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BEFORE THE NEW MEXICO PUBLIC SERVICE COMMISSION

RE: EL PASO ELECTRIC COMPANY) CASE NO. 2009

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF

THE ATTORNEY GENERAL

OF NEW MEXICO

VOLUME I

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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 employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, 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.

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 Texas Public Utilities 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 the benefits of PNM's Eastern Interconnection Project in Docket No. 1794, and on EPE's nuclear decommissioning fund in Docket No. 1833, Phase II.

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

A: Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. My paper "Revenue Stability Target Ratemaking" was published in Public Utilities Fortnightly, and another article "Opening the Utility Market to Conservation: A Competitive Approach" was presented at the 1984 national conference of the International Association of Energy Economists, and was published in the conference proceedings. 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 review the manner in which the Palo Verde Nuclear Generating Station (PVNGS) would enter ratebase, or otherwise be reflected in the New Mexico retail rates of the El Paso Electric Company (EPE). The purposes of my testimony include:

1. providing the Commission with a historical perspective on some of the issues raised by this proceeding;

2. reviewing the prudence of generation planning decisions regarding PVNGS taken by EPE, considering what EPE should have known at the time;

3. estimating the amount of PVNGS investment which can be placed in rate base without producing higher rates than those which would have resulted from prudent actions by EPE;

4. estimating the current market value of the plant, by comparison to alternative sources of supply;

5. proposing power plant performance standards which are fair to ratepayers and consistent with the estimated value of the investment; and

6. suggesting appropriate ratemaking approaches in light of the results of the analysis.

Q: Why are planning prudence and the value of PVNGS relevant to a proceeding which was docketed to consider ratemaking methodologies?

A: Before the Commission can design a rate moderation plan, to phase in the costs of PVNGS, it must determine the amount of investment for which cost recovery is to be allowed. If a sufficient portion of the investment is disallowed, there may be no rate shock or rate continuity problems. In the process of phasing a plant into rates, the Commission may treat deferred costs very differently, depending on whether those costs represent a useful investment for the ratepayers, or are simply a deadweight loss. Therefore, it is proper to consider whether the costs incurred were prudent and whether the investments are used and useful prior to determination of the rate moderation plan.[1]

The topics considered in my testimony may alter EPE's cost recovery for PVNGS in either of two respects. First, as this testimony will demonstrate, power from PVNGS is much more expensive than that from alternative sources which EPE could have developed instead of PVNGS. If the Commission agrees

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1. This order of determinations, while helpful, is not always possible. For example, the audit of PVNGS construction will not be completed soon enough to be incorporated in the rate moderation proceeding.

with my conclusion that EPE's decisions to continue its participation in PVNGS were imprudent, a large portion (perhaps all) of the excess costs attributable to PVNGS should not be recovered from ratepayers.

Second, regardless of the Commission's conclusions on prudence, the difference between the cost of PVNGS and its value may be treated as an extraordinary loss, just as if an act of Nature (e.g., storm damage) had caused an equivalent excess cost at the plant. Stockholders and ratepayers generally share the burden of these extraordinary losses: in some cases, the cost to stockholders is the delayed recovery of costs (e.g., a 10-year amortization) without interest on the deferred recovery.

Hence, my testimony presents evidence which may be vital to the Commission in determining either how much of the PVNGS investment will be recovered from ratepayers, in determining the ratemaking treatment of deferred cost recovery, or both.

Q: **What do you mean by "prudence"?**

A: When I refer to prudent behavior in this testimony, I mean actions which were responsible, careful, and business-like. Imprudent behavior, on the other hand, is generally reckless, careless, or at least not well thought through. I assess prudence in terms of what EPE knew, or should have known, given its situation.

Q: **Do the prudence issues considered in your testimony duplicate those which are addressed in the audit which is currently in progress?**

A: There is very little in common between the two analyses. As I understand the audit, it will primarily address the quality of construction management, which I do not consider at all. My testimony deals with prudence only in terms of generation planning decisions, specifically whether to continue participation in PVNGS. It is my understanding that the audit is addressing planning prudence only in the context of the initial 1973 decision to build PVNGS as a nuclear plant. Even if the audit addresses some of the same issues, the evidence in this testimony should be considered now. This would not preclude the commission making additional findings when the audit is completed.

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

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

Section 2 presents my conclusions regarding the prudence of EPE's investment in PVNGS, the economic value of PVNGS, and my recommendations regarding the ratemaking response of EPE's share of PVNGS.

Sections 3 and 4 address the prudence of EPE's generation planning process. Section 3.1 reviews the industry literature during the planning and construction of PVNGS, and establishes that EPE should have been aware of the problems of the nuclear industry when it made important decisions regarding its participation in PVNGS. Section 3.2 presents and analyzes the data on nuclear power plants' construction and operating costs which should have informed EPE's decisions to proceed with its ownership share of PVNGS, and to continue supporting construction of all units. Section 4 compares realistic cost projections for PVNGS power to those for the alternative power sources, especially coal, as of 1976, 1978, 1980 and 1982, and considers the availability of other supply options.

I then consider the present and future value of PVNGS to ratepayers. Section 5 compares the cost of PVNGS power to that of EPE's alternatives, and determines the portion of EPE's investment which is cost-effective over the course of its useful life.

Finally, Section 6 presents the rationale for applying power plant performance targets to PVNGS, discusses EPE's objections to such targets, and recommends performance standards.

The Appendices to this testimony provide more detailed explanations of various topics considered in the text. Appendix I is my resume, as referenced in the discussion of my qualifications, Section 1.1. Appendix II contains a more complete review of the nuclear industry literature, as discussed in Section 3.1. Appendix III, supporting Section 3.2, contains the analysis of nuclear power plant construction cost overruns and schedule slippage, along with the underlying data. Appendix IV presents the details of the retrospective cost comparisons discussed in Section 4. Appendix V (V-A through V-G) provides the derivation of my estimates of PVNGS's likely operating costs and capacity factor, which are used in determining the current value of the plant, in Section 5. Appendix VI is a copy of my paper on power plant performance standards, which is the basis for some of the recommendations in Section 6.

1.3 A Short History of PVNGS

Q: Please describe the PVNGS Project.

A: Palo Verde Nuclear Generating Station is located 55 miles west of Phoenix, in Wintersburg, Arizona. The project is managed and operated by Arizona Public Service (APS), but ownership is divided among six participants,[2] of which EPE currently owns 15.8%. The three Combustion Engineering pressurized water reactors (PWR's) have a rated capacity of 1270 megawatts each or a total of 3810 MW for the plant. Thus, EPE's share of PVNGS is 200 MW per unit.

Bechtel has been the Architect/Engineer and the Constructor ever since the project was ordered. The APS project organization is generally referred to as the Arizona Nuclear Power Project (ANPP).

Q: Please briefly recount the history of PVNGS construction.

A: All three Palo Verde units were ordered in October 1973 by Arizona Public Service. At this early stage, the total cost, including Allowance For Funds Used During Construction (AFUDC) was expected to be $2.5 billion with the three units scheduled for May 1981, November 1982 and May 1984,

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2. APS, EPE, Salt River Project (SRP), Southern California Edison (SCE), Public Service of New Mexico (PNM), and Southern California Public Power Authority (SCPPA).

respectively. (These total project costs including AFUDC are based on an EPE response to interrogatory, as will be explained).

Construction Permits for all three units were issued in May 1976. By then, the projected final cost had risen to $3.6 billion and the schedules had been pushed back about two years each. Unit 1 construction started immediately. The New Mexico Public Service Commission granted a Certificate of Convenience and Necessity in February of 1977, in Case 1216.

The schedule did not change again until 1979, when operation of Unit 1 slipped by a year. The total cost had risen gradually to $4.47 billion. The schedule was extended again in April of 1983, when Units 1 and 2 were delayed about a year each to May 1984 and February 1985 respectively, bringing the total projected cost to $7.2 billion by this time. The next slippage occurred in September 1984, when the schedule was extended to November 1985 and April 1986. The projected cost was increasing more rapidly, and totaled $9.54 billion by May 1984.

The NRC issued Unit 1 a low power operating license in December 1984 and a Full Power License in June 1985. Various operating utilities declared Unit 1 commercial in December 1985 through February 1986. Unit 2 received a Low Power License in December of 1985. Unit 3 has yet to receive an operating license.

Q: **What are your sources for PVNGS construction cost estimates?**

A: I have three sources for PVNGS construction cost estimates: an information response from EPE (IR-1-19), the EIA-254 Quarterly Reports and an Ernst and Whinney Review (1985).

ANPP excludes Allowance for Funds Used During Construction (AFUDC) from total project cost estimates, on the grounds that a different AFUDC rate is applied to each participant's share of the plant. For EPE's share of the total plant cost, I have relied on the EPE response because it provides EPE's specific AFUDC estimates. Table 1.1 calculates AFUDC for the total project scaled up from EPE's projected AFUDC cost for the various estimates from 1973 through 1985. Figure 1.5 displays the data from Column 6 of this table.

The EIA reports give total unit costs <u>excluding AFUDC</u> and the Ernst and Whinney review gives total <u>plant</u> cost estimates <u>excluding AFUDC</u>; both are listed in Table 1.2.

As this testimony reviews the economics of both the plant as a whole and the individual units (especially Unit 3), including AFUDC, I have divided the total plant cost including AFUDC among units with the allocation used in the EIA Quarterly Reports. Table 1.3 calculates this distribution among units. In 1974, the cost allocation appears to be fairly equal among the three units. However, the cost of Units 2 and 3 leveled out much earlier than Unit

1. By 1984, the cost for Unit 1 represented 40.5% of the PVNGS total cost, while Unit 2 and Unit 3 represented 28.3% and 31.1% respectively.

Most of the cost calculations in this testimony will refer to EPE's 15.8% share of the cost of PVNGS. Table 1.4 applies the unit percentages calculated in Table 1.3 to EPE's cost share including AFUDC, from Table 1.1.

A 1985 Forbes review of the cohort of plants under construction in January 1984, allows comparison of PVNGS to other nuclear plants on a cost per kilowatt basis. The median cost per kilowatt of this cohort (including the units that have since been cancelled) is about $2622/KW. In terms of the cost per KW, PVNGS, at its current cost estimate of $2497/KW, comes out below the median. The PVNGS cost is less than half of that of the most expensive plant in the cohort, but twice that of the least expensive. PVNGS is an expensive plant, but not one of the great disasters of the industry. Table 1.5 shows an updated listing of the nuclear plant under construction at the beginning of 1984.

Figures 1.2 and 1.3 illustrate progress on the project in terms of percent complete, and in terms of EPE's annual expenditures on the project. Table 1.6 lists the data graphed in Figure 1.3.

2 SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

2.1 Summary of This Testimony

Q: Mr. Chernick, please summarize the findings you will present in subsequent sections of this testimony.

A: I have found the following:

1. EPE should have been aware that nuclear power plant construction was subject to large cost overruns and to significant schedule slippage, ever since it first committed to the project in the early 1970s.

2. EPE should have anticipated as far back as 1976 that the cost of building PVNGS would be at least as high as the current official estimate.

3. EPE should have recognized that new power from coal capacity would be less expensive than that from PVNGS in 1976-1980, regardless of whether PVNGS could be sold, or whether it had to be canceled. Therefore, during this period, EPE should have sought to sell its share in PVNGS, or to force the cancellation of the plant.

4. Had EPE effected cancellation of PVNGS in the late 1970s, its sunk costs would have been small compared to

the net loss EPE has suffered by continuing its involvement in PVNGS.

5. Had EPE attempted to sell PVNGS shares before 1981, it probably would have succeeded.

6. EPE is now the owner of 600 MW of expensive PVNGS capacity, due to its own imprudent planning.

7. PVNGS capacity is worth no more than $1500/kW even if EPE is correct in its projections for operating characteristics, and no more than $600/kW, if my projections are correct.

Q: **What is the basis of your conclusion that EPE should have been aware of cost overruns and schedule slippage at nuclear power plants?**

A: As discussed in Section 3.1 of this testimony, the industry literature had reported extensively on the problems of constructing nuclear plants. EPE subscribed to many of the publications which contained very clear warnings about regulatory difficulties, cost overruns, and schedule slippage. Other utilities recognized the hazards of major commitments to nuclear construction, and reduced or terminated their nuclear construction programs. EPE did not.

As discussed in Section 3.2 of this testimony, and as demonstrated in the Tables in Appendix III, cost and schedule slippage was virtually universal in the industry, and would have been obvious to anyone who undertook to tabulate changes in nuclear cost estimates and schedules. Given the warnings in the literature, it would have been clearly irresponsible to participate in a major nuclear project without monitoring the reliability of cost and schedule projections in the industry. EPE does not appear to have conducted any such monitoring.

Q: **What is the basis of your conclusion that EPE should have anticipated that the cost of PVNGS would climb to the currently estimated level?**

A: As demonstrated in Section 3.2, continuation of the historically observed cost overruns at PVNGS would have resulted in even higher costs than are currently projected. This is true regardless of whether the experience is examined in 1972 or 1982, whether the data is drawn from completed plants or those under construction, and whether the data is stated in nominal dollars or corrected for inflation. Persons familiar with the record of nuclear power plant cost overruns should not have been surprised to find that the cost of PVNGS had reached its current level.

Similarly, PVNGS has experienced to date about the amount of schedule slippage which would have been anticipated, based on historical data available in the 1970s. Unit 1 has slipped much more than the historical norm, and Unit 3 (as currently scheduled) will have slipped less than most other units, but the average in-service date for the plant is close to (or a little earlier than) the date which would have resulted from a repetition of past experience.

Q: **What is the basis of your conclusion that EPE should have known that new coal capacity would produce less expensive power than PVNGS?**

A: Section 4.1 compares reasonable estimates of the busbar cost of power from PVNGS, to utility estimates of the busbar cost of power from new coal plants. The coal plants would have been less expensive than PVNGS for analyses performed at any time from 1976 through 1982. Even the remaining cost of PVNGS (excluding sunk costs to date) would have been greater than the cost of coal, through 1980.

Q: **What is the basis of your conclusion that EPE should have attempted to sell or cancel PVNGS?**

A: At any time through 1982, the sale of EPE's PVNGS share at book and the construction of new coal capacity would have been less expensive than continued participation in PVNGS. By 1981, sale of PVNGS was no longer possible (at least for full sunk cost). Cancellation of PVNGS (or sale of EPE's share for much less than book) and construction of coal capacity was less expensive than participation in PVNGS through 1980.

Q: **What is the basis of your conclusion that sales of PVNGS capacity were possible until 1980?**

A: As discussed in Section 4.4, other utilities were able to sell large amounts of PVNGS capacity in the 1970s and even until early 1981. EPE's efforts to sell in 1981 were too late to be successful: EPE was able to obtain tentative offers for 300 MW, but both offers fell through, as perceptions of nuclear power continued to deteriorate. The same transactions, and probably others as well, could have been successful if EPE had marketed its share even a year earlier. Sales of PVNGS capacity would have been easier still in the 1970s.

Q: **Could EPE have caused the cancellation of one or more PVNGS units?**

A: Since EPE never tried, we will never know for certain. There are many factors which would have tended to make EPE's efforts successful, including its significant share in the plant (15.8%); the aversion of the other owners to public criticism of their supply planning, which might have triggered a series of regulatory reviews featuring unfavorable testimony by EPE witnesses; and the desire of Salt River Project to reduce its share (SRP's sales, discussed in Section 4.4, would have been very difficult in the middle of a struggle over continuation of construction). The other owners, faced with a strong desire by EPE to exit the project, might well have agreed either to buy out EPE (perhaps coupled with cancellation of Unit 3) or to abandon the entire project.

At Seabrook, where minority owners (particularly Central Maine Power, with a 6% share) opposed the continuation of Unit 2, at which construction had reached about 22% completion, construction activity has indeed stopped and the unit is effectively cancelled. PVNGS 1 was at a comparable point of construction at the end of 1977, Unit 2 at the end of 1979, and Unit 3 in mid-1981: the entire plant (averaging over the three units) was 20-25% complete late in 1979.

Q: **What is the basis of your conclusion that PVNGS capacity is worth no more than $1500/kW?**

A: Section 5 of this testimony computes the value of the PVNGS investment by comparison with the cost of power from San Juan 4 and from the SPS purchase. These represent readily available sources of power which were obvious alternatives to PVNGS: in addition, San Juan 4 is typical of coal plants built in the 1980s, and may be thought of as a proxy for the generic coal alternative.[3] Even compared to the more expensive of these options, San Juan, using the most favorable plausible consumer discount rate, and using EPE's projections of PVNGS operating characteristics, only $1500/kW of PVNGS investment can be placed in rate base without producing higher rates than would have occurred, had EPE

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3. It is important to note that neither of these alternatives represents a truly least-cost supply plan, and that the standard of management quality they represent is far less than perfection. An optimal mix of conservation investments, purchases, and EPE central plant construction would be less expensive than either SPS or San Juan.

invested in the coal-fired alternative in the late 1970s or early 1980s. Compared to the currently estimated cost of \$2400/kW for PVNGS, the \$1500/kW value represents a loss of \$900/kW. Under any other combination of assumptions, the value per kilowatt is lower than \$1500 and the loss is greater than \$900/kW.

This \$900/kW figure has two distinct and independent interpretations. First, it is a conservative (e.g., probably understated) estimate of the minimum disallowance which would make EPE ratepayers no worse off than they would have been if EPE had acted prudently, by selling PVNGS or provoking early cancellation of one or more units. Second, it represents the difference between the plant's cost and its current market value, and hence the size of the extraordinary loss associated with EPE's involvement in PVNGS. The second interpretation requires no judgments about prudence, and simply views the outcome at PVNGS as if it were an act of Nature, like a storm.[4]

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4. In general, the cost of imprudence and the current market value of a generator would be different. The existence of a market for coal plant capacity (one of the prudent alternatives) in the Southwest, at close to book cost, causes these two values to be essentially the same for PVNGS.

2.2 Recommendations

Q: Based on your findings, what is your basic recommendation in this proceeding?

A: Since EPE's imprudence has resulted in a very large excess cost, I would recommend that the Commission not allow the Company to recover the associated costs from the ratepayers. On this basis, I would recommend that the Commission allow recovery of $600 to $1500/kW, depending on the operating costs and performance the Commission expects or requires. Compared to the $2400/kW cost currently estimated for PVNGS, $900 to $1800/kW is a deadweight loss due to EPE's imprudence, which should be written off and not recovered through rates.[5]

While I believe that the prudence analysis presented above is important and correct, it does not encompass all of the considerations the Commission might properly take into account in setting EPE's rates. I will discuss some of the other factors below.

Q: How does the sale/leaseback proposed for PVNGS 2 affect these recommendations?

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5. EPE may eventually be able to recover some of this loss from APS or Bechtel, if its actions resulted from material misrepresentations by those companies, or if the size of its loss was increased by construction mismanagement.

A: There is little effect. A new coal plant could also be sold and leased back. Since the nuclear plant is more capital-intensive than the coal plant, the cost differential would narrow slightly under sale/leaseback arrangements, depending on the terms of the two contracts.

Q: **Are there any considerations which might reasonably cause the Commission to disallow significantly less than the $900 to $1800/kW you have suggested based on prudence considerations?**

A: Yes, there are at least four such considerations which the Commission might apply. First, the Commission might agree with one or more of my conclusions regarding prudence, but disagree on the effects. For example, the Commission might find that EPE was imprudent in continuing its role in PVNGS in 1978, but not be sure that the entire cost of PVNGS was avoidable. It is conceivable that EPE would not have been able to sell all of its PVNGS share in 1978, or that it would only have been able to do so at less than book value, or that a sale of all three units would have been impossible and that cancellation (with a resulting loss) of at least Unit 3 would have been necessary.[6] I doubt that any of these outcomes would have resulted from prudent EPE actions, since PVNGS should have been canceled before expenditures were

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6. For example, canceling Unit 3 in 1980 would have cost about $120 million or $200/kW spread over EPE's entire 600 MW share, and canceling the entire plant in 1978 would have cost about $470/kW, in addition to the cost of replacement power.

significant, and since there was a market for PVNGS capacity through 1980, but they can not be ruled out. If the Commission believes that prudent EPE actions would have reduced the exposure to PVNGS by only a fraction of the total cost -- through a partial sale, through cancellation of only Unit 3, through cancellation of the entire plant, or through a sale below book cost -- it would be appropriate to disallow less than the full loss of $900 to $1800/kW.

Second, the same considerations apply if the Commission believes that there is legitimate uncertainty about the outcome: if there is a 50% probability that prudent behavior would have allowed EPE to escape the cost of PVNGS, half the loss ($450 - $900) should be disallowed. I would like to emphasize the issue of <u>legitimate</u> uncertainty. I can not prove one way or the other what outcomes would have flowed from prudent EPE actions in 1978 (or any other specific point). The only conclusive proof would have resulted from observations of prudent EPE actions: since EPE acted imprudently, there are no such observations. I believe that it is an important regulatory principle that the Commission should not reward for imprudence by assuming away the feasibility of prudent actions. Specifically, the Commission should assume the feasibility of actions which EPE should have taken but did not take (e.g., selling or canceling PVNGS), unless and until EPE can demonstrate that those actions were not feasible, or would not have been effective. For some actions, such as marketing PVNGS capacity in 1981 and 1982, we have EPE's empirical experience to indicate that the actions were not effective. In general, EPE did not attempt to resolve the uncertainties at the time they arose (or should have arisen, had EPE been seriously reviewing the problems posed by PVNGS), and now can only attempt to demonstrate that actions would have been ineffective through analogies and other indirect means.

Third, the Commission might simply disagree with my conclusions on prudence. Even if the Commission were to find EPE largely prudent (a position which I believe to be inconsistent with the historical record), it may wish to split the excess cost between shareholders and ratepayers. This is not an unusual response to cancellations, storm damage, and other extraordinary losses. The division of costs may be a simple disallowance of a portion of the loss (such as reducing rate base by $500/kW) or it may be a deferred amortization without return in the meantime (such as amortizing $1000/kW over 20 years without rate base or AFUDC treatment).

Fourth, the Commission might find that I am correct in all or most of my prudence determinations, but that disallowing all of the costs resulting from imprudence would cause severe financial distress, interfering with EPE's ability to serve customers and increasing overall costs of service. I have no opinion as to what level of disallowance would produce any particular level of financial distress, whether the resulting costs to customers would outweigh the savings from the disallowance, nor whether financial distress (even bankruptcy) would result in better or worse management in the future. Consideration of this factor may prompt the Commission to reduce the size of the disallowance, but need not do so.

It is important to recall that my basic recommendation is already rather generous, in that it does not rely on the lower (possibly zero) value of the PVNGS investment compared to the foregone SPS purchase, it incorporates optimistic assumptions on nuclear decommissioning costs, and it ignores entirely some categories of nuclear costs (overheads and A&G). In addition, the cost of PVNGS I use does not include the CWIP and extraordinary rate relief EPE has already received to finance its share. Finally, if the Commission uses the value of PVNGS based on EPE's projections of operating parameters, and only disallows $900/kW, it will have made several assumptions favorable to EPE.

Q: **What are the implications of PVNGS rate base treatment for plant performance standards and the recovery of operating costs?**

A: I recommend that a performance standard for PVNGS equivalent availability factor (EAF) be set at the capacity factor level used in calculating the value of PVNGS for rate base purposes. If the disallowance is less than $900/kW, the performance standard should be set at EPE's projections.

I also suggest that the Commission tie future recovery of PVNGS operating costs to the levels used in the PVNGS calculations from with the disallowances are derived. Again, if more than $1500/kW is recovered, the operating expense recovery should be capped at EPE current projections. EPE should always be free to request higher cost recovery for operating PVNGS, but EPE should be on notice that such requests will be granted only under unusual circumstances, such as high general inflation.

Q: **How do the ratemaking recommendations you make relate to the audit to be completed under the supervision of Ernst and Whinney?**

A: I believe that the issues I address are separate from those addressed by the audit, except that there is some overlap regarding the original 1973 commitment to PVNGS. I understand that the audit is primarily reviewing construction management (e.g., how much it cost to build the plant) rather than whether construction should have continued.

In terms of ratemaking, a decision by this Commission to disallow costs due to generation planning imprudence may eliminate the need for disallowances resulting from the audit. For example, if $700/kW is disallowed in this proceeding, due to the conclusion that prudent planning would have resulted in coal capacity equivalent to PVNGS at $1700/kW, and the audit finds that construction should have cost $2200/kW, rather than $2400/kW, no further disallowance would be in order. If the prudence disallowance in this case is small (say $400/kW) and the conclusion of the audit is that a larger savings (say $700/kW) could have been realized by building PVNGS correctly, the difference ($300/kW in my example) could be disallowed following the review of construction management. If the disallowance in this case is premised on risk-sharing, rather than prudence considerations, both construction mismanagement and risk-sharing disallowances may be applied in the future. For example, a finding that the loss on PVNGS is $1000/kW, and that shareholders should bear half of that (or $500/kW), followed by the finding that good construction would have saved $400/kW, could logically lead to a disallowance of $700/kW: all of the $400/kW loss due to mismanagement, and half of the remaining $600/kW loss.

3 THE HISTORY OF NUCLEAR CONSTRUCTION

3.1 THE DETERIORATION OF NUCLEAR POWER ECONOMICS: THE LITERATURE

Q: **What bearing does a review of the nuclear industry literature have on the issues of this case?**

A: This review demonstrates that EPE should have known at critical points in the planning and construction of PVNGS about fundamental problems facing the nuclear industry in general and regarding the reliability of nuclear cost and schedule projections in particular. This information provides important insight into the reasonableness of APS's projected cost of PVNGS, and thus into the reasonableness of EPE's decisions to continue committing funds to the construction of its share of PVNGS rather than attempting to sell a portion of its entitlement or to effect cancellation of one or more units.

Q: **Why are you certain that EPE could have identified these problems?**

The problems facing the nuclear industry were reflected in Power Engineering, Electrical World, publications of the Federal Power Commission, the comments of nuclear architect/engineers (A/Es), and other sources within the nuclear and utility industries. These sources were widely available, and referred to, within the industry. EPE subscribes to a large number of energy publications, including **Electrical World, Nuclear Industry**, and **Power Engineering.** Failure to be familiar with this literature while engaged in power supply planning, especially for a billion-dollar investment in a nuclear plant, would be reckless and irresponsible.

A pattern of substantial cost overruns and delays was quite obvious in the literature. The calculation of cost ratios, "myopia" factors, and duration ratios (which will be discussed in more detail in the next section) were simple ways of quantifying very important phenomena, requiring no strong assumptions or calculations. Any utility planning a significant investment in a nuclear plant should have noticed the same problems.

Q: **How have you organized your review of the nuclear industry literature?**

A: The review is divided into three parts. I will examine the state of knowledge about the nuclear power costs in the early 1970s, when EPE was considering participation in PVNGS; from 1973 to 1978, a period which ends just before the Three Mile Island accident; and after TMI into the early 1980s. This review provides a brief overview of the literature while more detailed documentation from the various sources is provided in Appendix II.

3.1.1 Infancy of the Industry: Experience to 1972

Q: What was known about nuclear economics in the early 1970s?

A: Forecasts of future plant costs indicated that nuclear units would remain competitive. However, any reasonably alert utility should have been aware of four crucial facts:

1. nuclear cost estimates were unreliable and almost always understated;
2. nuclear plant construction costs were increasing, so that the units ordered, started, or completed in any year were more expensive than those of the year before;
3. nuclear plant construction schedules were increasing, and the times from order to construction permit, and from permit to commercial operation, grew longer for each new cohort of plants; and
4. nuclear schedules were unpredictable and usually stretched out well beyond the expectations of the owners and their architect/engineers.

Q: How should these facts have affected the behavior of EPE in 1972 and throughout the PVNGS planning and construction?

A: EPE should have recognized from the beginning that APS's projections for PVNGS were subject to tremendous uncertainty. With this recognition, EPE should have been prepared to carefully monitor the state of the nuclear industry and the economics of PVNGS, and been prepared to react appropriately if the historical trends continued or accelerated.

Q: **On what do you base your statement that utilities should have known in 1972 that nuclear cost and schedule estimates were likely to be unreliable and understated?**

A: I have two sources. First, there is the data itself, which I present in Section 3.2. Second, it was common knowledge within the utility industry that nuclear plant costs and schedules had been subject to what were then considered to be shocking amounts of escalation and slippage. Representatives of one architect/engineer, Gilbert Associates, documents in 1972 the "explosive" increases in nuclear plant costs:

> The utility industry, about eight years ago, believed that a large light water reactor plant could be built for $125 per kilowatt or less. Today plants to be completed about eight years hence are generally being estimated at close to $400 per kilowatt, which is more than a 300% increase in expected costs over an eight-year period. Nuclear plant costs, then, have not merely evolved in eight years; they have exploded.
>
> Any analysis of past and current estimates quickly indicates the fact than almost all past estimates and many current estimates are far below what will be experienced...(McTague, et al. 1972)

Many sources discussed several reasons for the increased costs, including construction delays and unanticipated complexity of work. Electrical World's 1971 survey entitled "Nuclear Schedules Face Uncertainty" announced that "The big news is the continuing stretchout on schedules."

Q: **Is it your opinion that EPE's decision to commit to PVNGS construction was imprudent?**

A: Not necessarily. It would certainly have been imprudent for any utility to embark on a major nuclear construction program, on the assumption that its engineering cost estimates were likely to be accurate predictions of the final cost, and without making any provisions to re-examine the quality of the estimate and the economics of the project. It is possible that pursuing construction of PVNGS, coupled with a commitment to due diligence in the future, may have been a reasonable decision in 1973 and through the time PVNGS received its construction permit in May of 1976.

Q: **Considering the problems you have described, how could such a commitment have been reasonable?**

A: While nuclear power had serious problems, so did the other conventional generation alternatives which were perceived to be available in 1972. The perceived importance of economies of scale had become utility dogma, and it would have required considerable courage and vision for any utility to abandon construction of the large plants then in planning, in favor of smaller alternatives. Thus, it is hard to say that EPE erred in making its initial commitment to participate in

PVNGS, without allowing a certain amount of hindsight to influence our judgment.

3.1.2 The Long Decline: 1973-1978

Q: **How had the situation for PVNGS changed from the early 1970s by the end of 1978?**

A: All the problems of the previous period persisted and expanded. In addition, during the mid-seventies regulatory scrutiny towards potential safety problems increased. The direct and indirect effects of the first oil price shock also started to change the basic environment in which utilities operated. It should be noted that PVNGS received its construction permit in May 1976.

Q: **What information on the problems of the nuclear industry were reflected in the utility literature?**

A: The general tenor of the comments shifted perceptibly over the years from an early sense of annoyance and puzzlement with these cost and schedule problems to a later sense of deep concern. The continuing assurances that last year was the end of the trend and that next year would see the industry turning around were losing credibility. The trade journals, FPC reports, A/Es, and even some utilities documented "the long decline."

F. C. Olds, the Senior Editor of Power Engineering magazine, wrote that:

> The nuclear power industry continues to miss schedules, and more slippage appears to be ahead...Based on past performance and anticipating new impediments, it seems unlikely that [the current construction] target will be met. . .
>
> The great bulk of recently announced plants are now planned for 8 to 10 years, and considerable additional slippage lies ahead for these units...(Olds 1973)

PVNGS was a 1973 booking with a projected lead time of eight years for Unit 1 and can thus be included in "the great bulk of recently announced plants. . .now planned for 8 to 10 years," for which "considerable additional slippage lies ahead."[7] In 1978 Olds reported that "By 1973, however, hardly anyone should have hoped for lead times for new bookings as low as nine years."

In 1974, Olds headlined his report, "Power Plant Capital Costs Going Out of Sight," and wrote:

> From the mid-1960s on, power plant capital costs have risen faster than estimators can get their numbers changed. In spite of intensive study by many experts, the skyrocket performance of plant costs has defied complete analysis. . .

Electical World's 1975 Nuclear Survey reported:

> Industry falters as uncertainties mount in the areas of financial commitments, load growth demands, regulatory delays, fuel-cycle inadequacies, and unpredictable social and political hindrances.

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7. The Oct. 1973 announcement date is from **Electical World**, which listed the commercial operation schedule for Unit 1 as 1981, and for Units 2 and 3 as May 1983. EPE's first estimate of its share of PVNGS was dated December 1974, for unit CODs of 5/81, 11/82 and 5/83, durations of 7.5, 9.0 and 9.5 years respectively from the date of that estimate.

Each year during the 1973-1978 period, numerous sources provided updated versions of rising cost figures and plant slippage. What Olds was saying kept being said over and over in the series of **Electrical World** annual reviews, in the FPC reviews, in reports by experts in the field, and even by nuclear architect/engineers (though the A/Es were loath to admit that their current efforts were subject to the same problems).[8]

Q: **What was the reaction of other utilities?**

A: Several of the utilities which had been involved in nuclear development started to pull out, citing the very real problems which they faced. For example, Florida Power Corporation's President elaborated upon FPC's announcement to abandon its construction plans for the unnamed two-unit station it had scheduled for operation in the mid-1980s:

> We feel it is not in our customers' best interest at this time to proceed with our previously announced plans. There is too much governmental uncertainty as well as an almost unknown cost factor for construction for us to plunge ahead into the morass.(**Nuclear News** 1976)

The executives of Florida Power and Light similarly described the problems which resulted in the cancellation of the South Dade units:

> . . . Robert Uhrig, vice president for nuclear and general engineering, said he didn't see how any utility "that has to defend its actions to a public service commission could justify a business

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8. See Appendix II

decision to 'go nuclear' in the present environment...The nuclear licensing process has been destabilized to the point where sound business decisions cannot be exercised with respect to nuclear facilities. Sound business is dependent upon predictable time schedules and costs, and neither is present in today's era of uncertainty."(**Nuclear Industry** 1977b)

Q: **Was all of the commentary on the nuclear industry negative in this period?**

A: No. Many of the same authors who I have quoted also continued to express surprise at the size of the increases, even after the pattern had persisted for a decade. Also, even in the middle of a recitation of the industry's woes, many authors paused to express their faith in the need for nuclear power, and in the eventual recovery of the industry. Considering the close ties of many of the authors and their publications to the nuclear and utility industries,[9] it was predictable that they would endorse the overall objectives of those industries.

Q: **Can you identify any particular events or trends which contributed to the problems of the nuclear industry in the period 1972-1978?**

A: There were at least two groups of major influences. The first group arose directly and indirectly from the Arab oil embargo and the change in energy markets in 1973-74. The

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9. For example, **Nuclear News** is published by the American Nuclear Society, and **Nuclear Industry** by the Atomic Industrial Forum, the major nuclear political lobby.

second group consisted of changes in the nature of regulation in the nuclear power industry.

Q: **What effects did the oil embargo have on the nuclear industry?**

A: While the oil embargo and the subsequent rise in oil prices improved the relative economics of any technology which promised to reduce utility oil consumption, it also had several negative effects. The oil shock greatly increased the cost of electricity in many parts of the country; reduced load growth of many utilities to virtually unprecedented levels; encouraged conservation actions; established that energy efficiency improvements were an alternative to new power supplies; increased inflation; and greatly increased the financial stress on utilities. These factors combined to reduce the need for nuclear plants, making it harder to justify building any new generation and raising the possibility that new units might not be needed for long periods after they entered service.

Q: **How did regulatory scrutiny affect nuclear power?**

A: Attitudes changed both among the safety regulators at the Nuclear Regulatory Commission (NRC) and among the rate regulators at the state level. For the NRC, the March 1975 cable fire at Brown's Ferry nuclear power plant was particularly important in prompting stricter regulatory oversight. It alerted the NRC to the possibility that significant safety problems could slip past its initial screening, and thus be present in units under construction or in operation. Olds (1977) commented extensively on the growth in safety regulation, which he described as "ratcheting gone wild," and its adverse impact on plant costs. He noted that an average of three new requirements having significant impact on NSSS design were issued by the NRC every month during 1976.

State regulators started to inquire as to the need for the construction programs. In California, for example, the Sundesert nuclear plant was subjected to lengthy state hearings which led to its rejection and cancellation in 1978. The Wisconsin PSC undertook similar reviews of the need for planned facilities in that state, and concluded that further nuclear investments were inappropriate, which finally resulted in the cancellation of 3 nuclear units in the state.[10]

Q: **Did PVNGS experience many of the problems which plagued the industry in this period?**

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10. The chairman of the Wisconsin commission at that time, Charles Cicchetti, later testified on cost recovery mechanisms in MDPU 906 on behalf of Boston Edison. Prof. Cicchetti testified in some detail that he was aware, and utility managers should have been aware, in the early to mid-70s of several of the problems regarding nuclear plant cost overruns and schedule slippage, and utility financial stress discussed above.

A: Yes. As shown in the figures and tables in section one, PVNGS cost estimate increased from $2.5 billion in 1973 to $3.6 billion by the time a construction permit was issued in 1976. In the same period, the in-service date for Unit 1 had slipped 1 year, Unit 2 had slipped 18 months, and Unit 3 had slipped 2 years. Over the next two years, the estimates remained relatively stable, although the cost estimate rose about 10% during 1978. Graphs of the changes in total cost estimates and projected commercial operation dates are provided in Section 1.

Q: What was the regulatory reaction to EPE's involvement in PVNGS?

A: The New Mexico Public Service Commission issued a Certificate of Convenience and Necessity for EPE's PVNGS share in February 1977, in Case No. 1216. That approval was not unconditional, as the Order expressly stated that the certificate was "subject to modification" and indicated that no approval was being given regarding the value of the plant for ratemaking purposes.[11]

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11. These limitations, and the fact that the CCN was based on EPE's cost estimate for the plant, may indicate that the CCN does not inoculate EPE from a finding in this case that its decision to proceed with the plant in 1976 was imprudent. Even if EPE is so inoculated, the continuation of adverse news in the industry in 1977 and beyond should have prompted EPE to terminate its involvement in PVNGS by 1978, as will be demonstrated in Section 4.1.

3.1.3 TMI and the End of Hope: 1979 and Beyond

Q: What important developments occurred for PVNGS, in 1979 and after?

A: First, EPE received some important warnings regarding its nuclear construction program, including admonitions to reduce its commitment to PVNGS. Second, the April 1979 accident at Three Mile Island (TMI) further accelerated the ongoing changes in nuclear regulation and dashed any hope of rapid recovery in the industry. Third, the general deterioration in the economics of nuclear power continued, accompanied by a virtual torrent of plant cancellations which for the first time exceeded new orders in 1975, while the last new orders occurred in 1978.

Q: What warning signals regarding its PVNGS investment were presented to EPE in this same period?

A: Regulatory authorities in Texas repeatedly questioned the prudence of EPE's involvement in PVNGS.[12] In September 1979, PUCT Docket No. 2641, the El Paso City Council, concerned about reduced load growth and impact on ratepayers, recommended that EPE divest itself of 25% of the PVNGS project. In PUCT Docket No. 3254, September 1980, the City

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12. See testimony of R.E. York PUCT Docket No. 6350.

Council ordered EPE to divest itself of 50% of its PVNGS investment.[13]

In PSC 1454, dated June 8, 1979, the Public Service Commission of New Mexico reviewed the history of EPE's involvement in PVNGS and concluded:

> After analyzing the vast amount of testimony regarding El Paso's continued participation in the Palo Verde venture, we believe that serious questions have been raised concerning the prudence of El Paso's reliance upon the Palo Verde project as the best means available to serve its customers in the decade of the 1980s.
>
> However, we are unwilling to support or encourage the Company's continued participation in the ambitious Palo Verde project at customer expense without an exhaustive review of the costs/benefits of the programs. We do not believe that El Paso has given serious consideration to energy conservation methods in order to reduce demand. Moreover, El Paso's reliance on a fuel mix, composed of oil, gas, and nuclear creates substantial risks to the Company's future ability to serve. We are concerned with the financial problems occasioned by the Company's construction program. In short El Paso's construction program and means of financing it needs a thorough review.

Q: **How did NRC regulation change in this period?**

A: The accident at TMI further increased the NRC's reluctance to take unnecessary risks with potential safety problems at reactors under construction or in operation. It was widely perceived that another TMI-scale accident might well be a fatal blow to commercial nuclear power development, and

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13. EPE eventually agreed to an off-system sales credit tariff in exchange for the council's agreement to repeal its initial order.

almost any cost imposed on individual plants was preferable to collapse of the industry. While the post-TMI regulatory reaction was not a sharp break from the past trend, the accident was a clear indication that the trend was not about to moderate in the near future.

