189557	0.02065295	-6.870	0.0001

note: the procedure reg used 0.09 seconds and 780k and printed page 9.
note: sas used 780k memory.

note: sas institute inc.
sas circle
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cary, n.c. 27511-8000
*go
./off
*cpu 2.46 io 2390 hookup 0:14:08
*session costs: $3.31,50.00
*current balances: [illegible]

analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	4	2.43779506	0.60944626	20.558	0.0001
error	442	13.10341393	0.02964573		
c total	446	15.54119998			

root mse	0.1721794	r-square	0.1569
dep mean	0.6088747	adj r-sq	0.1492
c.v.	28.27929		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.71938704	0.03221212	22.333	0.0001
yr79_93	1	-0.06666122	0.01727738	-3.858	0.0001
age5	1	0.01989490	0.005011771	3.143	0.0018
out	1	-0.09330836	0.01963312	-4.751	0.0001
mu600	1	-0.12036653	0.01946956	-6.182	0.0001

note: the procedure reg used 0.08 seconds and 780k and printed page 7.

521 proc reg; model cf=yr79_93 age5 out mu600 age_12;

dep variable: cf

EQ.J ~~AC-1(6)/~~ 2

analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	5	2.77772591	0.55554515	19.195	0.0001
error	441	12.76347318	0.02894212		
c total	446	15.54119898			

root mse	0.1701228	r-square	0.1787
dep mean	0.6088747	adj r-sq	0.1694
c.v.	27.94059		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.72917217	0.03195540	22.819	0.0001
yr79_93	1	-0.07056141	0.01710900	-4.124	0.0001
age5	1	0.02239370	0.006027097	3.716	0.0002
out	1	-0.09684035	0.01943102	-4.984	0.0001
mu600	1	-0.13584275	0.01976003	-6.875	0.0001
age_12	1	-0.11585360	0.03380731	-3.427	0.0007

note: the procedure reg used 0.09 seconds and 780k and printed page 8.

532 proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12 mu600;

dep variable: cf
analysis of variance

analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	6	2.90633365	0.48438894	16.868	0.0001
error	440	12.63486533	0.02871560		
c total	446	15.54119898			

root mse	0.1694568	r-square	0.1870
dep mean	0.6088747	adj r-sq	0.1759
c.v.	27.83114		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.73187725	0.03185057	22.978	0.0001
yr79_83	1	-0.07159624	0.01704412	-4.201	0.0001
age5	1	0.02313512	0.006013670	3.847	0.0001
out	1	-0.10012220	0.01941136	-5.158	0.0001
mw600	1	-0.11407700	0.02267405	-5.031	0.0001
age_12	1	-0.10885552	0.03389244	-3.212	0.0014
u44	1	-0.03587917	0.01866693	-1.922	0.0552

note: the procedure reg used 0.07 seconds and 768k and printed page 1.

```
480         proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12
481           mw600 u44;
482
```

EQUATION 1

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All data

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	12	3.07188258	0.25599021	8.910	0.0001
error	434	12.46931641	0.02873114		
c total	446	15.54119898			

root mse	0.1695026	r-square	0.1977
dep mean	0.6088747	adj r-sq	0.1755
c.v.	27.83867		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.73574795	0.03230559	22.775	0.0001
if79	1	-0.05826619	0.03183987	-1.830	0.0679
if80	1	-0.07116639	0.03272638	-2.175	0.0302
if81	1	-0.02921724	0.03240835	-0.902	0.3678
if82	1	-0.06154001	0.03167219	-1.943	0.0527
if83	1	-0.08183278	0.03177482	-2.575	0.0103
if84	1	-0.007829391	0.03099735	-0.253	0.8007
if85	1	0.05104866	0.03175901	1.607	0.1087
age5	1	0.02087819	0.006665224	3.132	0.0019
out	1	-0.10004849	0.01950963	-5.128	0.0001
age_12	1	-0.12145015	0.03579999	-3.392	0.0008

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	6	3.04970880	0.50828480	19.538	0.0001
error	427	11.10857113	0.02601539		
c total	433	14.15827994			

root mse	0.1612929	r-square	0.2154
dep mean	0.6129032	adj r-sq	0.2044
c.v.	26.3162		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.74585292	0.03067203	24.317	0.0001
yr79_83	1	-0.06436848	0.01654269	-3.891	0.0001
age5	1	0.02211689	0.005771125	3.832	0.0001
out	1	-0.09405419	0.01877817	-5.009	0.0001
mw600	1	-0.12664695	0.02198399	-5.761	0.0001
age_12	1	-0.01159561	0.03562299	-0.326	0.7450
w44	1	-0.04730842	0.01784645	-2.651	0.0083

note: the procedure reg used 0.08 seconds and 768k and printed page 3.

```
proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12
  mw600 w44;
```

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dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	12	3.15446355	0.26287196	10.057	0.0001
error	421	11.00381639	0.02613733		
c total	433	14.15827994			

root mse	0.1616704	r-square	0.2228
dep mean	0.6129032	adj r-sq	0.2006
c.v.	26.37781		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.74785140	0.03109162	24.053	0.0001
if79	1	-0.06381800	0.03088633	-2.066	0.0394
if80	1	-0.06841058	0.03173699	-2.156	0.0317
if81	1	-0.02553540	0.03141598	-0.813	0.4168
if82	1	-0.05850233	0.03069328	-1.906	0.0573
if83	1	-0.08189055	0.03073803	-2.664	0.0080
if84	1.	-0.009948020	0.02996781	-0.332	0.7401
if85	1	0.02695919	0.03073071	0.877	0.3808
age5	1	0.02109829	0.006443897	3.274	0.0011
out	1	-0.09436547	0.01892236	-4.987	0.0001

nw600	1	-0.12945711	0.02292565	-5.647	0.0001
u44	1	-0.04596710	0.01799964	-2.554	0.0110

note: the procedure reg used 0.08 seconds and 768k and printed page 4.

2 sas(r) log os sas 5.08 vs2/mvs job ext73704 step 13:46 friday, april 11, 1986

```
488        data four; set two;
489          if id=6 then delete;
```

note: data set work.four has 449 observations and 24 variables. 97 obs/trk.
note: the data statement used 0.05 seconds and 438k.

```
490        proc reg; model cf=yr79_83 age5 out nw600 age_12 u44 ce;
```

sas 13:46 friday, april 11, 1986 5

No Palisades

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	7	3.05945734	0.43706533	16.270	0.0001
error	426	11.44357554	0.02686285		
c total	433	14.50303288			

root mse	0.1638989	r-square	0.2110
dep mean	0.6149493	adj r-sq	0.1980
c.v.	26.65243		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.71840794	0.03124083	22.996	0.0001
yr79_83	1	-0.07732383	0.01671339	-4.626	0.0001
age5	1	0.02451769	0.005877962	4.171	0.0001
out	1	-0.10291444	0.01902420	-5.410	0.0001
nw600	1	-0.12104464	0.02225759	-5.438	0.0001
age_12	1	-0.09964395	0.03397749	-2.933	0.0035
u44	1	-0.01611172	0.01845224	-0.873	0.3831
ce	1	0.07333213	0.02164250	3.388	0.0008

note: the procedure reg used 0.07 seconds and 768k and printed page 5.

```
491        proc reg; model cf=yr79_83 age5 out nw600 age_12 ce;
```

sas 13:46 friday, april 11, 1986 6

No Palisades

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	6	3.03897696	0.50649616	18.865	0.0001
error	427	11.46405592	0.02684791		
c total	433	14.50303288			

root mse 0.1638533 r-square 0.2095

c.v. 26.64501

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.71707807	0.03119500	22.987	0.0001
yr79_83	1	-0.07714964	0.01670755	-4.618	0.0001
age5	1	0.02432730	0.005872282	4.143	0.0001
out	1	-0.10241636	0.01901036	-5.387	0.0001
mw600	1	-0.13076522	0.01926804	-6.787	0.0001
age_12	1	-0.10261517	0.03379725	-3.036	0.0025
ce	1	0.07658867	0.02131278	3.594	0.0004

note: the procedure reg used 0.07 seconds and 768k and printed page 6.

492 proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12
493 mw600 u44 ce;

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No Policies

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	13	3.16882750	0.24375596	9.033	0.0001
~~error~~	~~420~~	~~11.33420539~~	~~0.02698620~~		
c total	433	14.50303288			

root mse	0.1642748	r-square	0.2185
dep mean	0.6149493	adj r-sq	0.1943
c.v.	26.71355		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.71774653	0.03182775	22.551	0.0001
if79	1	-0.07193065	0.03136072	-2.294	0.0223
if80	1	-0.08436547	0.03229318	-2.612	0.0093
if81	1	-0.04858714	0.03199638	-1.519	0.1296
if82	1	-0.07931066	0.03127156	-2.536	0.0116
if83	1	-0.10321012	0.03140878	-3.286	0.0011
if84	1	-0.02350915	0.03054615	-0.770	0.4420
if85	1	0.02049028	0.03132803	0.654	0.5134
age5	1	0.02480373	0.006584621	3.767	0.0002
out	1	-0.10299240	0.01915116	-5.378	0.0001
age_12	1	-0.10121623	0.03592131	-2.818	0.0051
mw600	1	-0.12118558	0.02333692	-5.193	0.0001
u44	1	-0.01536443	0.01854507	-0.828	0.4079
ce	1	0.07296955	0.02178808	3.349	0.0009

note: the procedure reg used 0.09 seconds and 768k and printed page 7.

494 proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12
495 mw600 ce;
496

496

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No Palisades

dep variables: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	12	3.15030423	0.26252535	9.735	0.0001
error	421	11.35272865	0.02696610		
c total	433	14.50303288			

root mse	0.1642136	r-square	0.2172
dep mean	0.6149493	adj r-sq	0.1949
c.v.	26.7036		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.71672413	0.03179197	22.544	0.0001
if79	1	-0.07105570	0.03133125	-2.268	0.0238
if80	1	-0.08315913	0.03224832	-2.579	0.0103
if81	1	-0.04769983	0.03196654	-1.492	0.1364
if82	1	-0.07860857	0.03124843	-2.516	0.0123
if83	1	-0.10249014	0.03138506	-3.266	0.0012
if84	1	-0.02253439	0.03051212	-0.739	0.4606
if85	1	0.02229624	0.03124046	0.714	0.4758
age5	1	0.02447166	0.006569962	3.725	0.0002
out	1	-0.10248486	0.01913423	-5.356	0.0001
age_12	1	-0.10463518	0.03567019	-2.933	0.0035
mw600	1	-0.13077834	0.02025443	-6.457	0.0001
ce	1	0.07594878	0.02148128	3.536	0.0005

note: the procedure reg used 0.08 seconds and 768k and printed page 8.

497 data five: set three;
498 if id=6 then delete;

note: data set work.five has 431 observations and 24 variables. 97 obs/trk.
note: the data statement used 0.05 seconds and 438k.

499 proc reg; model cf=yr79_83 age5 out mw600 age_12 w44 ce;

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No Palisades

dep variables: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	7	3.16427757	0.45203965	18.795	0.0001
error	413	9.93322708	0.02405140		
c total	420	13.09750465			

root mse	0.1550851	r-square	0.2416
dep mean	0.6192898	adj r-sq	0.2287
c.v.	25.04242		

analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	7	3.16427757	0.45203965	18.795	0.0001
error	413	9.93322708	0.02405140		
c total	420	13.09750465			

root mse	0.1550851	r-square	0.2416
dep mean	0.6192898	adj r-sq	0.2287
c.v.	25.04242		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.73117695	0.02991773	24.440	0.0001
yr79_83	1	-0.07060874	0.01612150	-4.380	0.0001
age5	1	0.02346429	0.005606709	4.185	0.0001
out	1	-0.09645443	0.01830140	-5.270	0.0001
mw600	1	-0.13074865	0.02141151	-6.106	0.0001
age_12	1	0.005373720	0.03574602	0.150	0.8806
u44	1	-0.02837636	0.01754759	-1.617	0.1066
ce	1	0.06838158	0.02050689	3.335	0.0009

note: the procedure reg used 0.08 seconds and 768k and printed page 9.