Q: **Did the utility industry literature continue to reflect the problems of the industry?**

A: Yes. From **Electrical World's** 1979 Nuclear Plant Survey come these observations:

> If you were disturbed by the statistics contained in last year's nuclear-plant survey, the 1979 roundup won't help to settle your stomach. Unit cancellations, delays and postponements are on the rise, while the total number of reactor commitments, through 1995, has dropped alarmingly.
>
> Another very disturbing element is the large number of postponements and delays in commercial operation, ranging from one year to as long as six years, with a concomitant increase - from seven to eleven - in the number of units now in the "indefinite" column. Just as discouraging is a new listing: two units in the "work suspended" designation.
>
> Although we usually endeavor to be upbeat and optimistic in seeking the often elusive silver lining in a cloudy report, this time around offers us an unprecedented challenge.

The nuclear A/Es were not silent, either. From Burns and Roe came the following observation:

> It is clear that nuclear power is in deep trouble. . . In the first eight months of 1979 alone, 67 nuclear plants were either deferred or canceled and the Nuclear Regulatory Commission has imposed a temporary moratorium on the licensing of nuclear power plants.

Many other sources shared the deep negative feelings while observing the state of the nuclear industry (see Appendix II).

3.2 The Experience

Q: What implications did the historical experience of the nuclear industry have for PVNGS?

A: The experience of the seventies and early eighties provided the background for EPE's decision to get involved with PVNGS, and was the basis for its interpretation of official cost and schedule estimates of the plant. Unless there was some reason to believe that the nuclear industry's ability to forecast costs and schedules had improved, it would have been appropriate for EPE to analyze the experience of nuclear plants in the seventies and early eighties, and adjust the cost and schedule estimates for PVNGS according to the results of these analyses. Thus, EPE management should have known that, if the factors which had caused other nuclear power plant estimates to be incorrect also operated for PVNGS, it would be considerably more expensive and time-consuming to construct than implied by the official projections from the operating utility (APS) and the Architect/Engineer, Bechtel.

Q: Did EPE have any reason to believe that the PVNGS cost and schedule estimates were more reliable than the national data would suggest?

A: No. EPE had no previous experience with building or participating in nuclear projects, nor was there any regional experience of this kind.[14] APS had never been involved in a nuclear power project previously. Thus, EPE had to base its decisions on national experience with completed nuclear plants, and units still under construction, which showed that it would not have been reasonable to place much faith in the quality of conventional cost estimates for PVNGS.

Q: **How realistic were ANPP's original in-service date estimates?**

A: Table 3.1 lists all units ordered in 1973, and the original projected in-service dates. The schedules for PVNGS Units 1 and 2 are a bit optimistic, with COD dates 3 and 8 months ahead of the averages. Although there is little experience with three unit plants, the schedule for PVNGS Unit 3 appears rather conservative, with a COD date 10 months later than the average. On average, the construction schedule was very similar to the industry norms.

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14. The closest operating nuclear power plant prior to PVNGS Unit 1 entering service was the Fort St. Vrain unit of Public Service of Colorado (PSCO). This unit is a high-temperature gas-cooled reactor, which does not have much direct relevance to the experience of a more conventional light-water reactor, such as those at PVNGS. Fort St. Vrain received its construction permit in September 1968, at which time it was projected to be in commercial operation by April 1972. It received an low power operating license in 12/73, but due to various operating problems, did not enter commercial operation until 1/79. Since that time, it has continued to have severe performance limitations, which have resulted in ratemaking penalties for PSCO.

Q: **Have you performed any analysis of the nuclear power plant cost and schedule information during the time in which EPE was under construction?**

A: Yes. I have examined five points in the planning and construction of PVNGS: the early 1970's (through 1972), the end of 1976, the end of 1978, the middle of 1980, and the middle of 1982. The first period corresponds to the decision to start the PVNGS project; the second period represents the receipt of construction permits and the beginning of construction; the third period reflects the state of the industry at the time of the Three Mile Island (TMI) accident; the fourth period is after the effects of TMI on nuclear construction were evident; and the fifth period is quite late in PVNGS construction, as measured by reported percentage completion.

Q: **What information was available regarding nuclear power plant cost estimates in the seventies and early eighties?**

A: Appendix III-A summarizes the cost and schedule estimate histories of all the commercial nuclear power plants which were in commercial operation by the end of each period under examination, and which were built without any extraordinary cost guarantees.[15] For each of these units, Appendix III-A

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15. I have excluded both 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.

lists the actual commercial operation date (COD), the actual construction cost, the date of the first available cost estimate, and the estimated cost and COD for that estimate. It is certainly not difficult to determine that both the cost estimates and construction schedules of these units grew significantly during their planning and construction.

To quantify the extent of the errors in cost and schedule estimation, I have calculated several statistics for each cost and schedule 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"),

- 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 were pushed further into the future, utilities more severely underestimated the cost of plant construction. I have measured this effect with the following formula:

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

Q: **Does the fact that PVNGS is a three unit plant create any particular complications?**

A: Yes. The reliability of schedules for first units (like PVNGS 1) in a project may differ from those of succeeding units (like PVNGS 2 and 3). The later units could be subject to greater delays and disruption, as problems arise on the leading unit, or they could profit from the experience of the leading unit. Accordingly, the analyses in Appendix III-A calculate average duration results separately for first units and for succeeding units. In general, the first units show slightly greater schedule slippage.

Q: **What do these results of these analyses imply for PVNGS?**

A: If the 1973 PVNGS cost estimate had increased as fast as had those of units completed by 1973, EPE's share of the PVNGS cost would have been $1.4 billion in 1973. Repeating the same calculation for later data would have produced higher final costs: for example, had the 1982 PVNGS estimate experienced increases comparable to completed plants through 1982, the final cost would have been $2.1 billion.

If the scheduled date of commercial operation for PVNGS had experienced delays comparable to the average completed plant, Unit 1 would have entered service in 1984, Unit 2 in 1986, and Unit 3 in 1989. This would be true for an analysis performed almost any time from 1973 through 1982.

The effect on PVNGS costs and schedules of continuing these historical trends is calculated from the average cost and schedule performance of completed units, as summarized by the statistics presented in Appendix III-A. A detailed explanation of this entire analysis is also contained in Appendix III-A. Table 3.2 summarizes the results of these analyses.

Q: How do the current estimates of PVNGS compare to the corrected estimates you have presented in Table 3.2?

A: EPE's current estimate of its cost of PVNGS is about $1.5 billion. This figure is at the lower end of the range which EPE reasonably could have expected, based on past cost increases in the industry. The corrected schedules summarized in Table 3.2 would have predicted an earlier in-service date for Unit 1 than actually occurred, and much later commercial operation at Unit 3 than is currently scheduled: the predicted COD for Unit 2, and the average date for the plant as a whole, are remarkably close to EPE's current projections.

Of course, the completion of Units 2 and 3 may still be delayed from their present schedule, and the final plant cost may significantly exceed the current estimate.

Q: **Were the experiences of cost and schedule slippage for the entire construction period of completed plants applicable to PVNGS, even after significant construction had been completed at PVNGS, such as in 1980 or 1982?**

A: Yes. Tables III-7 and III-10 in Appendix III-A demonstrate that cost overruns and schedule slippage were just about as severe for plants which were 18% and 33% complete as for those which were just starting construction. EPE would have observed the same pattern of cost overruns and delays, whether it had examined historical data starting from the estimate made around Construction Permit issuance, or at some significantly later point. Therefore, the corrected cost estimates from Table 3.2 are a fair representation of the final costs EPE should have expected for PVNGS.

Q: **Would EPE have reached very different conclusions had it examined the experience of nuclear plants which were**

still under construction, rather than those which were completed as of each of the review points you discussed above?

A: Yes. The picture presented by plants under construction was consistently gloomier than was the data from completed plants. Appendix III-A also presents and summarizes data for plants under construction at each of my review points. For most of the period PVNGS was in planning and construction, nuclear units under construction were only getting about one year closer to commercial operation for every two years that elapsed. If the historical experience had been repeated at PVNGS 1, the results through 1972 would have indicated an actual COD of July 1991, and experience through 1982 would have resulted in a September 1985 COD. Between 1978 and mid-1980, the in-service date of the average unit under construction actually slipped by more time than the interval between the dates of the estimates, resulting in negative progress: any unit which continued to experience negative progress would never have been completed.[16]

In addition to their slow progress, the plants under construction were experiencing rapid increases in their cost estimates. On the average, cost estimates for plants under construction were increasing from 16% to 24% annual, depending on the time period examined. Even after accounting

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16. In fact, many of the plants under construction in the 1976-82 period have since been canceled.

for the inflation and AFUDC caused by schedule slippage, costs were increasing by 12% to 17% in real terms. If these growth rates had applied at PVNGS, coupled with the average rate of progress until the Unit 1 COD, EPE's share of PVNGS cost would have been as much as $8.3 billion (starting with the September 1973 estimate), or perhaps only $2.3 billion (if the analysis starts with the May 1982 estimate). Table 3.3 offers a summary of these results, which are generally worse than the actual results, and worse than the extrapolation of results from completed plants.

Q: **What would a prudent utility have concluded from the experience at other nuclear units in the 1970s and early 1980s?**

A: By 1973, a prudent utility would have known that <u>if recent experience continued</u>, PVNGS would be completed much later than was then projected, and at a much higher cost. That prudent utility would also have known that, even if the historical experience moderated considerably, PVNGS would take a long time to build and would be very expensive, and that completion of the unit at anything like the official cost estimate would require a radical change in the nuclear construction environment.

By 1976, a prudent utility would have recognized that the adverse experience in the industry had continued for a long time. In light of the problems discussed in Section 3.1 and in Appendix II, this experience was not likely to improve quickly. Thus, the prudent utility would have expected the final cost of PVNGS to be similar to the current estimate, and would have known that the cost could have been much higher.

In the later 1970s and early 1980s, the continued deterioration in both the literature and in the construction estimates would have caused a prudent utility to abandon any expectation that the historical trends would reverse soon enough to aid PVNGS.

Q: **Do you make any particular assumptions in applying the historical experience of the nuclear power industry to PVNGS?**

A: Yes. Projecting the historical experience would have been appropriate in the late 1970's if one had assumed that the situation in the late 1970's and into the future was as unsettled as the previous decade, and that the PVNGS estimate was consistent with utility practice. I believe that a reading of the utility literature in Section 3.1 and Appendix II supports the first assumption (which is not subject to any rigorous test in any case). The second assumption is subject to more empirical tests, if rather rough ones.

In a period of 100% cost overruns in nuclear construction projects, the estimates for PVNGS in 1976 through 1978 included only tiny contingencies, on the order of 10% of direct costs.[17] These contingencies were comparable to, or even more optimistic than, contingencies in estimates for other nuclear power plants in the same period.

Q: Would EPE have needed any special expertise to identify the patterns of cost overruns and schedule slippage you discuss above?

A: No. The raw data on cost estimate histories (see Appendix III-B) indicate that cost overruns and schedule slippage was routine, and nearly universal. These relationships would be clearly apparent to any observer, and were noted in the industry literature at the time. It is more difficult to precisely quantify the lessons the observer should have drawn from the data. I do not believe, for example, that it is fair to assume that each utility involved in nuclear construction should have done regression analyses on the cost trends.[18] Regression is a fairly sophisticated technique, whose results are sensitive to the exact data and functional forms used in the analyses.

The methods I employ in this testimony -- looking at the percentage cost overrun, or annualizing that value, or comparing actual and projected construction durations -- are

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17. The absolute and relative size of contingencies in ANPP cost estimates fell considerably as construction progressed, so that they were only about 4% of direct costs by 1979 and 1980.

18. See the examples in my bibliography by Bupp, et al., Komanoff (1980), and Perl.

all simple, obvious ways of summarizing the large and growing experience of nuclear construction. I am not suggesting that EPE should have performed exactly the same summary calculations that I present in this testimony, but rather that EPE should have examined the uncertainties and contingencies involved in nuclear investments,[19] that they should have done some simple analyses of the historical data, and that the same general conclusions could have been reached through several types of analysis, including an informal examination of the data. Therefore, I believe that it is appropriate to judge EPE's prudence as if it had these calculations, since its staff should have been familiar with the industry literature and with the nuclear cost data and should have noted (formally or informally, rigorously or intuitively) the same patterns and relationships I present.

Q: **You mentioned above that many of the units under construction in the late 1970s and early 1980s were not completed. Please describe the history of nuclear cancellation in this period.**

A: A total of 46 units were canceled between 1976 and 1980. With few exceptions, the units canceled prior to 1980 were awaiting construction permits: units with permits were not heavily hit by the wave of cancellations until 1980. Figure

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19. As I have shown in the previous section, the utility industry literature provided ample notice that nuclear plant construction was subject to unusual problems.

3.1 portrays the annual and cumulative cancellations, through 1983. Figure 3.2 presents the number of new orders, the number of cancellations, and the net change in orders in the same period. Table 3.4 lists the plants canceled in 1977-82, with the construction status of each.

Q: **Based on your analysis of the nuclear power plant experience, what have you concluded about EPE's prudence in generation planning for PVNGS?**

A: A simple examination of the information available in the seventies and early eighties gives a clear indication of the excessive cost overrun and schedule slippage throughout the nuclear power plant history. Given this information, EPE should have anticipated the high cost and delayed commercial operation dates for PVNGS, and attempted to decrease or terminate its participation in PVNGS construction.

4 EPE'S ERRORS IN GENERATION PLANNING FOR PVNGS

4.1 EPE Should Have Expected PVNGS Power to be Expensive, Even Compared to Traditional Alternatives

Q: How did EPE review its participation in PVNGS?

A: EPE's efforts in this respect seem to have been limited to a series of short studies, probably prepared for hearings or for internal use, examining coal and nuclear costs.[20] All of these "Palo Verde versus Coal" studies basically rely on ANPP's cost and schedule forecasts. One of these studies claims to produce an independent estimate of the cost of power from PVNGS, but the only PVNGS cost parameters which come from sources other than PVNGS project documentation or EPE cost forecasts are the O&M projection and a 10% construction cost contingency.

Another set of studies which review EPE's participation in PVNGS, are the "participation studies" of which I have seen five.[21] These studies appear to have been started in

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20. The following studies were made available to me at EPE's headquarters in El Paso: "Coal Plant vs. Palo Verde Expense, Exhibits for Use in FERC Hearings ER78520," Arthur D. Little, October 5, 1978; "Palo Verde vs. Coal" by Stan Gross, February 7, 1980 and "Palo Verde vs. Coal" by Stan Gross, November 11, 1980.

21. Stone & Webster, "EPE, Level of Participating in Palo Verde," September, 1979; Stone & Webster, "EPE, Palo Verde Study,"

response to pressures from Texas regulators to evaluate the scope of EPE's participation in PVNGS, and only after the City Council had ordered EPE to sell part of its entitlement. Again, these studies use EPE or ANPP projections for costs, schedule and performance. I have found no EPE studies which directly question the accuracy of ANPP project management's cost and schedule forecasting methodology, or which attempt to make an independent, realistic estimate of the cost of PVNGS power.

In discovery,[22] I asked EPE to describe any efforts to independently review PVNGS cost and schedule estimates, and to provide studies and memoranda produced as a result of such a review. EPE's reply to this interrogatory was: "EPE conducted no such reviews."

Q: **What would EPE have found if it had realistically compared the cost of power from PVNGS to the cost of power from new coal plants?**

A: EPE would have found that PVNGS power was more expensive than the coal alternative, for any period between 1976 and 1982. Even neglecting the sunk costs of PVNGS, the costs of completing and operating the plant would be greater than the

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December, 1980; "Palo Verde Participation" by F. Mattson, December 1, 1980; Stone & Webster, "EPE, Palo Verde Study," March 27, 1981; EPE, "Palo Verde Participation Study," June 30, 1983.

22. See AG-IR-3-40.

cost of coal power, for an analysis performed any time from 1976 to 1980.

Q: How have you analyzed EPE's decisions to maintain its participation in, and to support continued construction of all three units of PVNGS throughout the late 1970s and early 1980s?

A: I reconstructed a traditional utility busbar[23] cost comparison of PVNGS to the usual alternatives -- new coal plants and existing oil or natural gas fired plants -- at four points in time during the interval from 1976 to 1982. I estimated the levelized busbar cost of energy from PVNGS, as it might reasonably have been projected by EPE in 1976, immediately following the start of construction; in 1978, just before the TMI accident; in 1980, after TMI;[24] and in 1982.

For PVNGS energy, I produced two sets of busbar costs: the EPE or "optimistic" case, which uses utility cost inputs, and the "historical" case, which replaces utility estimates for capacity factor and O&M with simple historical averages and

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23. The "busbar" cost refers to the full cost of production, including capital and operating costs, but excluding the costs of transmission, distribution, and line losses.

24. As noted in Sections 2 and 3, the regulatory and cost changes which followed the TMI accident were part of a continuing trend, rather than a major change in the historical pattern. TMI certainly dispelled any reasonable hope that the environment for nuclear construction might improve dramatically in the near future.

trends. For both comparisons, I assume realistic in-service dates (1986, 1987 and 1988 for Units 1, 2 and 3, respectively) and a realistic construction cost.(I use the current estimated construction cost for EPE's share of PVNGS, which was $1.486 billion as of October 1985.) As demonstrated in the previous section, EPE should have anticipated a final cost of this magnitude, as far back as 1976.

Q: **How did you determine the historical averages and trends?**

A: Appendix IV provides the data and a detailed explanation of the simple analyses I performed to determine historical averages and trends in O&M costs and capacity factor.

Q: **To what did you compare these PVNGS busbar cost estimates?**

A: I compare PVNGS levelized busbar costs to the levelized busbar cost of energy from the conventional sources which were the most obvious competitors to PVNGS, namely coal and natural gas, also reconstructed for 1976, 1978, 1980 and 1982.

Q: **Which of your nuclear cost cases best represents a careful projection by a prudent utility?**

A: The historical nuclear case is clearly preferable to the optimistic nuclear case, since the former is based on actual experience available at the time. I deliberately used only simple analyses, rather than the complex multiple regressions used by most analysts. It is quite reasonable to expect utilities to recognize the important trends which affect the economics of their investments. It is much harder to determine what functional forms of analysis a prudent utility should use to track those trends.

Q: **What are the results of your retrospective busbar power cost comparisons?**

A: The table below summarizes the results of this retrospective busbar comparison. Tables 4.1 through 4.8 present the components of the levelized costs.

LEVELIZED BUSBAR COST RESULTS, cents/kWh

PVNGS-Historical

Year		Average for Year	All Units	Unit 3		Coal	Gas
1976	Net		11.5	12.3	5.1-7.2		11.4
	Gross	11.8	12.4				
1978	Net		11.4	12.9	7.2	9.4	
	Gross	12.8	13.4				
1980	Net		7.9	9.2	7.4	13.4	
	Gross	12.1	11.4				
1982	Net		5.7	6.0	10.9	15.8	
	Gross	14.2	13.7				

The net, or incremental, bus bar cost calculation subtracts the sunk costs from the total cost. Net cost is appropriate for cancellation decisions, since the sunk costs could not be avoided by cancellation. The gross, or total, cost calculations are relevant for sales of capacity, which would recover most or all of the sunk costs.

Tables 4.1 - 4.8 present results for the four time cuts in pairs (first for net cost, then for gross cost), showing all components. The inputs for these tables come from the levelized cost calculations in Appendix IV.

Q: **What are the results of your analysis for 1976?**

A: In 1976, a realistic appraisal of the levelized net cost of PVNGS power would have been about 11.5 cents/kWh: PVNGS 3 would have been expected to cost about 12 cents/kWh. Sunk costs were very limited in 1976 (EPE's share totaled only about $50 million), and make virtually no difference to the analysis; gross cost is only minimally higher at 11.7 cents/kwh on average for PVNGS and 12.4 cents/kwh for Unit 3.

Compared to coal, at 5 - 7 cts/kwh, PVNGS looked very expensive, and even compared to gas, at 11 cts/kwh, PVNGS was not the most economical energy source.

Q: **What should EPE's response have been in 1976 to these realistic cost comparisons?**

A: EPE should have recognized that PVNGS would not be economic for gas (or oil) backout, and should have been pursuing other options to provide capacity and reduce costs. So long as conservation, cogeneration, purchases and other alternatives were sufficient to keep reasonably efficient gas as the average marginal fuel,[25] existing gas plants would be less expensive energy sources than PVNGS. Of course, gas and oil prices were (and still are) uncertain, and prudent management would still want to replace gas with an energy source having lower and less volatile costs.

Fortunately EPE had a much better source of base-load energy than either PVNGS or existing gas plants: coal plants were not only less risky to build, they could be on line faster than PVNGS.

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25. Of course, in some hours the marginal fuel could be from a cheaper source than 10,700 BTU/kWh natural gas, such as purchased coal, while in other hours the marginal fuel would be from a more expensive source, such as a gas turbine.

Q: What do the results of your comparison imply for 1978?

A: A realistic appraisal of the incremental cost for PVNGS would have been around 11.4 cents/kWh, while the total cost would have been almost 13 cents. Unit 3 costs would have been 1.4 to .5 cents higher than these figures, respectively. The increase in the cost of PVNGS power from the 1976 analysis to the 1978 analysis is primarily due to a reduction in capacity factor. Coal power would have been expected to cost about 7.3 cents/kWh, slightly higher than in 1976. Existing gas power would have cost less than 9.4 cents due to a slight drop in gas price projections for 1986, as well as a significantly lower projected escalation rate for gas beyond that date.[26]

The implications of the 1978 results would have been generally similar to those of the 1976 results, except that PVNGS looked worse and gas looked better. New coal plants still beat PVNGS by a wide margin. At 1978 projections of gas prices, EPE should have expected to be better off burning gas, rather than backing it out with either PVNGS or new coal capacity.

Q: Had the situation changed by mid-1980, over a year after the TMI accident?

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26. In 1976, EPE was assuming gas prices would escalate at 8% after the year 1985, and in 1978, EPE changed that assumption to a 6% growth rate after 1995.

A: Yes, in two important respects. First, PVNGS construction was now significantly advanced, so the differences between total costs and net costs were diverging, especially for Units 1 and 2.[27] The total cost of PVNGS would have been 12.5 cents/kWh, lower than in 1978. The net cost would have averaged only about 7.9 cents, about 3.5 cents less than in 1978. The remaining cost for Unit 3 would still have been about 9.2 cents.

Second, the expected levelized cost of gas had increased dramatically to 13.4 cents/kWh[28] over the 1986 - 2015 period. At these prices, gas would not remain an economical fuel over the expected life of PVNGS, even if the existing gas plants could be refurbished to operate for the entire period. However, as shown in Appendix IV, the cost of gas would not have exceeded the cost of PVNGS until the early 1990's, so there was no urgency in backing out gas with PVNGS. Even new coal would not have been cheaper than gas until about 1990.

Even with these changes, the incremental cost of power from the PVNGS plant as a whole would have been about one cent higher than the cost of a 1986 coal plant. Cancellation of PVNGS would have been of marginal benefit. The incremental cost of PVNGS 3 was at least 2 cents higher than that of new

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27. In addition, the cost of capital would have been higher, and capacity factors lower, but these would have been offset by a reduction in O&M for Units 2 and 3.

28. This was mainly due to a 10% inflation assumption.

coal, so cancellation of Unit 3 was still advantageous. Gas was no longer a viable long-run alternative to PVNGS or coal.

Q: **How does your analysis change when repeated for 1982?**

A: In 1982, the total cost of PVNGS power remained near the 1980 level of 13 cents/kWh. Since construction had progressed significantly, the sunk cost of the plant was higher than in 1980, bringing the incremental cost down to about 5.7 cents/kWh. Coal costs had risen to about 10 cts/kwh, as a result of both increased fuel costs[29] and of growing construction and ownership costs. New coal was now more expensive than finishing PVNGS. Nonetheless, the total cost of PVNGS was still greater than coal.

Gas cost projections were even higher than in 1980, but gas prices in the late 1980's were still expected to be less than the cost of power from PVNGS or from a new coal unit. In 1982, gas would have a levelized cost of nearly 16 cents/kWh.

Q: **What do you conclude from these retrospective analyses?**

A: Each of these analyses indicates that a realistic PVNGS cost estimate, given information available at the time, would have resulted in the conclusion that PVNGS power would be more expensive than power from contemporaneous coal units, based on an analysis performed anytime from 1976 to 1982. The

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29. Coal fuel prices rose sharply from 1980 to 1982, reflected in an increase of 1 - 2 cents on a levelized basis.

incremental cost of PVNGS would have exceeded coal costs through mid-1980, and the incremental cost of PVNGS 3 would have exceeded the cost of coal until 1982. Given the gas prices projected at the time, PVNGS was not even competitive over its lifetime with existing gas plants, for analyses conducted in 1976 and 1978.

4.2 EPE Failed To Pursue Coal-Fired Alternatives to PVNGS

Q: Given the foreseeable high cost of power from PVNGS, particularly in the 1976-82 period, did EPE respond properly?

A: No. EPE did not act in a timely fashion to investigate and facilitate the availability of any of the most promising alternative sources of power.

Q: What did EPE do to develop alternatives to PVNGS?

A: EPE did very little, if anything. I have seen no evidence EPE ever investigated the possibility of replacing its share of PVNGS with alternative sources of supply, from the time PVNGS was announced in 1973, into the 1980s. Even when EPE started to market half of its share of PVNGS in late 1981, it was simply attempting to dispose of excess capacity, rather than to replace an expensive source of power with more economical alternatives.

Q: What alternative sources of power should EPE have pursued?

A: EPE should have been more active in pursuing both new coal capacity, the traditional utility baseload alternative to nuclear power, and such less usual (but quite attractive) alternatives as conservation and cogeneration.

Q: **What actions with respect to coal would have been prudent, considering the foreseeable cost of PVNGS?**

A: As I discussed in Section 3, EPE should have known throughout the course of planning and building PVNGS that the cost of the unit was uncertain and subject to major upward revisions. Coal plants had been the obvious alternatives to PVNGS since the beginning of PVNGS planning. EPE had first participated in coal construction as a minority owner of the Four Corners coal plant in the late 1960's. In the nuclear construction environment of the 1970s, even if EPE <u>expected</u> nuclear plants to have cost advantages over coal plants, it should have kept open the coal option, in case the expectations did not materialize. In an environment of 100% cost increases for nuclear power plants, EPE should have been prepared to reduce or eliminate its PVNGS entitlement in favor of a coal alternative, almost from the time PVNGS planning began.

Q: **If EPE had acted in the way you suggest in the late 1970s, would it have been able to bring coal capacity on line in the 1980s?**

A: Yes. EPE had at least four options.

1. First, capacity has been available in San Juan Units 3 and 4. In mid-1976, Tucson Gas and Electric (TG&E, now Tucson Power and Light, TP&L) offered EPE firm power

from its half of San Juan 3 (which totaled about 240 MW).[30] EPE did not meet TG&E's price, and TG&E withdrew its offer in early 1977. San Juan 3 cost a little more than $900/kW. In 1979, TG&E sold its 50% share (236 MW) of San Juan 4 to PNM: since that plant cost PNM about $1250/kW, it is unlikely that TG&E's asking price for San Juan 3 would have been any more expensive.

After purchasing TG&E's share of San Juan 4, PNM found that it had excess capacity in general, and in the San Juan plant in particular. Portions of both San Juan 3 and San Juan 4 have been inventoried. The last portion of Unit 4 is not projected to leave inventory until around 1995. As a result, PNM sold off 40 MW of San Juan 4 to the City of Farmington in November 1981, 136 MW to the M-S-R municipals in California in December 1983, and 34 MW to Los Alamos County in December 1985. The sale prices gradually increased, from $1220/kW for the Farmington sale, to $1250/kW for the M-S-R sale, to $1390/kW for the Los Alamos sale.

Second, the New Mexico Generating Station (NMGS) was an option throughout the period PVNGS was under construction. This plant was envisioned by EPE and PNM (the Project Manager) as a set of four 500 MW units,

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30. Testimony of Fred Mattson, NMPSC Case No. 1454.

located in northwestern New Mexico and generally similar to the San Juan plant. Studies of NMGS started in 1973: when the plant was officially announced in April 1977, the first unit was scheduled for operation in 1983-85, with the other units following in 1987, 1989, and 1990.[31] PNM would have owned half the plant, EPE 15%, and Plains G&T the other 35%.

The NMGS schedule was allowed to slip, as PNM purchased TG&E's share of San Juan 4, and as Plains decided to build its own plant and withdrew from NMGS.[32] Had EPE locked up some of the San Juan capacity, PNM could have been expected to be more interested in pursuing NMGS. If EPE had been successful in effecting cancellation of one or all of the PVNGS units, NMGS would have been an obvious substitute: the combined shares of EPE and PNM in PVNGS were equivalent to two NMGS units. Cancellation of PVNGS would also have left the other participants (APS, SRP, SCE, and later the California municipals) looking for base-load power. Even with PVNGS in the picture, some California utilities (including San Diego G&E) were interested in NMGS capacity.[33]

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31. A fifth unit, scheduled for 1991, was also listed.

32. NMGS is now called the Dineh Power Project.

33. While NMGS or equivalent capacity was much more attractive than PVNGS in the 1970s and into the early 1980s, the fact that PVNGS is nearly complete and the large surplus of power throughout the Southwest has probably rendered addition

Third, Southwestern Public Service (SPS) has been building very economical coal plants very rapidly through the late 1970s and into the 1980s. The Tolk plant, whose two units entered service in 1982 and 1985, cost only $500/kW. Construction was completed on schedule both at Tolk and at the earlier three-unit Harrington plant (at which the first unit entered service in 1976). The units were generally completed within four or five years of ground-breaking and corporate authorization. Additional SPS coal capacity additions, such as the South Plains plant authorized in 1983 for operation in the 1990s, are apparently constrained by demand, rather than SPS's ability to build them.

SPS has shown considerable interest in sales to Intermountain Power Pool members. EPE actually arranged for a 100 MW purchase from SPS, but EPE's surplus of Palo Verde power has prompted it to reduce the size of this very economical purchase to 50 MW.[34] SPS was apparently unwilling to sell ownership in its

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capacity superfluous through most of the rest of this century. By its calculations, PNM will have excess capacity past the year 2000. If economical investments in conservation and cogeneration are pursued first, the Dineh project (the successor to NMGS) will not be required to serve New Mexico loads until well into the twenty-first century.

34. The EPE/SPS purchase will be discussed in greater detail in Section 5 of this testimony.

plants, but a life-of-unit contract for contingent capacity in one or more SPS plants should not have been much more expensive than direct EPE ownership. Considering the low cost of SPS capacity, it is entirely possible that a contingent purchase, even including the cost of new transmission, would have been EPE's least expensive source of coal power.

Fourth, EPE could have built its own coal plant, if all other options had been insufficient. Estimates by Stone & Webster (S&W) for New Mexico Electric Service Company in 1980[35] indicated that building new coal-fired units in a region close to EPE's south-eastern New Mexico service territory would cost from $234 million for a 120 MW unit ($1950/KW) to $540 million for a 450 MW unit ($1200/KW), including AFUDC (10% annually) and assuming service in 1987. Given these figures and the economies realized by second units, it would appear that EPE could have built a two or three unit coal plant totaling 600 MW for about $1200 to $1400/KW.

Since SPS had been so successful in building its own coal plants, EPE might have found it advantageous to hire SPS to design and build an EPE coal plant. This arrangement would have been most useful if coupled with

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35. PNM Response to Attorney General's 4th set of interrogatories, in Case 1794, page I-6.

an expansion of the DC interconnection between the two utilities and a hazard-sharing agreement, to spread the risk of outages at the EPE plant over a larger number of coal units.

Fifth, new and potential coal projects have been in excess supply in the Southwest.[36] For example, in June 1982, Utah P&L (UP&L) offered to sell EPE up to 25% (or 750 MW) of the Intermountain Power Project (IPP) in Utah. Since that time, the IPP has been scaled down and UP&L has dropped out, but UP&L still has excess capacity: it is attempting to sell 100 MW of Hunter Unit 3 to Nevada Power for $1353/kW, starting in 1988.[37] Thus, actual and proposed coal projects available in Utah alone would have been sufficient to replace all of EPE's 600 MW share of PVNGS: the coal capacity EPE actually needed would have been less than 600 MW.

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36. In their "Study of Interconnection With Utilities In Eastern New Mexico Or Texas," September 1979, Stone & Webster indicates that Texas Electric Service Company, Texas Power & Light Company, West Texas Utilities Company, and Texas Municipal Power Agency, each had attractive excess capacity. In the late 1970's, the Electric Reliability Council of Texas (ERCOT) refused to involve itself with interstate power transaction, making interconnection between these utilities and EPE impossible. In July 1980, ERCOT members and Central & Southwest Corporation filed a formal offer of settlement with FERC, which allowed for interconnection between states. Therefore, by mid-1980, EPE should have known that power purchases from any of the above mentioned utilities were feasible alternatives to PVNGS.

37. Hunter 3, a 400 MW unit with scrubbers, entered service in 1983, at $1140/KW (Interrogatory AG 9-6).

Of course, we can not now rerun history, to determine exactly what joint ownership in coal-fired facilities built by neighboring utilities would have been available at each point in time, or what opportunities EPE had for negotiating long-term purchases from those plants. Nor can we determine conclusively what sort of agreement EPE might have negotiated with other utilities for the purchase of power or for joint ownership in a coal plant. EPE's imprudence, in totally failing to pursue any coal plant ownership and purchase arrangements, precludes any absolute determination of the results of prudent actions.

Q: **If EPE had left the PVNGS project in 1976 or 1980, would EPE have been able to bring coal capacity on line in time to meet its needs?**

A: Yes. Existing capacity, such as San Juan and Hunter, are on line well in advance of EPE's need. For further coal capacity in the 1980s construction time would not have been a major impediment. Komanoff (1980) reports intervals of four to six years for construction of coal units with scrubbers in the 1970s, from boiler order to COD. Since all the units in his data set were on line by 1977, this information was available at the time EPE was making its important decisions regarding PVNGS. Budwani (1982) found that average construction times from first concrete for small coal plants (under 400 MW) were about 3 years, while the average for units over 800 MW was about 4.5 years. The 600 MW Somerset coal unit in New York was completed on schedule in 1984, after a construction period of 39 months.

The greater problem would have been siting and licensing. However, even back in 1973, EPE was aware that it took about the same amount of time to plan a coal plant as it did to construct one.[38] An EBASCO study (Patterson, et al., 1978) estimated that federal and generic state licensing for a coal plant would require 35 to 42 months from the start of site selection to permit issuance. More troublesome for a utility planner, the length of the licensing period was difficult to predict and control. Thus, it was important that the licensing and siting issues be resolved as early as possible, to allow informed decision-making. Given the data on nuclear costs available in the early 1970s, EPE should have been preparing a licensed coal alternative to PVNGS.

EPE estimated that construction of NMGS would have required approximately four years, and that by 1980 site approval could have required another 18 months.[39]

Q: **Was EPE imprudent in not abandoning PVNGS in the late 1970s, in favor of a coal plant?**

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38. A summary table in an EPEC-PNM Joint Planning study, dated August 1973 (page 5-19) shows lead time for a coal plant estimated at 6-8 years and actual construction time of 3.5-4 years.

39. Testimony of R.E. York, PUCT Docket 3382.

A: Yes. While there appear to have been even better options available, the choice between PVNGS and coal should have been a simple one. PVNGS was not likely to be cost-effective, and posed a substantial risk of being a major financial and economic disaster.

Q: **Why did EPE not abandon PVNGS?**

A: Basically, EPE appears to have hung on to PVNGS because planning for and executing any alternative required too much of an effort. As Rolland E. York explained in 1980 to the Texas PUC:

> It is extremely difficult to envision abandoning a construction project at any state of construction and starting over with site selection, design, environmental impact assessments, licensing, regulatory certification, engineering and awarding of contracts, all of which take time. It would be next to impossible and with considerable expense (sic) to get an alternative on line (commercial operation) at the same point in time to provide sufficient electrical energy mandated by the Company's franchise for its service area. Sunk costs or contract penalties for such a unilateral decision would also add to the cost. If future time tables could not be met, an allowance for replacement power costs would also be added. Generating units, whether coal or nuclear, take time and planning to construct and decisions to abandon are not made by utility management without thorough and exhaustive economic evaluations whether it (sic) be EPE or any other utility. (Testimony of R.E. York, PUCT Docket 3382, page 15)

Had EPE been able to imagine in 1973 or 1976 the possibility of eventually selling or abandoning PVNGS, it might even have undertaken the "thorough and exhaustive economic evaluations" which Mr. York still lacked in 1980. If performed realistically, that evaluation would have found that PVNGS was about the most expensive supply option available. In the course of that evaluation. EPE might also have realized that a coal plant could be designed and constructed faster than PVNGS could be completed, and started the siting and licensing process. When EPE finally decided to withdraw from PVNGS, which certainly should not have been later than mid-1980,[40] it would have been able to act quickly and decisively, selling its PVNGS entitlement and starting up its coal plant. Unfortunately, EPE never seriously evaluated the completion of PVNGS Units 1-3 against the coal alternative, and was therefore never really prepared to consider withdrawing from the project.

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40. As demonstrated in the previous section, the evidence available to EPE in 1976 or 1978 was sufficient to justify withdrawal from PVNGS. By 1980, EPE should have been able to recognize that the Three Mile Island accident in April 1979 had ruled out any reduction in regulatory pressure for the foreseeable future.

4.3 EPE's Choices and Decisions

Q: **What important decisions did EPE make regarding PVNGS?**

A: I would like to focus on three points:

1. For a utility of its size, EPE chose to own a very large portion of a single nuclear project.

2. Despite ample evidence that there were major difficulties in nuclear construction and cost control, EPE failed to actively seek a market for a substantial portion of its share of PVNGS until it was ordered to do so by the El Paso City Council in 1979. When EPE finally offered to sell 300 MW (half of its PVNGS share) in 1981, the Salt River Project (SRP) was also in the process of selling a major portion of its PVNGS share, and utilities had generally become very skeptical regarding investments in nuclear plants.

3. EPE does not appear to have ever opposed continued construction of PVNGS 3, even though cancellation of the unit would have been economical at least until 1980.

Q: **By what standards was EPE's share of PVNGS unusually large?**

A: Of all the utilities in the country, only Public Service of New Hampshire (PSNH) had a larger relative ownership in a single plant than did EPE. Table 4.9 lists the investor-owned utilities (and holding companies) with nuclear projects under construction (with construction permits but not yet licensed to operate) as of December 1978. For each such utility, Table 4.9 shows the utility's 1978 peak load, the nuclear construction project(s) in which it had the largest entitlement, the MW size of that entitlement, and the ratio of the ownership to the 1985 peak load.

Even Table 4.9 tells only part of the story. Many of the units listed have been canceled, the lead owners have reduced their entitlements in many of the remaining units, and several utilities are in financial distress due to the ownership levels shown on Table 4.9. For the examples with ratios exceeding 25%, 19 of the 28 units been cancelled (officially or otherwise).

In addition, the remaining nuclear investments have caused reduction or elimination of common dividends at PSNH, Public Service of Indiana, Gulf States, Consumers Power, and Long Island Lighting.

The experience of PSNH with Seabrook incorporates all these results. Since 1978, Seabrook 2 construction has been stopped, and PSNH has sold down to about 35% ownership, bringing its ownership/peak ratio down to 34%. PSNH is also in very poor financial condition, and has suspended common and preferred stock dividends.

Q: Please summarize the efforts of EPE to sell PVNGS capacity.

A: After repeatedly being ordered to sell part of its entitlement in PVNGS, EPE appears to have started looking for buyers in 1981. In December 1981, the M-S-R Power Agency (composed of the cities of Santa Clara and Redding, and the Modesto Irrigation District, all in California) agreed to buy 150 MW of PVNGS. The deal fell through when the voters of Modesto rejected the bond issuance to fund the purchase.

The Sacramento Municipal Utility District (SMUD) executed a Letter of Intent to purchase 150 MW in July 1982. This deal also was terminated, in this case by vote of the SMUD Directors.

Q: Would EPE have found it easier to sell PVNGS capacity if it had started earlier, in 1976, 1978, or even 1980?

A: The fact that California utilities purchased 27.41% of PVNGS during 1975-1981 indicates that to some extent it would have been easier to sell early on. In 1975, Tucson G&E sold its 15.8% share to Southern California Edison. SRP sold 5.7% of the project to the Los Angeles Department of Water and Power in 1977 and another 5.91% to the Southern California Public Power Agency (which includes the LADWP, 10 other cities, and the Imperial Irrigation District) in 1981.

As EPE admitted later,[41] its sales effort came too late:

1. Most utilities had made arrangements for meeting their loads in the 1980's.

2. Low load growth was producing excess capacity situations for many utilities in the region.

3. The projected in-service dates for the units were close enough that the 3-6 year lead time for new transmission ties interfered with some potential sales.

4. Potential purchasers were aware that PVNGS schedules were uncertain, and that the costs of the plants were high and likely to rise.

5. Nuclear power was no longer an attractive option: EPE referred to "diminishing confidence in the nuclear industry."

Most of these events were foreseeable. Had EPE realistically reviewed the prospects of PVNGS in the middle to late 1970s, it could have sold out before capacity plans were locked in for the 1980s, before transmission constraints were binding, before the bad news came out on the cost and schedule of PVNGS, and before utilities generally gave up on nuclear power.

Q: **Could PVNGS have been economical for any utility?**

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41. See the testimony of R. E. York in PUCT Docket 6350.

A: It might have been for the California utilities, whose generation planners were severely limited by the regulatory constraints of the area. New fossil-fueled plants would be very difficult to site in most of California, especially in the southern part of the state, due to air quality problems. Existing units in southern California were in some cases dispatched to minimize air pollution, rather than to minimize fuel costs. Even if a coal plant could be sited somewhere in the state, the pollution controls and fuel quality requirements would be very strict, and coal would have to be transported in from a considerable distance, so the cost of a California coal plant would be less competitive than the New Mexico and Texas alternatives available to EPE. Nuclear plants could not be located in California at all.

In addition, PVNGS would have been more attractive to a publicly-owned utility[42] than to EPE, due to the lower financing costs of public agencies. Since capital costs are a higher fraction of busbar costs for nuclear than for coal plants, PVNGS's cost disadvantage would be lower for a utility with lower AFUDC rates and carrying charges.

Q: **Does EPE appear to have properly questioned the wisdom of continuing PVNGS construction?**

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42. This category includes all the California utilities which purchased shares from SRP or signed initial agreements with EPE.

A: No. EPE appears to have accepted PVNGS without question until it had been ordered repeatedly to sell down. I have not found any evidence, in any of the documents EPE provided on discovery, indicating that EPE recognized the problems and risks of PVNGS until it was too late to sell its share. EPE never challenged the prudence of continued construction of any or all PVNGS units.

Q: What do you conclude regarding EPE's prudence in generation planning for PVNGS?

A: EPE's original decision to participate in the PVNGS project in 1973 would have been reasonable, if it had been accompanied by a commitment to carefully monitor developments in the industry and the plant. Since EPE failed to make (or fulfill) such a commitment, its participation was imprudent.

By the time PVNGS received a construction permit in 1976, EPE should have been attempting to sell its share of the plant, or to effect the cancellation of one or more PVNGS units, and to replace that capacity with a combination of new coal construction, purchases from other utilities, cogeneration development, and conservation programs. EPE erred seriously in failing to pursue either sales or cancellation in 1976.[43]

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43. The PSC approved a Certificate of Convenience and Necessity (CCN) for EPE's share of PVNGS on February 8, 1977, and EPE may argue that such approval demonstrates that its involvement in PVNGS was prudent to that date. This subject may involve legal issues, on which I can offer no opinion, but there are related factual matters which are worth noting. It is my understanding that the approval was dependent, in part, on EPE's representation regarding the eventual cost of

Continued construction of PVNGS was imprudent in 1978, and remained imprudent at least through 1980. In the 1976-80 period, sale of the plant, cancellation of Unit 3, or cancellation of the entire plant would have been cost-effective. In the early 1980s, sales were no longer feasible, and the cost of completing the plant had declined, so that completion of PVNGS become competitive with coal for the first time.

Q: Does EPE's minority ownership of PVNGS affect the prudence of its actions?

A: I believe that it should not, but there are two ways in which the Commission could treat EPE's minority status. The first, and simpler, view is that EPE retained its normal responsibilities to provide reliable service at the lowest possible cost. Thus, EPE would have a continuing duty to estimate the costs of PVNGS realistically, to compare that cost with alternatives, and to attempt to adjust its supply mix accordingly. I would recommend that the Commission adopt this usual standard of care, as it produces the clearest incentives for good management.

PVNGS, as about $660 million for EPE's share. If EPE had a duty to present an accurate and unbiased description of PVNGS in the CCN proceeding, its testimony should have included information comparable to that which I present in Sections 3.1 and 3.2. Had EPE realistically assessed the reliability of the PVNGS cost estimate, the case before the Commission probably would have looked much different. In any case, the granting of the CCN has no bearing on whether EPE was imprudent in 1978 and 1980.

The alternative rule for jointly owned plants allows minority owners to cede some of their responsibilities to the head owner. Specifically, cost estimation may be delegated in this way. If a joint owner takes this route, it must assume liability for the actions of the lead participant, which acts as its agent. Thus, the commission might find that EPE was entitled to rely on the APS cost estimates, and had no separate duty to review those estimates, but that EPE was consequently liable for the consequences of APS's errors in estimation. This is the rule before the Massachusetts Department of Public Utilities, for example. The effect is the same in either case: the utility actions were imprudent, and EPE is responsible for the outcome.

5 THE VALUE OF EPE'S INVESTMENT IN PVNGS

Q: **What is your estimate of the value of EPE's investment in PVNGS?**

A: I have calculated a range of values, based on differing assumptions about the replacement power source, PVNGS's operating characteristics, and the discount rate used in comparing costs over time. At best, the PVNGS investment is worth about $1500/kW. At the other extreme, some of EPE's entitlement may be worthless (or have negative value), since just running the plant may be more expensive than the alternative.[44]

Q: **How have you determined the value of PVNGS?**

A: I have estimated the value of PVNGS power as the cost of an equivalent amount of energy from an alternative source, such as an investment in a coal plant or in a contract to purchase power. The first two Tables in this section calculate the annual cost per kilowatt-hour of power from the San Juan 4 coal plant and of the Southwestern Public Service (SPS) purchase, two readily available alternative sources of power.

Q: **Why do you use these two alternative sources?**

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44. In addition, some of PVNGS appears to be excess to EPE's needs, and is thus worth even less than the figures I have computed.

A: In terms of capital cost, San Juan 4 appears to be representative of the coal capacity available for EPE purchase or ownership in the mid-80's.[45] As discussed in Section 4.2, San Juan 3 and 4 capacity has been available on the market since 1976.

EPE actually contracted to purchase 100 MW of capacity from Southwestern Public Service (SPS) but has now reduced that purchase to 50 MW, due to the operation of PVNGS. The additional 50 MW (which PVNGS has displaced) would have been a resource available well into the next decade, and perhaps indefinitely.

Q: Are these the least expensive alternatives to PVNGS?

A: No. As described in Section 4.3, many conservation programs would provide energy at much lower cost than either of these sources. Some cogeneration projects would also substitute for PVNGS at lower cost than new coal capacity, and with lower risk. An optimal mix of conservation, cogeneration, purchases and new construction would be substantially less costly than the alternatives used in my analysis.

Q: Why did you not compare PVNGS to a least-cost supply plan?

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45. For example, Hunter 3 is currently for sale at $1353/KW. EPE's projected cost of its next coal plant is $1100/KW in 1986 dollars (Interrogatory AG 3-30).

A: I have two reasons for not doing so. First, I have not determined the optimal mix of supply sources, or the cost of that mix. Second, it is not clearly appropriate to compare PVNGS to an optimal supply mix. While EPE has a basic responsibility to seek an optimal mix,[46] it cannot be expected to always produce an optimal mix. Utility supply planning will generally be less than perfect.

Therefore, I have used two proxies for supply costs which would have resulted from competent business-as-usual planning, rather than least-cost planning. In doing so, I have given EPE the benefit of the doubt, and intentionally compared PVNGS to fairly expensive, routine supply sources.

Q: How have you determined the cost of power from San Juan 4?

A: The cost of San Juan 4 power is estimated from current PNM projections of operating costs, plus capital recovery. Table 5.1 lists the cost components of a kilowatt of San Juan 4, and calculates an annual cost per kilowatt-hour in column [10]. The cost components include carrying costs, operating and maintenance (O&M) expense, fuel cost, and property taxes.[47] The levelized value of San Juan 4 ranges from about

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46. Unfortunately, EPE has failed to meet this responsibility, as discussed in Section 4.2.

47. San Juan 4 property taxes are from Interrogatory NMIEC 6-119, Case 1916. In reality, these taxes will be based on the depreciated book value of the coal unit and will thus decrease over time. For simplicity, we have held taxes

6.9 cents to about 7.8 cents per kilowatt-hour, depending on the discount rate used.

Q: **How have you determined the cost of the SPS purchase?**

A: The cost of power purchased from SPS is based on recent EPE studies. Table 5.2 combines the energy and demand charges for SPS purchases. This purchased power comes out substantially less expensive than power from San Juan, at about 4.9 to 6.2 cents per kilowatt-hour.

Q: **How did you calculate the value of EPE's PVNGS investment from these cent per kilowatt-hour values?**

A: I determined the value of a kilowatt of PVNGS by subtracting PVNGS operating costs--fuel, O&M, capital additions, decommissioning, property taxes and insurance--from the total value of PVNGS power, in terms of the cost per kilowatthour from alternative sources, to obtain an annual value of the initial capital investment. First, PVNGS fuel is subtracted in the last columns of both Tables 5.1 and 5.2, leaving the value of PVNGS non-fuel operating costs and capital investment.

Q: **How have you determined PVNGS non-fuel operating costs?**

A: My estimates of PVNGS non-fuel operating costs differ substantially from EPE's assumptions, so I have computed

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constant which will tend to overstate the cost of power from San Juan 4.

operating costs for two Cases, one using my estimates and one using EPE's assumptions. In Table 5.3, my estimates (labeled 'PLC') of annual O&M, capital additions, decommissioning, taxes and insurance are simply added to obtain total non-fuel operating costs.

EPE provided us with estimates for fixed and variable O&M expenses. EPE's forecast for fixed O&M and other fixed charges are summed in Table 5.4 as 'Operating Costs Minus Variable O&M' in column [6]. The variable O&M is determined by the capacity factor, another parameter for which my estimates vary from EPE's. I have therefore calculated two versions of EPE's annual non-fuel operating costs: one using EPE's projected capacity factor and one using my projected capacity factor, as shown in columns [8] and [9] of Table 5.4.

To simplify matters, I treat PVNGS as if the entire plant entered service on 1/1/87, in all Cases.

Q: **What were the sources for your projections of PVNGS non-fuel operating costs in Table 5.3?**

A: Appendix V describes the derivation of the important inputs to Table 5.3. My projections of capacity factor, O&M and capital additions are presented in Tables V-3, V-9 and Appendix I-1. Fuel, decommissioning, property taxes and insurance premiums are figures supplied by EPE in all Cases.

Q: **Please describe the calculation of PVNGS's economic value.**

A: Tables 5.5 through 5.12 present the final step in the calculation of the value of PVNGS. Cases 1 through 8 combine different assumptions about PVNGS performance and non-fuel operating costs. The odd-numbered Cases compare PVNGS to the cost of power from San Juan, and the even-numbered Cases calculate the value of PVNGS compared to the cost of purchased power from SPS. Cases 1 and 2 use my estimates of operating parameters, Cases 3 and 4 use my estimates of operating costs but EPE's capacity factor, Cases 5 and 6 use EPE's operating assumptions but my capacity factor projections, and Cases 7 and 8 are based entirely on EPE assumptions.

These Tables calculate the annual value of the investment in PVNGS: that is, what the capital investment is worth each year, after operating costs. From this series of values, we can determine what initial capital cost can be placed in rate base, without resulting in higher rates over the life of the plant than would have occurred had EPE wisely invested in equivalent coal capacity or had EPE maintained the SPS purchase at full capacity. This calculation is computed for discount rates of 12%, 15%, 18%, and 20%. The installed $/kW values may be thought of as the "comparable worth" of PVNGS capacity.

Q: What value does this process assign to a kilowatt of PVNGS?

A: Depending on the operating costs, the capacity factor and the discount rate assumed, the value of PVNGS ranges from $335/KW to $1541/kW, when compared to San Juan 4, and from -$196/kW to $908/kW, when compared to purchased power from SPS. The negative rate base indicates that PVNGS operating costs alone are more expensive than the total cost of power from SPS. This occurs when the discount rate applied is low, making the later years of negative annual capital values count more heavily.

For example, Table 5.5 presents Case 1, in which the value of PVNGS capacity is calculated so that PVNGS energy would have the same cost as power from San Juan 4. The value of PVNGS' non-fuel costs (San Juan total cost minus PVNGS fuel) is listed in column [1] for each year. Column [3] converts these values to $/kW-yr, using my projected capacity factor for PVNGS. Column [4] lists annual PVNGS non-fuel operating costs, using my projections from Table 5.3. Subtracting these operating costs leaves an annual value of the capital investment component in column [5]. The remaining columns compute the initial capital cost per kW which, when annualized at EPE's annual carrying charge rate and discounted at one of four different discount rates, would have the same present value as the comparable capital worth in column [5]. In this Case, the equivalent rate base is about $335 to $733 dollars per kilowatt of capacity.

Q: **How many comparable worth calculations have you done for PVNGS?**

A: Tables 5.6 through 5.12 present seven more Cases based on a forty year life, combining different assumptions. As one might expect, the use of EPE's highly optimistic assumptions (Cases 7 and 8), results in the highest economic value for PVNGS, and thus the highest rate base equivalent.

Q: **Which Case comparison do you consider to be most likely to reflect reality?**

A: Tables 5.5 and 5.6 are based on historical averages and trends, based on the results described in Section 6. All Cases 1 through 8 are somewhat optimistic in assuming a very long (forty year) life for PVNGS and in using EPE's assumed cost of decommissioning. However, Cases 1 and 2 are much more realistic than the Cases which utilize ANPP's very optimistic projections of PVNGS capacity factors, O&M expenses, and capital additions.

Since the SPS purchase is less expensive than San Juan 4, PVNGS capacity repriced to be comparable to the SPS purchase is always less valuable than that repriced to San Juan 4 cost. However, only 50 MW of additional SPS capacity is clearly available over the existing transmission line.

Q: **What is your best estimate of the value of PVNGS capacity under these conditions?**

A: The value of most of PVNGS's capacity would be around $550/kW, based on the compared to San Juan 4 power using my operating estimates for PVNGS, a 40 year life and a 15% discount rate.

Q: Have you relaxed the assumption of a forty year life for PVNGS?

A: Yes. Tables 5.13 - 5.16 repeat the background calculations of Tables 5.1 - 5.4, but for a 27 year useful life. Note that I also assume a 27 year life for San Juan 4, which is shorter than the likely life. Tables 5.17 - 5.24 repeat the eight Cases for the shorter life.

Q: What are the results for the 27 year useful life?

A: For the Cases which use my operating cost estimates, the value of the initial PVNGS investment is greater with the shorter life. This reflects the fact that, as noted in Appendix V-A, continued growth in O&M expense will make operation of PVNGS uneconomical. The shorter life avoids the highest operating costs. This effect is more pronounced for low discount rates and in comparison to San Juan. At lower discount rates, the later years are more important and have a greater impact on the present value of the time series. The shorter life also eliminates the most expensive years of the SPS purchase.

Overall, the 27 year life estimates range from $517/KW (Case 1, 12% discount rate) to $1,428/KW (Case 7, 12% discount rate) in comparison to San Juan 4, and from -$14/kW (Case 2, 12% discount rate) to $782/KW (Case 8, 12% discount rate), in comparison to SPS power.

If EPE is held to its current projections of capacity factor, O&M, and capital additions (Case 7), most of PVNGS would be worth $1381/kW at a 15% discount rate for a 27 year life, or $1,425/kW if depreciation is based on a 40 year life (and no recovery is allowed for earlier retirement). Fifty megawatts of PVNGS can be compared to the cost of the abandoned SPS purchase at a 15% discount rate: $72/kW for my operating projections, $694/kW for EPE's assumptions and a 27 year life, or $766/kW for EPE's assumptions with a 40 year life.

It is important to recall that these estimates are based on the cost of capacity which would have been needed if EPE had not participated in PVNGS, namely San Juan 4 or a purchase from SPS. Any capacity which would not have been needed would not be included in this calculation, which applies only to necessary kilowatts of capacity.

Q: **What are the implications of the values you have calculated?**

A: These results have two separate meanings for ratemaking purposes. First, they are estimates of how much PVNGS investment can be placed in rate base, without charging ratepayers more than they would have paid had EPE acted prudently with regard to PVNGS and generation planning in general. Thus, these figures allow the Commission to determine the excess costs which result from EPE's imprudence with regard to the decisions discussed in Section 4.

Second, independent of prudence considerations, these figures are estimates of the market value of PVNGS capacity. A purchaser which believed EPE's projections of PVNGS operating parameters might pay as much as $1500/kW, while one which believed my projections would only pay about $600/kW. Even if the Commission did not find any imprudence on EPE's part, or was unable to quantify the excess costs caused by that imprudence, these values determine the size of the loss EPE has incurred from PVNGS. That loss (roughly $900 to $1,800 per kilowatt) may then be divided between shareholders and ratepayers in any number of ways.

6 PERFORMANCE STANDARDS

6.1 Introduction

Q: Have you testified previously regarding performance targets for utility power plants?

A: Yes. I testified in Massachusetts Department of Public Utilities (MDPU) docket numbers 1048 and 1509, the first two reviews of Boston Edison's proposed power plant performance standards, under the new fuel clause statute, M.G.L. c. 164, section 94G (effective August 6, 1981). That statute eliminated the essentially automatic recovery of fuel costs, and required that the fuel adjustment charge be based on "the efficient and cost-effective operation of individual generating units".

I also testified before the Michigan Public Service Commission in the 1984 Power Supply Cost Recovery proceedings of Detroit Edison (Case No. U-7775) and Consumers Power (Case No. U-7785), on performance targets for those companies' nuclear power plants.

Finally, I have filed testimony before this Commission on PVNGS performance targets for PNM in Case No. 2004.

In addition to power plant performance cases, I have also testified on nuclear capacity factors in a number of planning and ratemaking proceedings, including Massachusetts DPU 20055, 20248, 84-25, 84-49/84-50, 84-145, 84-152, and 85-270; NHPUC DE 81-312; Illinois Commerce Commission 82-0026; Connecticut PUCA 83-03-01; NMPSC 1794; MEFSC 83-24; Maine PUC 84-113 Phase I, 84-113 Phase II, and 84-120; and Pennsylvania PUC R-842651 and R-850152; among others. This testimony is also listed in my resume.

Q: **Have you authored any publications on power plant performance standards?**

A: Yes. My paper "Power Plant Performance Standards: Some Elementary Principles," published in **Public Utilities Fortnightly**, is attached as Appendix VI to this testimony.

Q: **Why is it appropriate to set standards for power plant performance, rather than simply allowing EPE to recover its actual fuel costs, regardless of how well, or how poorly, PVNGS performs?**

A: This Commission has a legitimate concern with the reasonableness of EPE's rates. If PVNGS does not perform as well as it should, and EPE recovers both the costs of PVNGS and the cost of power to replace PVNGS output when it is not operating, rates will be unnecessarily high.

It is also important to insure that EPE's past and present projections for PVNGS performance are consistent with the performance for which consumers will be asked to pay. In particular, EPE's cost recovery for PVNGS may be determined in part by the projected value of PVNGS capacity. If that recovery is based on EPE's projections of the costs and benefits of PVNGS, including the number of kWh's each unit will generate annually, and PVNGS does not perform as well as EPE assumed, consumers will end up paying more for PVNGS than it is worth to them.

Q: **What is the fundamental goal of the standard-setting process?**

A: In setting power plant performance standards, the objective is to develop <u>normative</u> or <u>prescriptive</u> goals, specifying how the plant <u>should</u> behave. This is a very different concept from <u>positive</u> or <u>descriptive</u> projections, which predict how the plant <u>will</u> behave. These two types of analyses have very different purposes and may yield very different results. For example, if a utility breaks a plant in 1986, an accurate positive analysis might project a 1987 capacity factor of zero. It may be appropriate to base 1987 power supply cost recovery on the costs which should have been incurred reasonably and prudently if the plant had not been broken. Thus, the normative standard may be different from both the actual performance, and from the best estimate of future performance. Appendix VI discusses various approaches to setting normative standards.

Q: **What measure of performance is most important for PVNGS?**

A: In economic terms, the important performance parameter for PVNGS, or any other nuclear plant, is the amount of power the plant produces. The high cost of nuclear capacity is justified, if at all, by its low fuel costs and by the ability to spread the initial investment over many kilowatt-hours each year. Since nuclear fuel is relatively inexpensive, the economics of a nuclear plant depend more on the ability to produce many kWh, than on the ability to produce those kWh efficiently.[48] Hence, the capacity factor (CF) may be the most significant measure of PVNGS performance.

Q: Is capacity factor the only important measure of nuclear plant performance?

A: No. There are times when a plant does not produce all the energy of which it is capable, for reasons unrelated to its technical capabilities. The potential capacity factor, if not for economic and other systems constraints, is called the equivalent availability factor (EAF). The major difference between the capacity factor and the EAF for most units is a practice called "load following" or "cycling," in which the

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48. This description is slightly less true for EPE than for most other utilities, including the other owners of PVNGS. The fuel costs of Four Corners are not very different than those of PVNGS, at least in the next few years. San Juan fuel is more expensive, but is still only about one cent/kWh more than PVNGS fuel. Since EPE has already backed out most of its gas use, the fuel savings from PVNGS operation will be rather limited in the near term. Still, the net cost of PVNGS will be largely determined by the number of kWh it produces, for EPE's own use or for off-system sales.

units' output increases at times of high demand and falls during periods of low demands. Utilities rarely have all their available units operating at full capacity, simply because the amount of power necessary to meet peak loads in the middle of a weekday is not needed for other hours, particularly at night and on weekends. However, except in the Pacific Northwest, with its large hydroelectric capacity, nuclear plants are rarely if ever involved in load following. With their low fuel costs, nuclear plants are generally among the first units dispatched to meet load, and virtually all other plants will be turned down before the nuclear units' output is affected.

Other factors do produce differences between CF and EAF for most nuclear units. Transmission line failures can force units off line, even though there is nothing wrong with the generating plant. Power output is sometime reduced to delay the refueling of a nuclear plant, in order to avoid having several nuclear units (or other baseload plants) out of service simultaneously, to allow a unit to remain in service through the peak season, or to permit the utility's crews to complete refueling of another nuclear unit before starting on this unit.

Q: **Which of these factors is a better indicator of the performance of a nuclear plant?**

A: It is difficult to define one measure as more important than the other. The capacity factor reflects the plant's actual energy production, the real bottom line. CF is also an objective measure of performance, determined by the metered output of the unit, and by its rated capacity. On the other hand, there are times when increased capacity factor would be impossible for reasons independent of the plant's performance (e.g., there is nowhere for the power to go), or would be uneconomical. The EAF does not penalize the plant for these reductions in output, and is therefore a better measure of the plant's performance.

Unfortunately, EAF is not an objective measure. 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". Furthermore, the calculation of EAF assumes that the unit would have run <u>perfectly</u> if not for the "economic" limitation.

Considering all of the preceding factors, it is probably most useful to state nuclear power plant performance targets in terms of EAF, but to use the metered CF as a reality check. Differences between EAF and CF of more than 0.1% points should be thoroughly explained, including identification of the hours during which power was voluntarily reduced, and a description of the reason for each reduction. Differences of more than 0.5% are quite uncommon: if the reported EAF performance is to be used for ratemaking, such large differences should generally trigger an investigation to ensure that the reported EAF reasonably represents the plant's capability.

Q: How is the remainder of this section organized?

A: Section 6.2 discusses the PVNGS capacity factor projections utilized by EPE, and EPE's testimony on the propriety of performance standards for PVNGS. In Section 6.3, I suggest equivalent availability factor performance standards to be applied to EPE's share of PVNGS.

6.2 EPE's Approach to Performance Standards

Q: What are EPE's projections of the performance of its nuclear units?

A: Table 6.1 lists the capacity factors projected by EPE for each PVNGS unit. EPE projects a 74% mature capacity factor. Except for changes in the in-service dates, minor revisions in the intervals between refuelings, and reduced operation in the next few years due to excess capacity, these EAF projections appear to be the same as those EPE has used for several years. The projections in Table 6.1 have been used by EPE in many applications, such as for rate design and in projecting the economic impact of PVNGS for the present case. In addition, I use similar projections as the basis for the EPE capacity factor Cases in Section 5 of this testimony.

Q: Are these projections likely to be achieved?

A: No. Tables V-4 and V-5 in Appendix V-A display the capacity factors of all the PWRs of over 1000 MW which were in operation through the end of 1982. The average capacity factors (which in most cases are very similar to the EAFs) have been running between 55% and 60% for the group as a whole, and between 45% and 65% for individual units.

Table V-3 provides the results for PVNGS of Analysis and Inference's most recent regression analyses of PWR capacity factors, which are described in more detail in Appendix V-C.

Q: **For how long has there been evidence that EPE's projections of PVNGS capacity factor have been overstated?**

A: This has been evident for several years. Table IV-2 in Appendix IV lists the capacity factors for all PWR's of more than 800 MW, through 1985, and the averages through 1975, 1977, 1979, and 1981. The data clearly shows that EPE's projections are inconsistent with the experience of the industry even in the late 1970's.

Statistical analyses also indicated many years ago that capacity factors of large PWRs were much lower than EPE's projections for PVNGS. Komanoff (1976) projected from available experience that 1150 MW PWRs would have average capacity factors in their first ten years of 47.6%. Updates (Komanoff 1977 and 1978) revised the projections of levelized capacity factors to 55% and 59%. An analysis performed at Sandia National Laboratory for the Department of Energy (Easterling 1978) concluded that average capacity factors for 1100 MW PWRs in years 2-10 of operation would be about 57%. Applying Easterling's results to a unit with a 1270 MW DER (and assuming that the maximum generator nameplate, or MGN, rating Easterling uses would be 4% higher than the DER rating) would project a mature capacity factor of 55.5%.

Q: What is EPE's position regarding performance standards for PVNGS?

A: EPE opposes such standards. As explained in the testimony of Mr. Wasiak, EPE has four objections to the imposition of performance standards:

1. Plant safety could be reduced if the utility deferred maintenance and resisted NRC orders which would shut the plant down.

2. O&M could be increased to increase availability, even where the additional expense was not cost-effective.

3. EPE could be penalized for (or discouraged from) actions which would increase PVNGS availability in the summer season, while decreasing total availability, such as coasting down to refueling, or limiting output in the spring to keep a unit on line through the summer.

4. Many factors affecting PVNGS performance are not directly under management control.

Q: Is it true that performance standards for EPE would encourage the unsafe operation of PVNGS?

A: I doubt that they would do so, for two reasons. First, EPE is not the operator of the plant, and therefore has no direct control over the maintenance procedures. APS, the operator, is already subject to performance standards. Second, it has been my experience that utilities which ignore or resist safety concerns may improve their nuclear plant performance in the short run, but wind up with lower overall performance. Delayed retrofits will be more extensive, the outage is likely to come at a less favorable time (e.g., the NRC will not allow the utility to wait for the next refueling outage, if it has already been dragging its heels), and NRC scrutiny will be more intensive, resulting in longer outages. Thus, a rational utility will not take the course EPE proposes.

A performance target with annual goals and dead bands may encourage utilities to accelerate or delay outages, due to the non-linearity of incentives. For example, if the target were the 55% to 75% range proposed by EPE, and if the plant were operating near the bottom of the range, it would be advantageous for EPE if maintenance were deferred until the next year. If the result were a 56% EAF in the first year, and 60% in the second, instead of 54% and 65% with no manipulation of maintenance, EPE would be better off, the ratepayers would be worse off, and the plant would have operated less safely. This problem may be eliminated by omitting dead bands, which serve little purpose anyway, or by using running average targets, so that outage timing is less crucial.

Q: **Is EPE's concern with uneconomical increases in O&M expenses justified?**

A: No, again for two reasons. First, APS operates the plants and makes the decisions which influence O&M expenditures, and it is already operating under performance targets. If EPE is concerned that APS will spend funds which are not justified by their effect on performance, it should carefully monitor APS's operation of the plant, regardless of whether EPE is covered by performance standards.

Second, EPE is suggesting the wrong mechanism to control O&M expenses. Rather than discouraging uneconomical O&M by excusing the utilities from any responsibility for the operation of the plant, the Commission would better serve the interests of the ratepayers by holding EPE responsible for operating the plant both reliably and economically. Excessive O&M should be borne by the shareholders, as should the costs of low availability.

Q: **Would performance targets penalize EPE if PVNGS operates at a lower overall availability, but is available when it is most needed and most valuable, particularly in the summer?**

A: No, not if the target is expressed in terms of EAF, which includes power reductions for economic reasons.

Q: **Is it improper to penalize EPE for outcomes which are not subject to management control?**

A: No. If EPE promises a mature EAF of 74% to get more of PVNGS into rate base, it has an obligation to deliver on that promise. Management decided to participate in the plant, and decided to use availability projections which appear to be unrealistically high. If the plant fails to meet EPE's promises, the shareholders should pay at least some of the extra costs due to poor planning, and should absorb at least some of the costs which would have been excluded if EPE had been realistic in its performance projections.

Q: **Do you agree with Mr. Wasiak's criteria for a performance program?**

A: I agree with some of Mr. Wasiak's four criteria, and disagree with others. First, Mr. Wasiak suggests that the standard should be simple: I agree.

Second, he suggests that the standard should be fair, by which he means "not . . . weighted heavily towards penalties." I agree, so long as we are clear that the base line is EPE's promises, or the basis of rate recovery for the PVNGS investment, rather than an unbiased comparative estimate. If EPE's projected 74% EAF were a serious best-estimate projection, Mr. Wasiak's proposed performance range of 55-75% would virtually guarantee rewards, and essentially preclude net penalties. If my projections are correct, the 55%-75% range would produce many more penalties than rewards. I consider both of these considerations to be irrelevant: to the extent that the amount of PVNGS investment allowed into EPE's rate base is determined by an economic analysis (such as that in Cases 7 and 8 in Section 5) which assumes the plant will operate at 74% mature availability, ratemaking should demand that EPE deliver the benefits of a 74% EAF.

Third, Mr. Wasiak asks that the standard be flexible. EPE's proposal for "flexibility" has three elements:

1. EPE wants the standard to be based on a 62% comparative EAF target, much lower than the 74% figure EPE claims to expect from the plant and is presenting as a basis for evaluating the economic impact of the plant in this proceeding.

2. EPE wants the standard to take effect only for wide deviations from the target, so that consistently substandard performance will not be penalized. Only EAF results below 55% would result in charges to shareholders.

3. EPE wants the standard to be voided by major outages over which management has no control. This would exempt many of (and in the utility view, most of) the situations in which EAF falls below 55%.

Quite simply, Mr. Wasiak's definition of flexibility amounts to a request that any standards which may be established should never be allowed to penalize EPE. This is clearly inappropriate. In any case, as I stated above, performance standards for EPE should not be limited to a realistic assessment of PVNGS performance, nor limited to events which are under the control of management.

Mr. Wasiak's fourth criterion is that the performance standard should not result in large swings in earnings in either direction. To the extent that this goal can be achieved by an averaging mechanism, I agree that it is desirable. This concern should not be allowed to interfere with equitable ratemaking, or with the goal of protecting ratepayers from bearing the burden of a plant which is not paying its way. Of course, if the performance standard, or any other factor, threatens the financial viability of EPE, it may request extraordinary rate relief.

Q: **Is it necessary to have a "dead band" around the standard, so that small deviations have no effect?**

A: No. Small deviations would produce small rewards or penalties, which will not matter much. A dead band would only make sense where the deviation is so small that the effort of running the production costing model is not justified. As I noted above, the production costing runs will be necessary so long as any portion of EPE's entitlement in PVNGS is not in rate base.

Indeed, there are disadvantages to dead bands, which argue against their use except where they are required for administrative convenience. Depending on the distribution of outcomes around the target, applying a dead band on an annual basis may result in a net reward for poor performance, or a penalty for good performance. For example, if a plant often operates at an EAF 5 points above its target, but occasionally has a very bad year and operates 15 points below target, a 10 point dead band would result in penalties and no bonuses. In addition, dead bands may encourage utilities to manipulate maintenance outages, to keep one performance period within the dead band (even if very close to the bottom), while pushing another above the top of the dead band. In these situations, overall performance of a plant may be decreased, while the utility receives a performance incentive reward.

6.3 Recommendations on Performance Standards

Q: **What type of performance standard would you recommend be applied to EPE's share of PVNGS?**

A: I recommend that the Commission institute an "absolute" performance standard tied to the ratemaking allowed for the capital investment.[49] That ratemaking is likely to be based on EPE's representations regarding the EAFs of the PVNGS units. As I noted in Section 2, the Commission may be well advised to allow EPE to place in rate base an amount of PVNGS investment which could only be cost-effective if the plant operates at an optimistically high EAF. If high availability is assumed in placing a large amount of PVNGS in rate base, the same high availability should be assumed for performance target setting.

Table 6.2 lists current utility projections for PVNGS availability in terms of availability between refuelings, the period between refuelings, and the length of the refueling outages.[50] Table 6.1 provides EPE's projections for calendar

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49. Appendix VI discusses alternative designs for performance standards, and the rationale for each approach.

50. These particular projections were presented by PNM in Case No. 1916. Like EPE's projections, they are from ANPP estimates.

year capacity factors, for the commercial operation dates currently assumed. In the short run, these capacity factors are significantly less than projected EAFs, presumably due to load following. Variation in commercial operation dates and startup periods (which affects the time from commercial operation to the first refueling) may cause further changes in the annual capacity factors, even if EPE's basic performance assumptions are correct.

To moderate the effects of poor performance on earnings, I would suggest that the shareholders assume only half of the EAF risk, and that cost recovery be calculated as if PVNGS had operated at the average of its actual EAF and EPE's projection. This could be achieved by calculating power supply cost recovery and inventory effects as the average of actual costs and the costs which would have resulted had PVNGS operated at the standard.[51] I suspect that it will be easier to calculate cost recovery as if PVNGS availability were equal to the average of actual EAF and the performance target.[52]

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51. The average may be a weighted average, if the Commission wishes to set the shareholder portion of the risk at a value other than 50%. At this point, I see no reason to deviate from the 50% risk allocation.

52. Either approach will require the use of a production costing model to determine cost recovery, but the use of such a model would be required anyway, by either EPE's proposed inventory arrangement or any other arrangement which treats a portion of the plant's capacity separately from retail rate base. In these situations, production costing is required to compute sales from inventoried capacity to the retail jurisdiction, and to allocate revenues from off-system sales to inventoried and jurisdictional capacity.

Q: **For what period of time would you suggest that EPE be held to these standards?**

A: I would suggest that the standard be applied indefinitely. Of course, the Commission may decide at some point in the future to revise the standard, but I see no reason to establish an expiration date at this time.

Q: **Is your proposal in this case consistent with your testimony in Case No. 2004, on PNM's performance standard?**

A: Yes. The two situations are very similar in general outline, although they vary slightly in detail. The PNM inventory mechanism is already in place, and the role of the 74% EAF projection is implicit in the negotiation process which produced the inventory stipulation. The EPE ratemaking treatment for PVNGS is still in litigation, and the role of the 74% projection is explicit, at least in my analysis of the value of PVNGS.

Q: **Would the standard you have proposed have any long-term benefits, other than ensuring that ratepayers receive a larger share of the energy for which they will pay as PVNGS enters rate base?**

A: Yes. This precedent would tend to encourage accurate cost and performance projections by EPE and other New Mexico utilities for new plants. So long as utilities can justify cost recovery for their new plants by projecting (among other things) optimistic future operating performance, there is a positive disincentive for EPE to offer realistic projections to this Commission. If the Company's cost recovery is tied to the performance of the plant, this strategy no longer works. Promising stellar performance to get a plant into rate base is much less effective, if the utility bears some of the cost of not achieving that performance.

Similarly, utilities may expect that their troubles with cost recovery on uneconomical plants will be over once they get the investment into rate base, and that the extent of the penalty the Commission can extract from the shareholders will always be constrained by concerns about financial stability. In effect, a high performance standard can spread the shareholders' excess-cost penalty throughout the life of the plant, without requiring a large initial writeoff.

Q: **Does this conclude your testimony?**

A: Yes.

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TABLE 1.1: EPE SHARE OF PVNGS COST AND AFUDC, AND AN APPROXIMATION OF TOTAL COST PLUS AFUDC ($ Millions)

Date of Estimate	EPE Share PVNGS Cost (15.8%) [1]	EPE AFUDC [2]	EPE Cost + AFUDC [3]	Total (100%) PVNGS Cost Excl. AFUDC [4]	EPE AFUDC as % of EPE Share [5]	Total (100%) PVNGS Cost + AFUDC [6]	Scheduled In-Service [7] Unit 1	Unit 2	Unit 3
Sep-73	$327.5	$69.1	$396.6	$2,073.1	21.10%	$2,510.4	May-81	Nov-82	May-84
Dec-74	$409.5			$2,592.0			May-81	Nov-82	May-84
Dec-74	$414.3			$2,622.0			May-81	Nov-82	May-84
Jun-76	$437.1	$130.8	$567.9	$2,766.2	29.94%	$3,594.4	May-82	May-84	May-86
Jun-76	$443.2	$127.8	$571.0	$2,804.9	28.84%	$3,614.0	May-82	May-84	May-86
Sep-76	$438.2	$130.9	$569.0	$2,773.1	29.87%	$3,601.5	May-82	May-84	May-86
Jan-77	$442.4			$2,800.0			May-82	May-84	May-86
Jun-77	$441.0	$129.0	$570.0	$2,791.0	29.26%	$3,607.6	May-82	May-84	May-86
Apr-78	$464.4	$128.4	$592.8	$2,939.0	27.65%	$3,751.7	May-82	May-84	Jun-86
Nov-78	$464.4	$163.5	$627.9	$2,939.0	35.21%	$3,973.7	May-82	May-84	Jun-86
May-79	$520.2	$186.1	$706.2	$3,292.1	35.77%	$4,469.7	May-83	May-84	Jun-86
Nov-79	$550.1	$176.6	$726.7	$3,481.3	32.11%	$4,599.2	May-83	May-84	Jun-86
Sep-80	$572.8	$230.0	$802.8	$3,625.3	40.15%	$5,080.9	May-83	May-84	Jun-86
Oct-80	$605.4	$255.6	$861.1	$3,831.8	42.23%	$5,449.9	May-83	May-84	Jun-86
Apr-81	$630.6	$267.4	$898.1	$3,991.3	42.41%	$5,684.0	May-83	May-84	Jun-86
Jan-82	$676.7	$299.8	$976.5	$4,282.9	44.30%	$6,180.2	May-83	May-84	Jun-86
May-82	$769.0	$322.6	$1,091.6	$4,867.0	41.95%	$6,908.7	May-83	May-84	May-86
Nov-82	$796.3	$324.6	$1,121.0	$5,040.0	40.77%	$7,094.7	May-83	May-84	May-86
Apr-83	$805.3	$327.8	$1,133.1	$5,096.7	40.70%	$7,171.2	May-84	Feb-85	May-86
Nov-83	$934.6	$452.9	$1,387.5	$5,915.0	48.47%	$8,781.7	May-84	Sep-85	Dec-86
May-84	$975.4	$532.6	$1,508.0	$6,173.5	54.60%	$9,544.2	May-84	Sep-85	Dec-86
Sep-84	$977.5	$530.1	$1,507.6	$6,186.6	54.24%	$9,541.9	Nov-85	Apr-86	Jun-87
Apr-85	$971.1	$519.0	$1,490.1	$6,146.1	53.45%	$9,431.0	Nov-85	Apr-86	Jun-87
Oct-85	$975.6	$510.8	$1,486.4	$6,174.7	52.36%	$9,407.8	Nov-85	Apr-86	Jun-87

Notes: [1], [2] From AG-1-19, 2/18/86, pages 2-9.

[4] = [1]/15.8%. [5] = [2]/[1]. [6] = [2]*(1+[3]).