500 proc reg; model cf=yr79_83 age5 out mw600 u44 ce;

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	6	3.16373402	0.52728900	21.975	0.0001
error	414	9.93377062	0.02399462		
c total	420	13.09750465			

root mse	0.154902	r-square	0.2416
dep mean	0.6192898	adj r-sq	0.2306
c.v.	25.01284		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > "t"
intercep	1	0.73154766	0.02978071	24.564	0.0001
yr79_83	1	-0.07080823	0.01604781	-4.412	0.0001
age5	1	0.02359949	0.005527571	4.269	0.0001
out	1	-0.09662865	0.01824309	-5.297	0.0001
mw600	1	-0.13149851	0.02081361	-6.317	0.0001
u44	1	-0.02804765	0.01739027	-1.613	0.1075
ce	1	0.06828203	0.02047199	3.335	0.0009

note: the procedure reg used 0.07 seconds and 768k and printed page 10.

501 proc reg; model cf=yr79_83 age5 out mw600 ce;

501 proc reg; model cf=yr79_83 age5 out mw600 ce;

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No Publication or

EQUATION 2

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	5	3.10131825	0.62026365	25.751	0.0001
error	415	9.99618639	0.02408720		
c total	420	13.09750465			

root mse	0.1552005	r-square	0.2368
dep mean	0.6192898	adj r-sq	0.2276
c.v.	25.06105		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.72823617	0.02976711	24.464	0.0001
yr79_83	1	-0.07031368	0.01607581	-4.374	0.0001
age5	1	0.02307776	0.005528733	4.174	0.0001
out	1	-0.09548602	0.01826447	-5.228	0.0001
mw600	1	-0.14715365	0.01844385	-7.978	0.0001
ce	1	0.07425277	0.02017329	3.681	0.0003

note: the procedure reg used 0.07 seconds and 768k and printed page 11.

502 proc reg; model cf=if79 if80 if81 if82 if83 if84 if85 age5 out age_12
503 mw600 w44 ce;

sas 13:46 friday, april 11, 1986 12

dep variable: cf
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	13	3.25148825	0.25011448	10.339	0.0001
error	407	9.84601639	0.02419169		
c total	420	13.09750465			

root mse	0.1555368	r-square	0.2483
dep mean	0.6192898	adj r-sq	0.2242
c.v.	25.11535		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	0.72890575	0.03040728	23.971	0.0001
if79	1	-0.07794745	0.03021552	-2.580	0.0102
if80	1	-0.08152611	0.03109863	-2.622	0.0091
if81	1	-0.04484847	0.03080092	-1.456	0.1461
if82	1	-0.07652222	0.03008893	-2.543	0.0114
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Nuclear and Large Fossil Unit Operating Experience

NP-1191
Research Project 771-4

Final Report, September 1979

Prepared by

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Nuclear Power Division

Turbine Blades

Blade failures have been the most consequential turbine problem in terms of unit Availability and Capacity Factor losses. The impact of these problems, however, have varied for the different types of turbines. Turbine manufacturers for the units comprising this report's data base are as follows:

Westinghouse Turbines

40 Inch Blades

Calvert Cliffs 2
Ginna
Kewaunee 1
Point Beach 1 and 2
Prairie Island 1 and 2

44 Inch Blades - Generation 1

Cooper 1
Indian Point 2 and 3
Maine Yankee
Palisades
Robinson 2
Salem 1
Surry 1 and 2
Turkey Point 3 and 4

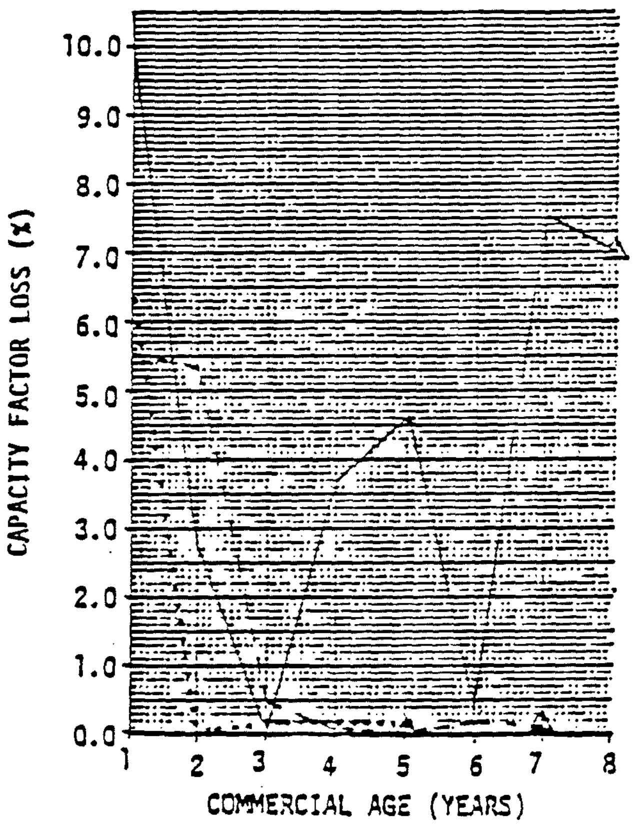
44 Inch Blades - Generation 2

Arkansas 1
Beaver Valley 1
Crystal River 3
Farley 1
Rancho Seco
St. Lucie 1
Zion 1 and 2

General Electric Turbines

Browns Ferry 1, 2, and 3
Brunswick 1 and 2
Calvert Cliffs 1
D.C. Cook 1
Davis Besse 1
Dresden 2 and 3
Duane Arnold
Fitzpatrick
Fort Calhoun 1
Hatch 1
Millstone Point 1 and 2
Monticello
Oconee 1, 2, and 3
Peach Bottom 2 and 3
Pilgrim 1
Quad Cities 1 and 2
Three Mile Island 1
Trojan
Vermont Yankee

It is apparent from the data given in the preceding section of this report that units with Westinghouse turbines have encountered more frequent and much more lengthy outages caused by turbine blade problems than have units with GE turbines. These outages have averaged 586.7 EFPHs lost per outage at units with Westinghouse turbines and only 79.7 EFPHs lost per outage at units with GE turbines. The majority of outages reported as GE turbine blade problems have been relatively brief shutdowns for vibration problems or balancing. GE turbines in this report's data base have experienced only one blade failure that resulted in a lengthy outage. Westinghouse turbines, however, have had many lengthy blade failures. Losses caused by those blade problems are plotted in Figures 7-31 and 7-32, and a summary of the turbine blade failures for the different types of turbines follows:



Westinghouse Blade Problems

40" Turbines ——
44" Gen. 1 Turbines - -
44" Gen. 2 Turbines ...

Data only through 197
but 40" turbines have wo
performance record than
44" turbines

NOTE:
△ Because of limited data for this year, the losses are weight-averaged with the adjacent years.

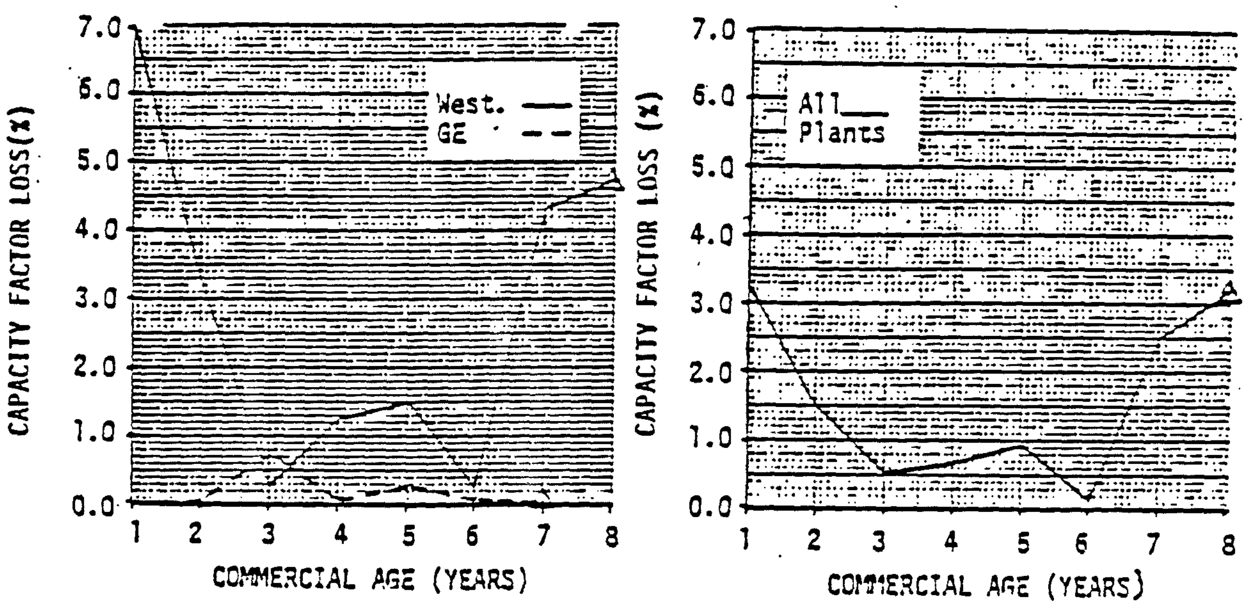


FIGURE 7-31: LOSSES FROM
TURBINE BLADE PROBLEMS
(Including vibration and balancing)

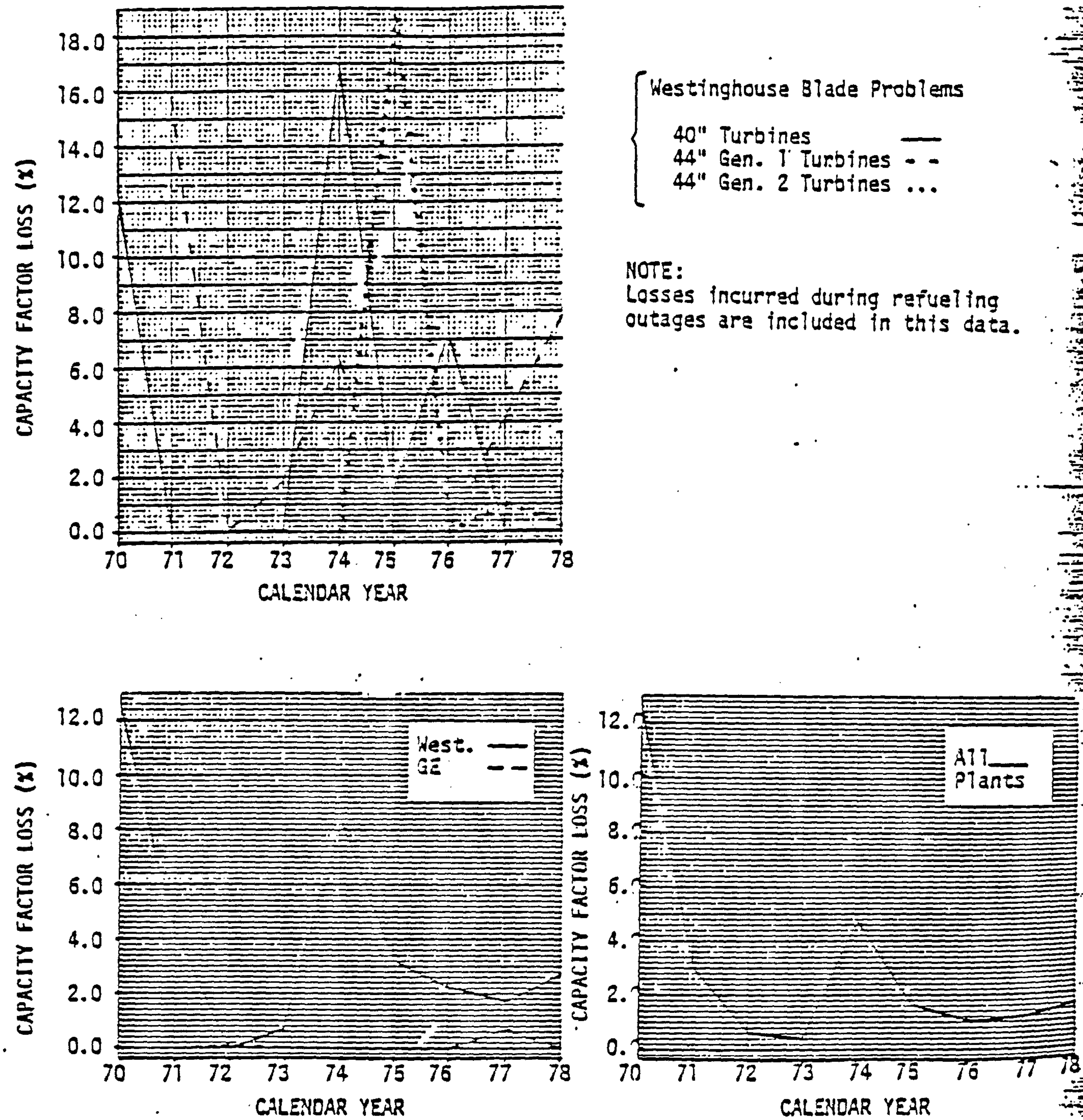


FIGURE 7-32: LOSSES FROM
TURBINE BLADE PROBLEMS
(Including vibration and balancing)

Nuclear Unit Operating Experience: 1980 Through 1982 Update

NP-3480
Research Project 2183-4

Final Report, April 1984

Prepared by

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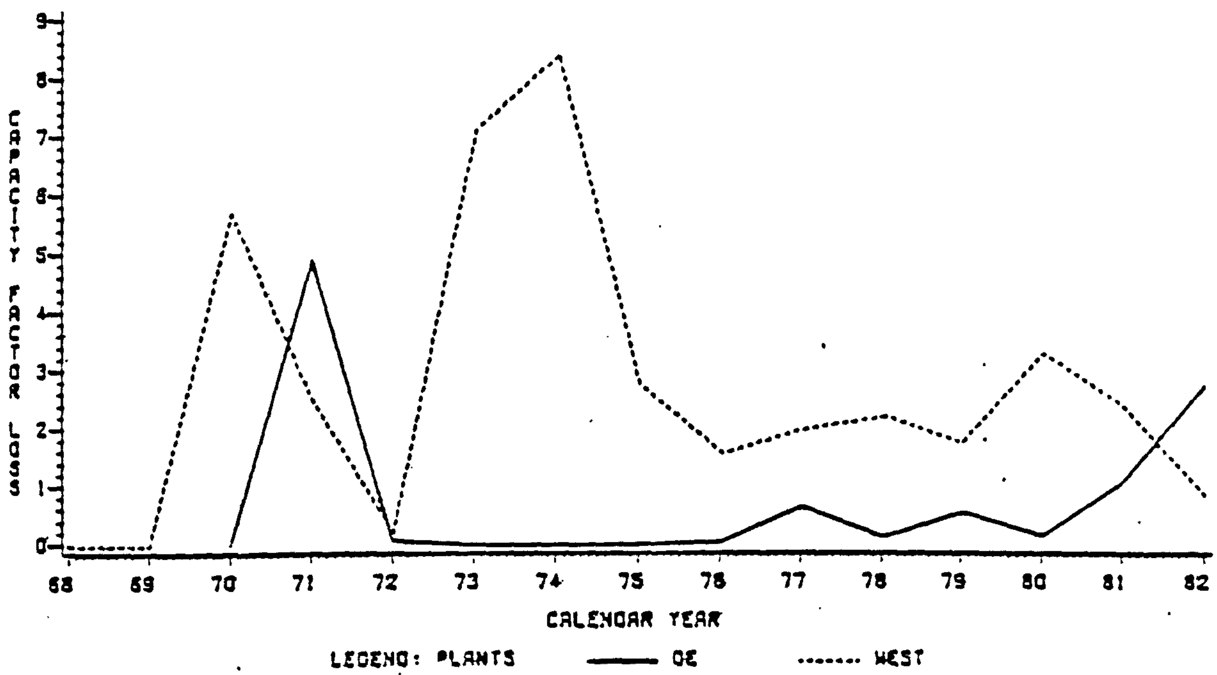
FIGURE 4-13
TURBINE BLADES AND ROTORS BY VENDOR
CAPACITY FACTOR LOSS BY CALENDAR YEAR



Data through 1982, Westinghouse turbines have clearly had a larger negative effect on capacity factors than other turbines

TABLE 6.2: PWR CAPACITY FACTOR REGRESSIONS

	Equation 1		Equation 2	
	Coef	t-stat	Coef	t-stat
CONSTANT	73.19%	23.0	72.52%	24.5
MW600 [1]	-11.41%	-5.0	-14.72%	-8.0
AGE5 [2]	2.31%	3.3	2.31%	4.2
AGE_12 [3]	-10.39%	-3.2	--	--
OUT [4]	-10.01%	-5.2	-9.55%	-5.2
W44 [5]	-3.59%	-1.9	--	--
YR79_83 [7]	-7.16%	-4.2	-7.03%	-4.4
CE [8]	--	--	7.43%	3.7
ADJUSTED R-SQ		0.176		0.228
F STATISTIC		16.9		23.3
OBSERVATIONS [9]		447		421

Notes: Equation 1 was run on all data. Equation 2 excludes data from Palisades and San Onofre 1.

[1] MW600 = 1, if Design Electrical Rating (DER) > 600 MW; 0 otherwise.
[2] AGE5 = minimum of AGE (years from COD to middle of current year), and 5.
[3] AGE_12 = 1, if AGE >= 12; 0 otherwise.
[4] OUT = number of refuelings in year, including other single outages lasting more than 3 months (OUT usually equals 0 or 1).
[5] W44 = 1, if unit contains Westinghouse 44" turbine; 0 otherwise.
[6] Indicator = 1 in this year; 0 otherwise.
[7] YR79-83 = 1, if between 1978 and 1984; 0 otherwise.
[8] CE = 1, if Combustion Engineering is the NSSS; 0 otherwise.
[9] Full calendar years of PWR operation, 1973-85.

APPENDIX F:

CAPITAL ADDITIONS ANALYSIS

CAPITAL ADDITIONS ANALYSIS

Paul Chernick
Joanna Wroblewska
Candae Wills

APPENDIX F: CAPITAL ADDITIONS ANALYSIS

INTRODUCTION

Capital Additions expenditures have always been difficult to analyze because of the large amount of annual variability in the historical data. For this reason, regression analysis has seemed inappropriate for the estimation of future capital additions. Our first approach to this problem was to calculate yearly averages of the capital additions data, which indicated a general time trend. By narrowing the comparison group of plants to those which had similar experiences to the plant in question, it was possible to project the recent experience of the comparison group into the future. Table 1 displays the results of these calculations.

We were recently asked to project the capital additions expenditures of one plant in particular, Palo Verde Nuclear Generating Station. PVNGS will eventually have three units, each sharing a common plant and each with the same size of 1270 MW. This is the largest plant ever to be built, which makes it difficult to choose a cohort with which to compare it. Only three plants have been completed with three units: Browns Ferry, Dresden, and Oconee. To use only this small group for comparison would be unwise. In addition, one of the Dresden units is very old and small. The other two Dresden units and all three Oconee units are only two-thirds as large as the PVNGS units. As an alternative, we determined that it is reasonable to look at the entire dataset for comparable experience, as long as certain variables were identified. We decided that the best method for making projections for an extreme plant such as PVNGS is to find a regression equation which represents the effects of various variables on capital additions costs.

VARIABLES

Total Capital Additions, our dependent variable, have been estimated as the change in book plant cost from the FERC Form 1 or comparable sources. All available capital additions data were converted to 1983 dollars.

In designing our regression equation, we decided it was essential to include the following independent variables:

1) Size (MW): We suspected that economies of scale exist in capital additions expenditures. As the size of a plant increases in MW, the capital additions for the plant would be expected to increase, but at a decreasing rate.

2) Units: We also suspected that economies of duplication exist in capital additions expenditures. As the number of units increases, capital additions should also increase, again, at a decreasing rate.

3) Year: We predicted that the amount of capital additions would rise significantly following the Three Mile Island accident in 1979. To measure this effect, we created dummy variables for each year following the TMI accident.

Table 2 lists all variables used in our regression equations.

Regressions

We began our regression analysis of capital additions with a linear model, using size # (MW), units, and year indicators as the independent variables. Our first step was to find the years which significantly affected capital additions expenditures. We initially included AFT78 in our equation, a dummy variable for all years after and including the year of the TMI accident. However, an examination of the individual years after 1978 indicated that capital additions increased following the TMI accident, but that the magnitude of the increase was not constant over time. After eliminating all insignificant year variables from our model, we were left with the years 1980, 1981, 1982, 1983, and 1984. These are represented in our equations as IF80, IF81, IF82, IF83, and IF84.

Our next step was to examine the size variables, MW and units. With size # (MW), unit, and IF80-84 as the independent variables in a linear model, all variables were significant, except for units. The coefficient for units was actually negative, indicating that additional units reduced the amount of capital additions (see Equation 1, Table 3). This was apparently a spurious result of the small amount of data for plants with three units in our database. In an attempt to eliminate this counter-intuitive effect, we normalized our equations by dividing capital additions and size # (MW) by the number of units. Our independent variables became MW/unit, units, and IF80-84, with capital additions/unit as the dependent variable. The results of our regressions with normalized equations (Equation 2) indicate that all variables were significant. However, the r-squared value was quite low for this model.

In addition to the low r-squared value in this model, we were equally dissatisfied with the theoretical explanation offered by a linear model. For example, the coefficient for MW/Unit indicates that each additional MW causes capital additions expenditures/unit to rise by $15.66 thousand, while the coefficient for units indicates that capital additions/unit decreases by $7,918 thousand with each additional unit. The coefficients remain the same for plants of large MW size and for plants with many units. These numbers suggest that a 12 unit plant with 600 MW/Unit would have negative capital additions expenditures, which is a rediculous assumption. However, as discussed earlier, we suspected that capital additions expenditures/unit increase with each additional MW, but at a decreasing rate, and that capital additions/unit decrease with each additional unit, also at a decreasing rate. Therefore, our model would not adequately explain the effects of economies of scale and duplication in capital additions expenditures. To improve the theoretical explanation in our model, we experimented with a series of log and semi-log models.

To capture the effect of economies of scale and duplication, we first ran a regression using the log of capital additions/unit as the dependent variable and the log of MW/Unit and the log of units as the independent variables (Equation 3). This linear log model specification would produce constant economies of scale, but the significance and explanitory power of the results were very poor.

To capture some non-linearities in economies of scale and duplication and avoid the problems of a linear log model, we tried a semi-log model, in which we regressed capital additions/unit on the log of MW/unit, with units and year indicators as additional independent variables (Equation 4). The results were consistant with our expectations and slightly improved from the linear model. We tried a second semi-log model, in which we regressed capital additions/unit on the log of units, MW/Unit, and the year indicators (Equation 5). This model was equally significant and consistant with our predictions. Our final model regressed capital additions/unit on the log of MW/Unit, the log of units, and the year indicators (Equation 6).

Based on t-statistics and the value of r-squared, the semi-log model in Equation 6 appears to be the best model. More importantly, the model in Equation 6 is most consistant with our theoretical assumptions of the effects of size and units on capital additions expenditures. For these reasons, we have chosen Equation 6 to forecast capital additions expenditures for PVNGS.