[7] From Nuclear News, 2/74 and EIA-254 Quarterly Progress Reports. Last available COD for that Date.

TABLE 1.2: PVNGS COST AND SCHEDULE HISTORY, EXCLUDING AFUDC

EIA-254 QUARTERLY PROGRESS REPORTS AND ERNST & WHINNEY REVIEW
* Construction Permit: 5/76

Date of Estimate	Unit 1 Cost	Unit 1 COD	Unit 1 % Comp.	Unit 2 Cost	Unit 2 COD	Unit 2 % Comp.	Unit 3 Cost	Unit 3 COD	Unit 3 % Comp.	Total Project Cost	E&W Total Cost [2]
Jun-74	$606	May-81	0.0%								
Sep-74	$613	May-81	0.0%	$586	Nov-82	0.0%	$605	May-84	0.0%	$1,804	
Dec-74			0.0%			0.0%			0.0%		
Mar-75	$1,000	May-82	0.0%	$827	May-84	0.0%	$941	May-86	0.0%	$2,768	
Jun-75			0.0%			0.0%			0.0%		
Sep-75			0.0%			0.0%			0.0%		
Dec-75	$975	May-82	0.0%	$845	May-84	0.0%	$950	May-86	0.0%	$2,770	
Mar-76			0.0%			0.0%			0.0%		
Jun-76 *			1.0%			0.0%			0.0%		
Sep-76			1.0%			0.0%			0.0%		
Dec-76			2.0%			0.0%	$950	Jun-86	0.0%		$2,784
Mar-77			7.1%			2.1%			0.0%		$2,800
Jun-77			11.3%			2.0%			0.0%		$2,840
Sep-77			16.8%			3.4%			0.0%		
Dec-77	$989	May-82	21.9%			5.1%			0.1%		$2,937
Mar-78	$1,263	May-82	24.6%	$769	May-84	7.3%	$834	Jun-86	0.9%	$2,866	
Jun-78			26.8%			6.3%			0.5%		$2,953
Sep-78	$760	May-82	28.5%	$598	May-84	7.8%	$702	Jun-86	0.5%	$2,060	
Dec-78			32.2%			11.2%			0.5%		$2,982
Mar-79	$911	May-83	43.0%			13.8%			0.8%		
Jun-79			43.0%	$710	May-84	17.6%	$833	Jun-86	1.5%		$3,342
Sep-79			46.7%			20.5%			2.1%		
Dec-79	$938	May-83	55.7%	$571	May-84	26.1%	$746	Jun-86	4.5%	$2,255	$3,385
Mar-80	$1,354	May-83	62.3%	$827	May-84	31.6%	$1,088	May-86	7.6%	$3,269	
Jun-80	$1,429	May-83	68.3%	$820	May-84	37.7%	$1,125	Jun-86	10.8%	$3,374	$3,671
Sep-80	$1,457	May-83	74.3%	$948	May-84	43.9%	$1,212	Jun-86	12.9%	$3,617	
Dec-80			80.6%			50.0%			15.6%		$3,835
Mar-81	$1,453	May-83	83.8%	$1,016	May-84	55.5%	$1,255	Jun-86	18.6%	$3,724	
Jun-81			87.8%			62.2%			22.0%		$3,972
Sep-81			92.8%	$1,075	May-84	68.5%	$1,227	Jun-86	26.0%		
Dec-81	$1,579	May-83	92.8%			75.4%			30.4%		$4,694
Mar-82	$1,671	May-83	96.5%	$1,136	May-84	82.6%	$1,487	May-86	36.7%	$4,294	
Jun-82			96.0%			87.7%			42.3%		$4,764
Sep-82			96.9%			92.0%			47.3%		
Dec-82			98.1%			94.0%			52.5%		$4,981
Mar-83	$1,671	May-84	99.3%	$1,136	Feb-85	96.9%	$1,487	May-86	61.7%		
Jun-83			99.3%	$1,136	Sep-85	97.9%	$1,487	Dec-86	70.8%		$5,700
Sep-83			99.5%			98.6%			78.6%		
Dec-83			99.5%			98.8%			85.3%		$5,900
Mar-84			99.6%			99.1%			89.4%		
Jun-84	$1,906	Nov-85	99.7%	$1,331	Apr-86	99.4%	$1,464	Jun-87	92.3%	$4,701	$5,900
Sep-84			99.7%			99.5%			94.6%		
Dec-84			99.7%			99.7%			95.9%		$5,900
Mar-85			99.7%			99.7%			97.1%		
Jun-85			100.0%			99.9%			98.0%		
Sep-85			100.0%			99.9%			98.8%		
Dec-85			100.0%			100.0%			99.2%		

Sources: EIA-254; IR-1-56a, 57, 58. [2] Ernst & Whinney,'Phase I Diagnostic Review[...]'11/1985, Exh. V-1.

TABLE 1.3: CALCULATION UNIT PERCENTAGE SHARE OF TOTAL COST (EIA-254)

Date of	EIA-254 Unit Cost			Total Project	PERCENTAGE SHARE OF TOTAL		
Estimate	Unit 1	Unit 2	Unit 3	Cost	Unit 1	Unit 2	Unit 3
Jun-74	$606						
Sep-74	$613	$586	$605	$1,804	34.0%	32.5%	33.5%
Dec-74							
Mar-75	$1,000	$827	$941	$2,768	36.1%	29.9%	34.0%
Jun-75							
Sep-75							
Dec-75	$975	$845	$950	$2,770	35.2%	30.5%	34.3%
Mar-76							
Jun-76							
Sep-76							
Dec-76			$950				
Mar-77							
Jun-77							
Sep-77							
Dec-77	$989						
Mar-78	$1,263	$769	$834	$2,866	44.1%	26.8%	29.1%
Jun-78							
Sep-78	$760	$598	$702	$2,060	36.9%	29.0%	34.1%
Dec-78							
Mar-79	$911						
Jun-79		$710	$833				
Sep-79							
Dec-79	$938	$571	$746	$2,255	41.6%	25.3%	33.1%
Mar-80	$1,354	$827	$1,088	$3,269	41.4%	25.3%	33.3%
Jun-80	$1,429	$820	$1,125	$3,374	42.4%	24.3%	33.3%
Sep-80	$1,457	$948	$1,212	$3,617	40.3%	26.2%	33.5%
Dec-80							
Mar-81	$1,453	$1,016	$1,255	$3,724	39.0%	27.3%	33.7%
Jun-81							
Sep-81		$1,075	$1,227				
Dec-81	$1,579						
Mar-82	$1,671	$1,136	$1,487	$4,294	38.9%	26.5%	34.6%
Jun-82							
Sep-82							
Dec-82			$2,474				
Mar-83	$1,671	$1,136	$1,487	$4,294	38.9%	26.5%	34.6%
Jun-83		$1,136	$1,487				
Sep-83							
Dec-83							
Mar-84							
Jun-84	$1,906	$1,331	$1,464	$4,701	40.5%	28.3%	31.1%

Source: See Table 1.2: EIA-254 Quarterly Progress Reports
Note: All costs exclude AFUDC.

TABLE 1.4: EPE SHARE PLUS AFUDC, ALLOCATED BY UNIT ($ 1000)

	EPE Share of Total Project Cost	(See Table 1.3) Unit % of Total Cost			EPE Share of Total Project Cost, Including AFUDC, per Unit		
		Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3
	[1]						
Sep-73	$396,641	34.0%	32.5%	33.5%	$134,779	$128,842	$133,020
Dec-74							
Dec-74							
Jun-76	$567,912	35.2%	30.5%	34.3%	$199,897	$173,244	$194,771
Jun-76	$571,005	35.2%	30.5%	34.3%	$200,985	$174,187	$195,832
Sep-76	$569,040	35.2%	30.5%	34.3%	$200,294	$173,588	$195,158
Jan-77							
Jun-77	$570,008	35.2%	30.5%	34.3%	$200,634	$173,883	$195,490
Apr-78	$592,774	44.1%	26.8%	29.1%	$261,226	$159,052	$172,496
Nov-78	$627,852	36.9%	29.0%	34.1%	$231,635	$182,260	$213,957
May-79	$706,207	36.9%	29.0%	34.1%	$260,542	$205,006	$240,659
Nov-79	$726,666	36.9%	29.0%	34.1%	$268,090	$210,945	$247,631
Sep-80	$802,783	40.3%	26.2%	33.5%	$323,377	$210,406	$269,000
Oct-80	$861,078	40.3%	26.2%	33.5%	$346,859	$225,685	$288,534
Apr-81	$898,068	39.0%	27.3%	33.7%	$350,401	$245,015	$302,652
Jan-82	$976,468	38.9%	26.5%	34.6%	$379,990	$258,330	$338,148
May-82	$1,091,576	38.9%	26.5%	34.6%	$424,784	$288,782	$378,010
Nov-82	$1,120,961	38.9%	26.5%	34.6%	$436,219	$296,556	$388,186
Apr-83	$1,133,055	38.9%	26.5%	34.6%	$440,926	$299,756	$392,374
Nov-83	$1,387,513	38.9%	26.5%	34.6%	$539,947	$367,074	$480,492
May-84	$1,507,982	38.9%	26.5%	34.6%	$586,828	$398,945	$522,210
Sep-84	$1,507,623	40.5%	28.3%	31.1%	$611,259	$426,855	$469,509
Apr-85	$1,490,099	40.5%	28.3%	31.1%	$604,154	$421,894	$464,051
Oct-85	$1,486,435	40.5%	28.3%	31.1%	$602,669	$420,856	$462,910

Note: 1. See Table 1.1

Sources: AG-1-19, 2/18/86, page 2-9 and EIA-254 Quart. Repts.

TABLE 1.5: COST AND COD ESTIMATES OF PLANTS UNDER CONSTRUCTION AS OF JANUARY 1, 1984

PLANT	(MW) NET CAPACITY	UPDATED COST ESTIMATE	UPDATED COST PER KW	UPDATED COD ESTIMATE	SOURCE	AFUDC % of COST	OPERATING UTILITY	ARCHITECT/ ENGINEER	CONSTRUCTION MANAGER	REACTOR SUPPLR
Midland 1	1233	cancelled	infinite			30%	Consumers Pwr	Bechtel	Bechtel	B&W
Midland 2	+	cancelled	infinite				"	"	"	"
Zimmer 1	810	cancelled	infinite			35%	Cincinnati G&E	S&L	Kaiser	GE
Marble Hill 1	2260	cancelled	infinite			50%	PS of Indiana	S&L	Utility	W
Marble Hill 2	+	cancelled	infinite				"	"	"	"
Shoreham	809	$4.50	$5,562	*	N/*	35%	LILCo	S&W	Utility	GE
Nine Mile Point 2	1084	$5.35	$4,935	Oct-86	T/T	34%	Niagara Mohawk	S&W	S&W	GE
Beaver Valley 2	833	$3.96	$4,753	Aug-87	T/NN	33%	Duquesne Light	S&W	Utility	W
River Bend 1	940	$4.00	$4,255	Dec-85	U/U	24%	Gulf States	S&W	S&W	GE
Seabrook 1	1150	$4.56	$3,965	Oct-86	T/T	36%	PSNH	UE&C	NH Yankee	W
Vogtle 1	2200	$8.40	$3,818	Jun-87	N/T	34%	Georgia P&L	Util/Bech.	Utility	W
Vogtle 2	+	+		Sep-88	+/T		"	"	"	"
Harris 1	900	$3.42	$3,803	Sep-86	T/T	26%	Carolina P&L	Ebasco	Daniel	W
Hope Creek 1	1067	$3.80	$3,557	Dec-86	T/T	24%	Publ.Serv.E&G	Bechtel	Bechtel	GE
Limerick 1	2110	$7.30	$3,460	Feb-86	U/T	31%	Philadel. Elec.	Bechtel	Bechtel	GE
Limerick 2	+	+		Jul-90	+/U		"	"	"	"
Fermi 2	1100	$3.77	$3,427	Feb-86	N/U	31%	Detroit Ed.	Utility	Daniel	GE
Millstone 3	1150	$3.83	$3,326	May-86	T/T	31%	Northeast Util.	S&W	S&W	W
South Texas 1	2500	$8.30	$3,320	Jun-87	U/T	27%	Houston P&L	Bechtel	Ebasco	W
South Texas 2	+	+		Jun-89	+/T		"	"	"	"
Clinton 1	950	$3.15	$3,314	Nov-86	T/T	25%	Illinois Power	S&L	Baldwin	GE
Perry 1	1205	$3.90	$3,237	Mar-86	U/T	30%	Cleveland Elec.	Gilbert	Utility	GE
WNP-2	1100	$3.32	$3,022	Dec-84	U/NRC	-	WPPSS	B&R	Bechtel	GE
Grand Gulf 1	1250	$3.50	$2,800	Jul-85	U/NRC	46%	Middle South	Bechtel	Bechtel	GE
Callaway 1	1150	$3.00	$2,609	Dec-84	T/NRC	37%	Union Electric	Bechtel	Daniel	W
Wolf Creek	1150	$3.03	$2,635	Sep-85	T/U	32%	Kansas G&E	Bechtel/S&L	Daniel	W
Diablo Canyon 1	2190	$5.56	$2,538	May-85	T/NRC	34%	Pacific G&E	Utility	Utility	W
Diablo Canyon 2	+	+		Nov-85	+/T		"	"	"	"
Palo Verde 1	3810	$9.51	$2,497	Dec-85	U/T	37%	Arizona PS	Bechtel	Bechtel	CE
Palo Verde 2	+	+		Apr-86	+/T		"	"	"	"
Palo Verde 3	+	+		Jun-87	+/T		"	"	"	"
Waterford 3	1104	$2.73	$2,476	Sep-85	T/NRC	21%	Louisiana P&L	Ebasco	Ebasco	CE
Comanche Peak 1	2300	$5.46	$2,374	Jun-87	T/N	24%	Texas Utils.	Gibbs&Hill	Brwn&Root	W
Comanche Peak 2	+	+		Dec-87	+/N		"	"	"	"
Bellefonte 1	2426	$5.66	$2,333	Jan-94	U/T	40%	TVA	Utility	Utility	B&W
Bellefonte 2	+	+		Jan-96	+/T		"	"	"	"
Braidwood 1	2240	$5.01	$2,237	May-87	N/N	43%	Comm. Ed.	S&L	Utility	W
Braidwood 2	+	+		Sep-88	+/N		"	"	"	"
Byron 1	2240	$4.65	$2,076	Sep-85	N/NRC	39%	Comm. Ed.	S&L	Utility	W
Byron 2	+	+		May-87	+/N		"	"	"	"
Susquehanna 2	1050	$2.16	$2,056	Feb-85	T/T	31%	Pennsylv. P&L	Bechtel	Bechtel	GE
San Onofre 2	2200	$4.50	$2,045	Aug-83	T/T					
San Onofre 3	+	+		Apr-84	+/T	40%	S.Calif.Ed.	Bechtel	Utility	CE
Watts Bar 1	2354	$4.10	$1,742	Jun-86	U/U	33%	TVA	Utility	Utility	W
Watts Bar 2	+	+		Apr-88	+/U		"	"	"	"
Catawba 1	2290	$3.90	$1,703	Jun-85	T/NRC	35%	Duke Power	Utility	Utility	W
Catawba 2	+	+		Jun-87	+/T		Duke Power	Utility	Utility	W
Summer 1	900	$1.28	$1,426	Jan-84	T/NRC	24%	South Carol.E&G	Gilbert	Daniel	W
LaSalle 2	1078	$1.16	$1,074	Oct-84	T/NRC	22%	Comm. Ed.	S&L	Utility	GE
McGuire 2	1180	$1.10	$929	Mar-84	T/NRC	33%	Duke Power	Utility	Utility	W

Table 1.5 provides an update to the table in "Nuclear Follies," Forbes, James Cook, February 11, 1985, pp. 1, 82-100.

EXPLANATION OF COLUMNS (from left to right):

PLANT	The plants listed are the same as those found in the Forbes Table with the addition of: Midland 1 (adding 425 MW capacity, correcting the Forbes' cost per KW) Limerick 2 (1066MW) San Onofre 2 (1100 MW) The plants are sorted by cost per KW with the cancelled plants listed first.
NET CAPACITY (MW)	Capacity ratings are the ones used by Forbes (Ratings used by Forbes do not always agree with the NRC Grey and Yellow Book DER) The combined Net Capacity of Bellefonte 1 & 2 was corrected as 2426 MW.
COST ESTIMATE COD ESTIMATE SOURCE	The cost estimate and COD were updated using several sources. The updated estimates are referenced in the "Source" column as: source for cost estimate/source for COD estimate. U Data Per Telephone (6/85) from Utility T Data from Tennessee Valley Authority, "US Nuclear Plants, Cost Per KW Report," March 1985 N Newspaper (Wall Street Journal or New York Times) NRC NRC Grey Book, 12/84 * Paul Chernick's current estimate of Utility Cost Forecast
OPERATING UTILITY ARCHITECT/ENGINEER CONSTRUCTION MANAGER REACTOR SUPPLIER	Information from the last four columns is from the Forbes article. Only the operating utility is listed; Percent ownership was omitted

+ data for second unit combined with data for the first
average excludes San Onofre 2 & 3 as well as the cancelled plants
median excludes San Onofre 2 & 3 and includes cancelled plants

TABLE 1.6: EPE ANNUAL CONSTRUCTION EXPENDITURES ($ 1000)

Year	Annual Expense
1973	$829.0
1974	$3,066.2
1975	$3,235.9
1976	$12,685.2
1977	$30,864.7
1978	$67,890.5
1979	$88,746.0
1980	$106,467.1
1981	$116,635.6
1982	$92,445.8
1983	$67,292.2
1984	$47,278.3
1985	$44,477.0

Source: AG-IR-1-23, 2/5/86, 'Schedule of Request for Funds'.

Notes: [1] 1973 expenditures for October-December, 1973.

TABLE 3.1: INITIAL SCHEDULES OF PLANTS ORDERED IN 1973

Name	Unit 1 COD	Unit 2 COD	Unit 3 COD
Palo Verde	May-81	Nov-82	May-84
Allens Creek	Jun-80	Jun-82	
Black Fox	Jun-82	Jun-84	
Blue Hills	Sep-80		
Callaway	Oct-81	Apr-83	
Cherokee	Apr-83	Sep-83	Feb-84
Clinton	Jun-80	Jun-83	
Davis-Besse	Jun-81	Jan-83	
Haven	Feb-81	Jun-82	
Jamesport	Jun-81		
Millstone	Mar-78		
Pebble Springs	Jul-80		
Thomas L. Perkins	Jan-81	Jan-82	Nov-82
Skagit	Jul-81		
S.R.	Mar-83	Mar-84	
South Texas	Jun-80	Jun-82	
Sterling	Oct-82		
Tyrone	Jun-82	Jun-84	
PSE&G(NJ)	May-85	May-86	
Wolf Creek	Apr-81		
WPPSS 3	Sep-81		
Averages:	Aug-81	Jul-83	Jul-83

Sources: Nuclear News, August, 1974 and 1976, and February, 1978; Atomic Industrial Forum, Historical Profile, January, 1985.

Notes: [1] No month was given for the COD's of South Texas Project 1 & 2, Tyrone 1 & 2, Black Fox 1 & 2, and Jamesport. June was assumed for each unit.

[2] No COD's were available for S.R. 3 (Carolina Light & Power) and Vogtle 3 & 4.

[3] Averages exclude Palo Verde.

[4] Davis Besse 2 and 3 are considered first and second units in this table, since their schedules were not affected by Davis Besse 1 (completed in 11/77).

[5] Millstone 3 is considered a first unit in this table, since its schedule was not affected by Millstone 2 and 3.

[6] River Bend 2 was omitted from the table, because it is not clear whether its scedule would have been affected by River Bend 1.

TABLE 3.2: REVISED COST AND SCHEDULE ESTIMATES FOR PVNGS, BASED ON ESTIMATES OF COMPLETED PLANTS

EPE/ANPP Estimates					
Date of Estimate:	Sep-73	Sep-76	Nov-78	Sep-80	May-82
Cost Estimate (EPE's Share, $ Million):	$396.6	$569.0	$627.9	$802.8	$1,091.6
COD Estimates					
Unit 1:	May-81	May-82	May-82	May-83	May-83
Unit 2:	Nov-82	May-84	May-84	May-84	May-84
Unit 3:	May-84	May-86	Jun-86	Jun-86	May-86

Revised Cost Estimates Based on Completed Units From 1969-1982:

	|-Sep-73-	|-Sep-76-|	|-Nov-78|	|-Sep-80-|	|-May-82-|
Projection Method	Revised Est.	Revised Est.	Revised Est.	Revised Est.	Revised Est.
1. Nominal Cost Ratio	$835.1	$1,671.1	$1,372.8	$1,747.1	$2,609.3
2. Nominal Myopia Factor	$1,871.6	$2,750.2	$2,078.7	$1,905.7	$1,869.3
3. Real Cost Ratio	$975.6	$1,310.1	$1,546.6	$1,807.8	$2,403.7
4. Annual Growth Rate	$2,060.5	$2,379.2	$2,064.8	$1,873.3	$1,887.2

Revised COD Estimates Based on Completed Units From 1969-1982 [1]:

	|-Sep-73-|		|-Sep-76-|		|-Nov-78|		|-Sep-80-|		|-May-82-|	
	Dur. Ratio	Revised Est.	Dur. Ratio	Revised Est.	Dur. Ratio	Revised Est.	Dur. Ratio	Revised Est.	Dur. Ratio	Revised Est.
Unit 1	1.44	Oct-84	1.66	Feb-86	1.72	Nov-84	1.73	Apr-85	1.77	Feb-84
Unit 2	1.44	Dec-86	1.50	Mar-88	1.67	Jan-88	1.65	Sep-86	1.82	Jan-86
Unit 3	1.44	Feb-89	1.50	Mar-91	1.67	Jul-91	1.65	Mar-90	1.82	Aug-89

Notes: [1] Revised COD date = (EPE estimated duration * duration ratio) + date of estimate.
[2] See Appendix III for a detailed explanation of calculations.

TABLE 3.3: REVISED COST AND SCHEDULE ESTIMATES FOR PVNGS, BASED ON ESTIMATES OF PLANTS UNDER CONSTRUCTION

EPE Cost and Schedule Estimates

Date of Estimate:	Sep-73	Sep-76	Nov-78	Sep-80	May-82
Cost Estimate($ Million):	$396.6	$569.0	$627.9	$802.8	$1,091.6
COD Estimates					
Unit 1:	May-81	May-82	May-82	May-83	May-83
Unit 2:	Nov-82	May-84	May-84	May-84	May-84
Unit 3:	May-84	May-86	Jun-86	Jun-86	May-86

Revised Schedule Estimates Based on Completed Units From 1969-1982 [1]:

Progress Ratio:	43.0%	36.3%	41.4%	-9.0%	29.7%
Revised Duration					
Unit 1:	18	16	8		3
Unit 2:	21	21	13		7
Unit 3:	25	27	18		13
Corrected COD:					
Unit 1:	Jul-91	May-92	Apr-87		Sep-85
Unit 2:	Jan-95	Nov-97	Feb-92		Feb-89
Unit 3:	Jul-98	May-2003	Mar-97		Nov-95

Revised Cost for PVNGS Based on Duration for Unit 1 ($ Million):

	|-Sep-73-|		|-Sep-76-|		|Nov-78-|		|-Sep-80-|		|-May-82-|	
Projection Method	Cost Growth Rate	Revised Cost	Cost Growth Rate	Revised Cost	Cost Growth Rate	Revised Cost	Cost Growth Rate	Revised Cost	Cost Growth Rate	Revised Cost
1. Nominal [2]	18.6%	$8,382	16.4%	$6,149	17.9%	$2,522	17.7%		24.0%	$2,251
2. Real [3]	13.2%	$5,619	12.1%	$6,398	12.9%	$3,145	8.6%		16.6%	$3,073

Notes: [1] EPE's estimated duration divided by the progress ratio.
[2] Revised cost = EPE estimated cost * (nominal cost ratio escalated to the revised duration).
[3] Revised cost = EPE estimated cost * (real cost ratio escalated to the revised duration). Inflation not included in revised cost estimate.
[4] See Appendix III for a detailed explanation of calculations.

Table 3.4: Plant Cancellations: 1977-1980

Unit Name	Year of Cancellation	Construction Status	% Complete
Alan Barton 1	1977	order	
Alan Barton 2		order	
Douglas Point 1		order	
Ft. Calhoun 2		order	
South Dade 1		order	
South Dade 2		order	
Surry 3		cp	0%
Surry 4		cp	0%
Sears Island		order	
Atlantic 1	1978	order	
Atlantic 2		order	
Blue Hills 1		order	
Blue Hills 2		order	
Haven 2		order	
Islote		order	
S.R. 1		order	
S.R. 2		order	
Sundesert 1		order	
Sundesert 2		order	
PSE&G Co. unit 1		order	
PSE&G Co. unit 2		order	
Wm. H. Zimmer 2		order	
Greene County	1979	order	
NEP-1		order	
NEP-2		order	
Palo Verde 4		order	
Palo Verde 5		order	
Tyrone 1		cp	0%
Davis Besse 2	1980	limited work authority	0%
Davis Besse 3		limited work authority	0%
Erie 1		order	
Erie 2		order	
Forked River 1		cp	5%
Greenwood 2		order	
Greenwood 3		order	
Haven 1		order	
Jamesport 1		cp	0%
Jamesport 2		cp	0%
Montague 1		order	
Montague 2		order	
New Haven 1		order	
New Haven 2		order	
North Anna 4		cp	4%
Sterling		cp	0%
Bailly Nuclear 1	1981	cp	<1%
Callaway 2		cp	<1%
Shearon Harris 3		cp	1%
Shearon Harris 4		cp	1%
Hope Creek 2		cp	19%
Pilgrim 2		order	

Table 3.4: Plant Cancellations: 1977-1980

Allens Creek 1	1982	order	
Black Fox 1		lwa	<1%
Black Fox 2		lwa	<1%
Cherokee 2		cp	0%
Cherokee 3		cp	0%
Hartsville B-1		cp	17%
Hartsville B-2		cp	7%
North Anna 3		cp	7%
Pebble Spring 1		order	
Pebble Spring 2		order	
Perkins 1		order	
Perkins 2		order	
Perkins 3		order	
Phipps Bend 1		cp	27%
Phipps Bend 2		cp	5%
Vandalia		order	
WPPS 4		cp	23%
WPPS 5		cp	16%

Source: Atomic Industrial Forum, "Background Info", January, 1984.

TABLE 4.1: BUSBAR COST COMPARISON IN 1976

	Total	PVNGS			PVNGS			COAL	COAL	COAL	GAS
1. CASE:	Total	EPE			HISTORICAL			EPE-1977	EPE-1975	NEPLAN	
2. Unit		1	2	3	1	2	3				
3. Unit Cost, % of Total Project		35.2%	30.5%	34.3%	35.2%	30.5%	34.3%				
4. Construction Cost, $Mill.	$1,486	$523	$453	$510	$523	$453	$510	$223	$240	$136	
5. Sunk Cost, $Million	$51	$30	$11	$10	$30	$11	$10	$0	$0	$0	
6. Net Investment, $Million		$493	$442	$500	$493	$442	$500	$223	$240	$136	
7. EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	200	
8. Levelized Carrying Charges, %		17%	17%	17%	17%	17%	17%	17%	17%	17%	
9. Annual Carrying Cost, $/KW-YR		$419	$376	$425	$419	$376	$425	$190	$204	$115	
10. O&M, $/KW-YR		$41	$44	$47	$233	$240	$265	$75	$18	$114	
11. Annual Cost, $/KW-YR		$460	$419	$471	$652	$616	$690	$265	$222	$229	
12. Capacity Factor		74.0%	74.0%	74.0%	69.3%	69.3%	69.3%	73.5%	73.5%	71.9%	
13. Non-Fuel Cost, cents/kwh		7.10	6.47	7.27	10.74	10.14	11.37	4.12	3.44	3.64	
14. Fuel Cost, cents/kwh		0.83	0.88	0.92	0.74	0.69	0.92	3.13	1.62	2.38	11.39
15. Total Cost, cents/kwh		7.93	7.34	8.19	11.48	10.83	12.29	7.24	5.06	6.02	11.39
16. Average, cts/kwh			7.82			11.53					

Notes:

3. See Table 1.3. Unit percentage share of total project cost.
4. EPE Share of Construction Cost: PVNGS: current (October 1985) estimate, incl. AFUDC. Coal-EPE 1977: Capital $1117/KW. Avg. of 4 units, Bisti Preliminary Information, April 1977. Coal-EPE 1975: Joint Resource Study, 2/75, page 38: Average of $850/KW (#1) and $783/KW (#2,esc 2 yrs). Coal-NEPOOL: Capital Cost: 678.2/KW (1980 dollars). NEPLAN & GTF, December 1976 Generation Task Force Report.
   IR-1-4, "EPE Resource Planning, Alternatives for Future Load Requirements" COAL: 1000 MWe Coal unit Capital cost would range 450-510$/KW. Total Generation Costs would range 21.3-27.2 mills/KWH. Coal: 7.1-11.4 mills/KWH. NUCLEAR: A 1000 MWe nuclear unit capital cost would range 510-540 $/KWH. Total generation costs range 15.2 - 20.4 mills/KWH.
5. EPE share of sunk cost from 1976 Annual Report. AFUDC added for years 1977 - 1986 at accrual rate of 7.5%. Allocation among units in same proportion as 1976 sunk cost totals given in IR-AG-7-2. 58%, 22%, 20%
6. = (4) - (5)
7. EPE share of PVNGS and Coal unit capacity. Coal unit sizes: EPE-1977: 468 MW, EPE 1975: 1000 MW, NEPOOL: 600 MW.
8. Levelized Fixed Charge, from Bisti Preliminary Information, April 1977.
9. = (6)*(8)*1,000,000 / ((7)*1000)
10. See Appendix H-1
11. = (9) + (10)
12. See Appendix H-1
13. = (13)*100 / ((12)*8760)
14. See Appendix H-1. For the NEPOOL Coal plant we have substituted Mine Mouth fuel.

TABLE 4.2: GROSS BUSBAR COST COMPARISON IN 1976

		PUNGS			PUNGS			COAL	COAL	COAL	GAS
1. CASE:	Total	EPE			HISTORICAL			EPE-1977	EPE-1975	NEPLAN	
2. Unit		1	2	3	1	2	3				
3. Unit Cost, % of Total Project		35.2%	30.5%	34.3%	35.2%	30.5%	34.3%				
4. Construction Cost, $Mill.	$1,486	$523	$453	$510	$523	$453	$510	$223	$240	$136	
5. Sunk Cost, $Million	rtab41	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Net Investment, $Million		$523	$453	$510	$523	$453	$510	$223	$240	$136	
7. EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	200	
8. Levelized Carrying Charges, %		17%	17%	17%	17%	17%	17%	17%	17%	17%	
9. Annual Carrying Cost, $/KW-YR		$445	$385	$433	$445	$385	$433	$190	$204	$115	
10. O&M, $/KW-YR		$41	$44	$47	$233	$240	$265	$75	$18	$114	
11. Annual Cost, $/KW-YR		$485	$429	$480	$677	$625	$699	$265	$222	$229	
12. Capacity Factor		74.0%	74.0%	74.0%	69.3%	69.3%	69.3%	73.5%	73.5%	71.9%	
13. Non-Fuel Cost, cents/kwh		7.49	6.62	7.40	11.16	10.30	11.51	4.12	3.44	3.64	
14. Fuel Cost, cents/kwh		0.83	0.88	0.92	0.74	0.69	0.92	3.13	1.62	2.38	11.39
15. Total Cost, cents/kwh		8.32	7.49	8.33	11.90	10.98	12.43	7.24	5.06	6.02	11.39
16. Average, cts/kwh			8.05			11.77					

TABLE 4.3: BUSBAR COST COMPARISON IN 1978

		PVNGS			PVNGS			COAL	COAL	COAL	GAS
1. CASE:	Total	EPE			HISTORICAL			EPE	APS/S&L	APS/nera	
2. Unit		1	2	3	1	2	3				
3. Unit Cost, % of Total Project		36.9%	29.0%	34.1%	36.9%	29.0%	34.1%				
4. Construction Cost, $Mill.	$1,486	$548	$431	$507	$548	$431	$507	$249	$200	$213	
5. Sunk Cost, $Million	$280	$171	$73	$36	$171	$73	$36	$0	$0	$0	
6. Net Investment, $Million		$378	$358	$470	$378	$358	$470	$249	$200	$213	
7. EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	200	
8. Levelized Carrying Charges, %		15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	13.4%	13.4%	13.4%	
9. Annual Carrying Cost, $/KW-YR		$287	$272	$358	$287	$272	$358	$167	$134	$143	
10. O&M, $/KW-YR		$44	$47	$49	$176	$201	$218	$62	$42	$22	
11. Annual Cost, $/KW-YR		$331	$319	$407	$463	$473	$576	$229	$176	$165	
12. Capacity Factor		56.9%	56.9%	56.9%	58.4%	58.4%	58.4%	67.8%	63.0%	68.0%	
13. Non-Fuel Cost, cents/kwh		6.64	6.40	8.16	9.05	9.25	11.25	3.86	3.20	2.78	
14. Fuel Cost, cents/kwh		1.45	1.57	1.64	1.45	1.57	1.64	3.38	3.26	5.77	9.36
15. Total Cost, cents/kwh		8.09	7.97	9.80	10.50	10.82	12.88	7.24	6.45	8.55	9.36
16. Average, cents/kwh			8.62			11.40					

Notes: 3. See Table 1.3. Unit percentage share of total project cost.

4. EPE share of Construction Costs: PVNGS: current (October 1985) estimate, incl. AFUDC. COAL-EPE: Arthur D.Little, October 1978: 'Coal Plant vs. Palo Verde' page 13. Bisti, New Mexico Site. Average Cost/KW over 3 units in 1986: $1,246 /KW. COAL-APS: Sargent & Lundy, April 1979. p. II-3. Average of 3 units in 1986: $1,001 /KW.
5. EPE share of sunk cost from 1978 Annual Report: $135.6 M. AFUDC added for years 1979 - 1986 at 9.5% accrual rate. Allocation among units 61%, 26% and 13% see Table 4.1, note 5 (IR-AG-7-2).
6. = (4) - (5)
7. EPE share of PVNGS or Coal unit capacity. Coal unit sizes: EPE: 500 MW, APS: 812 MW, NERA: 600 MW.
8. Levelized Fixed Charges Palo Verde and EPE Coal from Arthur D. Little Study, Oct. 1978 page 16 (Exh.5). (Sargent & Lundy study for APS, April 1979: Coal fixed charge: 16.7%, Exh.III-10, p.2 of 2. (NERA study for APS coal, April 1979. (Table 10A) coal fixed charge: 14.8%).
9. = (6)*(8)*1,000,000 / ((7)*1000)
10. See Appendix H-2
11. = (9) + (10)
12. See Appendix H-2. Levelized CF for APS/nera Coal: Table 10A, NERA 4/79 Study. (750 MW size units).
13. = (13)*100 / ((12)*8760)
14. See Appendix H-2
15. = (13) + (14)

TABLE 4.4: GROSS BUSBAR COST COMPARISON IN 1978

			PVNGS			PVNGS			COAL	COAL	COAL	GAS
1.	CASE:	Total	EPE			HISTORICAL			EPE	APS/S&L	APS/nera	
2.	Unit		1	2	3	1	2	3				
3.	Unit Cost, % of Total Project		36.9%	29.0%	34.1%	36.9%	29.0%	34.1%				
4.	Construction Cost, $Mill.	$1,486	$548	$431	$507	$548	$431	$507	$249	$200	$213	
5.	Sunk Cost, $Million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6.	Net Investment, $Million		$548	$431	$507	$548	$431	$507	$249	$200	$213	
7.	EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	200	
8.	Levelized Carrying Charges, %		15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	13.4%	13.4%	13.4%	
9.	Annual Carrying Cost, $/KW-YR		$417	$328	$386	$417	$328	$386	$167	$134	$143	
10.	O&M, $/KW-YR		$44	$47	$49	$176	$201	$218	$62	$42	$22	
11.	Annual Cost, $/KW-YR		$461	$375	$435	$593	$529	$603	$229	$176	$165	
12.	Capacity Factor		56.9%	56.9%	56.9%	58.4%	58.4%	58.4%	67.8%	63.0%	68.0%	
13.	Non-Fuel Cost, cents/kwh		9.25	7.52	8.72	11.59	10.33	11.79	3.86	3.20	2.78	
14.	Fuel Cost, cents/kwh		1.45	1.57	1.64	1.45	1.57	1.64	3.38	3.26	5.77	9.36
15.	Total Cost, cents/kwh		10.70	9.09	10.36	13.04	11.90	13.43	7.24	6.45	8.55	9.36
16.	Average, cents/kwh			10.05			12.79					

TABLE 4.5: BUSBAR COST COMPARISON IN 1980

		Total	PVNGS			PVNGS			COAL	COAL	GAS
1.	CASE:	Total	EPE/S&W			HISTORICAL			S&W/EPE	EPE	
2.	Unit		1	2	3	1	2	3			
3.	Unit Cost, % of Total Project		40.3%	26.2%	33.5%	40.3%	26.2%	33.5%			
4.	Construction Cost, $Mill.	$1,486	$599	$389	$498	$599	$389	$498	$170	$266	
5.	Sunk Cost, $Million	$743	$357	$260	$126	$357	$260	$126	$0	$0	
6.	Net Investment, $Million		$242	$129	$372	$242	$129	$372	$170	$266	
7.	EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	
8.	Levelized Carrying Charges, %		17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	16.5%	16.5%	
9.	*Annual Carrying Cost*, $/KW-YR		$206	$110	$316	$206	$110	$316	$140	$219	
10.	O&M, $/KW-YR		$19	$31	$33	$193	$51	$56	$50	$75	
11.	Annual Cost, $/KW-YR		$225	$141	$348	$399	$161	$372	$191	$294	
12.	Capacity Factor		63.0%	63.0%	62.6%	56.1%	56.1%	56.1%	67.5%	75.0%	
13.	Non-Fuel Cost, cents/kwh		4.08	2.54	6.35	8.11	3.27	7.56	3.23	4.48	
14.	Fuel Cost, cents/kwh		1.43	1.53	1.64	1.43	1.53	1.64	2.93	2.93	13.4
15.	Total Cost, cents/kwh		5.50	4.07	7.99	9.54	4.80	9.20	6.16	7.41	13.4
16.	Average, cents/kwh			5.86			7.85				

Notes:

3. See Table 1.3. Unit percentage share of total project cost.
4. EPE Share of Construction Cost: PVNGS: October 1985 cost estimate, including AFUDC.
   Coal EPE/S&W (New Mexico) Capital cost: AG-IR-3-51, Stone & Webster 12/80 study (p.29). Average of cost for 3 coal units (Respectively, with CODs in 1990, 1991, and 1992: $196.2, $156.2 and $197.8 million per 100 MW., deflated at 8% to 1986).
   Coal-EPE Capital Cost from EPE 'Palo Verde vs Coal' November 1980 study. Esc. 7%
   $1160/KW (Exh.1) assumed 1984 dollars.
5. EPE share of sunk cost from 1980 Annual Report: $ 378.52 M. AFUDC added for years 1981 - 1986 at 11.9% accrual rate
   Allocation among units 48%, 35% and 17% see Table 4.1, note 5 (IR-AG-7-2).
6. = (4) - (5)
7. EPE share of PVNGS capacity. Coal unit size based on cost estimates given.
8. *Various sources dated around mid-1980 give fixed charges ranging from 16.6-17% for nuclear, and 16.3%-16.8% for coal*
9. = (6)*(8)*1,000,000 / ((7)*1000)
10. See Appendix H-3
11. = (9) + (10)
12. See Appendix H-3
13. = (13)*100 / ((12)*8760)
14. See Appendix H-3. EPE Future Coal used with both the S&W and EPE coal estimates.
15. = (13) + (14)