Table 1: Yearly Average Capital Additions by Number of Units

ALL DATA

All years before and including:	Capital Additions per MW (1983$) 1 unit	2 units	3 units	Capital Additions per unit (1983$) 1 unit	2 units	3 units
72	1.00		27.63	879		17175
73	9.96	26.02	-7.57	5853	16051	-4703
74	12.92	6.95	2.06	6452	5423	1282
75	9.28	7.96	5.31	5328	6288	3634
76	18.07	8.38	3.99	8137	8029	2654
77	24.00	9.49	4.30	12978	8024	3585
78	22.31	6.11	9.68	15461	5234	8522
79	18.48	6.97	4.64	12830	6306	3312
80	32.80	21.16	4.54	22171	19020	3365
81	38.03	24.63	2.47	23805	21773	2049
82	35.53	20.68	8.38	23479	18322	6820
83	40.17	19.72	3.86	27252	17848	3372
84	58.33	20.54	35.56	42104	16100	28181

ALL PLANTS > 800 MW PER UNIT

All years before and including:	Capital Additions per MW (1983$) 1 unit	2 units	3 units	Capital Additions per unit (1983$) 1 unit	2 units	3 units
72						
73	38.90	15.96		31545	13213	
74	26.82	10.66		21792	8889	
75	19.72	7.50	0.17	16608	7099	149
76	5.31	8.79	1.33	4062	9681	1178
77	12.78	8.75	6.89	11504	9329	6110
78	25.94	6.88	7.34	22679	6609	8317
79	16.75	7.97	1.99	16409	7895	1880
80	27.97	26.49	2.72	26990	24473	2508
81	28.33	28.67	2.54	28014	26537	2350
82	24.80	17.66	5.72	23641	17022	5976
83	28.37	19.02	3.48	25877	18418	3628
84	39.87	16.14	18.92	37044	13735	20870

TABLE 2: VARIABLES USED FOR ANALYSIS OF CAPITAL ADDITIONS EXPENDITURES

Variable	Description	Source
UNITS	Number of units in the same plant	[1]
MW	Maximum Generator Nameplate	[1]
MWPUN	MW/UNITS; MW per unit	Calculated
YEAR	Calender Year	[1]
AFT78	Dummy variable indicating whether datapoint occurs after 1978	[1]
IF8#	Dummy variable indicating whether datapoint is from given year(80-84 only)	[1]
CA83	Capital additions in 1983 dollars	[1,2]
CA83PUN	CA83/UNITS; Capital Additions per unit	Calculated

Sources:

[1] Energy Information Administration, Historical Plant Cost and Annual Production Expenses for Selected Electric Plants, DOE/EIA-0455, annual to 1983. 1984 data from FERC Forms No. 1, for individual utilities.

[2] Handy Whitman Index of Public Utility Construction Costs.

TABLE 3: REGRESSION EQUATIONS FOR PREDICTING CAPITAL ADDITIONS ($1983 THOUSAND)

	Equation 1		Equation 2		Equation 3		Equation 4		Equation 5		Equation 6	
	CA83		CA83PUN		CA83PUN		CA83PUN		CA83PUN		ln(CA83PUN)	
	Coeff.	t-stat	Coeff.	t-stat	Coeff.	t-stat	Coeff.	t-stat	Coeff.	t-stat	Coeff.	t-stat
Intercept	9215	2.6	8324	2.9	10.92	0.216	-23622	-2.8	311	0.1		-3.7
MW	10.58	3										
ln(MW)												
MWPUN			15.66	4.4					16.02	4.4		
ln(MWPUN)					0.058	0.035	6671.3	4.8			6776.7	4.8
UNITS	-6754	-1.6	-7918	-4.5			-7743	-4.5				
ln(UNITS)					-0.166	0.07			-13039	-4.6	-12960	-4.5
IF80	14081	3	11098	3	0.131	0.09	11201	3.1	11106	3	11221	3.1
IF81	16756	3.6	13025	3.6	0.141	0.09	13085	3.6	13061	3.6	13131	3.6
IF82	15397	3.4	11474	3.3	0.143	0.09	11585	3.3	11540	3.3	11667	3.4
IF83	16893	3.7	13210	3.8	0.135	0.09	13383	3.8	13320	3.8	13508	3.9
IF84	28836	6.3	22574	6.4	0.002	0.09	22730	6.5	22692	6.4	22861	6.5
Adjusted R-sq.	0.142		0.158		0.0139		0.164		0.159			
F-Statistic	13.2		14.9		2.05		15.5		15			

TABLE 4: CAPITAL ADDITIONS PROJECTIONS

LINEAR (CAPITAL ADDITIONS/UNIT)

Constant:	8323.73
MW/UNITS:	15.66
Units:	-7918.21
Avg 80-84:	14276

	Unit 1	Unit 2	Unit 3
Per Unit	$34,570	$26,652	$18,733
PVNGS Total	$34,570	$53,303	$56,200
Incremental	$34,570	$18,733	$2,897

LN(MW/UNIT)

Constant:	-23621.8
MW/UNITS:	6671.86
Units:	-7743.18
Avg 80-84:	14396.57

	Unit 1	Unit 2	Unit 3
Per Unit	$30,714	$22,971	$15,227
PVNGS Total	$30,714	$45,941	$45,682
Incremental	$30,714	$15,227	($259)

LN(UNITS)

Constant:	311.29
MW/UNITS:	16.02
Units:	-13038.6
Avg 80-84:	14343.92

	Unit 1	Unit 2	Unit 3
Per Unit	$35,001	$25,963	$20,676
PVNGS Total	$35,001	$51,926	$62,028
Incremental	$35,001	$16,925	$10,103

LN(UNITS) and LN(MW

Constant:	-31904.6
MW/UNITS:	6776.68
Units:	-12690.1
Avg 80-84:	14477.57

	Unit 1	Unit 2	Unit 3
Per Unit	$31,004	$22,208	$17,063
PVNGS Total	$31,004	$44,416	$51,188
Incremental	$31,004	$13,412	$6,772

LN(UNITS)

Constant:	9215.37
MW/UNITS:	10.58
Units:	-6753.65
Avg 80-84	18392.5

	Unit 1	Unit 2	Unit 3
Per Unit:	$34,291	$20,487	$15,886
PVNGS Total:	$34,291	$40,974	$47,657
Incremental:	$34,291	$6,683	$6,683

TABLE 5: Comparison of Predictions with Actuals for Existing 3-Unit Plants

Plant	Year	MW	Cap. Add's 1983 $	Cap. Add's per unit	# of Units	Predicted Cap. Add's per unit	Predicted minus Actual
Browns Ferry 1&2	75	2304	.		2		
Browns Ferry 1&2	76	2304	66749	33374	2	7070	-26305
Browns Ferry 1,2,3	77	3456	.		3		
Browns Ferry 1,2,3	78	3456	47072	15691	3	1924	-13766
Browns Ferry 1,2,3	79	3456	3092	1031	3	1924	894
Browns Ferry 1,2,3	80	3456	2485	828	3	13146	12317
Browns Ferry 1,2,3	81	3456	2503	834	3	15055	14221
Browns Ferry 1,2,3	82	3456	23404	7801	3	13591	5790
Browns Ferry 1,2,3	83	3456	13976	4659	3	15432	10774
Browns Ferry 1,2,3	84	3456	106449	35483	3	24785	-10698
					Average Residual:		-847

Plant	Year	MW	Cap. Add's 1983 $	Cap. Add's per unit	# of Units	Predicted Cap. Add's per unit	Predicted minus Actual
Oconee 1	73	886	.		1		
Oconee 1,2,3	74	2660	.		3		
Oconee 1,2,3	75	2660	446	149	3	150	2
Oconee 1,2,3	76	2660	3534	1178	3	150	-1028
Oconee 1,2,3	77	2660	18331	6110	3	150	-5960
Oconee 1,2,3	78	2661	2832	944	3	153	-791
Oconee 1,2,3	79	2661	8187	2729	3	153	-2576
Oconee 1,2,3	80	2661	12560	4187	3	11374	7187
Oconee 1,2,3	81	2666	11598	3866	3	13297	9431
Oconee 1,2,3	82	2666	12454	4151	3	11832	7681
Oconee 1,2,3	83	2667	7791	2597	3	13675	11078
Oconee 1,2,3	84	2667	18768	6256	3	23028	16772
					Average Residual:		4180

note: the procedure sort used 0.12 seconds and 1516k.

442 proc reg; model callout=income limits lf80 lf81 lf82 lf83 lf84;
443 output out=tmp r=resid;

dep variable: callout
analysis of variance

source	df	sum of squares	mean square	f value	prob>f
model	7	51918742402	7416963200	15.591	0.0001
error	512	[illegible]	475726258		
c total	519	[illegible]			

root mse	21811.15	r-square	0.1757
dep mean	14375.12	adj r-sq	0.1644
c.v.	151.7283		

parameter estimates

variable	df	parameter estimate	standard error	t for h0: parameter=0	prob > |t|
intercep	1	-31904.61971	8576.82055	-3.720	0.0002
income	1	6776.12408	1398.03468	4.847	0.0001
limits	1	-12690.14977	2793.20592	-4.543	0.0001
lf80	1	11271.38461	3623.73233	3.097	0.0021
lf81	1	13131.11716	3824.46992	3.423	0.0008
lf82	1	11666.55565	3475.55555	3.357	0.0008
lf83	1	13507.92701	3482.30028	3.879	0.0001

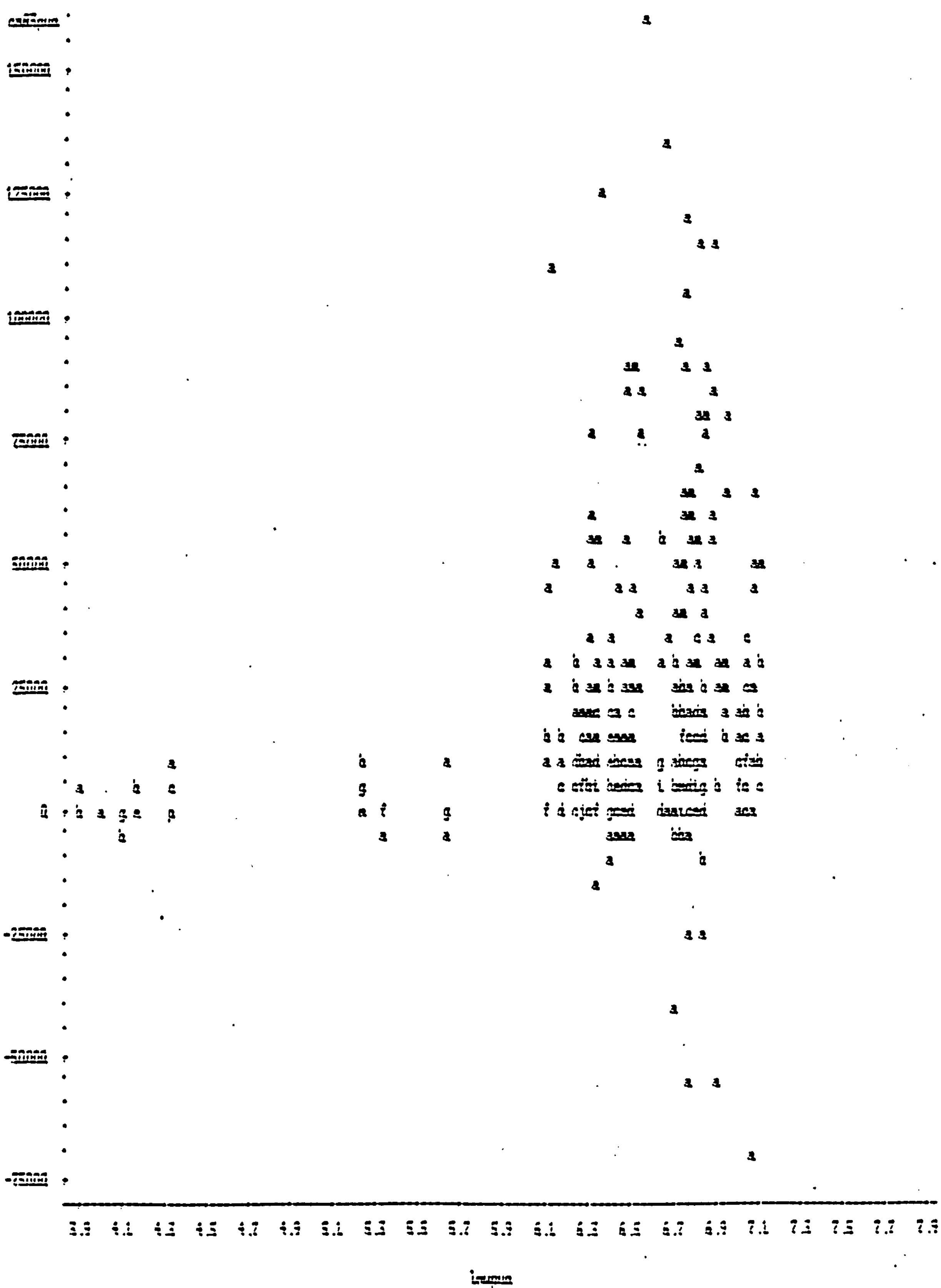
note: the data set work.tmp has 520 observations and 11 variables. 79 obs/trk.

lf84	1	22860.81203	3514.85627	6.504	0.0001

note: the procedure reg used 0.16 seconds and 974k and printed page 1.

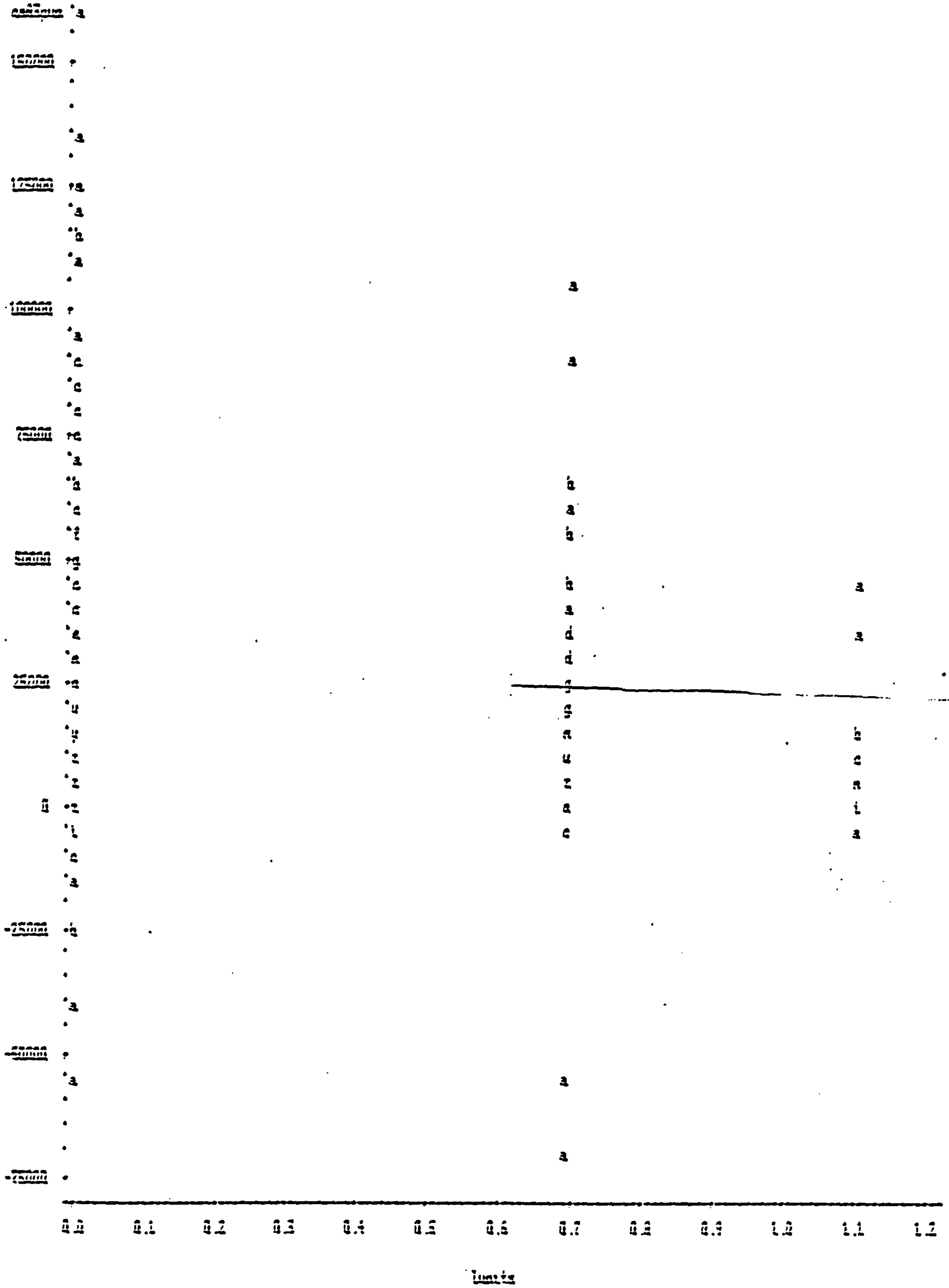
444 proc chart; vbar resid;

plot of calcium*lnmum   legend: a = 1 obs, b = 2 obs, etc.



note: 99 obs had missing values
note: the procedure plot used 0.08 seconds and 712k and printed page 7.

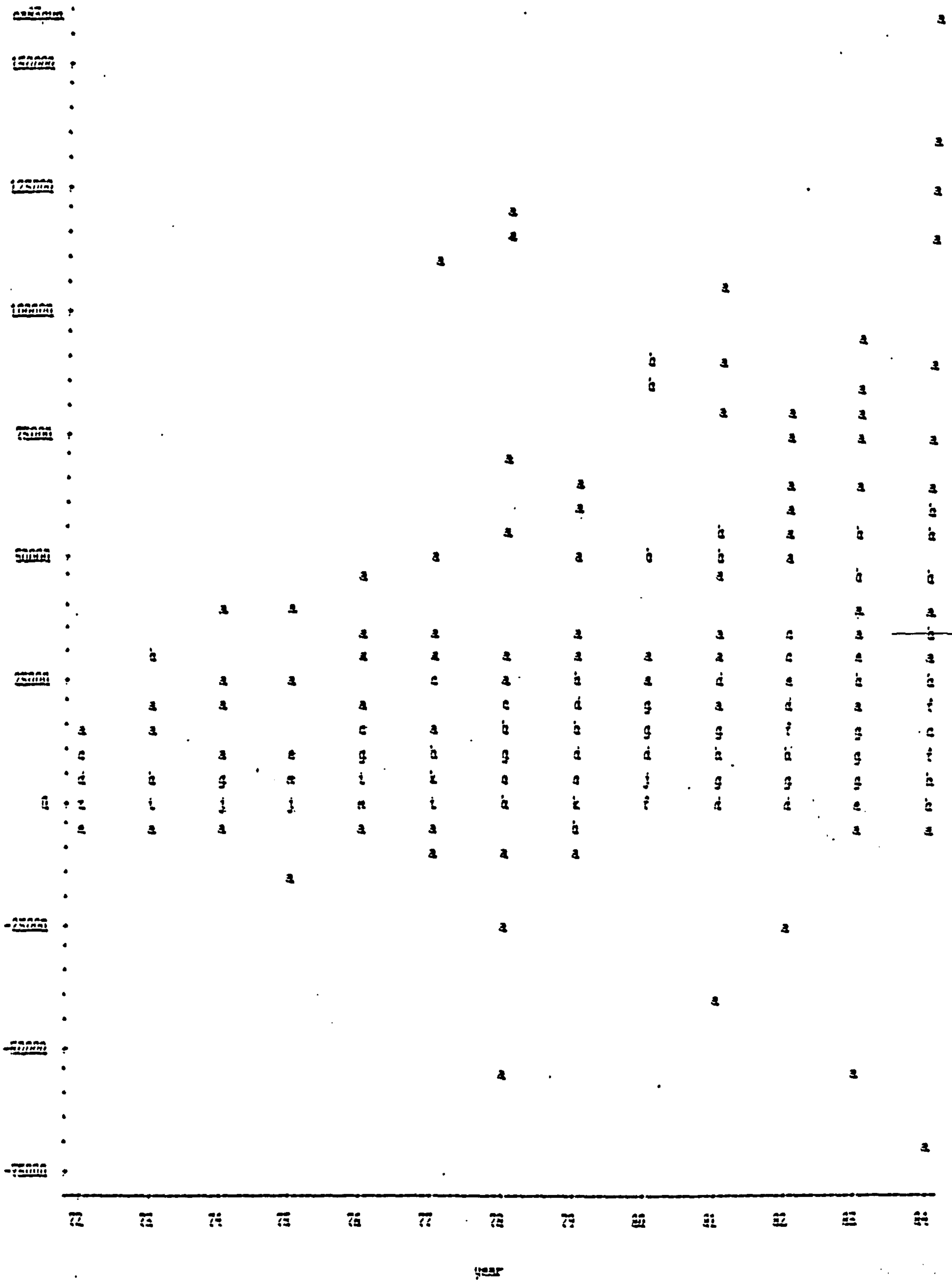
plot of cd40pure*lunits   legend: a = 1 obs, b = 2 obs, etc.



note: 98 obs had missing values   157 obs hidden
note: the procedure plot used 0.08 seconds and 712k and printed page 4.

667   proc plots; plot cd40pure*years;

plot of cashflow*year legend: a = 1 obs, b = 2 obs, etc.



note: [illegible] obs had missing values [illegible] obs hidden
note: the procedure plot used [illegible] seconds and [illegible]k and printed page [illegible].
note: sas used [illegible]k memory.

note: sas institute inc.

APPENDIX G:

OPERATIONS AND MAINTENANCE ANALYSIS

OPERATIONS & MAINTENANCE ANALYSIS

Paul Chernick
Joanna Wroblewska
Candae Wills

APPENDIX G: O&M REGRESSION ANALYSIS

This appendix summarizes the results of our statistical analysis of operation and maintance (O&M) expenditures at domestic nuclear power plants. The purpose of our analysis is prediction of future O&M expenditures at new and existing units, from regression estimates based on historical data.

The non-fuel O&M expenditures were assembled for all commercial light water reactors operating since 1968. Data is available through 1984. Years in which new nuclear units were added were excluded from the analysis, so each observation represents a full year's O&M. The total number of observations is 535. This data was converted to 1983 dollars by inflating (or deflating) with the implicit GNP deflator.

VARIABLES

Our dependent variable was O&M expenditures in 1983 GNP dollars. The following variables were expected to affect O&M and thus ought to be included in the model:

Size -- There is a wide range of sizes of nuclear plants. Individual units in our database range from 50 MW to 3456 MW. A positive relationship between O&M expenditures and MW would be expected both from past observations and from first principle: larger units (or plants) have more and larger components, which should cost more to maintain and operate.

As the size of a plant or a unit increases, so do the expenditures (see Plot 1, Attachment 1). However, there should also be some economies of scale: O&M should increase less rapidly than size.

Units -- Most plants consist of 1 or 2 units: only three plants have had 3 operating units, and 3-unit plants constitute only 28 observations. Including in the model the number of units per plant allows us to determine whether a change in MW caused by an increase in the number of units has the same cost implications as the same MW change due to the size of the units in the plant. We suspected that two small units would require more O&M than one large unit of equal total MW size, but our prior beliefs were not strong.

Year -- Nuclear O&M expenditures have been increasing rapidly over time, so the variable YEAR was included in the model to capture the effect of time on O&M. A positive relationship between YEAR and O&M is visible in Plot 3 in Attachment 1.

Table E-1 lists all the variables used in our regressions.

REGRESSION SPECIFICATION

We expected a non-linear relationship between the size of a plant (or of a unit if size is measured in MW/unit) and O&M expenditures, and between a number of units and O&M. O&M expenditures (and most other costs) are not directly proportional to the size of a plant. Increasing size by a constant amount (say 100 MW) is not likely to increase the O&M expenditures by a constant dollar amount each time. Instead, it is reasonable to assume a constant elasticity of O&M expenditures with respect to size. In other words, increasing the size of a plant (or a unit) by a certain percentage will change the expenditures by a constant percentage each time. This is the standard assumption of constant economies of scale, which implies a linear relationship between the logs of the variables. The assumption can be verified by comparing plots 1 and 2 in Attachment 1. The former is the plot of O&M per unit against MW per unit. The relationship is positive, but non-linear. Plotting ln(O&M per unit) against ln(MW per unit) shows a positive and linear relationship, which confirms our expectation.

Similarly, the relationship between the number of units and the O&M expenditures is not likely to be linear.. Increasing the number of units from 1 to 2 and from 2 to 3 will probably not produce the same absolute increments in the O&M expenditures. It seems reasonable to suspect that each additional unit will increase O&M by a smaller amount.

The above effects are best captured by a log-linear model: we estimated coefficients for three versions, the results of which are listed in Attachment 2. Coefficients in a regression of ln(O&M) on ln(MW) and ln(UNITS) represent the constant elasticities of O&M with respect to MW and UNITS, i.e. the percentage changes in O&M with a percentage change in MW and UNITS, respectively. When both ln(MW) and ln(UNITS) are included in the equation (see Equation 1 in Table G-2) as explanatory variables, the latter is insignificant. Once the number of megawatts is accounted for, the number of units makes little difference. In other words, the coefficient of MW captures most of the effect of the number of units.