TABLE 4.6: GROSS BUSBAR COST COMPARISON IN 1980

		Total	PVNGS			PVNGS			COAL	COAL	GAS
1.	CASE:		EPE/S&W			HISTORICAL			S&W/EPE	EPE	
2.	Unit		1	2	3	1	2	3			
3.	Unit Cost, % of Total Project		40.3%	26.2%	33.5%	40.3%	26.2%	33.5%			
4.	Construction Cost, $Mill.	$1,486	$599	$389	$498	$599	$389	$498	$170	$266	
5.	Sunk Cost, $Million	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6.	Net Investment, $Million		$599	$389	$498	$599	$389	$498	$170	$266	
7.	EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	
8.	Levelized Carrying Charges, %		17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	16.5%	16.5%	
9.	Annual Carrying Cost, $/KW-YR		$509	$331	$423	$509	$331	$423	$140	$219	
10.	O&M, $/KW-YR		$19	$31	$33	$193	$51	$56	$50	$75	
11.	Annual Cost, $/KW-YR		$528	$362	$456	$702	$382	$479	$191	$294	
12.	Capacity Factor		63.0%	63.0%	62.6%	56.1%	56.1%	56.1%	67.5%	75.0%	
13.	Non-Fuel Cost, cents/kwh		9.57	6.55	8.31	14.28	7.77	9.74	3.23	4.48	
14.	Fuel Cost, cents/kwh		1.43	1.53	1.64	1.43	1.53	1.64	2.93	2.93	13.4
15.	Total Cost, cents/kwh		11.00	8.08	9.95	15.71	9.29	11.38	6.16	7.41	13.4
16.	Average, cents/kwh			9.67			12.13				

TABLE 4.7: BUSBAR COST COMPARISON IN 1982

	Total	PVNGS EPE 1	2	3	PVNGS HISTORICAL 1	2	3	COAL EPE/82	COAL EPE/83	COAL SPS/82	GAS
1. CASE:	Total	EPE			HISTORICAL			EPE/82	EPE/83	SPS/82	
2. Unit		1	2	3	1	2	3				
3. Unit Cost, % of Total Project		38.9%	26.5%	34.6%	38.9%	26.5%	34.6%				
4. Construction Cost, $Mill.	$1,486	$578	$394	$514	$578	$394	$514	$363	$338	$153	
5. Sunk Cost, $Million	$1,210	$436	$411	$363	$436	$411	$363	$0	$0	$0	
6. Net Investment, $Million		$143	($18)	$151	$143	($18)	$151	$363	$338	$153	
7. EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	200	
8. Levelized Carrying Charges, %		21%	21%	21%	21%	21%	21%	20%	20%	20%	
9. Annual Carrying Cost, $/KW-YR		$150	($18)	$159	$150	($18)	$159	$363	$338	$153	
10. O&M, $/KW-YR		$77	$83	$90	$211	$52	$57	$80	$54	$66	
11. Annual Cost, $/KW-YR		$227	$65	$249	$360	$33	$216	$443	$392	$219	
12. Capacity Factor		68.5%	68.6%	69.2%	56.8%	56.8%	56.8%	75.0%	85.4%	75.0%	
13. Non-Fuel Cost, cents/kwh		3.78	1.07	4.11	7.24	0.67	4.34	6.74	5.23	3.34	
14. Fuel Cost, cents/kwh		1.46	1.57	1.69	1.46	1.57	1.69	4.11	4.91	6.46	15.76
15. Total Cost, cents/kwh		5.24	2.65	5.80	8.71	2.24	6.03	10.85	10.14	9.79	15.76
16. Average, cents/kwh			4.56			5.66					

Notes:

3. See Table 1.3. Unit percentage share of total project cost.
4. EPE Share of Construction Cost: PVNGS: current (October 1985) cost estimate, including AFUDC. COAL: EPE/82: Alternative Generation Resources Analysis Report, July 1982: $2379.4/KW in 1990. Coal/EPE-83 from EPE, Palo Verde Participation Study, June, 1983, p. 48 of 60. $1380/KW in 1983$ Escalated at 7% per year. SPS Coal from EPE/Stone & Webster, 'Study of an Interconnection With the Southwestern Public Service Company,' February 1982. Page V-4. Average of Tolk #2 and CF #6, $766.6 in 1986.
5. EPE share of sunk cost from 1982 Annual Report: $ 734.34 M. AFUDC added for years 1983 - 1986 at 13.3% accrual rate. Allocation among units 36%, 34% and 30% see Table 4.1, note 5 (IR-AG-7-2).
6. = (4) - (5)
7. EPE share of PVNGS capacity. Coal unit size based on cost estimates given. EPE/82: 500 MW.
8. Various sources dated around mid-1982 give fixed charges ranging from 19%-22.6% for nuclear, and 19%-20.8% for coal.
9. = (6)*(8)*1,000,000 / ((7)*1000)
10. See Appendix H-4
11. = (9) + (10)
12. See Appendix H-4. Assumed 75% (EPE/82) for SPS coal plant.
13. = (13)*100 / ((12)*8760)
14. See Appendix H-4
15. = (13) + (14)

TABLE 4.8: GROSS BUSBAR COST COMPARISON IN 1982

		PVNGS			PVNGS			COAL	COAL	COAL	GAS
1. CASE:	Total	EPE			HISTORICAL			EPE/82	EPE/83	SPS/82	
2. Unit		1	2	3	1	2	3				
3. Unit Cost, % of Total Project		38.9%	26.5%	34.6%	38.9%	26.5%	34.6%				
4. Construction Cost, $Mill.	$1,486	$578	$394	$514	$578	$394	$514	$363	$338	$153	
5. Sunk Cost, $Million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Net Investment, $Million		$578	$394	$514	$578	$394	$514	$363	$338	$153	
7. EPE Share of Capacity, MW		200	200	200	200	200	200	200	200	200	
8. Levelized Carrying Charges, %		21%	21%	21%	21%	21%	21%	20%	20%	20%	
9. Annual Carrying Cost, $/KW-YR		$607	$414	$540	$607	$414	$540	$363	$338	$153	
10. O&M, $/KW-YR		$77	$83	$90	$211	$52	$57	$80	$54	$66	
11. Annual Cost, $/KW-YR		$684	$497	$630	$818	$465	$597	$443	$392	$219	
12. Capacity Factor		68.5%	68.6%	69.2%	56.8%	56.8%	56.8%	75.0%	85.4%	75.0%	
13. Non-Fuel Cost, cents/kwh		11.40	8.26	10.40	16.44	9.35	12.00	6.74	5.23	3.34	
14. Fuel Cost, cents/kwh		1.46	1.57	1.69	1.46	1.57	1.69	4.11	4.91	6.46	15.76
15. Total Cost, cents/kwh		12.86	9.84	12.09	17.90	10.93	13.70	10.85	10.14	9.79	15.76
16. Average, cents/kwh			11.60			14.17					

TABLE 4.9: OWNERSHIP IN NUCLEAR PLANTS UNDER CONSTRUCTION AS A PERCENTAGE OF PEAK LOAD (1978)

Utility (Investor Owned)	Plant	Ownership (MW)	1978 Peak Load (MW)	1978 Ownership as % of Peak Load	Official or Effective Cancellation
Public Service NH	Seabrook 1 & 2	1,150	1,178	97.6%	Unit 2 Cancelled
EL PASO ELECTRIC	PALO VERDE 1-3	602	690	87.2%	-
Carolina P & L	Shearon Harris 1-4	3,600	5,588	64.4%	Units 2,3,4 Cancelled
Illinois Power	Clinton 1 & 2	1,528	2,824	54.1%	Unit 2 Cancelled
Public Service Indiana	Marble Hill 1 & 2	1,859	3,718	50.0%	Plant Cancelled
Public Service of NM	Palo Verde 1-3	389	809	48.0%	-
Pennsylvania P & L	Susquehanna 1 & 2	2,100	4,701	44.7%	-
Arizona Public Service	Palo Verde 1-3	1,109	2,549	43.5%	-
Union Electric	Callaway 1 & 2	2,314	5,528	41.9%	Unit 2 Cancelled
Duke Power	Cherokee 1-3	3,840	9,844	39.0%	Plant Cancelled
Kansas G & E	Wolf Creek	575	1,533	37.5%	-
Philadelphia Elec	Limerick 1 & 2	2,110	5,667	37.2%	Unit 2 Suspended
Gulf States Utilities	River Bend 1 & 2	1,880	5,138	36.6%	Unit 2 Cancelled
Virginia Elec Power	North Anna 2-4	2,810	7,805	36.0%	Units 3,4 Cancelled
Toledo Edison	Perry 1 & 2	480	1,395	34.4%	Unit 2 Cancelled
Public Service E & G	Hope Creek 1 & 2	2,027	6,615	30.6%	Unit 2 Cancelled
No. Indiana Pub Serv	Bailly	660	2,239	29.5%	Plant Cancelled
Consumers Power	Midland 1 & 2	1,271	4,610	27.6%	Plant Cancelled
Kansas City P & L	Wolf Creek	575	2,097	27.4%	-
Long Island Lighting	Shoreham	819	2,997	27.3%	-
So. Carolina E & G	Summer	603	2,271	26.6%	-
San Diego G & E	San Onofre 2 & 3	456	1,894	24.1%	-
Duke Power	McGuire 1 & 2	2,360	9,844	24.0%	-
Mississippi P & L	Grand Gulf 1 & 2	2,500	10,648 *	23.5%	Unit 2 Suspended
Duke Power	Catawba 1 & 2	2,306	9,844	23.4%	-
Cleveland Elec. Illum.	Perry 1 & 2	750	3,249	23.1%	Unit 2 Suspended
Northeast Utilities	Millstone 3	805	3,951	20.4%	-
Jersey Central P & L	Forked River	1,120	6,173 *	18.1%	Cancelled
Texas Utilities	Comanche Pk 1 & 2	2,071	11,548	17.9%	-
So. Carolina PS Authority	Summer	297	1,678	17.7%	-
Ohio Edison	Perry 1 & 2	723	4,105	17.6%	Unit 2 Suspended
Pacific G & E	Diablo Canyon 1 & 2	2,120	12,971	16.3%	-
Commonwealth Edison	Byron 1 & 2	2,240	13,720	16.3%	-
Commonwealth Edison	Braidwood 1 & 2	2,240	13,720	16.3%	-
Detroit Edison	Fermi 2	1,150	7,312	15.7%	-
Commonwealth Edison	LaSalle 1 & 2	2,156	13,720	15.7%	-
So. California Edison	San Onofre 2 & 3	1,824	11,997	15.2%	-
Duquesne Light	Perry 1 & 2	333	2,379	14.0%	Unit 2 Abandoned
Georgia Power	Vogtle 1 & 2	2,226	18,173 *	12.2%	-
Toledo Edison	Beaver Valley 2	170	1,395	12.2%	-
Dayton P & L	Zimmer	255	2,105	12.1%	-
Columbus & So. Ohio Elec.	Zimmer	231	1,907	12.1%	-
Cincinnati G & E	Zimmer	324	2,835	11.4%	-
Louisiana P & L	Waterford 3	1,165	10,648 *	10.9%	-
Atlantic City Elec	Hope Creek 1 & 2	107	1,043	10.2%	Unit 2 Cancelled
Florida Power & Light	St. Lucie 2	810	8,791	9.2%	-
Ohio Edison	Beaver Valley 2	357	4,105	8.7%	-
Arkansas P & L	Arkansas 2	912	10,648 *	8.6%	-
Philadelphia Elec	Salem 2	475	5,667	8.4%	-

TABLE 4.9: OWNERSHIP IN NUCLEAR PLANTS UNDER CONSTRUCTION AS A PERCENTAGE OF PEAK LOAD (1978)

Utility (Investor Owned)	Plant	Ownership (MW)	1978 Peak Load (MW)	1978 Ownership as % of Peak Load	Official or Effective Cancellation
Houston L & P	South Texas 1 & 2	770	9,362	8.2%	-
Niagara Mohawk	Nine Mile Pt 2	451	5,500	8.2%	-
Atlantic City Elec	Salem 2	83	1,043	7.9%	-
Central P & L	South Texas 1 & 2	630	8,014 *	7.9%	-
Public Service E & G	Salem 2	475	6,615	7.2%	-
Cleveland Elec. Illum.	Beaver Valley 2	208	3,249	6.4%	-
Delmarva P & L	Salem 2	83	1,476	5.6%	-
So. California Edison	Palo Verde 1-3	602	11,997	5.0%	-
Duqesne Light	Beaver Valley 2	117	2,379	4.9%	-
Alabama Power	Farley 2	860	18,173 *	4.7%	-
Pa. Power	Perry 1 & 2	125	4,701	2.7%	Unit 2 Suspended
Georgia Power	Hatch 2	398	18,173 *	2.2%	-

NOTES: [1] Listing includes units with construction permits, but not completed as of 12/31/78. Tyrone and Sterling units excluded, because they lacked state licenses.

[2] * indicates that the peak load is for the holding company.

TABLE 4.10 EPE AVOIDED COST ESTIMATE

Year	Estimate for Small Power and Cogeneration (cents/kWH) [1]	Estimate for PVNGS (cents/kWH) [2]
1986	2.5	2.2
1987	2.4	1.5
1988	2.3	2.0
1989	2.5	2.2
1990	2.6	2.8
1991	2.9	3.7
1992	3.1	3.9
1993	3.4	4.7
1994	4.0	4.9
1995	4.3	7.5

NOTES: [1] Average of Summer and Winter for 100 MW. From "El Paso Electric Company System Cost Data For New Mexico Public Service Commission, General Order #37, 12/31/85.

[2] Production Expense differential from AG-IR-11-1, divided by EPE Forecast of PVNGS generation. From AG-IR-11-1, June 6, 1986. Capacity Factors from Table 7.1. Assumes COD dates of 8/86 for Unit 2 and 9/87 for Unit 3.

TABLE 5.1: CALCULATION OF THE VALUE OF PVNGS NON-FUEL COSTS IN TERMS OF SAN JUAN 4 COSTS

Year	Capacity Factor	Carrying Charge	Carrying Cost $/KW-YR	Carrying Cost cts/kwh	Non-fuel Operating Costs cts/kwh	Property Tax & Insurance cts/kwh	Total Fixed Costs cts/kwh	Fuel Costs cts/kwh	Total Costs cts/kwh	PVNGS Fuel Cost cts/kwh	Value of PVNGS non-fuel costs cts/kwh
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
1987	90%	20.8%	$289.6	3.7	0.7	0.1	4.4	1.6	6.1	1.05	5.0
1988	84%	20.2%	$281.0	3.8	0.7	0.1	4.6	1.8	6.4	0.98	5.4
1989	83%	19.3%	$267.9	3.7	0.8	0.1	4.5	1.9	6.4	0.90	5.5
1990	84%	18.4%	$255.7	3.5	0.9	0.1	4.5	2.0	6.5	0.83	5.6
1991	75%	17.6%	$244.3	3.7	0.9	0.1	4.7	2.2	6.9	0.80	6.1
1992	80%	16.8%	$233.9	3.3	0.9	0.1	4.3	2.4	6.7	0.81	5.9
1993	82%	16.1%	$223.5	3.1	0.9	0.1	4.1	2.5	6.7	0.87	5.8
1994	83%	15.4%	$214.0	2.9	1.0	0.1	4.0	2.8	6.8	0.94	5.8
1995	84%	14.7%	$204.6	2.8	1.1	0.1	3.9	3.0	6.9	1.03	5.9
1996	81%	14.0%	$195.1	2.7	1.0	0.1	3.9	3.2	7.1	1.09	6.0
1997	87%	13.4%	$185.6	2.4	1.1	0.1	3.6	3.5	7.1	1.16	5.9
1998	87%	12.7%	$176.1	2.3	1.2	0.1	3.5	3.7	7.3	1.23	6.1
1999	85%	12.0%	$166.6	2.2	1.2	0.1	3.5	4.0	7.6	1.31	6.2
2000	87%	11.3%	$157.1	2.1	1.3	0.1	3.5	4.4	7.8	1.39	6.5
2001	81%	10.6%	$147.6	2.1	1.3	0.1	3.5	4.7	8.2	1.48	6.7
2002	87%	9.9%	$138.1	1.8	1.4	0.1	3.3	5.1	8.4	1.57	6.8
2003	87%	9.6%	$134.1	1.8	1.5	0.1	3.3	5.5	8.8	1.67	7.1
2004	87%	9.4%	$130.1	1.7	1.5	0.1	3.3	5.9	9.2	1.78	7.5
2005	87%	9.1%	$126.1	1.7	1.6	0.1	3.3	6.4	9.7	1.89	7.8
2006	81%	8.8%	$122.1	1.7	1.7	0.1	3.5	6.9	10.4	2.01	8.4
2007	87%	8.5%	$118.1	1.5	1.8	0.1	3.4	7.4	10.8	2.14	8.7
2008	87%	8.2%	$114.1	1.5	1.8	0.1	3.4	8.0	11.5	2.27	9.2
2009	87%	7.9%	$110.1	1.4	1.9	0.1	3.5	8.7	12.1	2.41	9.7
2010	87%	7.6%	$106.1	1.4	2.0	0.1	3.5	9.4	12.9	2.57	10.3
2011	81%	7.3%	$102.1	1.4	2.1	0.1	3.6	10.1	13.7	2.73	11.0
2012	87%	7.1%	$98.1	1.3	2.2	0.1	3.6	10.9	14.5	2.90	11.6
2013	87%	6.8%	$94.1	1.2	2.3	0.1	3.6	11.7	15.4	3.08	12.3
2014	87%	6.5%	$90.1	1.2	2.4	0.1	3.7	12.7	16.4	3.28	13.1
2015	87%	6.2%	$86.2	1.1	2.6	0.1	3.8	13.7	17.4	3.48	14.0
2016	81%	5.9%	$82.1	1.2	2.7	0.1	3.9	14.8	18.7	3.70	15.0
2017	87%	5.6%	$78.1	1.0	2.8	0.1	3.9	15.9	19.8	3.93	15.9
2018	87%	5.3%	$74.2	1.0	2.9	0.1	4.0	17.2	21.2	4.18	17.0
2019	87%	5.0%	$70.2	0.9	3.1	0.1	4.1	18.5	22.6	4.45	18.2
2020	87%	4.8%	$66.2	0.9	3.2	0.1	4.2	20.0	24.2	4.73	19.5
2021	81%	4.5%	$62.2	0.9	3.4	0.1	4.4	21.6	25.9	5.02	20.9
2022	87%	4.2%	$58.2	0.8	3.6	0.1	4.4	23.3	27.7	5.34	22.3
2023	87%	3.9%	$54.2	0.7	3.7	0.1	4.5	25.1	29.6	5.68	24.0
2024	87%	3.6%	$50.2	0.7	3.9	0.1	4.6	27.1	31.8	6.03	25.7
2025	87%	3.3%	$46.2	0.6	4.1	0.1	4.8	29.3	34.0	6.41	27.6
2026	87%	3.0%	$42.2	0.6	4.3	0.1	4.9	31.6	36.5	6.82	29.7
								Levelized @			
								12%	7.8		
								15%	7.3		
								18%	7.0		
								20%	6.9		

Notes Table 5.1:

1. For simplification purposes in section 5 tables, it is assumed that all plants come on line in 1987.
2. PNM Microfiche PROMOD runs, 1986-2004, 2005-2024: Assumed 87%, maintenance cycle results in lower C.F. every 5 years.
3. Carrying Charge from Dirmeier, El Paso Electric Co. Ownership Option, Coal Plant Fixed Charge Factor.
4. Coal Plant Cost: $1,390 /kw capital cost assumed. From Rogers Testimony, Page 4: Case PSC 1923/25, 12/88 sale of 34 MW to Los Alamos County.
5. [4] * 100 / 8760 / C.F.
6. PNM Microfiche PROMOD runs, 1986-2004, 2005-2024: escalated at 4.8%.
7. Property tax from Interrogatory NMIEC 6-119, Case 1916
8. [5]+[6]+[7].
9. PNM Microfiche PROMOD runs, 1986-2004, 2005-2024: escalated at 7.9%.
10. [8]+[9].
11. BEB7, Table IV. Heat rate from PNM Microfiche: .01006 MMBTU/kwh (10.06 (1000*)BTU/kwh) esc. at 6.3%.
12. [10]-[11].

TABLE 5.2: CALCULATION OF THE VALUE OF PUNGS NON-FUEL COSTS IN TERMS OF SPS COSTS

Year	Capacity Factor	Demand Charge $/KW-YR	Demand Charge cts/kwh	Energy Charge cts/kwh	SPS Purchase Total cts/kwh	PUNGS Fuel Cost cts/kwh	Value of PUNGS non-fuel costs cts/kwh
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1987	90%	$107.3	1.4	2.3	3.6	1.0	2.6
1988	90%	$107.3	1.4	2.4	3.7	1.0	2.8
1989	90%	$107.3	1.4	2.4	3.8	0.9	2.9
1990	90%	$130.6	1.7	2.2	3.8	0.8	3.0
1991	90%	$130.6	1.7	2.4	4.1	0.8	3.3
1992	90%	$130.6	1.7	2.6	4.3	0.8	3.5
1993	90%	$158.2	2.0	2.9	4.9	0.9	4.1
1994	90%	$158.2	2.0	3.2	5.2	0.9	4.3
1995	90%	$158.2	2.0	3.6	5.6	1.0	4.5
1996	90%	$192.0	2.4	3.7	6.2	1.1	5.1
1997	90%	$192.0	2.4	3.9	6.4	1.2	5.2
1998	90%	$192.0	2.4	4.1	6.6	1.2	5.3
1999	90%	$233.1	3.0	4.3	7.3	1.3	6.0
2000	90%	$233.1	3.0	4.5	7.5	1.4	6.1
2001	90%	$233.1	3.0	4.8	7.7	1.5	6.2
2002	90%	$283.0	3.6	5.0	8.6	1.6	7.0
2003	90%	$283.0	3.6	5.3	8.8	1.7	7.2
2004	90%	$283.0	3.6	5.5	9.1	1.8	7.3
2005	90%	$343.5	4.4	5.8	10.2	1.9	8.3
2006	90%	$343.5	4.4	6.1	10.4	2.0	8.4
2007	90%	$343.5	4.4	6.4	10.8	2.1	8.6
2008	90%	$417.1	5.3	6.7	12.0	2.3	9.7
2009	90%	$417.1	5.3	7.0	12.3	2.4	9.9
2010	90%	$417.1	5.3	7.4	12.7	2.6	10.1
2011	90%	$506.3	6.4	7.8	14.2	2.7	11.5
2012	90%	$506.3	6.4	8.2	14.6	2.9	11.7
2013	90%	$506.3	6.4	8.6	15.0	3.1	11.9
2014	90%	$614.6	7.8	9.0	16.8	3.3	13.5
2015	90%	$614.6	7.8	9.4	17.2	3.5	13.8
2016	90%	$614.6	7.8	9.9	17.7	3.7	14.0
2017	90%	$746.2	9.5	10.4	19.9	3.9	15.9
2018	90%	$746.2	9.5	10.9	20.4	4.2	16.2
2019	90%	$746.2	9.5	11.5	20.9	4.4	16.5
2020	90%	$905.9	11.5	12.1	23.5	4.7	18.8
2021	90%	$905.9	11.5	12.7	24.1	5.0	19.1
2022	90%	$905.9	11.5	13.3	24.8	5.3	19.4
2023	90%	$1,099.7	13.9	14.0	27.9	5.7	22.2
2024	90%	$1,099.7	13.9	14.7	28.6	6.0	22.6
2025	90%	$1,099.7	13.9	15.4	29.3	6.4	22.9
2026	90%	$1,099.7	13.9	16.2	30.1	6.8	23.3
				Levelized @			
				12%	6.2		
				15%	5.5		
				18%	5.1		
				20%	4.9		

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Notes Table 5.2:

1. From EPE PROMOD run: 'SPS Coal 1'.
2. Demand charge from Table 1A, 'El Paso Electric Company, SPS Purchase Power Reduction Study', 2/25/86. AG-IR-2-5(d). Assumed to increase by 21.4% every three years.
3. [2]*100/8760/c.f.
4. Energy charge from IR-AG-11-23, June 6, 1986. Escalated at a calculated 5% average growth rate.
5. [3]+[4].

TABLE 5.3: PLC ASSUMPTIONS, PVNGS NON-FUEL OPERATING COSTS

Palo Verde Nuclear Generating Station:

Year	O&M $/KW-YR	Capital Additions $/KW-YR	Decommis-sioning $/KW-YR	Property Tax $/KW-YR	Insurance $/KW-YR	PLC Operating Cost $/KW-YR
	[1]	[2]	[3]	[4]	[5]	[6]
1987	$45.3	$0.0	$2.4	$17.9	$1.3	$66.9
1988	$53.6	$3.4	$3.3	$21.2	$1.4	$82.8
1989	$63.3	$3.4	$3.3	$21.9	$1.5	$93.4
1990	$74.3	$6.7	$4.1	$22.2	$1.6	$108.9
1991	$86.5	$10.1	$4.9	$22.9	$1.7	$126.1
1992	$100.0	$13.4	$4.9	$23.6	$1.8	$143.7
1993	$114.8	$16.8	$4.9	$24.0	$2.0	$162.5
1994	$130.9	$20.3	$4.9	$23.8	$2.1	$182.0
1995	$148.8	$23.7	$4.9	$23.0	$2.2	$202.8
1996	$168.7	$27.3	$4.9	$23.8	$2.4	$227.1
1997	$190.4	$30.9	$4.9	$24.5	$2.7	$253.5
1998	$214.3	$34.5	$4.9	$25.3	$2.9	$282.0
1999	$240.7	$38.4	$4.9	$26.2	$3.2	$313.3
2000	$269.3	$42.5	$4.9	$27.0	$3.5	$347.2
2001	$299.2	$46.8	$4.9	$27.9	$3.8	$382.6
2002	$331.7	$51.4	$4.9	$28.8	$4.1	$420.9
2003	$367.0	$56.1	$4.9	$29.7	$4.5	$462.2
2004	$405.3	$61.2	$4.9	$30.6	$4.9	$506.9
2005	$446.8	$66.5	$4.9	$31.6	$5.3	$555.1
2006	$491.8	$72.1	$4.9	$32.7	$5.8	$607.2
2007	$540.6	$78.0	$4.9	$33.7	$6.3	$663.5
2008	$593.4	$84.2	$4.9	$34.8	$6.9	$724.2
2009	$650.6	$90.8	$4.9	$35.9	$7.5	$789.8
2010	$712.5	$97.8	$4.9	$37.1	$8.2	$860.4
2011	$779.4	$105.3	$4.9	$38.3	$8.9	$936.7
2012	$851.7	$113.2	$4.9	$39.5	$9.7	$1,019.0
2013	$929.8	$121.7	$4.9	$40.8	$10.6	$1,107.7
2014	$1,014.2	$130.7	$4.9	$42.1	$11.6	$1,203.4
2015	$1,105.3	$140.4	$4.9	$43.4	$12.6	$1,306.6
2016	$1,203.6	$150.9	$4.9	$44.8	$13.7	$1,417.9
2017	$1,309.7	$162.2	$4.9	$46.3	$15.0	$1,538.0
2018	$1,424.1	$168.6	$4.9	$47.8	$16.3	$1,661.7
2019	$1,547.4	$178.2	$4.9	$49.3	$17.8	$1,797.6
2020	$1,680.3	$191.5	$4.9	$50.9	$19.4	$1,947.0
2021	$1,823.6	$209.6	$4.9	$52.5	$21.1	$2,111.8
2022	$1,977.9	$234.2	$4.9	$54.2	$23.0	$2,294.2
2023	$2,144.0	$269.2	$4.9	$56.0	$25.1	$2,499.1
2024	$2,322.9	$321.1	$4.9	$57.8	$27.4	$2,734.0
2025	$2,515.4	$406.9	$4.9	$59.6	$29.8	$3,016.6
2026	$2,722.5	$593.7	$4.9	$61.5	$32.5	$3,415.1

Notes: 1. From Table 6.9, Col. 6. 1987 O&M from the same regression.
2. From Appendix I-A.
3. From Application for proposed Decommissioning Reserve Fund, NMPSC Case # 1833, Phase II. May 1, 1986, Exh. II.
4. From EPE.
5. From AG-IR-11-2, p 1. Esc. @ avg. growth rate: 9%
6. [1]+[2]+[3]+[4].

TABLE 5.4: EPE ASSUMPTIONS, PVNGS NON-FUEL OPERATING COSTS

Palo Verde Nuclear Generating Station:

Year	Fixed O&M $/KW-YR	Capital Additions $/KW-YR	Decommis-sioning $/KW-YR	Property Tax $/KW-YR	Insurance $/KW-YR	Operating Cost minus Var. O&M $/KW-YR	Variable O&M at 100% Capacity $/KW-YR	Non-fuel Operating PLC C.F. $/KW-YR	Non-fuel Operating EPE C.F. $/KW-YR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1987	$45.8	0.0	$2.4	$17.9	$1.3	$67.4	$32.0	$87.0	$89.1
1988	$46.3	2.1	$3.3	$21.2	$1.4	$74.2	$30.5	$90.7	$92.5
1989	$49.5	2.1	$3.3	$21.9	$1.5	$78.2	$30.7	$95.5	$99.4
1990	$52.3	3.8	$4.1	$22.2	$1.6	$84.0	$32.0	$102.7	$107.7
1991	$55.6	5.6	$4.9	$22.9	$1.7	$90.7	$34.0	$111.3	$115.9
1992	$59.0	7.5	$4.9	$23.6	$1.8	$96.9	$36.1	$119.2	$123.6
1993	$62.7	9.4	$4.9	$24.0	$2.0	$103.0	$38.4	$126.7	$131.4
1994	$66.5	11.4	$4.9	$23.8	$2.1	$108.7	$40.7	$133.9	$138.8
1995	$70.7	13.4	$4.9	$23.0	$2.2	$114.3	$43.3	$141.0	$146.3
1996	$75.2	15.4	$4.9	$23.8	$2.4	$121.8	$46.0	$150.3	$155.8
1997	$80.0	17.6	$4.9	$24.5	$2.7	$129.7	$49.0	$160.0	$165.9
1998	$85.1	19.7	$4.9	$25.3	$2.9	$137.9	$52.1	$170.2	$176.5
1999	$90.7	21.9	$4.9	$26.2	$3.2	$146.8	$55.5	$178.1	$187.9
2000	$96.5	24.2	$4.9	$27.0	$3.5	$156.0	$59.1	$189.4	$199.7
2001	$102.1	26.7	$4.9	$27.9	$3.8	$165.4	$62.5	$200.7	$211.7
2002	$108.2	29.3	$4.9	$28.8	$4.1	$175.2	$66.2	$212.6	$224.3
2003	$114.6	32.0	$4.9	$29.7	$4.5	$185.6	$70.1	$225.2	$237.5
2004	$121.3	34.9	$4.9	$30.6	$4.9	$196.6	$74.3	$238.5	$251.6
2005	$128.5	37.9	$4.9	$31.6	$5.3	$208.3	$78.7	$252.6	$266.5
2006	$136.1	41.1	$4.9	$32.7	$5.8	$220.5	$83.3	$267.5	$282.2
2007	$144.1	44.5	$4.9	$33.7	$6.3	$233.5	$88.2	$283.3	$298.8
2008	$152.6	48.0	$4.9	$34.8	$6.9	$247.2	$93.4	$299.9	$316.4
2009	$161.6	51.8	$4.9	$35.9	$7.5	$261.8	$98.9	$317.6	$335.0
2010	$171.1	55.9	$4.9	$37.1	$8.2	$277.1	$104.8	$336.2	$354.7
2011	$181.2	60.1	$4.9	$38.3	$8.9	$293.4	$111.0	$356.0	$375.5
2012	$191.9	64.7	$4.9	$39.5	$9.7	$310.7	$117.5	$377.0	$397.6
2013	$203.2	69.5	$4.9	$40.8	$10.6	$329.0	$124.4	$399.2	$421.1
2014	$215.2	74.7	$4.9	$42.1	$11.6	$348.4	$131.8	$422.7	$445.9
2015	$227.9	80.2	$4.9	$43.4	$12.6	$369.1	$139.6	$447.8	$472.3
2016	$241.4	86.2	$4.9	$44.8	$13.7	$391.0	$147.8	$474.4	$500.4
2017	$255.6	92.7	$4.9	$46.3	$15.0	$414.4	$156.5	$502.7	$530.2
2018	$270.7	96.4	$4.9	$47.8	$16.3	$436.0	$165.8	$529.5	$558.7
2019	$286.7	101.8	$4.9	$49.3	$17.8	$460.5	$175.5	$559.5	$590.4
2020	$303.6	109.4	$4.9	$50.9	$19.4	$488.2	$185.9	$593.0	$625.7
2021	$321.5	119.8	$4.9	$52.5	$21.1	$519.8	$196.9	$630.9	$665.5
2022	$340.4	133.9	$4.9	$54.2	$23.0	$556.5	$208.5	$674.0	$710.7
2023	$360.5	153.8	$4.9	$56.0	$25.1	$600.3	$220.8	$724.8	$763.7
2024	$381.8	183.5	$4.9	$57.8	$27.4	$655.4	$233.8	$787.2	$828.4
2025	$404.3	232.6	$4.9	$59.6	$29.8	$731.3	$247.6	$870.9	$914.5
2026	$428.2	339.3	$4.9	$61.5	$32.5	$866.5	$262.2	$1,014.3	$1,060.5

Notes: 1. From AG-IR-6-14, 2/28/86. Inflation rates from AG-IR-8-2, 4/1/86 (averages), 1984 rate from 'Economic Report of the President, February 1985.

2. From AG-IR-6-13, 2/28/86. Inflation rates from AG-IR-8-2, 4/1/86.

3. See Table 5.3, Note #3.

4. From EPE, esc. @ avg. growth rate: 3.33%

5. From AG-IR-11-2, p.1. Esc. @ avg. growth rate: 9%

6. [1]+[2]+[3]+[4].

7. From AG-IR-6-14, 2/28/86.

TABLE 5.5: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT   Case 1 - San Juan 4 Value, PLC Assumptions

Year	San Juan Value of PVNGS Non-fuel Costs cts/kwh	PLC Capacity Factor	San Juan Value of PVNGS Non-fuel Costs $/KW-YR	PLC Non-fuel Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12.0% Rate Base [7]: $335	15.0% $550	18.0% $677	20.0% $733
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	5.0	61.3%	$269.5	$66.9	$202.6	21.5%	$72	$118	$146	$158
1988	5.4	53.8%	$255.3	$82.8	$172.5	20.8%	$70	$114	$141	$152
1989	5.5	56.1%	$271.1	$93.4	$177.8	19.8%	$66	$109	$134	$145
1990	5.6	58.4%	$287.6	$108.9	$178.7	18.9%	$63	$104	$128	$139
1991	6.1	60.7%	$323.2	$126.1	$197.1	18.1%	$61	$99	$123	$133
1992	5.9	61.9%	$318.7	$143.7	$175.0	17.3%	$58	$95	$117	$127
1993	5.8	61.9%	$315.3	$162.5	$152.8	16.5%	$55	$91	$112	$121
1994	5.8	61.9%	$316.2	$182.0	$134.2	15.7%	$53	$86	$106	$115
1995	5.9	61.9%	$318.4	$202.8	$115.6	15.0%	$50	$82	$101	$110
1996	6.0	61.9%	$324.5	$227.1	$97.4	14.2%	$48	$78	$96	$104
1997	5.9	61.9%	$320.3	$253.5	$66.8	13.4%	$45	$74	$91	$99
1998	6.1	61.9%	$328.6	$282.0	$46.6	13.1%	$44	$72	$89	$96
1999	6.2	56.4%	$308.4	$313.3	($5.0)	12.8%	$43	$70	$87	$94
2000	6.5	56.4%	$318.8	$347.2	($28.3)	12.4%	$42	$68	$84	$91
2001	6.7	56.4%	$331.7	$382.6	($50.9)	12.1%	$41	$67	$82	$89
2002	6.8	56.4%	$335.4	$420.9	($85.4)	11.8%	$39	$65	$80	$86
2003	7.1	56.4%	$351.4	$462.2	($110.8)	11.4%	$38	$63	$77	$84
2004	7.5	56.4%	$368.8	$506.9	($138.1)	11.1%	$37	$61	$75	$81
2005	7.8	56.4%	$387.4	$555.1	($167.7)	10.8%	$36	$59	$73	$79
2006	8.4	56.4%	$413.9	$607.2	($193.4)	10.4%	$35	$57	$71	$77
2007	8.7	56.4%	$429.8	$663.5	($233.7)	10.1%	$34	$56	$68	$74
2008	9.2	56.4%	$453.8	$724.2	($270.4)	9.8%	$33	$54	$66	$72
2009	9.7	56.4%	$479.8	$789.8	($309.9)	9.4%	$32	$52	$64	$69
2010	10.3	56.4%	$508.1	$860.4	($352.3)	9.1%	$30	$50	$62	$67
2011	11.0	56.4%	$544.1	$936.7	($392.7)	8.8%	$29	$48	$59	$64
2012	11.6	56.4%	$572.2	$1,019.0	($446.8)	8.4%	$28	$46	$57	$62
2013	12.3	56.4%	$608.3	$1,107.7	($499.4)	8.1%	$27	$44	$55	$59
2014	13.1	56.4%	$647.5	$1,203.4	($555.9)	7.8%	$26	$43	$53	$57
2015	14.0	56.4%	$690.0	$1,306.6	($616.6)	7.4%	$25	$41	$50	$54
2016	15.0	56.4%	$740.3	$1,417.9	($677.6)	7.1%	$24	$39	$48	$52
2017	15.9	56.4%	$785.9	$1,538.0	($752.1)	6.8%	$23	$37	$46	$50
2018	17.0	56.4%	$839.9	$1,661.7	($821.8)	6.4%	$22	$35	$43	$47
2019	18.2	56.4%	$898.3	$1,797.6	($899.3)	6.1%	$20	$33	$41	$45
2020	19.5	56.4%	$961.5	$1,947.0	($985.5)	5.8%	$19	$32	$39	$42
2021	20.9	56.4%	$1,033.3	$2,111.8	($1,078.5)	5.4%	$18	$30	$37	$40
2022	22.3	56.4%	$1,104.0	$2,294.2	($1,190.2)	5.1%	$17	$28	$34	$37
2023	24.0	56.4%	$1,184.2	$2,499.1	($1,315.0)	4.7%	$16	$26	$32	$35
2024	25.7	56.4%	$1,270.8	$2,734.0	($1,463.2)	4.4%	$15	$24	$30	$32
2025	27.6	56.4%	$1,364.5	$3,016.6	($1,652.1)	4.1%	$14	$22	$28	$30
2026	29.7	56.4%	$1,465.8	$3,415.1	($1,949.3)	3.7%	$13	$21	$25	$27
				PV@		-----	-----	-----	-----	-----
				12%	$446		$446	$617	$657	$652
				15%	$617					
				18%	$657					
				20%	$652					
				Levelized @						
				12%	$54	16.2%	$54	$93	$118	$131
				15%	$93	16.9%				
				18%	$118	17.5%				
				20%	$131	17.8%				

TABLE 5.6: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 2 - SPS Value, PLC Assumptions

Year	SPS Value of PVNGS non-fuel costs cts/kwh	PLC Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	PLC Non-fuel Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12.0% Rate Base [7]: ($196)	15.0% ($6)	18.0% $102	20.0% $148
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	61.3%	$139.3	$66.9	$72.4	21.5%	($42)	($1)	$22	$32
1988	2.8	53.8%	$129.8	$82.8	$47.0	20.8%	($41)	($1)	$21	$31
1989	2.9	56.1%	$140.8	$93.4	$47.5	19.8%	($39)	($1)	$20	$29
1990	3.0	58.4%	$154.0	$108.9	$45.2	18.9%	($37)	($1)	$19	$28
1991	3.3	60.7%	$172.9	$126.1	$46.8	18.1%	($35)	($1)	$18	$27
1992	3.5	61.9%	$188.8	$143.7	$45.0	17.3%	($34)	($1)	$18	$26
1993	4.1	61.9%	$219.7	$162.5	$57.2	16.5%	($32)	($1)	$17	$24
1994	4.3	61.9%	$231.6	$182.0	$49.6	15.7%	($31)	($1)	$16	$23
1995	4.5	61.9%	$246.2	$202.8	$43.4	15.0%	($29)	($1)	$15	$22
1996	5.1	61.9%	$275.6	$227.1	$48.5	14.2%	($28)	($1)	$15	$21
1997	5.2	61.9%	$282.0	$253.5	$28.5	13.4%	($26)	($1)	$14	$20
1998	5.3	61.9%	$288.7	$282.0	$6.7	13.1%	($26)	($1)	$13	$19
1999	6.0	56.4%	$295.1	$313.3	($18.2)	12.8%	($25)	($1)	$13	$19
2000	6.1	56.4%	$301.7	$347.2	($45.4)	12.4%	($24)	($1)	$13	$18
2001	6.2	56.4%	$308.6	$382.6	($73.9)	12.1%	($24)	($1)	$12	$18
2002	7.0	56.4%	$347.1	$420.9	($73.8)	11.8%	($23)	($1)	$12	$17
2003	7.2	56.4%	$354.5	$462.2	($107.6)	11.4%	($22)	($1)	$12	$17
2004	7.3	56.4%	$362.3	$506.9	($144.5)	11.1%	($22)	($1)	$11	$16
2005	8.3	56.4%	$408.4	$555.1	($146.7)	10.8%	($21)	($1)	$11	$16
2006	8.4	56.4%	$416.8	$607.2	($190.4)	10.4%	($20)	($1)	$11	$15
2007	8.6	56.4%	$425.6	$663.5	($237.9)	10.1%	($20)	($1)	$10	$15
2008	9.7	56.4%	$480.8	$724.2	($243.4)	9.8%	($19)	($1)	$10	$14
2009	9.9	56.4%	$490.3	$789.8	($299.4)	9.4%	($19)	($1)	$10	$14
2010	10.1	56.4%	$500.2	$860.4	($360.2)	9.1%	($18)	($1)	$9	$13
2011	11.5	56.4%	$566.5	$936.7	($370.2)	8.8%	($17)	($0)	$9	$13
2012	11.7	56.4%	$577.2	$1,019.0	($441.8)	8.4%	($17)	($0)	$9	$12
2013	11.9	56.4%	$588.3	$1,107.7	($519.4)	8.1%	($16)	($0)	$8	$12
2014	13.5	56.4%	$667.8	$1,203.4	($535.6)	7.8%	($15)	($0)	$8	$11
2015	13.8	56.4%	$679.8	$1,306.6	($626.8)	7.4%	($15)	($0)	$8	$11
2016	14.0	56.4%	$692.3	$1,417.9	($725.6)	7.1%	($14)	($0)	$7	$10
2017	15.9	56.4%	$787.7	$1,538.0	($750.3)	6.8%	($13)	($0)	$7	$10
2018	16.2	56.4%	$801.2	$1,661.7	($860.5)	6.4%	($13)	($0)	$7	$9
2019	16.5	56.4%	$815.2	$1,797.6	($982.4)	6.1%	($12)	($0)	$6	$9
2020	18.8	56.4%	$929.8	$1,947.0	($1,017.2)	5.8%	($11)	($0)	$6	$8
2021	19.1	56.4%	$944.8	$2,111.8	($1,166.9)	5.4%	($11)	($0)	$6	$8
2022	19.4	56.4%	$960.5	$2,294.2	($1,333.8)	5.1%	($10)	($0)	$5	$7
2023	22.2	56.4%	$1,098.2	$2,499.1	($1,401.0)	4.7%	($9)	($0)	$5	$7
2024	22.6	56.4%	$1,115.0	$2,734.0	($1,619.0)	4.4%	($9)	($0)	$5	$7
2025	22.9	56.4%	$1,132.4	$3,016.6	($1,884.2)	4.1%	($8)	($0)	$4	$6
2026	23.3	56.4%	$1,150.4	$3,415.1	($2,264.7)	3.7%	($7)	($0)	$4	$6
				PV@		-----	-----	-----	-----	-----
				12%	($261)		($261)	($6)	$99	$131
				15%	($6)					
				18%	$99					
				20%	$131					
				Levelized @						
				12%	($32)		($32)	($1)	$18	$26
				15%	($1)					
				18%	$18					
				20%	$26					

TABLE 5.7: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 3 - San Juan Value, PLC Assumptions
EPE Capacity Factor

Year	San Juan Value of PVNGS non-fuel costs cts/kwh	EPE Capacity Factor	San Juan Value of PVNGS non-fuel costs $/KW-YR	PLC Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $816	15.0% $960	18.0% $1,043	20.0% $1,077
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	5.0	68.0%	$299.0	$66.9	$232.1	21.5%	$175	$206	$224	$232
1988	5.4	60.0%	$284.8	$82.8	$202.0	20.8%	$170	$200	$217	$224
1989	5.5	69.0%	$333.5	$93.4	$240.1	19.8%	$161	$190	$206	$213
1990	5.6	74.0%	$364.4	$108.9	$255.6	18.9%	$154	$181	$197	$204
1991	6.1	74.0%	$394.1	$126.1	$268.0	18.1%	$148	$174	$189	$195
1992	5.9	74.0%	$381.0	$143.7	$237.3	17.3%	$141	$166	$180	$186
1993	5.8	74.0%	$376.9	$162.5	$214.4	16.5%	$134	$158	$172	$178
1994	5.8	74.0%	$378.0	$182.0	$196.0	15.7%	$128	$151	$164	$169
1995	5.9	74.0%	$380.6	$202.8	$177.8	15.0%	$122	$144	$156	$161
1996	6.0	74.0%	$388.0	$227.1	$160.9	14.2%	$116	$136	$148	$153
1997	5.9	74.0%	$382.9	$253.5	$129.4	13.4%	$110	$129	$140	$145
1998	6.1	74.0%	$392.9	$282.0	$110.8	13.1%	$107	$126	$137	$141
1999	6.2	74.0%	$404.6	$313.3	$91.3	12.8%	$104	$123	$133	$138
2000	6.5	74.0%	$418.3	$347.2	$71.1	12.4%	$101	$120	$130	$134
2001	6.7	74.0%	$435.2	$382.6	$52.6	12.1%	$99	$116	$126	$130
2002	6.8	74.0%	$440.1	$420.9	$19.2	11.8%	$96	$113	$123	$127
2003	7.1	74.0%	$461.1	$462.2	($1.1)	11.4%	$93	$110	$119	$123
2004	7.5	74.0%	$483.9	$506.9	($23.0)	11.1%	$91	$107	$116	$120
2005	7.8	74.0%	$508.3	$555.1	($46.8)	10.8%	$88	$103	$112	$116
2006	8.4	74.0%	$543.0	$607.2	($64.2)	10.4%	$85	$100	$109	$112
2007	8.7	74.0%	$563.9	$663.5	($99.6)	10.1%	$82	$97	$105	$109
2008	9.2	74.0%	$595.4	$724.2	($128.8)	9.8%	$80	$94	$102	$105
2009	9.7	74.0%	$629.6	$789.8	($160.2)	9.4%	$77	$91	$98	$102
2010	10.3	74.0%	$666.7	$860.4	($193.8)	9.1%	$74	$87	$95	$98
2011	11.0	74.0%	$713.8	$936.7	($222.9)	8.8%	$71	$84	$91	$94
2012	11.6	74.0%	$750.7	$1,019.0	($268.3)	8.4%	$69	$81	$88	$91
2013	12.3	74.0%	$798.2	$1,107.7	($309.5)	8.1%	$66	$78	$84	$87
2014	13.1	74.0%	$849.6	$1,203.4	($353.8)	7.8%	$63	$75	$81	$84
2015	14.0	74.0%	$905.3	$1,306.6	($401.3)	7.4%	$61	$71	$77	$80
2016	15.0	74.0%	$971.3	$1,417.9	($446.6)	7.1%	$58	$68	$74	$76
2017	15.9	74.0%	$1,031.1	$1,538.0	($506.9)	6.8%	$55	$65	$70	$73
2018	17.0	74.0%	$1,101.9	$1,661.7	($559.7)	6.4%	$52	$62	$67	$69
2019	18.2	74.0%	$1,178.6	$1,797.6	($619.0)	6.1%	$50	$58	$63	$66
2020	19.5	74.0%	$1,261.6	$1,947.0	($685.4)	5.8%	$47	$55	$60	$62
2021	20.9	74.0%	$1,355.7	$2,111.8	($756.0)	5.4%	$44	$52	$56	$58
2022	22.3	74.0%	$1,448.6	$2,294.2	($845.7)	5.1%	$41	$49	$53	$55
2023	24.0	74.0%	$1,553.7	$2,499.1	($945.4)	4.7%	$39	$46	$49	$51
2024	25.7	74.0%	$1,667.4	$2,734.0	($1,066.7)	4.4%	$36	$42	$46	$48
2025	27.6	74.0%	$1,790.3	$3,016.6	($1,226.3)	4.1%	$33	$39	$43	$44
2026	29.7	74.0%	$1,923.3	$3,415.1	($1,491.8)	3.7%	$31	$36	$39	$40
				PV@		-----	-----	-----	-----	-----
				12%	$1,086		$1,086	$1,078	$1,011	$958
				15%	$1,078					
				18%	$1,011					
				20%	$958					
				Levelized @						
				12%	$132		$132	$162	$182	$192
				15%	$162					
				18%	$182					
				20%	$192					

TABLE 5.8: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 4 - SPS Value, PLC Assumptions

Year	SPS Value of PVNGS non-fuel costs cts/kwh	EPE Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	PLC Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EPE Capacity Factor EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $183	15.0% $302	18.0% $362	20.0% $385
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	68.0%	$154.5	$66.9	$87.7	21.5%	$39	$65	$78	$83
1988	2.8	60.0%	$144.8	$82.8	$62.0	20.8%	$38	$63	$75	$80
1989	2.9	69.0%	$173.2	$93.4	$79.8	19.8%	$36	$60	$72	$76
1990	3.0	74.0%	$195.2	$108.9	$86.3	18.9%	$35	$57	$68	$73
1991	3.3	74.0%	$210.8	$126.1	$84.7	18.1%	$33	$55	$66	$70
1992	3.5	74.0%	$225.7	$143.7	$81.9	17.3%	$32	$52	$63	$67
1993	4.1	74.0%	$262.6	$162.5	$100.1	16.5%	$30	$50	$60	$63
1994	4.3	74.0%	$276.8	$182.0	$94.8	15.7%	$29	$47	$57	$61
1995	4.5	74.0%	$294.3	$202.8	$91.5	15.0%	$27	$45	$54	$58
1996	5.1	74.0%	$329.5	$227.1	$102.4	14.2%	$26	$43	$51	$55
1997	5.2	74.0%	$337.1	$253.5	$83.7	13.4%	$25	$41	$49	$52
1998	5.3	74.0%	$345.1	$282.0	$63.1	13.1%	$24	$40	$48	$50
1999	6.0	74.0%	$387.2	$313.3	$73.9	12.8%	$23	$39	$46	$49
2000	6.1	74.0%	$395.9	$347.2	$48.7	12.4%	$23	$38	$45	$48
2001	6.2	74.0%	$404.9	$382.6	$22.4	12.1%	$22	$37	$44	$47
2002	7.0	74.0%	$455.4	$420.9	$34.5	11.8%	$22	$36	$43	$45
2003	7.2	74.0%	$465.2	$462.2	$3.0	11.4%	$21	$35	$41	$44
2004	7.3	74.0%	$475.4	$506.9	($31.5)	11.1%	$20	$34	$40	$43
2005	8.3	74.0%	$535.8	$555.1	($19.3)	10.8%	$20	$33	$39	$41
2006	8.4	74.0%	$546.9	$607.2	($60.3)	10.4%	$19	$32	$38	$40
2007	8.6	74.0%	$558.4	$663.5	($105.1)	10.1%	$19	$31	$37	$39
2008	9.7	74.0%	$630.9	$724.2	($93.3)	9.8%	$18	$29	$35	$38
2009	9.9	74.0%	$643.4	$789.8	($146.4)	9.4%	$17	$28	$34	$36
2010	10.1	74.0%	$656.4	$860.4	($204.1)	9.1%	$17	$27	$33	$35
2011	11.5	74.0%	$743.2	$936.7	($193.5)	8.8%	$16	$26	$32	$34
2012	11.7	74.0%	$757.3	$1,019.0	($261.7)	8.4%	$15	$25	$31	$32
2013	11.9	74.0%	$771.9	$1,107.7	($335.8)	8.1%	$15	$24	$29	$31
2014	13.5	74.0%	$876.2	$1,203.4	($327.2)	7.8%	$14	$23	$28	$30
2015	13.8	74.0%	$892.0	$1,306.6	($414.7)	7.4%	$14	$22	$27	$29
2016	14.0	74.0%	$908.3	$1,417.9	($509.6)	7.1%	$13	$21	$26	$27
2017	15.9	74.0%	$1,033.5	$1,538.0	($504.5)	6.8%	$12	$20	$24	$26
2018	16.2	74.0%	$1,051.2	$1,661.7	($610.5)	6.4%	$12	$19	$23	$25
2019	16.5	74.0%	$1,069.6	$1,797.6	($728.0)	6.1%	$11	$18	$22	$23
2020	18.8	74.0%	$1,219.9	$1,947.0	($727.1)	5.8%	$11	$17	$21	$22
2021	19.1	74.0%	$1,239.7	$2,111.8	($872.1)	5.4%	$10	$16	$20	$21
2022	19.4	74.0%	$1,260.2	$2,294.2	($1,034.0)	5.1%	$9	$15	$18	$20
2023	22.2	74.0%	$1,440.9	$2,499.1	($1,058.3)	4.7%	$9	$14	$17	$18
2024	22.6	74.0%	$1,462.9	$2,734.0	($1,271.1)	4.4%	$8	$13	$16	$17
2025	22.9	74.0%	$1,485.8	$3,016.6	($1,530.9)	4.1%	$7	$12	$15	$16
2026	23.3	74.0%	$1,509.4	$3,415.1	($1,905.7)	3.7%	$7	$11	$14	$14
				PV@		-----	-----	-----	-----	-----
				12%	$244		$244	$339	$351	$342
				15%	$339					
				18%	$351					
				20%	$342					
				Levelized @						
				12%	$30		$30	$51	$63	$69
				15%	$51					
				18%	$63					
				20%	$69					

TABLE 5.9: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 5 - San Juan Value, EPE Assumptions
PLC Capacity Factor

Year	San Juan Value of PVNGS non-fuel costs cts/kwh	PLC Capacity Factor	San Juan Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $1,104	15.0% $1,049	18.0% $1,015	20.0% $999
[1]	[2]	[3]	[4]	[5]	[6]		[8]			
1987	5.0	61.3%	$269.5	$87.0	$182.5	21.5%	$237	$226	$218	$215
1988	5.4	53.8%	$255.3	$90.7	$164.7	20.8%	$229	$218	$211	$208
1989	5.5	56.1%	$271.1	$95.5	$175.7	19.8%	$218	$208	$201	$198
1990	5.6	58.4%	$287.6	$102.7	$185.0	18.9%	$209	$198	$192	$189
1991	6.1	60.7%	$323.2	$111.3	$211.9	18.1%	$200	$190	$184	$181
1992	5.9	61.9%	$318.7	$119.2	$199.5	17.3%	$191	$181	$175	$173
1993	5.8	61.9%	$315.3	$126.7	$188.5	16.5%	$182	$173	$167	$165
1994	5.8	61.9%	$316.2	$133.9	$182.3	15.7%	$174	$165	$160	$157
1995	5.9	61.9%	$318.4	$141.0	$177.3	15.0%	$165	$157	$152	$149
1996	6.0	61.9%	$324.5	$150.3	$174.3	14.2%	$157	$149	$144	$142
1997	5.9	61.9%	$320.3	$160.0	$160.3	13.4%	$148	$141	$137	$134
1998	6.1	61.9%	$328.6	$170.2	$158.4	13.1%	$145	$138	$133	$131
1999	6.2	56.4%	$308.4	$178.1	$130.3	12.8%	$141	$134	$130	$128
2000	6.5	56.4%	$318.8	$189.4	$129.5	12.4%	$137	$131	$126	$124
2001	6.7	56.4%	$331.7	$200.7	$131.0	12.1%	$134	$127	$123	$121
2002	6.8	56.4%	$335.4	$212.6	$122.8	11.8%	$130	$124	$120	$118
2003	7.1	56.4%	$351.4	$225.2	$126.2	11.4%	$126	$120	$116	$114
2004	7.5	56.4%	$368.8	$238.5	$130.3	11.1%	$123	$117	$113	$111
2005	7.8	56.4%	$387.4	$252.6	$134.8	10.8%	$119	$113	$109	$108
2006	8.4	56.4%	$413.9	$267.5	$146.4	10.4%	$115	$110	$106	$104
2007	8.7	56.4%	$429.8	$283.3	$146.5	10.1%	$111	$106	$103	$101
2008	9.2	56.4%	$453.8	$299.9	$153.9	9.8%	$108	$102	$99	$98
2009	9.7	56.4%	$479.8	$317.6	$162.3	9.4%	$104	$99	$96	$94
2010	10.3	56.4%	$508.1	$336.2	$171.9	9.1%	$100	$95	$92	$91
2011	11.0	56.4%	$544.1	$356.0	$188.1	8.8%	$97	$92	$89	$88
2012	11.6	56.4%	$572.2	$377.0	$195.2	8.4%	$93	$88	$86	$84
2013	12.3	56.4%	$608.3	$399.2	$209.2	8.1%	$89	$85	$82	$81
2014	13.1	56.4%	$647.5	$422.7	$224.8	7.8%	$86	$81	$79	$77
2015	14.0	56.4%	$690.0	$447.8	$242.2	7.4%	$82	$78	$75	$74
2016	15.0	56.4%	$740.3	$474.4	$265.9	7.1%	$78	$74	$72	$71
2017	15.9	56.4%	$785.9	$502.7	$283.2	6.8%	$75	$71	$69	$67
2018	17.0	56.4%	$839.9	$529.5	$310.4	6.4%	$71	$67	$65	$64
2019	18.2	56.4%	$898.3	$559.5	$338.8	6.1%	$67	$64	$62	$61
2020	19.5	56.4%	$961.5	$593.0	$368.5	5.8%	$63	$60	$58	$57
2021	20.9	56.4%	$1,033.3	$630.9	$402.4	5.4%	$60	$57	$55	$54
2022	22.3	56.4%	$1,104.0	$674.0	$430.0	5.1%	$56	$53	$52	$51
2023	24.0	56.4%	$1,184.2	$724.8	$459.3	4.7%	$52	$50	$48	$47
2024	25.7	56.4%	$1,270.8	$787.2	$483.6	4.4%	$49	$46	$45	$44
2025	27.6	56.4%	$1,364.5	$870.9	$493.6	4.1%	$45	$43	$41	$41
2026	29.7	56.4%	$1,465.8	$1,014.3	$451.5	3.7%	$41	$39	$38	$37
				PV@		-----	-----	-----	-----	-----
				12%	$1,470		$1,470	$1,178	$984	$888
				15%	$1,178					
				18%	$984					
				20%	$888					
				Levelized @						
				12%	$178		$178	$177	$177	$178
				15%	$177					
				18%	$177					
				20%	$178					

TABLE 5.10: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 6 - SPS Value, EPE Assumptions

PLC Capacity Factor

Year	SPS Value of PVNGS non-fuel costs cts/kwh	PLC Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $572	15.0% $494	18.0% $440	20.0% $413
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	61.3%	$139.3	$87.0	$52.3	21.5%	$123	$106	$95	$89
1988	2.8	53.8%	$129.8	$90.7	$39.2	20.8%	$119	$103	$91	$86
1989	2.9	56.1%	$140.8	$95.5	$45.4	19.8%	$113	$98	$87	$82
1990	3.0	58.4%	$154.0	$102.7	$51.4	18.9%	$108	$93	$83	$78
1991	3.3	60.7%	$172.9	$111.3	$61.5	18.1%	$104	$89	$80	$75
1992	3.5	61.9%	$188.8	$119.2	$69.5	17.3%	$99	$85	$76	$71
1993	4.1	61.9%	$219.7	$126.7	$92.9	16.5%	$94	$81	$73	$68
1994	4.3	61.9%	$231.6	$133.9	$97.7	15.7%	$90	$78	$69	$65
1995	4.5	61.9%	$246.2	$141.0	$105.1	15.0%	$86	$74	$66	$62
1996	5.1	61.9%	$275.6	$150.3	$125.3	14.2%	$81	$70	$63	$59
1997	5.2	61.9%	$282.0	$160.0	$122.0	13.4%	$77	$66	$59	$56
1998	5.3	61.9%	$288.7	$170.2	$118.5	13.1%	$75	$65	$58	$54
1999	6.0	56.4%	$295.1	$178.1	$117.1	12.8%	$73	$63	$56	$53
2000	6.1	56.4%	$301.7	$189.4	$112.4	12.4%	$71	$61	$55	$51
2001	6.2	56.4%	$308.6	$200.7	$108.0	12.1%	$69	$60	$53	$50
2002	7.0	56.4%	$347.1	$212.6	$134.5	11.8%	$67	$58	$52	$49
2003	7.2	56.4%	$354.5	$225.2	$129.4	11.4%	$65	$57	$50	$47
2004	7.3	56.4%	$362.3	$238.5	$123.8	11.1%	$64	$55	$49	$46
2005	8.3	56.4%	$408.4	$252.6	$155.8	10.8%	$62	$53	$47	$44
2006	8.4	56.4%	$416.8	$267.5	$149.3	10.4%	$60	$52	$46	$43
2007	8.6	56.4%	$425.6	$283.3	$142.3	10.1%	$58	$50	$44	$42
2008	9.7	56.4%	$480.8	$299.9	$180.9	9.8%	$56	$48	$43	$40
2009	9.9	56.4%	$490.3	$317.6	$172.8	9.4%	$54	$47	$41	$39
2010	10.1	56.4%	$500.2	$336.2	$164.0	9.1%	$52	$45	$40	$38
2011	11.5	56.4%	$566.5	$356.0	$210.5	8.8%	$50	$43	$39	$36
2012	11.7	56.4%	$577.2	$377.0	$200.2	8.4%	$48	$42	$37	$35
2013	11.9	56.4%	$588.3	$399.2	$189.1	8.1%	$46	$40	$36	$33
2014	13.5	56.4%	$667.8	$422.7	$245.0	7.8%	$44	$38	$34	$32
2015	13.8	56.4%	$679.8	$447.8	$232.0	7.4%	$42	$37	$33	$31
2016	14.0	56.4%	$692.3	$474.4	$217.9	7.1%	$41	$35	$31	$29
2017	15.9	56.4%	$787.7	$502.7	$285.0	6.8%	$39	$33	$30	$28
2018	16.2	56.4%	$801.2	$529.5	$271.7	6.4%	$37	$32	$28	$26
2019	16.5	56.4%	$815.2	$559.5	$255.7	6.1%	$35	$30	$27	$25
2020	18.8	56.4%	$929.8	$593.0	$336.8	5.8%	$33	$28	$25	$24
2021	19.1	56.4%	$944.8	$630.9	$314.0	5.4%	$31	$27	$24	$22
2022	19.4	56.4%	$960.5	$674.0	$286.4	5.1%	$29	$25	$22	$21
2023	22.2	56.4%	$1,098.2	$724.8	$373.3	4.7%	$27	$23	$21	$20
2024	22.6	56.4%	$1,115.0	$787.2	$327.8	4.4%	$25	$22	$19	$18
2025	22.9	56.4%	$1,132.4	$870.9	$261.5	4.1%	$23	$20	$18	$17
2026	23.3	56.4%	$1,150.4	$1,014.3	$136.1	3.7%	$21	$18	$16	$15
				PV@		-----	-----	-----	-----	-----
				12%	$762		$762	$554	$427	$367
				15%	$554					
				18%	$427					
				20%	$367					
				Levelized @						
				12%	$92		$92	$83	$77	$73
				15%	$83					
				18%	$77					
				20%	$73					

TABLE 5.11: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 7 - San Juan Value, EPE Assumptions
EPE Capacity Factor

Year	San Juan Value of PVNGS non-fuel costs cts/kwh	EPE Capacity Factor	San Juan Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $1,541	15.0% $1,425	18.0% $1,351	20.0% $1,315
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	5.0	68.0%	$299.0	$89.1	$209.8	21.5%	$331	$306	$290	$283
1988	5.4	60.0%	$284.8	$92.5	$192.2	20.8%	$320	$296	$281	$273
1989	5.5	69.0%	$333.5	$99.4	$234.0	19.8%	$305	$282	$267	$260
1990	5.6	74.0%	$364.4	$107.7	$256.8	18.9%	$291	$269	$255	$248
1991	6.1	74.0%	$394.1	$115.9	$278.2	18.1%	$279	$258	$244	$238
1992	5.9	74.0%	$381.0	$123.6	$257.5	17.3%	$266	$246	$233	$227
1993	5.8	74.0%	$376.9	$131.4	$245.5	16.5%	$254	$235	$223	$217
1994	5.8	74.0%	$378.0	$138.8	$239.2	15.7%	$242	$224	$212	$207
1995	5.9	74.0%	$380.6	$146.3	$234.3	15.0%	$231	$213	$202	$197
1996	6.0	74.0%	$388.0	$155.8	$232.1	14.2%	$219	$202	$192	$187
1997	5.9	74.0%	$382.9	$165.9	$217.0	13.4%	$207	$192	$182	$177
1998	6.1	74.0%	$392.9	$176.5	$216.4	13.1%	$202	$187	$177	$172
1999	6.2	74.0%	$404.6	$187.9	$216.8	12.8%	$197	$182	$173	$168
2000	6.5	74.0%	$418.3	$199.7	$218.6	12.4%	$192	$177	$168	$164
2001	6.7	74.0%	$435.2	$211.7	$223.5	12.1%	$187	$173	$164	$159
2002	6.8	74.0%	$440.1	$224.3	$215.8	11.8%	$181	$168	$159	$155
2003	7.1	74.0%	$461.1	$237.5	$223.5	11.4%	$176	$163	$155	$150
2004	7.5	74.0%	$483.9	$251.6	$232.3	11.1%	$171	$158	$150	$146
2005	7.8	74.0%	$508.3	$266.5	$241.9	10.8%	$166	$153	$145	$142
2006	8.4	74.0%	$543.0	$282.2	$260.8	10.4%	$161	$149	$141	$137
2007	8.7	74.0%	$563.9	$298.8	$265.1	10.1%	$156	$144	$136	$133
2008	9.2	74.0%	$595.4	$316.4	$279.0	9.8%	$150	$139	$132	$128
2009	9.7	74.0%	$629.6	$335.0	$294.6	9.4%	$145	$134	$127	$124
2010	10.3	74.0%	$666.7	$354.7	$312.0	9.1%	$140	$130	$123	$120
2011	11.0	74.0%	$713.8	$375.5	$338.3	8.8%	$135	$125	$118	$115
2012	11.6	74.0%	$750.7	$397.6	$353.1	8.4%	$130	$120	$114	$111
2013	12.3	74.0%	$798.2	$421.1	$377.1	8.1%	$125	$115	$109	$106
2014	13.1	74.0%	$849.6	$445.9	$403.7	7.8%	$120	$111	$105	$102
2015	14.0	74.0%	$905.3	$472.3	$433.0	7.4%	$114	$106	$100	$98
2016	15.0	74.0%	$971.3	$500.4	$470.9	7.1%	$109	$101	$96	$93
2017	15.9	74.0%	$1,031.1	$530.2	$500.9	6.8%	$104	$96	$91	$89
2018	17.0	74.0%	$1,101.9	$558.7	$543.3	6.4%	$99	$91	$87	$84
2019	18.2	74.0%	$1,178.6	$590.4	$588.2	6.1%	$94	$87	$82	$80
2020	19.5	74.0%	$1,261.6	$625.7	$635.9	5.8%	$89	$82	$78	$76
2021	20.9	74.0%	$1,355.7	$665.5	$690.2	5.4%	$83	$77	$73	$71
2022	22.3	74.0%	$1,448.6	$710.7	$737.8	5.1%	$78	$72	$69	$67
2023	24.0	74.0%	$1,553.7	$763.7	$790.0	4.7%	$73	$68	$64	$62
2024	25.7	74.0%	$1,667.4	$828.4	$839.0	4.4%	$68	$63	$60	$58
2025	27.6	74.0%	$1,790.3	$914.5	$875.9	4.1%	$63	$58	$55	$54
2026	29.7	74.0%	$1,923.3	$1,060.5	$862.8	3.7%	$58	$53	$51	$49
				PV@		-----	-----	-----	-----	-----
				12%	$2,052		$2,052	$1,599	$1,310	$1,169
				15%	$1,599					
				18%	$1,310					
				20%	$1,169					
				Levelized @						
				12%	$249		$249	$241	$236	$234
				15%	$241					
				18%	$236					
				20%	$234					

TABLE 5.12: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 8 - SPS Value, EPE Assumptions

EPE Capacity Factor

Year	SPS Value of PVNGS non-fuel costs cts/kwh	EPE Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $908	15.0% $766	18.0% $670	20.0% $623
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	68.0%	$154.5	$89.1	$65.4	21.5%	$195	$165	$144	$134
1988	2.8	60.0%	$144.8	$92.5	$52.3	20.8%	$189	$159	$139	$129
1989	2.9	69.0%	$173.2	$99.4	$73.8	19.8%	$180	$152	$133	$123
1990	3.0	74.0%	$195.2	$107.7	$87.5	18.9%	$172	$145	$127	$118
1991	3.3	74.0%	$210.8	$115.9	$94.9	18.1%	$164	$139	$121	$113
1992	3.5	74.0%	$225.7	$123.6	$102.1	17.3%	$157	$132	$116	$108
1993	4.1	74.0%	$262.6	$131.4	$131.2	16.5%	$150	$126	$110	$103
1994	4.3	74.0%	$276.8	$138.8	$138.0	15.7%	$143	$120	$105	$98
1995	4.5	74.0%	$294.3	$146.3	$148.0	15.0%	$136	$115	$100	$93
1996	5.1	74.0%	$329.5	$155.8	$173.6	14.2%	$129	$109	$95	$88
1997	5.2	74.0%	$337.1	$165.9	$171.2	13.4%	$122	$103	$90	$84
1998	5.3	74.0%	$345.1	$176.5	$168.6	13.1%	$119	$100	$88	$82
1999	6.0	74.0%	$387.2	$187.9	$199.4	12.8%	$116	$98	$86	$80
2000	6.1	74.0%	$395.9	$199.7	$196.2	12.4%	$113	$95	$83	$77
2001	6.2	74.0%	$404.9	$211.7	$193.3	12.1%	$110	$93	$81	$75
2002	7.0	74.0%	$455.4	$224.3	$231.1	11.8%	$107	$90	$79	$73
2003	7.2	74.0%	$465.2	$237.5	$227.6	11.4%	$104	$88	$77	$71
2004	7.3	74.0%	$475.4	$251.6	$223.8	11.1%	$101	$85	$74	$69
2005	8.3	74.0%	$535.8	$266.5	$269.4	10.8%	$98	$83	$72	$67
2006	8.4	74.0%	$546.9	$282.2	$264.7	10.4%	$95	$80	$70	$65
2007	8.6	74.0%	$558.4	$298.8	$259.6	10.1%	$92	$77	$68	$63
2008	9.7	74.0%	$630.9	$316.4	$314.5	9.8%	$89	$75	$65	$61
2009	9.9	74.0%	$643.4	$335.0	$308.4	9.4%	$86	$72	$63	$59
2010	10.1	74.0%	$656.4	$354.7	$301.7	9.1%	$83	$70	$61	$57
2011	11.5	74.0%	$743.2	$375.5	$367.7	8.8%	$80	$67	$59	$55
2012	11.7	74.0%	$757.3	$397.6	$359.7	8.4%	$77	$65	$56	$52
2013	11.9	74.0%	$771.9	$421.1	$350.8	8.1%	$74	$62	$54	$50
2014	13.5	74.0%	$876.2	$445.9	$430.2	7.8%	$70	$59	$52	$48
2015	13.8	74.0%	$892.0	$472.3	$419.6	7.4%	$67	$57	$50	$46
2016	14.0	74.0%	$908.3	$500.4	$408.0	7.1%	$64	$54	$48	$44
2017	15.9	74.0%	$1,033.5	$530.2	$503.3	6.8%	$61	$52	$45	$42
2018	16.2	74.0%	$1,051.2	$558.7	$492.5	6.4%	$58	$49	$43	$40
2019	16.5	74.0%	$1,069.6	$590.4	$479.2	6.1%	$55	$47	$41	$38
2020	18.8	74.0%	$1,219.9	$625.7	$594.2	5.8%	$52	$44	$39	$36
2021	19.1	74.0%	$1,239.7	$665.5	$574.2	5.4%	$49	$41	$36	$34
2022	19.4	74.0%	$1,260.2	$710.7	$549.5	5.1%	$46	$39	$34	$32
2023	22.2	74.0%	$1,440.9	$763.7	$677.2	4.7%	$43	$36	$32	$30
2024	22.6	74.0%	$1,462.9	$828.4	$634.5	4.4%	$40	$34	$30	$27
2025	22.9	74.0%	$1,485.8	$914.5	$571.3	4.1%	$37	$31	$27	$25
2026	23.3	74.0%	$1,509.4	$1,060.5	$449.0	3.7%	$34	$29	$25	$23
				PV@		-----	-----	-----	-----	-----
				12%	$1,210		$1,210	$860	$650	$554
				15%	$860					
				18%	$650					
				20%	$554					
			Levelized @							
				12%	$147		$147	$129	$117	$111
				15%	$129					
				18%	$117					
				20%	$111					

TABLE 5.13 CALCULATION OF THE VALUE OF PVNGS NON-FUEL COSTS IN TERMS OF SAN JUAN 4 COSTS

Year	Capacity Factor	Carrying Charge	Carrying Cost $/KW-YR	cts/kwh	Non-fuel Operating Costs cts/kwh	Property Tax & Insurance cts/kwh	Total Fixed Costs cts/kwh	Fuel Costs cts/kwh	Total Costs cts/kwh	PVNGS Fuel Cost cts/kwh	Value of PVNGS non-fuel costs cts/kwh
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
1987	90%	22.2%	$308.0	3.9	0.7	0.1	4.7	1.6	6.3	1.05	5.3
1988	84%	21.4%	$297.5	4.0	0.7	0.1	4.9	1.8	6.6	0.98	5.6
1989	83%	20.3%	$282.4	3.9	0.8	0.1	4.7	1.9	6.6	0.90	5.7
1990	84%	19.3%	$268.3	3.6	0.9	0.1	4.6	2.0	6.6	0.83	5.8
1991	75%	18.3%	$255.0	3.9	0.9	0.1	4.9	2.2	7.0	0.80	6.2
1992	80%	17.5%	$242.7	3.5	0.9	0.1	4.5	2.4	6.8	0.81	6.0
1993	82%	16.6%	$230.4	3.2	0.9	0.1	4.2	2.5	6.8	0.87	5.9
1994	83%	15.8%	$218.9	3.0	1.0	0.1	4.1	2.8	6.8	0.94	5.9
1995	84%	14.9%	$207.5	2.8	1.1	0.1	4.0	3.0	6.9	1.03	5.9
1996	81%	14.1%	$196.1	2.8	1.0	0.1	3.9	3.2	7.1	1.09	6.0
1997	87%	13.3%	$184.7	2.4	1.1	0.1	3.6	3.5	7.1	1.16	5.9
1998	87%	12.5%	$173.3	2.3	1.2	0.1	3.5	3.7	7.3	1.23	6.0
1999	85%	11.6%	$161.9	2.2	1.2	0.1	3.5	4.0	7.5	1.31	6.2
2000	87%	10.8%	$150.5	2.0	1.3	0.1	3.4	4.4	7.8	1.39	6.4
2001	81%	10.0%	$139.0	2.0	1.3	0.1	3.4	4.7	8.1	1.48	6.6
2002	87%	9.2%	$127.6	1.7	1.4	0.1	3.1	5.1	8.2	1.57	6.7
2003	87%	8.8%	$121.7	1.6	1.5	0.1	3.1	5.5	8.6	1.67	6.9
2004	87%	8.3%	$115.8	1.5	1.5	0.1	3.1	5.9	9.1	1.78	7.3
2005	87%	7.9%	$109.9	1.4	1.6	0.1	3.1	6.4	9.5	1.89	7.6
2006	81%	7.5%	$103.9	1.5	1.7	0.1	3.2	6.9	10.1	2.01	8.1
2007	87%	7.1%	$98.0	1.3	1.8	0.1	3.1	7.4	10.6	2.14	8.4
2008	87%	6.6%	$92.1	1.2	1.8	0.1	3.1	8.0	11.2	2.27	8.9
2009	87%	6.2%	$86.2	1.1	1.9	0.1	3.1	8.7	11.8	2.41	9.4
2010	87%	5.8%	$80.2	1.1	2.0	0.1	3.2	9.4	12.5	2.57	9.9
2011	81%	5.3%	$74.3	1.0	2.1	0.1	3.3	10.1	13.3	2.73	10.6
2012	87%	4.9%	$68.4	0.9	2.2	0.1	3.2	10.9	14.1	2.90	11.2
2013	87%	4.5%	$62.5	0.8	2.3	0.1	3.2	11.7	15.0	3.08	11.9
								Levelized @			
								12%	7.3		
								15%	7.1		
								18%	7.0		
								20%	6.9		

TABLE 5.14: CALCULATION OF THE VALUE OF PVNGS NON-FUEL COSTS IN TERMS OF SPS COSTS

Year	Capacity Factor	Demand Charge $/KW-YR	Demand Charge cts/kwh	Energy Charge cts/kwh	SPS Purchase Total cts/kwh	PVNGS Fuel Cost cts/kwh	Value of PVNGS non-fuel costs cts/kwh
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1987	90%	$107.3	1.4	2.3	3.6	1.0	2.6
1988	90%	$107.3	1.4	2.4	3.7	1.0	2.8
1989	90%	$107.3	1.4	2.4	3.8	0.9	2.9
1990	90%	$130.6	1.7	2.2	3.8	0.8	3.0
1991	90%	$130.6	1.7	2.4	4.1	0.8	3.3
1992	90%	$130.6	1.7	2.6	4.3	0.8	3.5
1993	90%	$158.2	2.0	2.9	4.9	0.9	4.1
1994	90%	$158.2	2.0	3.2	5.2	0.9	4.3
1995	90%	$158.2	2.0	3.6	5.6	1.0	4.5
1996	90%	$192.0	2.4	3.7	6.2	1.1	5.1
1997	90%	$192.0	2.4	3.9	6.4	1.2	5.2
1998	90%	$192.0	2.4	4.1	6.6	1.2	5.3
1999	90%	$233.1	3.0	4.3	7.3	1.3	6.0
2000	90%	$233.1	3.0	4.5	7.5	1.4	6.1
2001	90%	$233.1	3.0	4.8	7.7	1.5	6.2
2002	90%	$283.0	3.6	5.0	8.6	1.6	7.0
2003	90%	$283.0	3.6	5.3	8.8	1.7	7.2
2004	90%	$283.0	3.6	5.5	9.1	1.8	7.3
2005	90%	$343.5	4.4	5.8	10.2	1.9	8.3
2006	90%	$343.5	4.4	6.1	10.4	2.0	8.4
2007	90%	$343.5	4.4	6.4	10.8	2.1	8.6
2008	90%	$417.1	5.3	6.7	12.0	2.3	9.7
2009	90%	$417.1	5.3	7.0	12.3	2.4	9.9
2010	90%	$417.1	5.3	7.4	12.7	2.6	10.1
2011	90%	$506.3	6.4	7.8	14.2	2.7	11.5
2012	90%	$506.3	6.4	8.2	14.6	2.9	11.7
2013	90%	$506.3	6.4	8.6	15.0	3.1	11.9
				Levelized @			
				12%	5.6		
				15%	5.2		
				18%	4.9		
				20%	4.8		

Notes Table 5.2:

1. From EPE PROMOD run: "SPS Coal 1".
2. Demand charge from Table 1A, "El Paso Electric Company, SPS Purchase Power Reduction Study", 2/25/86. AG-IR-2-5(d). Assumed to increase by 21.4% every three years.
3. [2]*100/8760/c.f.
4. Energy charge from AG-IR-11-23,6/6/86. Escalated at a calculated average growth rate of 5%.
5. [3]+[4].