In order to estimate the separate effects, we used ln(MW/unit) instead of ln(MW) in Equations 2 and 3. In both equations ln(UNITS) had a positive coefficient, and the variable was significant.

The variable YEAR was included in the model in a linear form, which assumes that there has been a constant growth rate rather than a constant elasticity of O&M over time.[1] YEAR was significant in all the equations. Our assumption can be verified by plotting YEAR against O&M, as in Plot 3. O&M expenditures (even after inflation is removed) evidently increase with time, and the increments increase over the year. A plot of year against ln(O&M), Plot 4, looks linear, implying a constant rate of growth of O&M over time. To test the constancy of the growth rate over time, we ran an equation with dummy variables for each year from 1969 to 1984n. The estimated coefficients at the dummies were then plotted against the respective years (see Plot 5 in Attachment 1). The graph shows clearly that not only do O&M costs rise every year, but the increments lie on an almost straight line from 1971 to 1984.

----

1. A constant elasticity of O&M with respect to time is not a natural concept. Since time has no obvious zero point, it is not clear what a "percentage increase in time" would mean.

Equation 3 also tests for a separate effect of a plant's location. Previous studies have found that nuclear plants located in the Northeast cost more to build and to operate than other plants. A Northeast dummy variable (NE) was included in the model. NE equals 1 if a plant is located in the Northeast and 0 otherwise. Although other coefficients did not change very much, the variable is highly significant.

The value of R-squared in Equation 3 is relatively high, indicating that most of the variation in O&M is explained by the explanatory variables. All the variables are highly significant, both separately and jointly, as indicated by the F-statistic.

TABLE G-1: VARIABLES USED IN REGRESSION ANALYSIS OF NON-FUEL O&M

Variable	Description
O&M	operation and maintenance expenditures in 1983 dollars.
MW	number of megawatts in Design Electrical Rating.
UNITS	number of units in a plant.
YEAR	calendar year - 1900.
NE	a dummy variable measuring whether the plant is located in the Northeast region. NE-1 if located in the Northeast, NE-O otherwise.

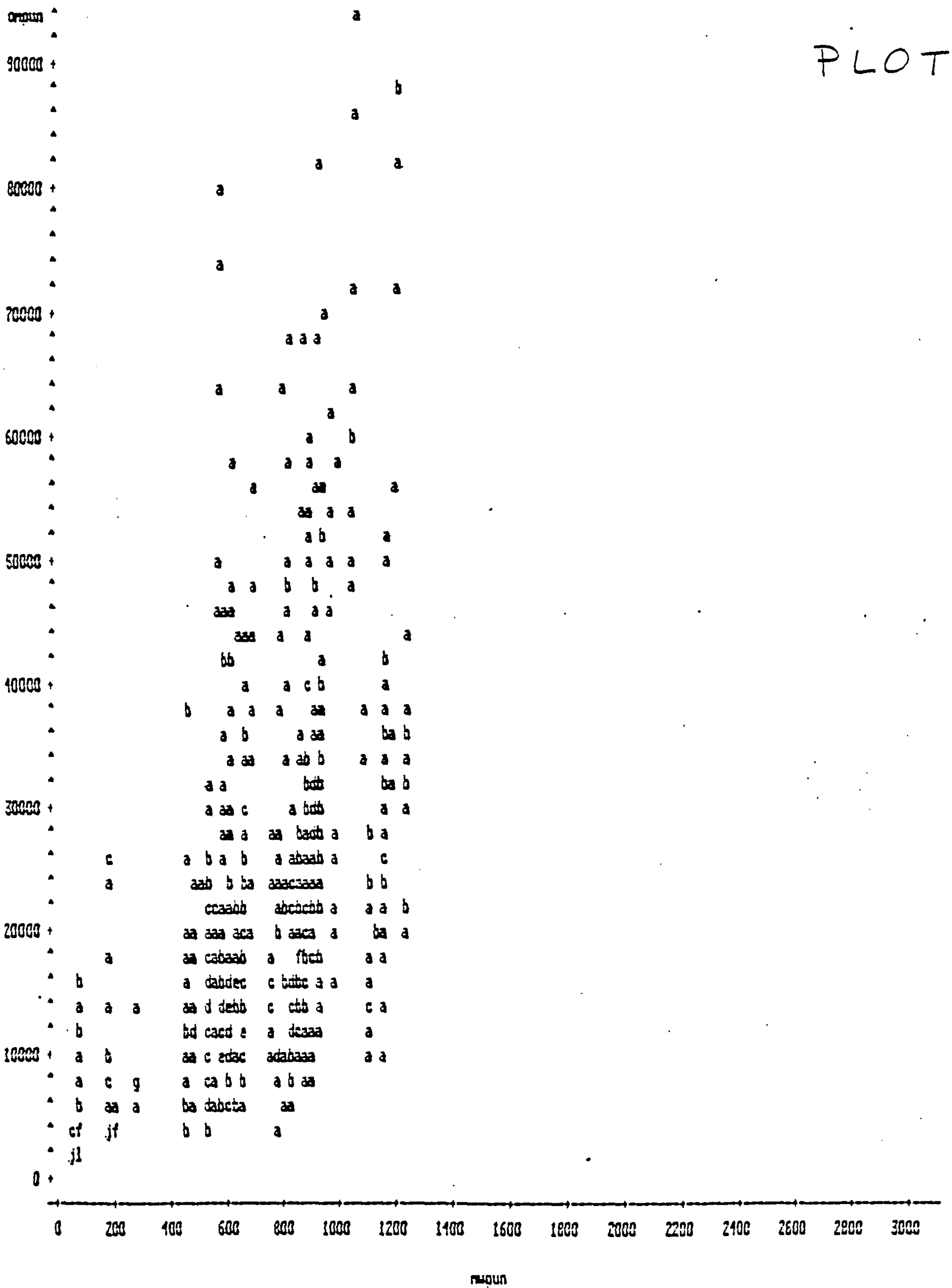
636 proc plot; plot ompun*mwoun;
637

sas 11:40 tuesday, july 1, 1986 2

Attachment 1

PLOT 1

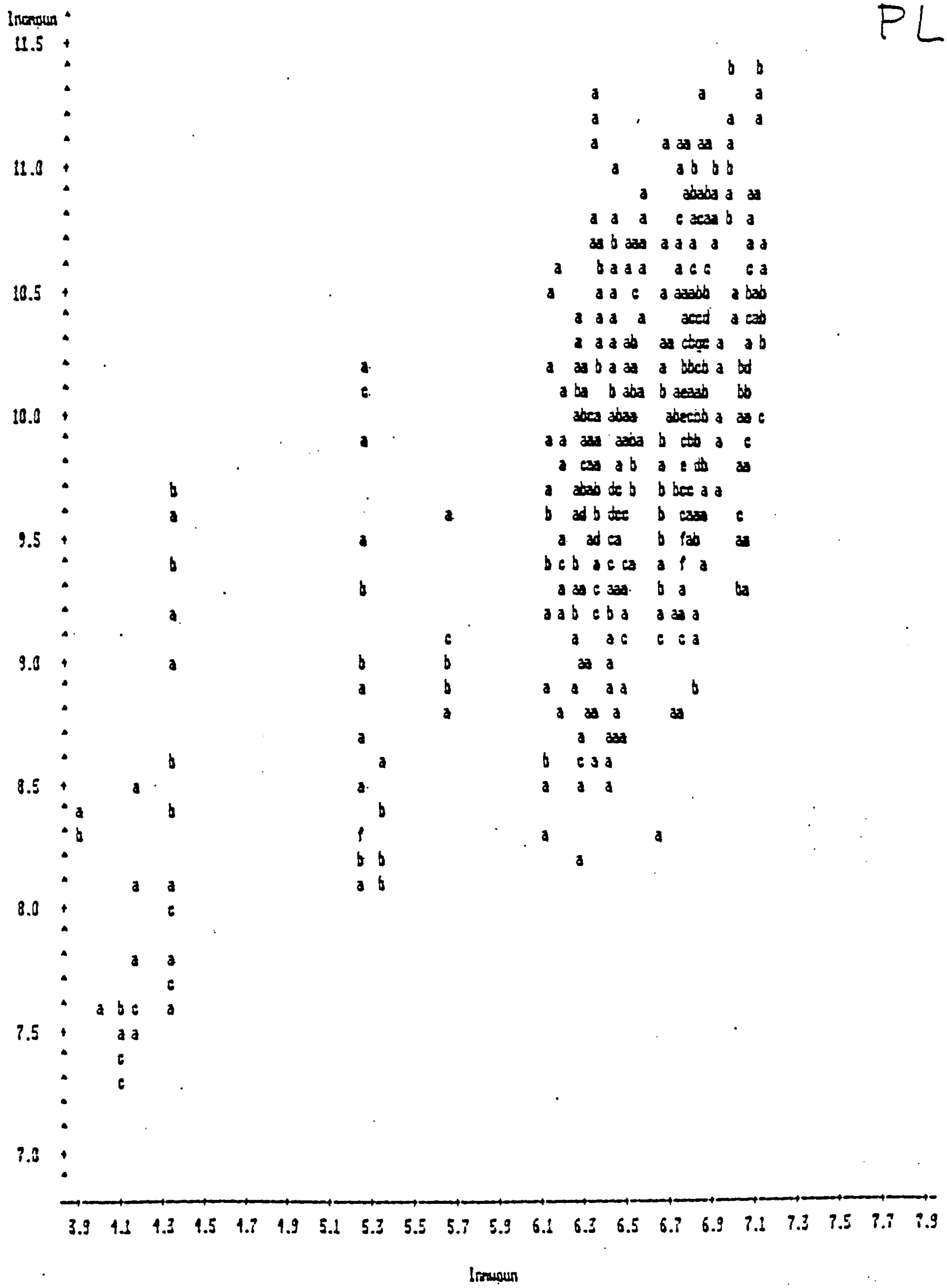
plot of ompun*mwoun legend: a = 1 obs, b = 2 obs, etc.



note: 82 obs had missing values
note: the procedure plot used 0.08 seconds and 718k and printed page 2.
note: sas used 718k memory.

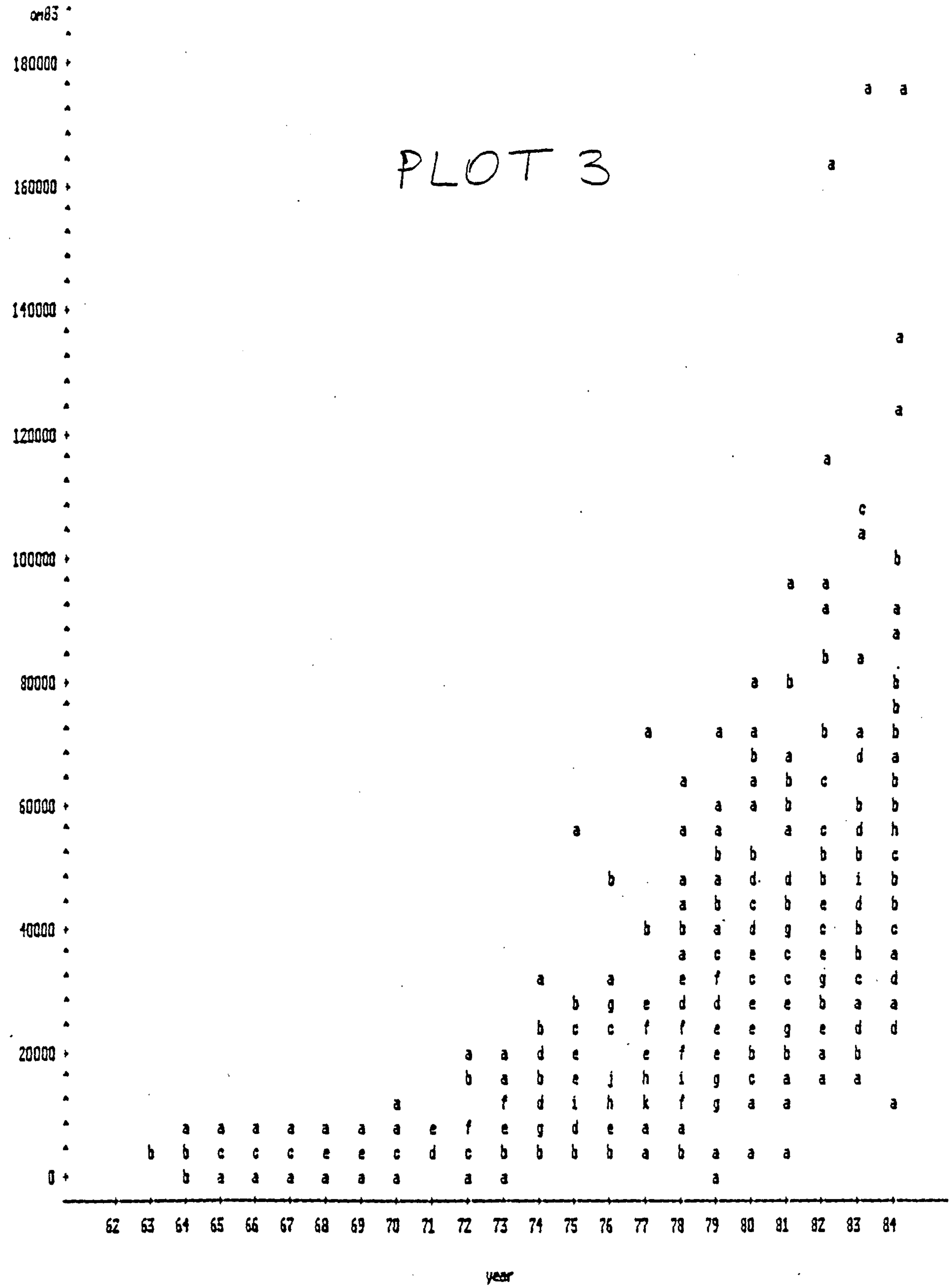
plot of lncmoun*lnmuoun legend: a = 1 obs, b = 2 obs, etc.