TABLE 5.15: PLC ASSUMPTIONS, PVNGS NON-FUEL OPERATING COSTS

Palo Verde Nuclear Generating Station:

Year	O&M $/KW-YR	Capital Additions $/KW-YR	Decommis-sioning $/KW-YR	Property Tax $/KW-YR	Insurance $/KW-YR	PLC Operating Cost $/KW-YR
	[1]	[2]	[3]	[4]	[5]	[6]
1987	$45.3	$0.0	$2.4	$17.9	$1.3	$66.8
1988	$53.6	$3.6	$3.3	$21.2	$1.4	$83.0
1989	$63.3	$7.1	$3.3	$21.9	$1.5	$97.0
1990	$74.3	$10.6	$4.1	$22.2	$1.6	$112.8
1991	$86.5	$14.2	$4.9	$22.9	$1.7	$130.2
1992	$100.0	$17.8	$4.9	$23.6	$1.8	$148.1
1993	$114.8	$21.4	$4.9	$24.0	$2.0	$167.1
1994	$130.9	$25.1	$4.9	$23.8	$2.1	$186.9
1995	$148.8	$28.9	$4.9	$23.0	$2.2	$207.9
1996	$168.7	$32.7	$4.9	$23.8	$2.4	$232.5
1997	$190.4	$36.6	$4.9	$24.5	$2.7	$259.2
1998	$214.3	$40.8	$4.9	$25.3	$2.9	$288.3
1999	$240.7	$45.2	$4.9	$26.2	$3.2	$320.1
2000	$269.3	$49.9	$4.9	$27.0	$3.5	$354.5
2001	$299.2	$54.8	$4.9	$27.9	$3.8	$390.6
2002	$331.7	$60.1	$4.9	$28.8	$4.1	$429.6
2003	$367.0	$65.8	$4.9	$29.7	$4.5	$471.9
2004	$405.3	$71.9	$4.9	$30.6	$4.9	$517.6
2005	$446.8	$75.6	$4.9	$31.6	$5.3	$564.3
2006	$491.8	$80.8	$4.9	$32.7	$5.8	$616.0
2007	$540.6	$87.9	$4.9	$33.7	$6.3	$673.5
2008	$593.4	$97.4	$4.9	$34.8	$6.9	$737.4
2009	$650.6	$110.1	$4.9	$35.9	$7.5	$809.1
2010	$712.5	$127.9	$4.9	$37.1	$8.2	$890.6
2011	$779.4	$154.2	$4.9	$38.3	$8.9	$985.7
2012	$851.7	$197.4	$4.9	$39.5	$9.7	$1,103.2
2013	$929.8	$285.2	$4.9	$40.8	$10.6	$1,271.2

Notes: 1. From Table 6.9, Col. 6. 1987 O&M from the same regression.
2. From Table 6.12. Derivation of capital additions cost recovery in Appendix I-C.
3. From Application for proposed Decommissioning Reserve Fund, NMPSC Case #1833, Phase II. May 1, 1986, Exh. II.
4. From EPE.
5. From AG-IR-11-2, p 1. Esc. @ avg. growth rate: 9%

TABLE 5.16: EPE ASSUMPTIONS, PVNGS NON-FUEL OPERATING COSTS

Palo Verde Nuclear Generating Station:

Year	Fixed O&M $/KW-YR	Capital Additions $/KW-YR	Decommis-sioning $/KW-YR	Property Tax $/KW-YR	Insurance $/KW-YR	Operating Cost minus Var. O&M $/KW-YR	Variable O&M at 100% Capacity $/KW-YR	Non-fuel Operating PLC C.F. $/KW-YR	Non-fuel Operating EPE C.F. $/KW-YR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1987	$45.8	$0.0	$2.4	$17.9	$1.3	$67.4	$32.0	$87.0	$89.1
1988	$46.3	$2.2	$3.3	$21.2	$1.4	$74.4	$30.5	$90.8	$92.7
1989	$49.5	$4.0	$3.3	$21.9	$1.5	$80.1	$30.7	$97.3	$101.3
1990	$52.3	$6.0	$4.1	$22.2	$9.5	$94.0	$32.0	$112.7	$117.7
1991	$55.5	$8.0	$4.9	$22.9	$1.7	$92.9	$34.0	$113.5	$118.0
1992	$58.9	$10.0	$4.9	$23.6	$1.8	$99.2	$36.1	$121.5	$125.9
1993	$62.5	$12.1	$4.9	$24.0	$2.0	$105.5	$38.3	$129.2	$133.8
1994	$66.4	$14.2	$4.9	$23.8	$2.1	$111.4	$40.7	$136.6	$141.5
1995	$70.5	$16.3	$4.9	$23.0	$2.2	$117.0	$43.2	$143.7	$148.9
1996	$74.9	$18.6	$4.9	$23.8	$2.4	$124.6	$45.9	$153.0	$158.6
1997	$79.7	$20.8	$4.9	$24.5	$2.7	$132.7	$48.8	$162.9	$168.8
1998	$84.8	$23.2	$4.9	$25.3	$2.9	$141.2	$51.9	$173.3	$179.6
1999	$90.2	$25.8	$4.9	$26.2	$3.2	$150.2	$55.3	$181.4	$191.1
2000	$96.1	$28.4	$4.9	$27.0	$3.5	$159.9	$58.8	$193.1	$203.4
2001	$102.2	$31.3	$4.9	$27.9	$3.8	$170.1	$62.6	$205.4	$216.4
2002	$108.3	$34.3	$4.9	$28.8	$4.1	$180.4	$66.3	$217.8	$229.4
2003	$114.7	$37.6	$4.9	$29.7	$4.5	$191.3	$70.2	$230.9	$243.3
2004	$121.4	$41.1	$4.9	$30.6	$4.9	$202.9	$74.4	$244.9	$258.0
2005	$128.6	$43.2	$4.9	$31.6	$5.3	$213.6	$78.7	$258.0	$271.9
2006	$136.2	$46.2	$4.9	$32.7	$5.8	$225.7	$83.4	$272.7	$287.4
2007	$144.2	$50.2	$4.9	$33.7	$6.3	$239.4	$88.3	$289.2	$304.7
2008	$152.7	$55.6	$4.9	$34.8	$6.9	$254.9	$93.5	$307.7	$324.2
2009	$161.7	$62.9	$4.9	$35.9	$7.5	$273.0	$99.0	$328.8	$346.3
2010	$171.3	$73.1	$4.9	$37.1	$8.2	$294.5	$104.9	$353.7	$372.1
2011	$181.4	$88.1	$4.9	$38.3	$8.9	$321.6	$111.1	$384.2	$403.8
2012	$192.1	$112.8	$4.9	$39.5	$9.7	$359.0	$117.6	$425.3	$446.0
2013	$203.4	$163.0	$4.9	$40.8	$10.6	$422.7	$124.6	$492.9	$514.8

Notes:
1. From AG-IR-6-14, 2/28/86. Inflation rates from AG-IR-8-2, 4/1/86 (averages). 1984 rate from 'Economic Report of the President, February 1985.
2. From AG-IR-6-13, 2/28/86. Inflation rates from AG-IR-8-2, 4/1/86. Derivation of Capital Additions cost recovery in Appendix I-D.
3. From Application for proposed Decommissioning Reserve Fund, NMPSC Case #1833, Phase II. May 1, 1986, Exh. II.
4. From EPE, esc. @ avg. growth rate: 3.33%
5. From AG-IR-11-2, p.1. Esc. @ avg. growth rate: 9%
6. [1]+[2]+[3]+[4].
7. From AG-IR-6-14, 2/28/86.
8. [6] * plc capacity factor.
9. [6] * plc capacity factor.

TABLE 5.17: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT   Case 1 - San Juan 4 Value, PLC Assumptions

Year	San Juan Value of PVNGS Non-fuel Costs cts/kwh	PLC Capacity Factor	San Juan Value of PVNGS Non-fuel Costs $/KW-YR	PLC Non-fuel Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12.0% Rate Base [7]: $517	15.0% $628	18.0% $706	20.0% $744
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	5.3	61.3%	$282.0	$66.8	$215.2	23.1%	$120	$145	$163	$172
1988	5.6	53.8%	$265.9	$83.0	$182.9	22.3%	$115	$140	$157	$166
1989	5.7	56.1%	$280.9	$97.0	$183.9	21.1%	$109	$133	$149	$157
1990	5.8	58.4%	$296.4	$112.8	$183.6	20.1%	$104	$126	$141	$149
1991	6.2	60.7%	$331.9	$130.2	$201.7	19.1%	$99	$120	$135	$142
1992	6.0	61.9%	$325.5	$148.1	$177.4	18.1%	$94	$114	$128	$135
1993	5.9	61.9%	$320.4	$167.1	$153.3	17.2%	$89	$108	$121	$128
1994	5.9	61.9%	$319.9	$186.9	$133.0	16.2%	$84	$102	$115	$121
1995	5.9	61.9%	$320.6	$207.9	$112.6	15.3%	$79	$96	$108	$114
1996	6.0	61.9%	$325.3	$232.5	$92.8	14.4%	$74	$90	$102	$107
1997	5.9	61.9%	$319.7	$259.2	$60.5	13.5%	$70	$85	$95	$100
1998	6.0	61.9%	$326.6	$288.3	$38.4	13.0%	$67	$82	$92	$97
1999	6.2	56.4%	$305.2	$320.1	($14.9)	12.5%	$64	$78	$88	$93
2000	6.4	56.4%	$314.5	$354.5	($40.0)	12.0%	$62	$75	$85	$89
2001	6.6	56.4%	$325.7	$390.6	($64.9)	11.5%	$59	$72	$81	$85
2002	6.7	56.4%	$328.6	$429.6	($101.0)	11.0%	$57	$69	$78	$82
2003	6.9	56.4%	$343.4	$471.9	($128.5)	10.5%	$54	$66	$74	$78
2004	7.3	56.4%	$359.5	$517.6	($158.1)	10.0%	$52	$63	$71	$74
2005	7.6	56.4%	$376.9	$564.3	($187.4)	9.5%	$49	$60	$67	$71
2006	8.1	56.4%	$401.2	$616.0	($214.8)	9.0%	$47	$57	$64	$67
2007	8.4	56.4%	$416.7	$673.5	($256.7)	8.5%	$44	$54	$60	$63
2008	8.9	56.4%	$439.5	$737.4	($298.0)	8.0%	$41	$50	$57	$60
2009	9.4	56.4%	$464.3	$809.1	($344.8)	7.5%	$39	$47	$53	$56
2010	9.9	56.4%	$491.3	$890.6	($399.2)	7.0%	$36	$44	$50	$52
2011	10.6	56.4%	$524.7	$985.7	($461.0)	6.5%	$34	$41	$46	$49
2012	11.2	56.4%	$552.9	$1,103.2	($550.2)	6.0%	$31	$38	$43	$45
2013	11.9	56.4%	$587.8	$1,271.2	($683.4)	5.5%	$29	$35	$39	$41
				PV@		-----	-----	-----	-----	-----
				12%	$699		$699	$727	$712	$692
				15%	$727					
				18%	$712					
				20%	$692					
				Levelized @						
				12%	$88	17.0%	$88	$112	$130	$139
				15%	$112	17.8%				
				18%	$130	18.4%				
				20%	$139	18.7%				

TABLE 5.18: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT   Case 2 - SPS Value, PLC Assumptions

Year	SPS Value of PVNGS non-fuel costs cts/kwh	PLC Capacity Factor	SPS Value of PVNGS PLC non-fuel costs $/KW-YR	PLC Non-fuel Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12.0% Rate Base [7]: ($14)	15.0% $72	18.0% $130	20.0% $158
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	61.3%	$139.3	$66.8	$72.5	21.5%	($3)	$15	$28	$34
1988	2.8	53.8%	$129.8	$83.0	$46.8	20.8%	($3)	$15	$27	$33
1989	2.9	56.1%	$140.8	$97.0	$43.8	19.8%	($3)	$14	$26	$31
1990	3.0	58.4%	$154.0	$112.8	$41.3	18.9%	($3)	$14	$25	$30
1991	3.3	60.7%	$172.9	$130.2	$42.7	18.1%	($3)	$13	$24	$29
1992	3.5	61.9%	$188.8	$148.1	$40.7	17.3%	($2)	$12	$22	$27
1993	4.1	61.9%	$219.7	$167.1	$52.5	16.5%	($2)	$12	$21	$26
1994	4.3	61.9%	$231.6	$186.9	$44.7	15.7%	($2)	$11	$20	$25
1995	4.5	61.9%	$246.2	$207.9	$38.3	15.0%	($2)	$11	$19	$24
1996	5.1	61.9%	$275.6	$232.5	$43.1	14.2%	($2)	$10	$18	$22
1997	5.2	61.9%	$282.0	$259.2	$22.8	13.4%	($2)	$10	$17	$21
1998	5.3	61.9%	$288.7	$288.3	$0.4	13.1%	($2)	$9	$17	$21
1999	6.0	56.4%	$295.1	$320.1	($25.0)	12.8%	($2)	$9	$17	$20
2000	6.1	56.4%	$301.7	$354.5	($52.8)	12.4%	($2)	$9	$16	$20
2001	6.2	56.4%	$308.6	$390.6	($82.0)	12.1%	($2)	$9	$16	$19
2002	7.0	56.4%	$347.1	$429.8	($82.6)	11.8%	($2)	$8	$15	$19
2003	7.2	56.4%	$354.5	$471.9	($117.3)	11.4%	($2)	$8	$15	$18
2004	7.3	56.4%	$362.3	$517.6	($155.3)	11.1%	($2)	$8	$14	$18
2005	8.3	56.4%	$408.4	$564.3	($155.9)	10.8%	($1)	$8	$14	$17
2006	8.4	56.4%	$416.8	$616.0	($199.2)	10.4%	($1)	$7	$14	$17
2007	8.6	56.4%	$425.6	$673.5	($247.9)	10.1%	($1)	$7	$13	$16
2008	9.7	56.4%	$480.8	$737.4	($256.6)	9.8%	($1)	$7	$13	$15
2009	9.9	56.4%	$490.3	$809.1	($318.7)	9.4%	($1)	$7	$12	$15
2010	10.1	56.4%	$500.2	$890.6	($390.3)	9.1%	($1)	$7	$12	$14
2011	11.5	56.4%	$566.5	$985.7	($419.2)	8.8%	($1)	$6	$11	$14
2012	11.7	56.4%	$577.2	$1,103.2	($526.0)	8.4%	($1)	$6	$11	$13
2013	11.9	56.4%	$588.3	$1,271.2	($682.9)	8.1%	($1)	$6	$11	$13
				PV@		-----	-----	-----	-----	-----
				12%	($18)		($18)	$80	$126	$140
				15%	$80					
				18%	$126					
				20%	$140					
			Levelized @							
				12%	($2)		($2)	$12	$23	$28
				15%	$12					
				18%	$23					
				20%	$28					

TABLE 5.19: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 3 - San Juan Value, PLC Assumptions
EPE Capacity Factor

Year	San Juan Value of PVNGS non-fuel costs cts/kwh	EPE Capacity Factor	San Juan Value of PVNGS non-fuel costs $/KW-YR	PLC Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $958	15.0% $1,039	18.0% $1,094	20.0% $1,120
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	5.3	68.0%	$312.9	$66.8	$246.0	21.5%	$206	$223	$235	$241
1988	5.6	68.0%	$296.5	$83.0	$213.5	20.8%	$199	$216	$227	$233
1989	5.7	69.0%	$345.5	$97.0	$248.5	19.8%	$190	$206	$216	$222
1990	5.8	74.0%	$375.5	$112.8	$262.8	18.9%	$181	$196	$207	$212
1991	6.2	74.0%	$404.6	$130.2	$274.4	18.1%	$173	$188	$198	$203
1992	6.0	74.0%	$389.1	$148.1	$241.0	17.3%	$166	$180	$189	$194
1993	5.9	74.0%	$383.1	$167.1	$216.0	16.5%	$158	$171	$180	$185
1994	5.9	74.0%	$382.4	$186.9	$195.5	15.7%	$151	$163	$172	$176
1995	5.9	74.0%	$383.2	$207.9	$175.3	15.0%	$143	$155	$164	$168
1996	6.0	74.0%	$388.9	$232.5	$156.4	14.2%	$136	$148	$155	$159
1997	5.9	74.0%	$382.2	$259.2	$123.0	13.4%	$129	$140	$147	$151
1998	6.0	74.0%	$390.5	$288.3	$102.2	13.1%	$126	$136	$143	$147
1999	6.2	74.0%	$400.5	$320.1	$80.4	12.8%	$122	$133	$140	$143
2000	6.4	74.0%	$412.7	$354.5	$58.1	12.4%	$119	$129	$136	$139
2001	6.6	74.0%	$427.4	$390.6	$36.8	12.1%	$116	$126	$132	$136
2002	6.7	74.0%	$431.2	$429.6	$1.5	11.8%	$113	$122	$129	$132
2003	6.9	74.0%	$450.5	$471.9	($21.4)	11.4%	$110	$119	$125	$128
2004	7.3	74.0%	$471.7	$517.6	($46.0)	11.1%	$106	$115	$121	$124
2005	7.6	74.0%	$494.5	$564.3	($69.8)	10.8%	$103	$112	$118	$121
2006	8.1	74.0%	$526.4	$616.0	($89.6)	10.4%	$100	$108	$114	$117
2007	8.4	74.0%	$546.8	$673.5	($126.7)	10.1%	$97	$105	$110	$113
2008	8.9	74.0%	$576.6	$737.4	($160.8)	9.8%	$94	$101	$107	$109
2009	9.4	74.0%	$603.2	$803.1	($199.9)	9.4%	$90	$98	$103	$106
2010	9.9	74.0%	$644.7	$890.6	($245.9)	9.1%	$87	$94	$99	$102
2011	10.6	74.0%	$668.4	$965.7	($297.3)	8.8%	$84	$91	$96	$98
2012	11.2	74.0%	$725.4	$1,103.2	($377.7)	8.4%	$81	$88	$92	$94
2013	11.9	74.0%	$771.2	$1,271.2	($500.0)	8.1%	$77	$84	$89	$91
				PVE		-----	-----	-----	-----	-----
				12%	$1,257		$1,257	$1,157	$1,057	$993
				15%	$1,157					
				18%	$1,057					
				20%	$993					
				Levelized @						
				12%	$158		$158	$178	$192	$200
				15%	$178					
				18%	$192					
				20%	$200					

TABLE 5.20: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 4 - SPS Value, PLC Assumptions
EPE Capacity Factor

Year	SPS Value of PVNGS non-fuel costs cts/kWh	EPE Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	PLC Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $311	15.0% $352	18.0% $376	20.0% $387
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	68.0%	$154.5	$66.8	$87.7	21.5%	$67	$76	$81	$83
1988	2.8	68.0%	$144.8	$83.0	$61.8	20.8%	$65	$73	$78	$80
1989	2.9	69.0%	$173.2	$97.0	$76.2	19.8%	$62	$70	$75	$77
1990	3.0	74.0%	$195.2	$112.8	$82.4	18.9%	$59	$66	$71	$73
1991	3.3	74.0%	$210.8	$130.2	$80.6	18.1%	$56	$64	$68	$70
1992	3.5	74.0%	$225.7	$148.1	$77.6	17.3%	$54	$61	$65	$67
1993	4.1	74.0%	$262.6	$167.1	$95.5	16.5%	$51	$58	$62	$64
1994	4.3	74.0%	$276.8	$186.9	$90.0	15.7%	$49	$55	$59	$61
1995	4.5	74.0%	$294.3	$207.9	$86.4	15.0%	$47	$53	$56	$58
1996	5.1	74.0%	$329.5	$232.5	$97.0	14.2%	$44	$50	$53	$55
1997	5.2	74.0%	$337.1	$259.2	$77.9	13.4%	$42	$47	$51	$52
1998	5.3	74.0%	$345.1	$288.3	$56.9	13.1%	$41	$46	$49	$51
1999	6.0	74.0%	$387.2	$320.1	$67.1	12.8%	$40	$45	$48	$49
2000	6.1	74.0%	$395.9	$354.5	$41.4	12.4%	$39	$44	$47	$48
2001	6.2	74.0%	$404.9	$390.6	$14.4	12.1%	$38	$43	$46	$47
2002	7.0	74.0%	$455.4	$429.6	$25.8	11.8%	$37	$41	$44	$46
2003	7.2	74.0%	$465.2	$471.9	($6.7)	11.4%	$36	$40	$43	$44
2004	7.3	74.0%	$475.4	$517.6	($42.2)	11.1%	$35	$39	$42	$43
2005	8.3	74.0%	$535.8	$564.3	($28.4)	10.8%	$34	$38	$41	$42
2006	8.4	74.0%	$546.9	$616.0	($69.1)	10.4%	$32	$37	$39	$40
2007	8.6	74.0%	$558.4	$673.5	($115.0)	10.1%	$31	$36	$38	$39
2008	9.7	74.0%	$630.9	$737.4	($106.6)	9.8%	$30	$34	$37	$38
2009	9.9	74.0%	$643.4	$809.1	($165.7)	9.4%	$29	$33	$36	$36
2010	10.1	74.0%	$656.4	$890.6	($234.2)	9.1%	$28	$32	$34	$35
2011	11.5	74.0%	$743.2	$985.7	($242.4)	8.8%	$27	$31	$33	$34
2012	11.7	74.0%	$757.3	$1,103.2	($345.9)	8.4%	$26	$30	$32	$33
2013	11.9	74.0%	$771.9	$1,271.2	($499.3)	8.1%	$25	$28	$30	$31
				PVs		-----	-----	-----	-----	-----
				12%	$409		$409	$392	$364	$343
				15%	$392					
				18%	$364					
				20%	$343					
				Levelized @						
				12%	$51		$51	$60	$66	$69
				15%	$60					
				18%	$66					
				20%	$69					

TABLE 5.21: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 5 - San Juan Value, EPE Assumptions

PLC Capacity Factor

EQUIVALENT TOTAL RATE BASE:

Year	San Juan Value of PVNGS non-fuel costs cts/kWh	PLC Capacity Factor	San Juan Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	Discount Rate: 12% Rate Base [7]: $1,040	15.0% $1,027	18.0% $1,016	20.0% $1,009
[1]	[2]	[3]	[4]	[5]	[6]		[8]			
1987	5.3	61.3%	$282.0	$87.0	$195.1	21.5%	$224	$221	$218	$217
1988	5.6	53.8%	$265.9	$90.8	$175.1	20.8%	$216	$213	$211	$210
1989	5.7	56.1%	$280.9	$97.3	$183.6	19.8%	$206	$203	$201	$200
1990	5.8	58.4%	$296.4	$112.7	$183.7	18.9%	$196	$194	$192	$191
1991	6.2	60.7%	$331.9	$113.5	$218.4	18.1%	$188	$186	$184	$182
1992	6.0	61.9%	$325.5	$121.5	$204.0	17.3%	$180	$177	$176	$174
1993	5.9	61.9%	$320.4	$129.2	$191.2	16.5%	$171	$169	$167	$166
1994	5.9	61.9%	$319.9	$136.6	$183.3	15.7%	$163	$161	$160	$159
1995	5.9	61.9%	$320.6	$143.7	$176.8	15.0%	$156	$154	$152	$151
1996	6.0	61.9%	$325.3	$153.0	$172.3	14.2%	$148	$146	$144	$143
1997	5.9	61.9%	$319.7	$162.9	$156.8	13.4%	$140	$138	$137	$136
1998	6.0	61.9%	$326.6	$173.3	$153.3	13.1%	$136	$135	$133	$132
1999	6.2	56.4%	$305.2	$181.4	$123.9	12.8%	$133	$131	$130	$129
2000	6.4	56.4%	$314.5	$193.1	$121.4	12.4%	$129	$128	$126	$126
2001	6.6	56.4%	$325.7	$205.4	$120.3	12.1%	$126	$124	$123	$122
2002	6.7	56.4%	$328.6	$217.8	$110.9	11.8%	$122	$121	$120	$119
2003	6.9	56.4%	$343.4	$230.9	$112.5	11.4%	$119	$117	$116	$115
2004	7.3	56.4%	$359.5	$244.9	$114.6	11.1%	$115	$114	$113	$112
2005	7.6	56.4%	$376.9	$258.0	$118.9	10.8%	$112	$111	$109	$109
2006	8.1	56.4%	$401.2	$272.7	$128.5	10.4%	$109	$107	$106	$105
2007	8.4	56.4%	$416.7	$289.2	$127.6	10.1%	$105	$104	$103	$102
2008	8.9	56.4%	$439.5	$307.7	$131.8	9.8%	$102	$100	$99	$99
2009	9.4	56.4%	$464.3	$328.8	$135.5	9.4%	$98	$97	$96	$95
2010	9.9	56.4%	$491.3	$353.7	$137.7	9.1%	$95	$93	$92	$92
2011	10.6	56.4%	$524.7	$384.2	$140.4	8.8%	$91	$90	$89	$88
2012	11.2	56.4%	$552.9	$425.3	$127.6	8.4%	$88	$87	$86	$85
2013	11.9	56.4%	$587.8	$492.9	$94.9	8.1%	$84	$83	$82	$82
				PVE		-----	-----	-----	-----	-----
				12%	$1,366		$1,366	$1,144	$981	$895
				15%	$1,144					
				18%	$981					
				20%	$895					
				Levelized @						
				12%	$172		$172	$176	$179	$180
				15%	$176					
				18%	$179					
				20%	$180					

TABLE 5.22: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 6 - SPS Value, EPE Assumptions

PLC Capacity Factor

Year	SPS Value of PVNGS non-fuel costs cts/KWH	PLC Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $493	15.0% $446	18.0% $408	20.0% $387
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	61.3%	$139.3	$87.0	$52.4	21.5%	$106	$96	$88	$83
1988	2.8	53.8%	$129.8	$90.8	$39.1	20.8%	$103	$93	$85	$81
1989	2.9	56.1%	$140.8	$97.3	$43.5	19.8%	$98	$88	$81	$77
1990	3.0	58.4%	$154.0	$112.7	$41.3	18.9%	$93	$84	$77	$73
1991	3.3	60.7%	$172.9	$113.5	$59.4	18.1%	$89	$81	$74	$70
1992	3.5	61.9%	$188.8	$121.5	$67.2	17.3%	$85	$77	$71	$67
1993	4.1	61.9%	$219.7	$129.2	$90.5	16.5%	$81	$73	$67	$64
1994	4.3	61.9%	$231.6	$136.6	$94.9	15.7%	$78	$70	$64	$61
1995	4.5	61.9%	$246.2	$143.7	$102.5	15.0%	$74	$67	$61	$58
1996	5.1	61.9%	$275.6	$153.0	$122.6	14.2%	$70	$63	$58	$55
1997	5.2	61.9%	$282.0	$162.9	$119.1	13.4%	$66	$60	$55	$52
1998	5.3	61.9%	$288.7	$173.3	$115.3	13.1%	$65	$58	$54	$51
1999	6.0	56.4%	$295.1	$181.4	$113.7	12.8%	$63	$57	$52	$50
2000	6.1	56.4%	$301.7	$193.1	$108.7	12.4%	$61	$55	$51	$48
2001	6.2	56.4%	$308.6	$205.4	$103.3	12.1%	$60	$54	$49	$47
2002	7.0	56.4%	$347.1	$217.8	$129.3	11.8%	$58	$52	$48	$46
2003	7.2	56.4%	$354.5	$230.9	$123.7	11.4%	$56	$51	$47	$44
2004	7.3	56.4%	$362.3	$244.9	$117.5	11.1%	$55	$50	$45	$43
2005	8.3	56.4%	$408.4	$258.0	$150.4	10.8%	$53	$48	$44	$42
2006	8.4	56.4%	$416.8	$272.7	$144.1	10.4%	$52	$47	$43	$40
2007	8.6	56.4%	$425.6	$289.2	$136.5	10.1%	$50	$45	$41	$39
2008	9.7	56.4%	$480.8	$307.7	$173.1	9.8%	$48	$44	$40	$38
2009	9.9	56.4%	$490.3	$328.8	$161.5	9.4%	$47	$42	$38	$37
2010	10.1	56.4%	$500.2	$353.7	$146.6	9.1%	$45	$41	$37	$35
2011	11.5	56.4%	$566.5	$384.2	$182.2	8.8%	$43	$39	$36	$34
2012	11.7	56.4%	$577.2	$425.3	$151.9	8.4%	$42	$38	$34	$33
2013	11.9	56.4%	$588.3	$492.9	$95.4	8.1%	$40	$36	$33	$31
				PVE		-----	-----	-----	-----	-----
				12%	$648		$648	$497	$394	$344
				15%	$497					
				18%	$394					
				20%	$344					
			Levelized @							
				12%	$82		$82	$76	$72	$69
				15%	$76					
				18%	$72					
				20%	$69					

TABLE 5.23: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 7 - San Juan Value, EPE Assumptions

EPE Capacity Factor

Year	San Juan Value of PVNGS non-fuel costs cts/kWh	EPE Capacity Factor	San Juan Value of PVNGS non-fuel costs $/kW-yr	EPE Operating Cost $/kW-yr	Value of PVNGS Annual Capital $/kW-yr	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $1,428	15.0% $1,381	18.0% $1,343	20.0% $1,322
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	5.3	68.0%	$312.9	$89.1	$223.8	21.5%	$307	$297	$289	$284
1988	5.6	68.0%	$296.5	$92.7	$203.9	20.0%	$297	$287	$279	$275
1989	5.7	69.0%	$345.5	$101.3	$244.2	19.0%	$283	$273	$266	$262
1990	5.8	74.0%	$375.5	$117.7	$257.8	18.9%	$270	$261	$254	$250
1991	6.2	74.0%	$404.6	$118.0	$286.6	18.1%	$258	$250	$243	$239
1992	6.0	74.0%	$389.1	$125.9	$263.2	17.3%	$247	$239	$232	$229
1993	5.9	74.0%	$383.1	$133.8	$249.2	16.5%	$235	$228	$221	$218
1994	5.9	74.0%	$382.4	$141.5	$240.9	15.7%	$225	$217	$211	$208
1995	5.9	74.0%	$383.2	$148.9	$234.3	15.0%	$214	$207	$201	$198
1996	6.0	74.0%	$388.9	$150.6	$238.3	14.2%	$203	$196	$191	$188
1997	5.9	74.0%	$382.2	$168.8	$213.4	13.4%	$192	$186	$181	$178
1998	6.0	74.0%	$390.5	$179.6	$210.9	13.1%	$187	$181	$176	$173
1999	6.2	74.0%	$400.5	$191.1	$209.4	12.8%	$182	$176	$172	$169
2000	6.4	74.0%	$412.7	$203.4	$209.2	12.4%	$178	$172	$167	$165
2001	6.6	74.0%	$427.4	$216.4	$211.0	12.1%	$173	$167	$163	$160
2002	6.7	74.0%	$431.2	$229.4	$201.7	11.8%	$168	$163	$158	$156
2003	6.9	74.0%	$450.5	$243.3	$207.2	11.4%	$163	$158	$154	$151
2004	7.3	74.0%	$471.7	$258.0	$213.7	11.1%	$159	$153	$149	$147
2005	7.6	74.0%	$494.5	$271.9	$222.6	10.8%	$154	$149	$145	$142
2006	8.1	74.0%	$526.4	$287.4	$239.0	10.4%	$149	$144	$140	$138
2007	8.4	74.0%	$546.8	$304.7	$242.1	10.1%	$144	$139	$136	$134
2008	8.9	74.0%	$576.6	$324.2	$252.5	9.8%	$139	$135	$131	$129
2009	9.4	74.0%	$609.2	$346.3	$262.9	9.4%	$135	$130	$127	$125
2010	9.9	74.0%	$644.7	$372.1	$272.5	9.1%	$130	$126	$122	$120
2011	10.6	74.0%	$688.4	$403.8	$284.6	8.8%	$125	$121	$118	$116
2012	11.2	74.0%	$725.4	$446.0	$279.4	8.4%	$120	$116	$113	$111
2013	11.9	74.0%	$771.2	$514.8	$256.4	8.1%	$116	$112	$109	$107
				PVs		-----	-----	-----	-----	-----
				12%	$1,875		$1,875	$1,539	$1,298	$1,173
				15%	$1,539					
				18%	$1,298					
				20%	$1,173					
				Levelized @						
				12%	$236.1		$236.1	$236.2	$236.3	$236.4
				15%	$236.2					
				18%	$236.3					
				20%	$236.4					

TABLE 5.24: CALCULATION OF THE VALUE OF PVNGS CAPITAL INVESTMENT Case 8 - SPS Value, EPE Assumptions

EPE Capacity Factor

Year	SPS Value of PVNGS non-fuel costs cts/kwh	EPE Capacity Factor	SPS Value of PVNGS non-fuel costs $/KW-YR	EPE Operating Cost $/KW-YR	Value of PVNGS Annual Capital $/KW-YR	Carrying Charge	EQUIVALENT TOTAL RATE BASE: Discount Rate: 12% Rate Base [7]: $782	15.0% $694	18.0% $626	20.0% $590
	[1]	[2]	[3]	[4]	[5]	[6]	[8]			
1987	2.6	68.0%	$154.5	$89.1	$65.5	21.5%	$168	$149	$135	$127
1988	2.8	60.0%	$144.8	$92.7	$52.1	20.8%	$162	$144	$130	$123
1989	2.9	69.0%	$173.2	$101.3	$71.9	19.8%	$155	$137	$124	$117
1990	3.0	74.0%	$195.2	$117.7	$77.5	18.9%	$148	$131	$118	$111
1991	3.3	74.0%	$210.8	$118.0	$92.7	18.1%	$141	$126	$113	$107
1992	3.5	74.0%	$225.7	$125.9	$99.8	17.3%	$135	$120	$108	$102
1993	4.1	74.0%	$262.6	$133.8	$128.8	16.5%	$129	$114	$103	$97
1994	4.3	74.0%	$276.8	$141.5	$135.3	15.7%	$123	$109	$98	$93
1995	4.5	74.0%	$294.3	$148.9	$145.4	15.0%	$117	$104	$94	$88
1996	5.1	74.0%	$329.5	$158.6	$170.9	14.2%	$111	$99	$89	$84
1997	5.2	74.0%	$337.1	$168.8	$168.3	13.4%	$105	$93	$84	$79
1998	5.3	74.0%	$345.1	$179.6	$165.5	13.1%	$103	$91	$82	$77
1999	6.0	74.0%	$387.2	$191.1	$196.1	12.8%	$100	$89	$80	$75
2000	6.1	74.0%	$395.9	$203.4	$192.5	12.4%	$97	$86	$78	$73
2001	6.2	74.0%	$404.9	$216.4	$188.5	12.1%	$95	$84	$76	$71
2002	7.0	74.0%	$455.4	$229.4	$225.9	11.8%	$92	$82	$74	$69
2003	7.2	74.0%	$465.2	$243.3	$221.9	11.4%	$89	$79	$72	$67
2004	7.3	74.0%	$475.4	$258.0	$217.5	11.1%	$87	$77	$70	$65
2005	8.3	74.0%	$535.8	$271.9	$263.9	10.8%	$84	$75	$67	$64
2006	8.4	74.0%	$546.9	$287.4	$259.5	10.4%	$82	$72	$65	$62
2007	8.6	74.0%	$558.4	$304.7	$253.7	10.1%	$79	$70	$63	$60
2008	9.7	74.0%	$630.9	$324.2	$306.7	9.8%	$76	$68	$61	$58
2009	9.9	74.0%	$643.4	$346.3	$297.1	9.4%	$74	$65	$59	$56
2010	10.1	74.0%	$656.4	$372.1	$284.2	9.1%	$71	$63	$57	$54
2011	11.5	74.0%	$743.2	$403.8	$339.5	8.8%	$68	$61	$55	$52
2012	11.7	74.0%	$757.3	$446.0	$311.3	8.4%	$66	$58	$53	$50
2013	11.9	74.0%	$771.9	$514.8	$257.1	8.1%	$63	$56	$51	$48
				PVR		-----	-----	-----	-----	-----
				12%	$1,026		$1,026	$773	$605	$523
				15%	$773					
				18%	$605					
				20%	$523					

Notes for Tables 5.1-5.24:

1. San Juan Value of PVNGS non-fuel costs: See table 5.1.
   SPS Value of PVNGS non-fuel costs: See table 5.2.
2. PLC Capacity factor: From Table 6.3. Result of regression, average of four cases.
   EPE Capacity Factor: From PNM Exhibit EWF-2. Testimony of Eugene Fisher. Case 2004.
3. [1]/100*8760*[2].
4. PLC Operating Cost: See Table 5.3.
5. [3]-[4].
6. From Dirmeier. Nuclear Plant Fixed Charge Factor.
7. Present Value of Annual Capital divided by the present value of the carrying charges.
8. [7]*[6].

TABLE 6.1: EPE PROJECTIONS, PALO VERDE CAPACITY FACTORS

Year	Palo Verde #1	Palo Verde #2	Palo Verde #3
1986	57%	68%	
1987	63%	59%	48%
1988	66%	50%	53%
1989	72%	71%	60%
1990	67%	74%	72%
1991	70%	74%	74%
1992	71%	74%	74%
1993	72%	74%	74%
1994	72%	74%	74%
1995	77%	74%	74%

Source: IR-AG-8-3: EPE PROMOD runs. April 7, 1986.

TABLE 6.2: UTILITY EAF PROJECTIONS AS INTERVALS, EAF BETWEEN REFUELINGS, AND LENGTH OF REFUELING

	UNIT 1	UNIT 2	UNIT 3
1. EAF from COD to first refueling	68.4%	68.4%	68.4%
2. Months from COD to end of first refueling	12	16	16
3. Weeks for first refueling outage	7	7	7
4. EAF from end of first refueling to end of second refueling	78.5%	78.5%	78.5%
5. Months from end of first refueling to end of second refueling	12	12	12
6. Weeks for second refueling outage	7	7	7
7. Mature EAF between refueling	85.4%	85.4%	85.4%
8. Mature months between refueling	12	12	12

Source: Exhibit JRH-2, Case # 1916.