PLOT 2



note: 82 obs had missing values
note: the procedure plot used 0.09 seconds and 712k and printed page 1.

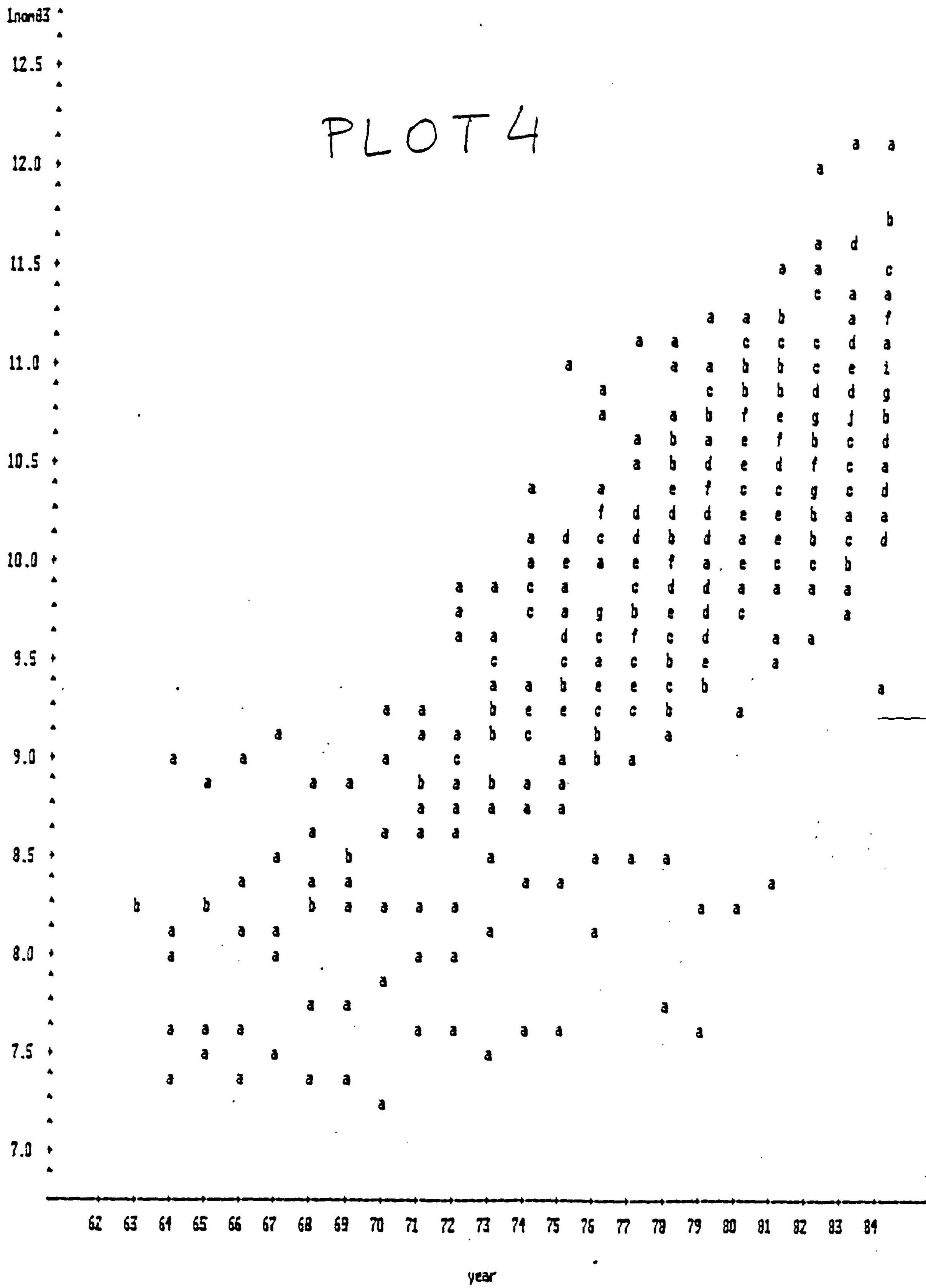
636 proc plot; plot cmoun*muoun;
637




```
note:     82 obs had missing values
note: the procedure plot used 0.07 seconds and 718k and printed page 10.

644       data two; set one; if nw>300;

note: data set work.two has 528 observations and 12 variables. 171 obs/trk.
note: the data statement used 0.04 seconds and 582k.

645       proc reg; model lnom83=ne lnwoun lnunits year;
```

plot of lnom83*year   legend: a = 1 obs, b = 2 obs, etc.

PLOT 4

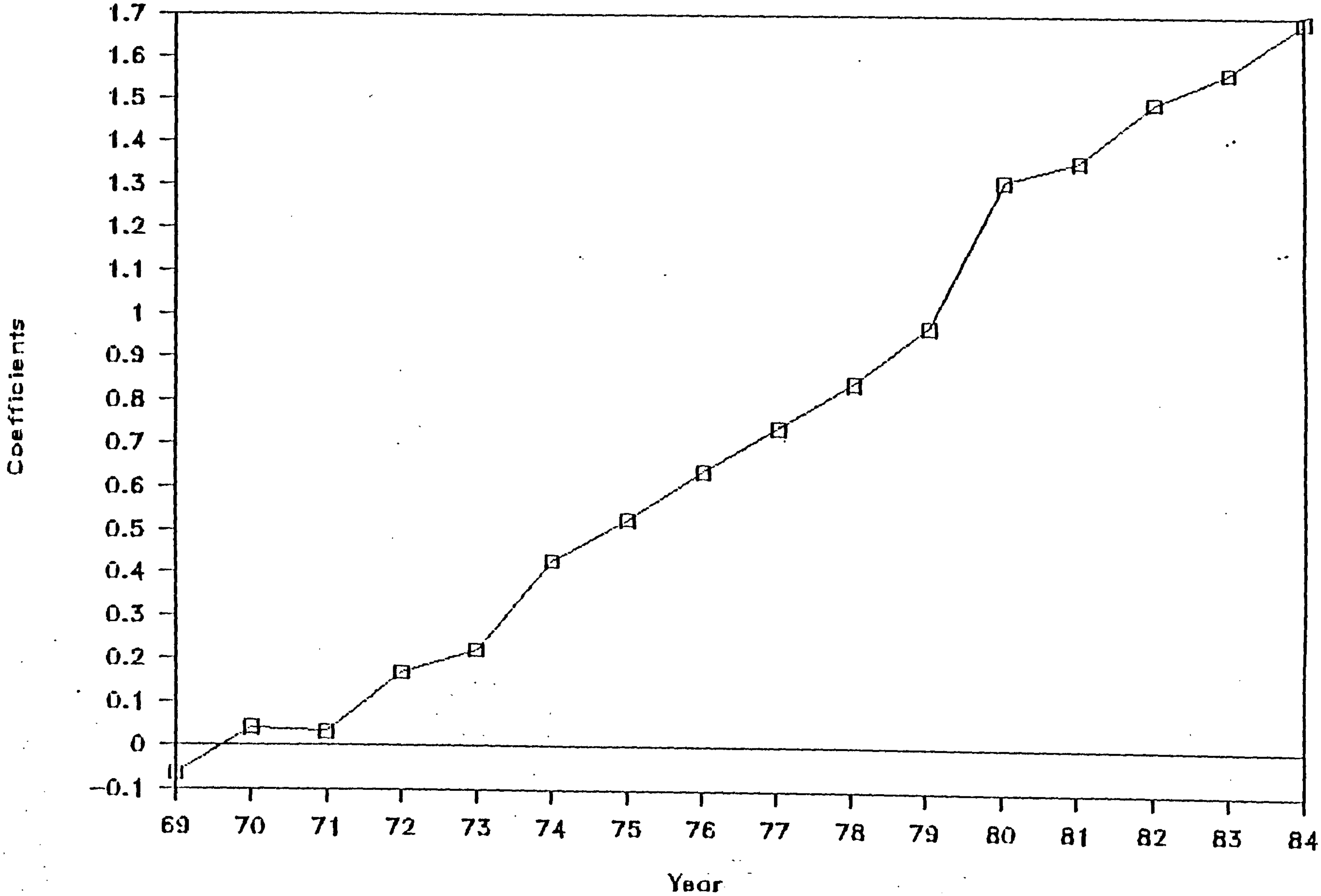


note: 82 obs had missing values
note: the procedure plot used 0.08 seconds and 718k and printed page 5.

638   proc plot; plot om83*ne;

PLOT 5

YEAR DUMMIES' COEFFICIENTS



Attachment 2

```
633          proc reg; model lnom83=ne lnmwpun lnunits year;
634

sas
                     14:06 tuesday, june 10, 1986     1

dep variable: lnom83
analysis of variance

                      sum of           mean
source     df        squares          square         f value        prob>f

model       4      410.43429       102.60857         903.419        0.0001
error     530    60.19634136      0.11357800
c total   534      470.63063

    root mse       0.3370134      r-square         0.8721
    dep mean        9.958911      adj r-sq         0.8711
    c.v.            3.383698

parameter estimates

                    parameter           standard        t for h0:
variable   df        estimate              error      parameter=0        prob > ^t^

intercep    1     -2.19728929         0.24946907           -8.808            0.0001
ne          1      0.28001897         0.03199336            8.752            0.0001
lnmwpun     1      0.48331595         0.02395104           20.179            0.0001
lnunits     1      0.69455323         0.04547845           15.272            0.0001
year        1      0.11312148        0.003625168           31.204            0.0001
```

TABLE G-2: RESULTS OF REGRESSIONS ON O&M DATA (All plants in dataset)

	Equation 1		Equation 2		Equation 3	
	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-2.12	-7.94	-2.12	-7.94	-2.19	-8.77
ln(MW) [2]	0.53	21.15	--	--	--	--
ln(UNITS)	0.03	0.56	0.56	12.27	0.70	15.34
YEAR [3]	0.11	28.62	0.11	28.62	0.11	31.24
UNITS	--	--	--	--	--	--
ln(MW/unit)	--	--	0.53	21.15	0.48	20.23
NE [4]	--	--	--	--	0.28	8.78
Adjusted R-sq.		0.85		0.85		0.87
F statistic		1032.2		1032.2		904.3

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$).

[2] MW = number of MegaWatt in Design Electrical Rating (DER)

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Susquehanna 2 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

#61R

THE STATE OF TEXAS

BEFORE THE PUBLIC UTILITIES COMMISSION

RE: The Economic Viability of Unit 2 of the South Texas Electric Generating Station	)

SUPPLEMENTARY TESTIMONY OF PAUL CHERNICK

ON BEHALF OF

THE COMMITTEE FOR CONSUMER RATE RELIEF

September 14, 1987

Q: Please identify yourself.

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

Q: Are you the same Paul Chernick who submitted direct testimony in this docket?

A: Yes.

Q: What is the subject of your supplementary testimony?

A: I will discuss the appropriate discount rates to use in this docket.

Q: Why are discount rates significant in this proceeding?

A: Economic cost-benefit analyses use discount rates, because in general costs (or benefits) are more important if they occur sooner, rather than later. Individuals and other economic entities would usually prefer to receive benefits early, and pay the costs late.[1] The discount rate is intended to approximate this time preference: if the consumer considers $1 this year to be as valuable as $1.15 next year, the appropriate annual discount rate is 15%.

The appropriate discount rates for investment decisions vary. First, different entities have different discount rates, since the short-term sacrifices they would have to make for long-term benefits will differ. A rich person, a

1 Hence the attraction of "Fly now, pay later." Unfortunately, STNP (and many other investments) require us to "Pay now, fly later." In the case of STNP, the situation may be "Pay now, and someone else will get to fly in twenty years."

poor person, a non-profit organization, a start-up high-tech firm, the local branch of an international conglomerate, and the State of Texas will find different ways of raising funds to pay an additional cost, such as increased electric bills to pay for STNP2. The rich person may put less in his mutual fund, the poor person may do without dinner, and the start-up firm may cut back on the research program which would have made it a market leader. Thus, the discount rate chosen for an evaluation should reflect the time preferences of the entities which will be paying the bills and receiving the benefits.[2]

Second, not all investments carry the same risks. Investors require a higher expected return from equity holdings in high-risk start up ventures than from risk-free Treasury securities, for example. The discount rate used should therefore reflect the degree of risk involved in the projected stream of costs and benefits.

Q: What discount rates do the utilities propose?

A: The discount rates sponsored by Mr. Lattner are 9.91% for CP&L, 9.95% for HL&P, and 6.12% for the municipals.

Q: Are these reasonable values?

A: No. The discount rates in Mr. Lattner's testimony are far too low. The Commission should be using an estimate of

---

2 It is meaningless to apply discount rates to anything other than cash, such as depreciation, AFUDC, or other non-cash accounting concepts.

customer discount rates, rather than estimates of the utility's discount rates. The discount rates are being used to discount cash costs and benefits to customers, not utility cash outlays, and should therefore reflect the time and risk preferences of the customers, rather than of utility shareholders or bondholders.

The proposed 6-10% discount rates are not reasonable approximations of customers' discount rates. If STNP2 just broke even for the customers (had a 0 net present value) at 6%, for example, it would be equivalent to a return of 6%, roughly equivalent to a 17 year payback.[3] When electric ratepayers have the opportunity to make conservation investments, even ones much less risky than STNP2, they generally appear to require returns well in excess of 6% or even 10%. From the ratepayer's point of view, STNP2 is an up-front investment which reduces future electricity bills, just as a more efficient refrigerator or reflective windows would.

Commercial firms and institutions (e.g., colleges and hospitals) generally report required paybacks on the order of 2 to 5 years: it is rare to find such an enterprise using a discount rate of less than 20%. Industrial firms

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3 This simplification would be correct if the benefits to the ratepayers were very long-lived and constant, which they are not. Since traditional ratemaking front-loads the costs of new plants, and since the benefits of STNP2 grow over its lifetime, the payback would be later than 17 years.

will also rarely make non-productive investments with expected paybacks of more than four years, and for some firms (especially those in the least secure financial situations) this target is less than one year. Similarly, Hausman (1979) found that residential consumers used real discount rates of 15-25% in comparing appliances of differing efficiencies. Chernoff (1983) surveyed several studies, all of which found that consumer discount rates exceed 20% and in some cases exceeded 50%. Ruderman, _et al_., found consumer discount rates of about 20% for air conditioner purchases, with discount rates for other appliances varying from 40% to over 800%. These discount rates had increased, or decreased only slightly, from 1972 through 1980. These high discount rates indicate that most consumers would not be willing to pay the costs of STNP2, if they could expect a return of only 10% (let alone 6%), even if STNP2 were only as risky as typical conservation investments.

Furthermore, STNP2 is not a typical investment in terms of risk. The risky aspects of PVNGS include its capacity factor, operating costs, capital additions, decommissioning costs, useful life, and the chance of an accident at the plant. STNP2 must be much riskier than HL&P's or CP&L's business risk, for their distribution, transmission, and even fossil generation, and also must be much riskier than the typical investment in customer conservation. STNP2 is obviously very much riskier than the average risk of default to holders of Austin or San Antonio bonds.[4]

For an investment with the risk characteristics of STNP, 10% is an implausibly low target return. This is roughly the return on would expect from an investment in risk-free Treasury securities, which are currently yielding about 9.8%. I do not believe that any reasonable person would suggest that STNP2 is as safe an investment as government bonds.

For the cost-benefit analyses of STNP, given the considerations outlined above, I would recommend 15% as a minimum reasonable discount rate, and value of 20% should be used as a proxy for an all-customer average.

Q: How should the Commission determine whether to use utility discount rates or customer discount rates, in evaluating investment decision?

A: It is necessary to look at the nature of the costs and benefits being discounted. If the Commission is analyzing the utility cash flow stream, the utility discount rate is appropriate. If the Commission is analyzing the customer cash flow stream, as utility costs are passed on through

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4 Short of default, the city's ratepayers and taxpayers assume all the risks associated with municipal financing. The bond rates are therefore irrelevant as measures of STNP risks.

depreciation, return, deferred tax accounting, and so on, the customer discount rate is appropriate. It is my understanding that the financial model adopted for this proceeding assumes that the utilities will be allowed a fair return: this case is thus primarily concerned with the costs to rate payers. The financial model generates those ratepayer costs, not utility costs, and the results should thus be analyzed with an appropriate estimate of an average ratepayer discount rate.

Q: What is the "entity making the investment", for the purpose of selecting a discount rate in this proceeding?

A: The ratepayers are making the "investment" analyzed in the financial model. Ratepayers will pay higher bills for many years, while STNP2 is hot heavily depreciated and while the avoided replacement costs are low. In exchange for this investment, ratepayers (many of them different from the ratepayers who made the investment) are likely to eventually pay lower bills for a subsequent period of years. Thus, it is <u>ratepayer</u> costs which must be compared over time, and a ratepayer discount rate which is relevant to the comparison.

Q: Would a utility discount rate ever be relevant for this proceeding?

A: Only if the utility offered to defer recovery of all STNP2 costs in excess of the unit's annual benefits, until such time as annual benefits exceed annual costs, and further to take all risks related to STNP2 which might cause the costs to permanently exceed the benefits. In that situation, the utility finance cost and discount rate would be available to ratepayers, to shift STNP2 costs into the same time period as the benefits.[5] If the utilities are unwilling to make such commitments, the ratepayer discount rate (for which I suggest a 20% proxy value) must be used.

Q: Does this conclude your supplementary testimony?

A: Yes.

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5 The municipal utilities cannot absorb these risks, so HL&P and CP&L would have to make this guarantee.

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THE STATE OF TEXAS

BEFORE THE PUBLIC UTILITIES COMMISSION

RE: The Economic Viability of Unit 2 of the South Texas Electric Generating Station	)

SUPPLEMENTARY TESTIMONY OF PAUL CHERNICK

ON BEHALF OF

THE COMMITTEE FOR CONSUMER RATE RELIEF

September 14, 1987

Q: Please identify yourself.

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

Q: Are you the same Paul Chernick who submitted direct testimony in this docket?

A: Yes.

Q: What is the subject of your supplementary testimony?

A: I will discuss the appropriate discount rates to use in this docket.

Q: Why are discount rates significant in this proceeding?

A: Economic cost-benefit analyses use discount rates, because in general costs (or benefits) are more important if they occur sooner, rather than later. Individuals and other economic entities would usually prefer to receive benefits early, and pay the costs late.[1] The discount rate is intended to approximate this time preference: if the consumer considers $1 this year to be as valuable as $1.15 next year, the appropriate annual discount rate is 15%.

The appropriate discount rates for investment decisions vary. First, different entities have different discount rates, since the short-term sacrifices they would have to make for long-term benefits will differ. A rich person, a

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1 Hence the attraction of "Fly now, pay later." Unfortunately, STNP (and many other investments) require us to "Pay now, fly later." In the case of STNP, the situation may be "Pay now, and someone else will get to fly in twenty years."

poor person, a non-profit organization, a start-up high-tech firm, the local branch of an international conglomerate, and the State of Texas will find different ways of raising funds to pay an additional cost, such as increased electric bills to pay for STNP2. The rich person may put less in his mutual fund, the poor person may do without dinner, and the start-up firm may cut back on the research program which would have made it a market leader. Thus, the discount rate chosen for an evaluation should reflect the time preferences of the entities which will be paying the bills and receiving the benefits.[2]

Second, not all investments carry the same risks. Investors require a higher expected return from equity holdings in high-risk start up ventures than from risk-free Treasury securities, for example. The discount rate used should therefore reflect the degree of risk involved in the projected stream of costs and benefits.

Q: What discount rates do the utilities propose?

A: The discount rates sponsored by Mr. Lattner are 9.91% for CP&L, 9.95% for HL&P, and 6.12% for the municipals.

Q: Are these reasonable values?

A: No. The discount rates in Mr. Lattner's testimony are far too low. The Commission should be using an estimate of

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2 It is meaningless to apply discount rates to anything other than cash, such as depreciation, AFUDC, or other non-cash accounting concepts.

customer discount rates, rather than estimates of the utility's discount rates. The discount rates are being used to discount cash costs and benefits to customers, not utility cash outlays, and should therefore reflect the time and risk preferences of the customers, rather than of utility shareholders or bondholders.

The proposed 6-10% discount rates are not reasonable approximations of customers' discount rates. If STNP2 just broke even for the customers (had a 0 net present value) at 6%, for example, it would be equivalent to a return of 6%, roughly equivalent to a 17 year payback.[3] When electric ratepayers have the opportunity to make conservation investments, even ones much less risky than STNP2, they generally appear to require returns well in excess of 6% or even 10%. From the ratepayer's point of view, STNP2 is an up-front investment which reduces future electricity bills, just as a more efficient refrigerator or reflective windows would.

Commercial firms and institutions (e.g., colleges and hospitals) generally report required paybacks on the order of 2 to 5 years: it is rare to find such an enterprise using a discount rate of less than 20%. Industrial firms

3 This simplification would be correct if the benefits to the ratepayers were very long-lived and constant, which they are not. Since traditional ratemaking front-loads the costs of new plants, and since the benefits of STNP2 grow over its lifetime, the payback would be later than 17 years.

will also rarely make non-productive investments with expected paybacks of more than four years, and for some firms (especially those in the least secure financial situations) this target is less than one year. Similarly, Hausman (1979) found that residential consumers used real discount rates of 15-25% in comparing appliances of differing efficiencies. Chernoff (1983) surveyed several studies, all of which found that consumer discount rates exceed 20% and in some cases exceeded 50%. Ruderman, et al., found consumer discount rates of about 20% for air conditioner purchases, with discount rates for other appliances varying from 40% to over 800%. These discount rates had increased, or decreased only slightly, from 1972 through 1980. These high discount rates indicate that most consumers would not be willing to pay the costs of STNP2, if they could expect a return of only 10% (let alone 6%), even if STNP2 were only as risky as typical conservation investments.

Furthermore, STNP2 is not a typical investment in terms of risk. The risky aspects of PVNGS include its capacity factor, operating costs, capital additions, decommissioning costs, useful life, and the chance of an accident at the plant. STNP2 must be much riskier than HL&P's or CP&L's business risk, for their distribution, transmission, and even fossil generation, and also must be much riskier than the typical investment in customer conservation. STNP2 is obviously very much riskier than the average risk of default to holders of Austin or San Antonio bonds.[4]

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