FIGURE 1.1: EPE FORECAST HISTORY

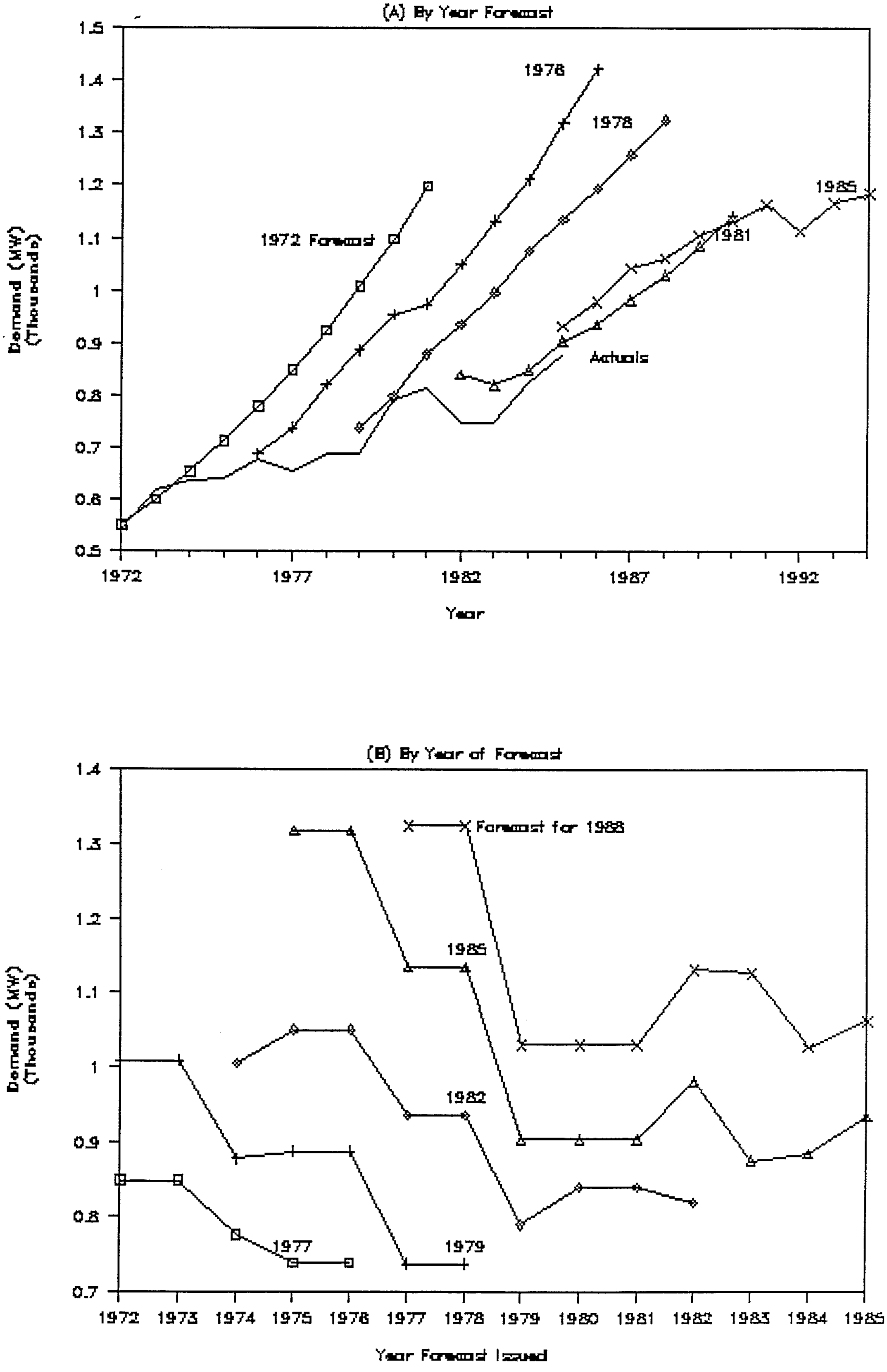


FIGURE 1.2: PVNGS PERCENT COMPLETE

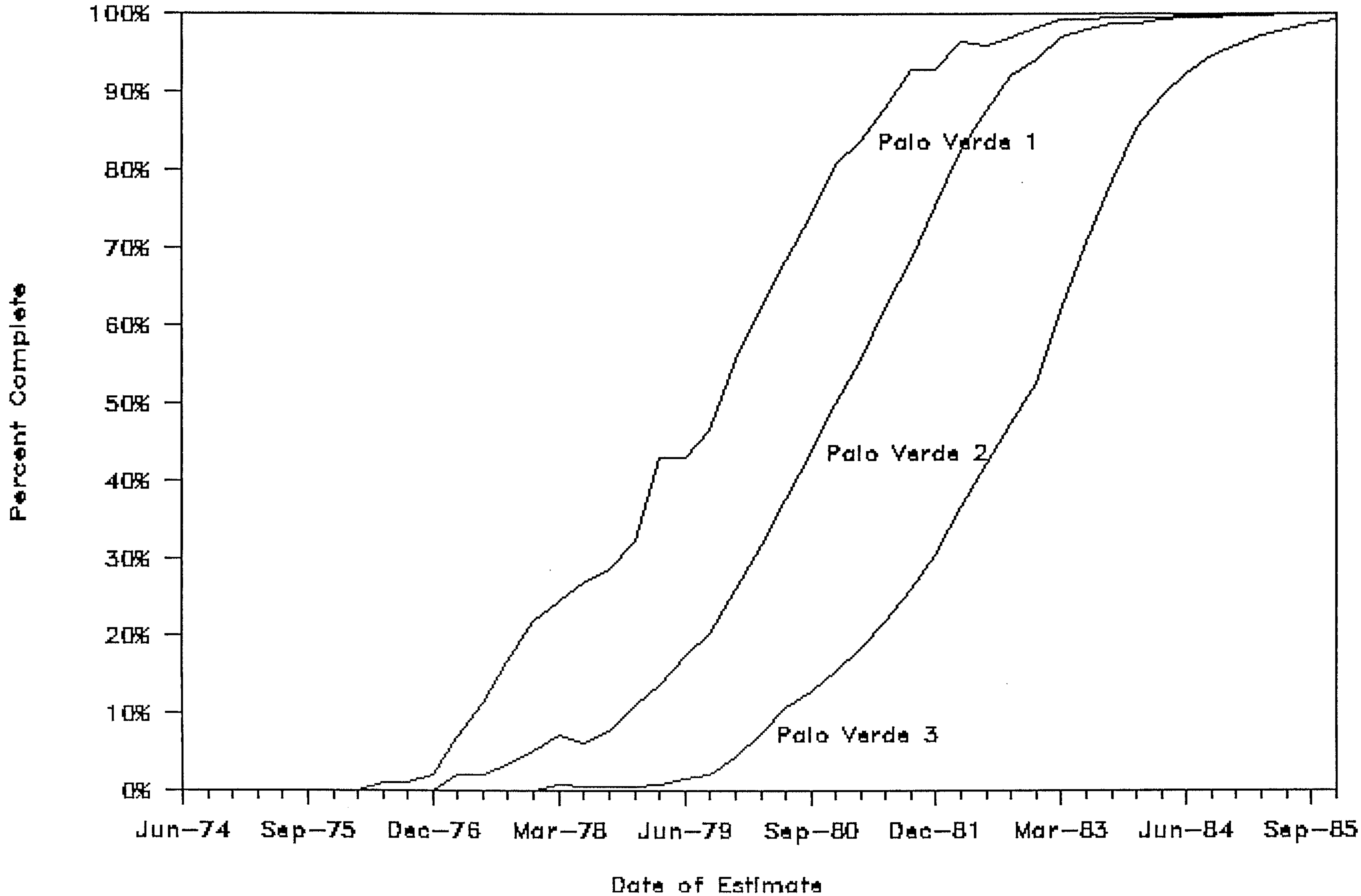


FIGURE 1.3

EPE Annual Construction Expenditures

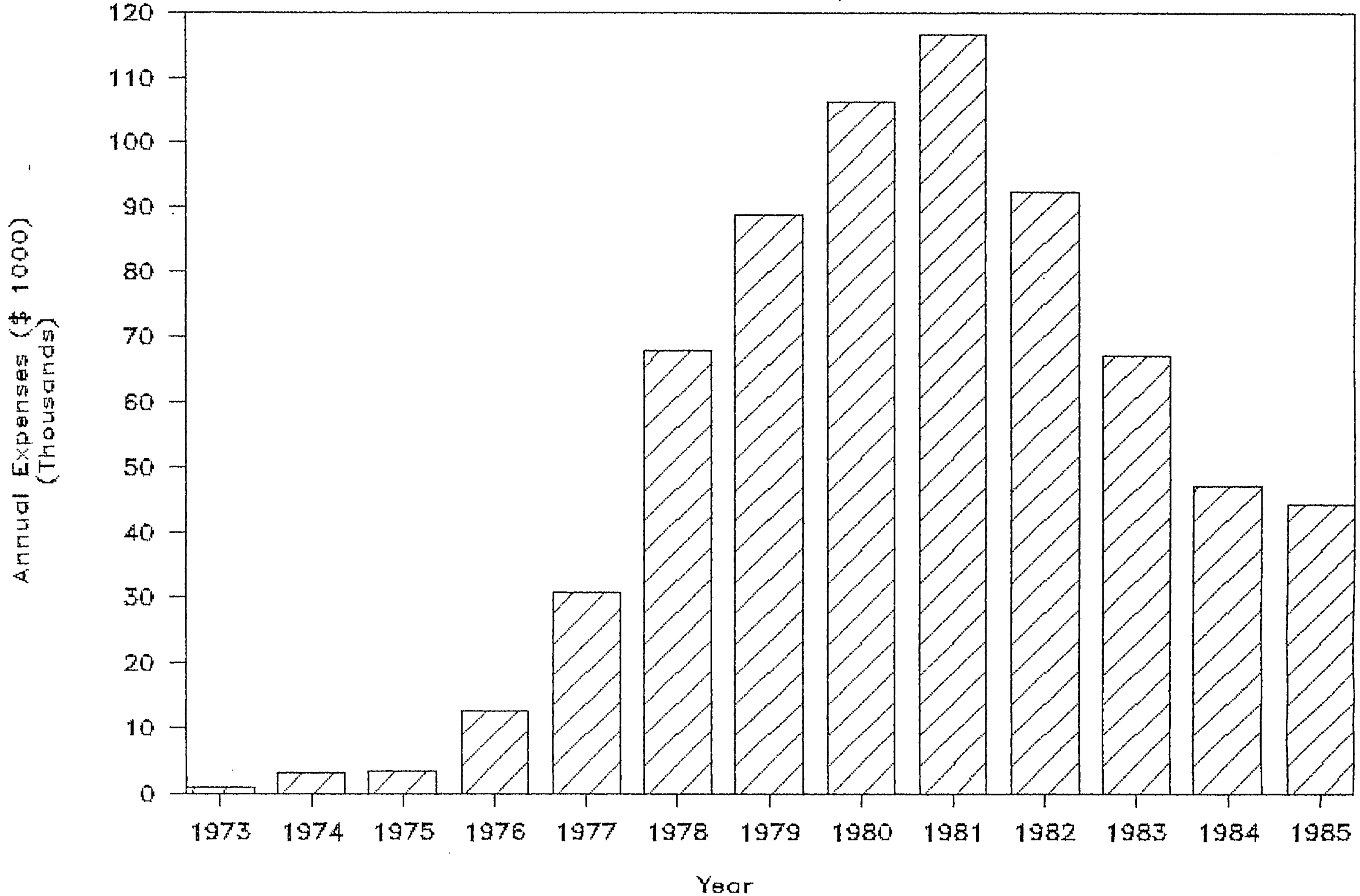


FIGURE 1.4: PVNGS COD ESTIMATES

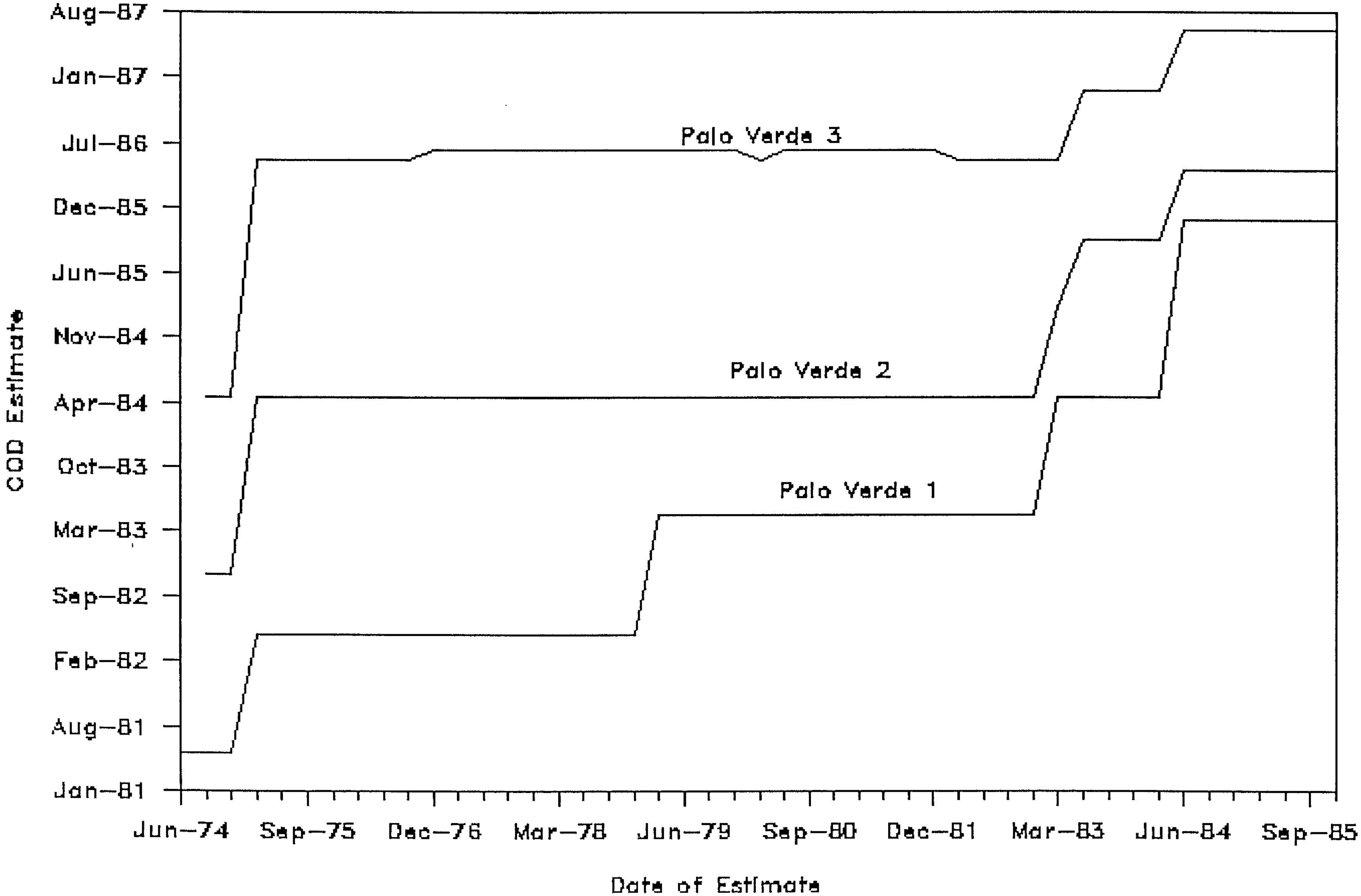


FIGURE 1.5: PVNGS TOTAL COST ESTIMATES

With AFUDC

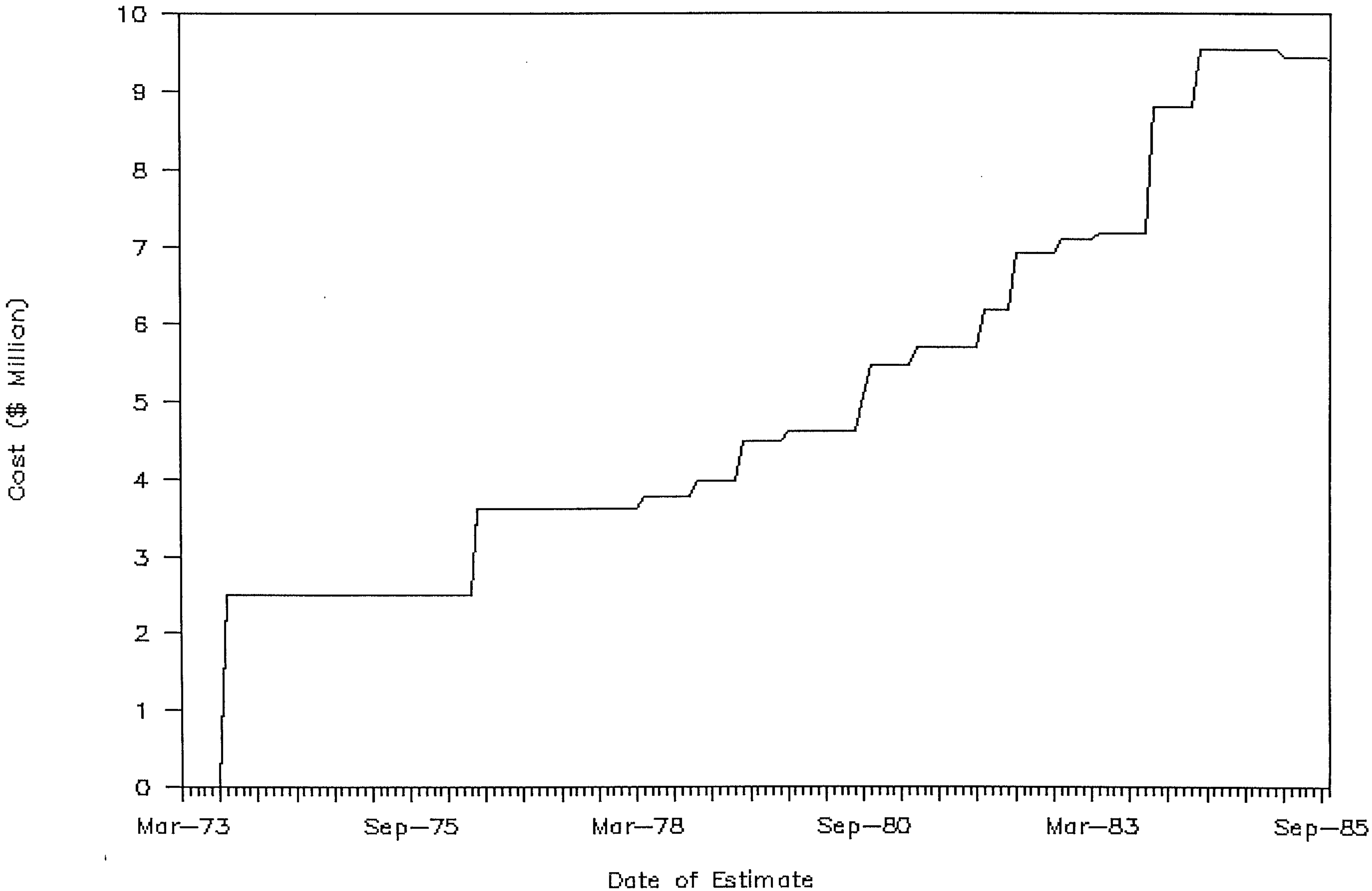


Figure 3.1: Plant Cancellations:

With, and Without Construction Permit

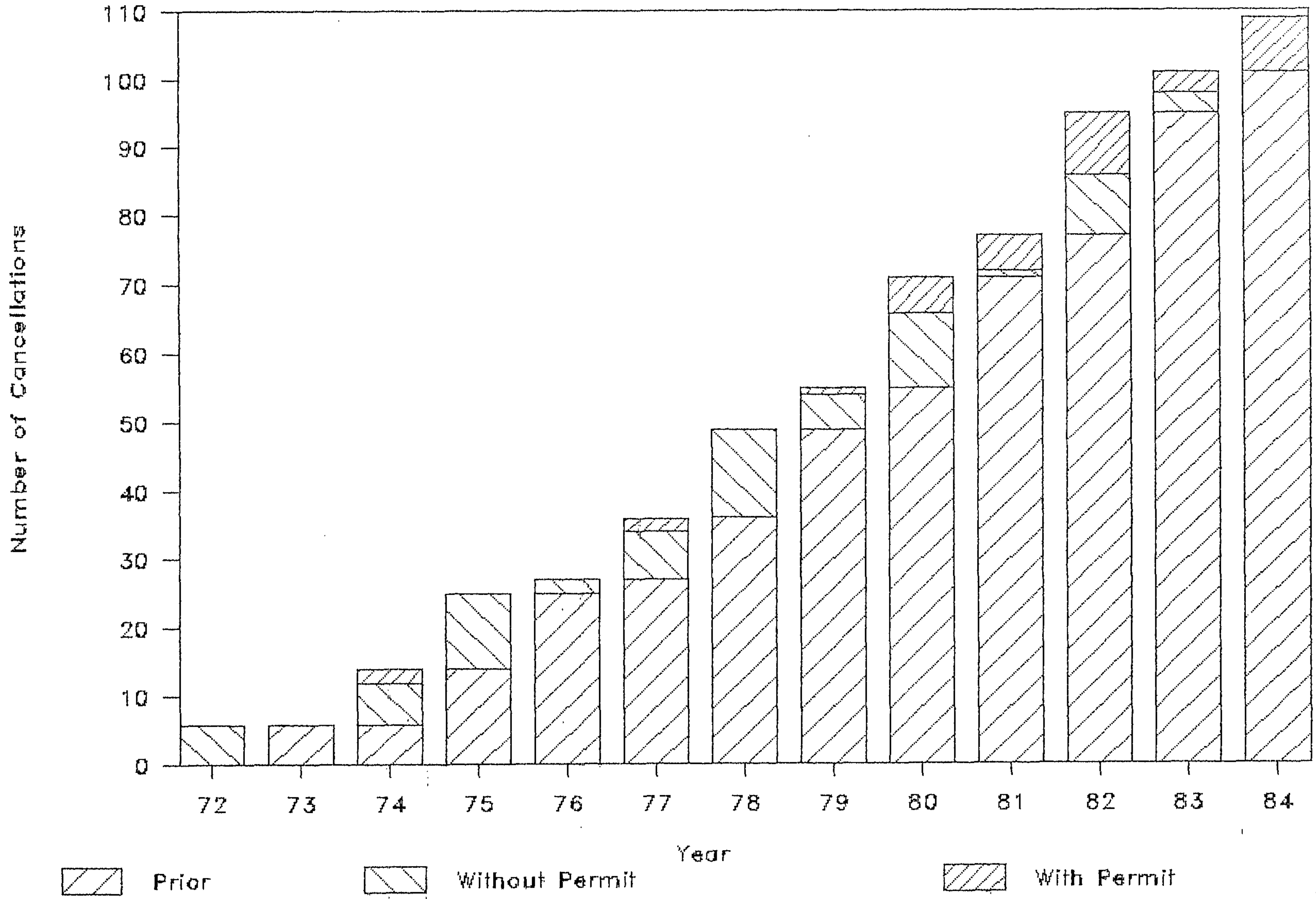


Figure 3.2: NET NUCLEAR ORDERS

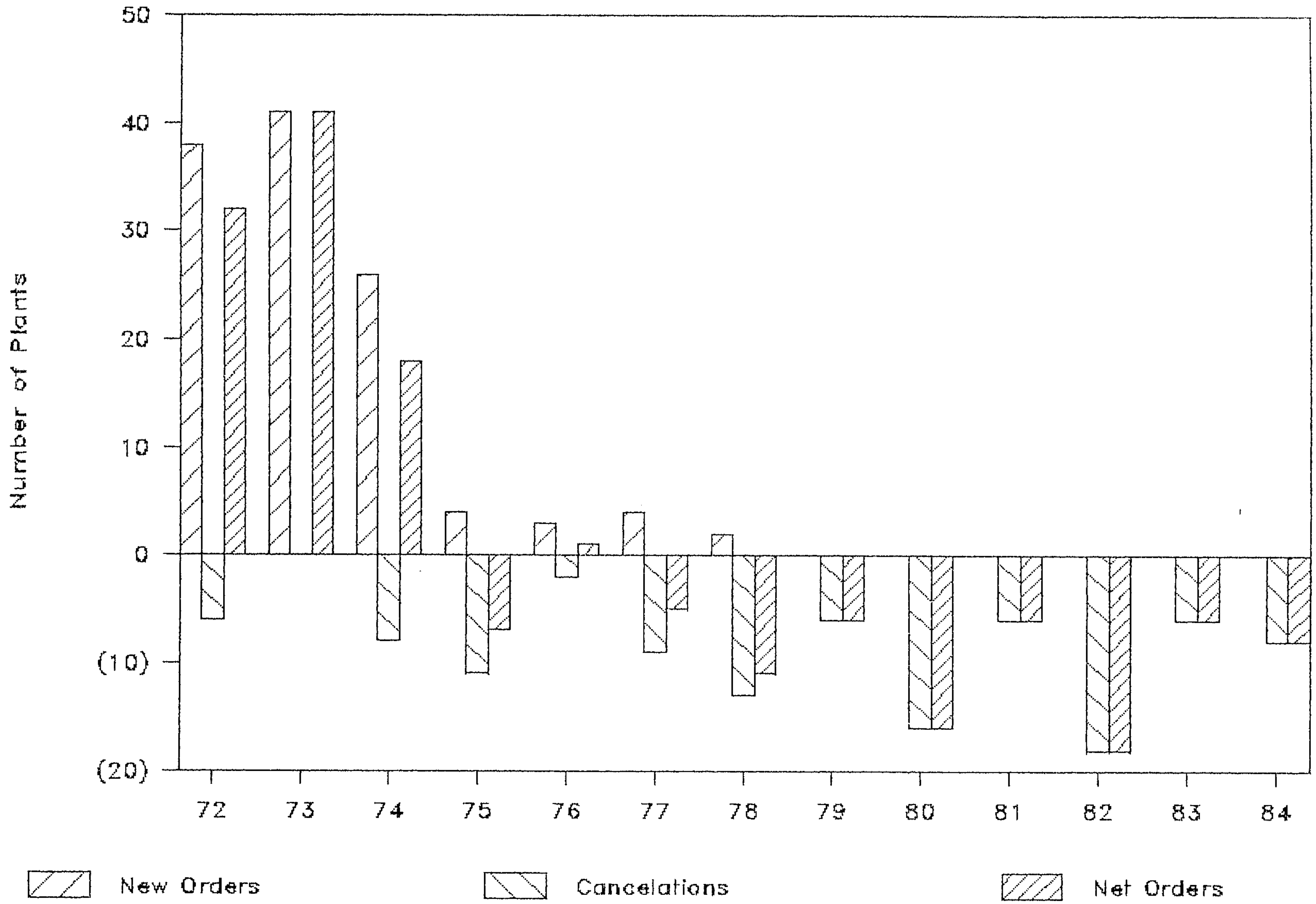


TABLE 1.1: EPE SHARE OF PVNGS COST AND AFUDC, AND AN APPROXIMATION OF TOTAL COST PLUS AFUDC ($ Millions)

Date of Estimate	EPE Share PVNGS Cost (15.8%) [1]	EPE AFUDC [2]	EPE Cost + AFUDC [3]	Total (100%) PVNGS Cost Excl. AFUDC [4]	EPE AFUDC as % of EPE Share [5]	Total (100%) PVNGS Cost + AFUDC [6]	Scheduled In-Service [7] Unit 1	Unit 2	Unit 3
Sep-73	$327.5	$69.1	$396.6	$2,073.1	21.10%	$2,510.4	May-81	Nov-82	May-84
Dec-74	$409.5			$2,592.0			May-81	Nov-82	May-84
Dec-74	$414.3			$2,622.0			May-81	Nov-82	May-84
Jun-76	$437.1	$130.8	$567.9	$2,766.2	29.94%	$3,594.4	May-82	May-84	May-86
Jun-76	$443.2	$127.8	$571.0	$2,804.9	28.84%	$3,614.0	May-82	May-84	May-86
Sep-76	$438.2	$130.9	$569.0	$2,773.1	29.87%	$3,601.5	May-82	May-84	May-86
Jan-77	$442.4			$2,800.0			May-82	May-84	May-86
Jun-77	$441.0	$129.0	$570.0	$2,791.0	29.26%	$3,607.6	May-82	May-84	May-86
Apr-78	$464.4	$128.4	$592.8	$2,939.0	27.65%	$3,751.7	May-82	May-84	Jun-86
Nov-78	$464.4	$163.5	$627.9	$2,939.0	35.21%	$3,973.7	May-82	May-84	Jun-86
May-79	$520.2	$186.1	$706.2	$3,292.1	35.77%	$4,469.7	May-83	May-84	Jun-86
Nov-79	$550.1	$176.6	$726.7	$3,481.3	32.11%	$4,599.2	May-83	May-84	Jun-86
Sep-80	$572.8	$230.0	$802.8	$3,625.3	40.15%	$5,080.9	May-83	May-84	Jun-86
Oct-80	$605.4	$255.6	$861.1	$3,831.8	42.23%	$5,449.9	May-83	May-84	Jun-86
Apr-81	$630.6	$267.4	$898.1	$3,991.3	42.41%	$5,684.0	May-83	May-84	Jun-86
Jan-82	$676.7	$299.8	$976.5	$4,282.9	44.30%	$6,180.2	May-83	May-84	Jun-86
May-82	$769.0	$322.6	$1,091.6	$4,867.0	41.95%	$6,908.7	May-83	May-84	May-86
Nov-82	$796.3	$324.6	$1,121.0	$5,040.0	40.77%	$7,094.7	May-83	May-84	May-86
Apr-83	$805.3	$327.8	$1,133.1	$5,096.7	40.70%	$7,171.2	May-84	Feb-85	May-86
Nov-83	$934.6	$452.9	$1,387.5	$5,915.0	48.47%	$8,781.7	May-84	Sep-85	Dec-86
May-84	$975.4	$532.6	$1,508.0	$6,173.5	54.60%	$9,544.2	May-84	Sep-85	Dec-86
Sep-84	$977.5	$530.1	$1,507.6	$6,186.6	54.24%	$9,541.9	Nov-85	Apr-86	Jun-87
Apr-85	$971.1	$519.0	$1,490.1	$6,146.1	53.45%	$9,431.0	Nov-85	Apr-86	Jun-87
Oct-85	$975.6	$510.8	$1,486.4	$6,174.7	52.36%	$9,407.8	Nov-85	Apr-86	Jun-87

Notes: [1], [2] From AG-1-19, 2/18/86, pages 2-9.
[4] = [1]/15.8%. [5] = [2]/[1]. [6] = [2]*(1+[3]).
[7] From Nuclear News, 2/74 and EIA-254 Quarterly Progress Reports. Last available COD for that Date.

TABLE 1.2: PVNGS COST AND SCHEDULE HISTORY, EXCLUDING AFUDC

EIA-254 QUARTERLY PROGRESS REPORTS AND ERNST & WHINNEY REVIEW
* Construction Permit: 5/76

Date of Estimate	Unit 1 Cost	Unit 1 COD	Unit 1 % Comp.	Unit 2 Cost	Unit 2 COD	Unit 2 % Comp.	Unit 3 Cost	Unit 3 COD	Unit 3 % Comp.	Total Project Cost	E&W Total Cost [2]
Jun-74	$606	May-81	0.0%								
Sep-74	$613	May-81	0.0%	$586	Nov-82	0.0%	$605	May-84	0.0%	$1,804	
Dec-74			0.0%			0.0%			0.0%		
Mar-75	$1,000	May-82	0.0%	$827	May-84	0.0%	$941	May-86	0.0%	$2,768	
Jun-75			0.0%			0.0%			0.0%		
Sep-75			0.0%			0.0%			0.0%		
Dec-75	$975	May-82	0.0%	$845	May-84	0.0%	$950	May-86	0.0%	$2,770	
Mar-76			0.0%			0.0%			0.0%		
Jun-76 *			1.0%			0.0%			0.0%		
Sep-76			1.0%			0.0%			0.0%		
Dec-76			2.0%			0.0%	$950	Jun-86	0.0%		$2,784
Mar-77			7.1%			2.1%			0.0%		$2,800
Jun-77			11.3%			2.0%			0.0%		$2,840
Sep-77			16.8%			3.4%			0.0%		
Dec-77	$989	May-82	21.9%			5.1%			0.1%		$2,937
Mar-78	$1,263	May-82	24.6%	$769	May-84	7.3%	$834	Jun-86	0.9%	$2,866	
Jun-78			26.8%			6.3%			0.5%		$2,953
Sep-78	$760	May-82	28.5%	$598	May-84	7.8%	$702	Jun-86	0.5%	$2,060	
Dec-78			32.2%			11.2%			0.5%		$2,982
Mar-79	$911	May-83	43.0%			13.8%			0.8%		
Jun-79			43.0%	$710	May-84	17.6%	$833	Jun-86	1.5%		$3,342
Sep-79			46.7%			20.5%			2.1%		
Dec-79	$938	May-83	55.7%	$571	May-84	26.1%	$746	Jun-86	4.5%	$2,255	$3,385
Mar-80	$1,354	May-83	62.3%	$827	May-84	31.6%	$1,088	May-86	7.6%	$3,269	
Jun-80	$1,429	May-83	68.3%	$820	May-84	37.7%	$1,125	Jun-86	10.8%	$3,374	$3,671
Sep-80	$1,457	May-83	74.3%	$948	May-84	43.9%	$1,212	Jun-86	12.9%	$3,617	
Dec-80			80.6%			50.0%			15.6%		$3,835
Mar-81	$1,453	May-83	83.8%	$1,016	May-84	55.5%	$1,255	Jun-86	18.6%	$3,724	
Jun-81			87.8%			62.2%			22.0%		$3,972
Sep-81			92.8%	$1,075	May-84	68.5%	$1,227	Jun-86	26.0%		
Dec-81	$1,579	May-83	92.8%			75.4%			30.4%		$4,694
Mar-82	$1,671	May-83	96.5%	$1,136	May-84	82.6%	$1,487	May-86	36.7%	$4,294	
Jun-82			96.0%			87.7%			42.3%		$4,764
Sep-82			96.9%			92.0%			47.3%		
Dec-82			98.1%			94.0%			52.5%		$4,981
Mar-83	$1,671	May-84	99.3%	$1,136	Feb-85	96.9%	$1,487	May-86	61.7%		
Jun-83			99.3%	$1,136	Sep-85	97.9%	$1,487	Dec-86	70.8%		$5,700
Sep-83			99.5%			98.6%			78.6%		
Dec-83			99.5%			98.8%			85.3%		$5,900
Mar-84			99.6%			99.1%			89.4%		
Jun-84	$1,906	Nov-85	99.7%	$1,331	Apr-86	99.4%	$1,464	Jun-87	92.3%	$4,701	$5,900
Sep-84			99.7%			99.5%			94.6%		
Dec-84			99.7%			99.7%			95.9%		$5,900
Mar-85			99.7%			99.7%			97.1%		
Jun-85			100.0%			99.9%			98.0%		
Sep-85			100.0%			99.9%			98.8%		
Dec-85			100.0%			100.0%			99.2%		

Sources: EIA-254; IR-1-56a, 57, 58. [2] Ernst & Whinney,'Phase I Diagnostic Review[...]'11/1985, Exh. V-1.

FIGURE 1.1: EPE FORECAST HISTORY

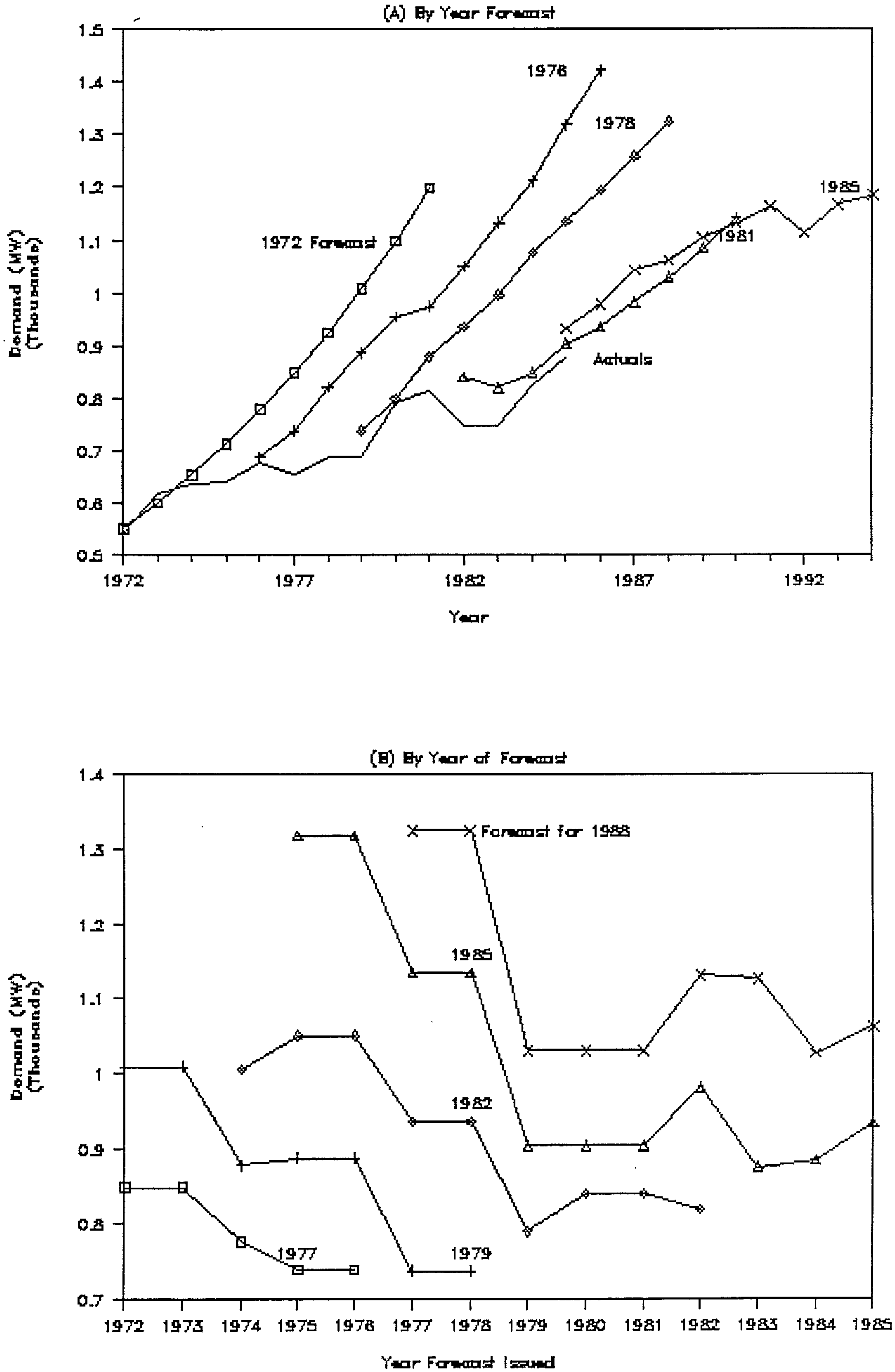


FIGURE 1.2: PVNGS PERCENT COMPLETE

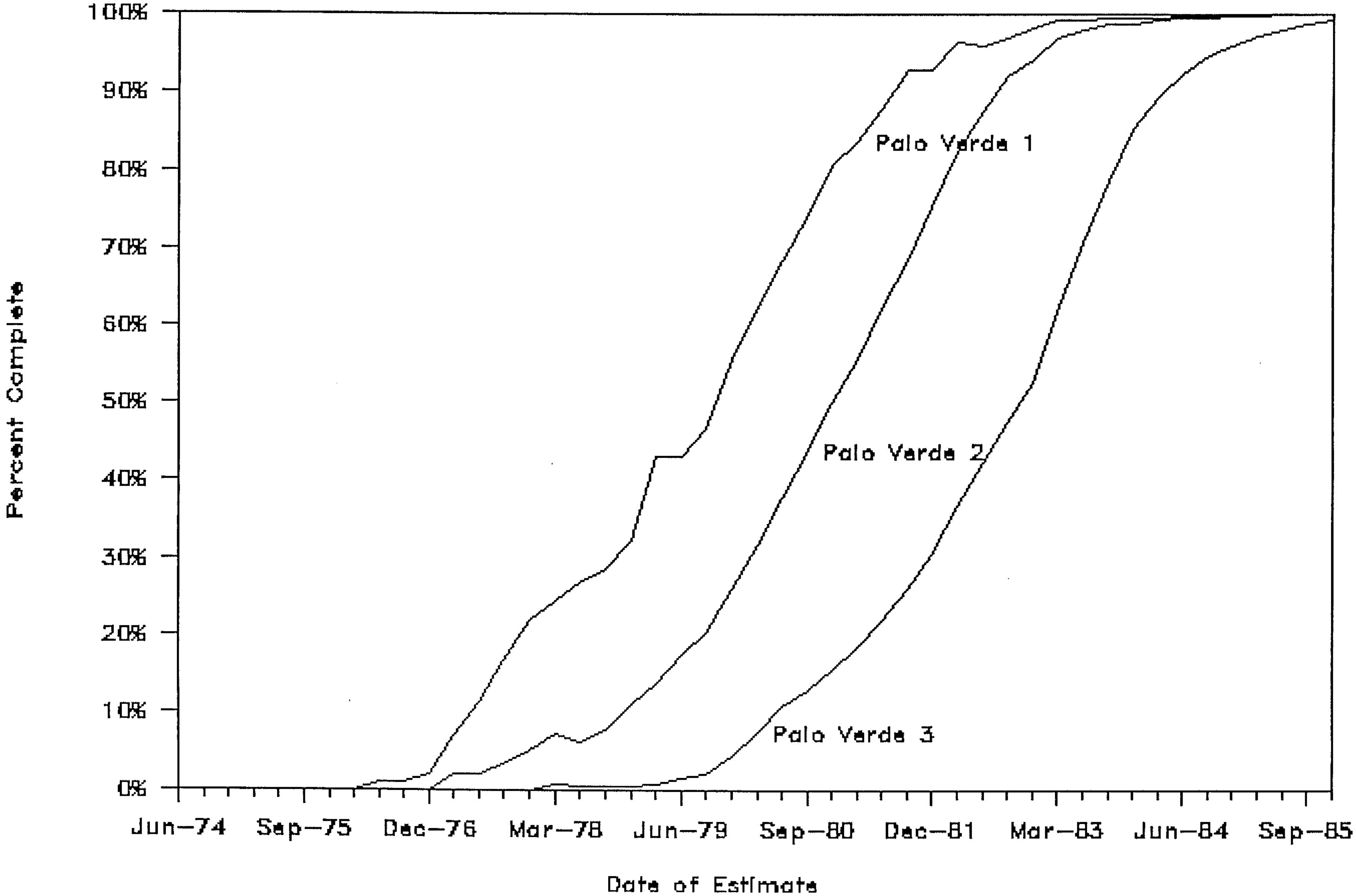


FIGURE 1.3

EPE Annual Construction Expenditures

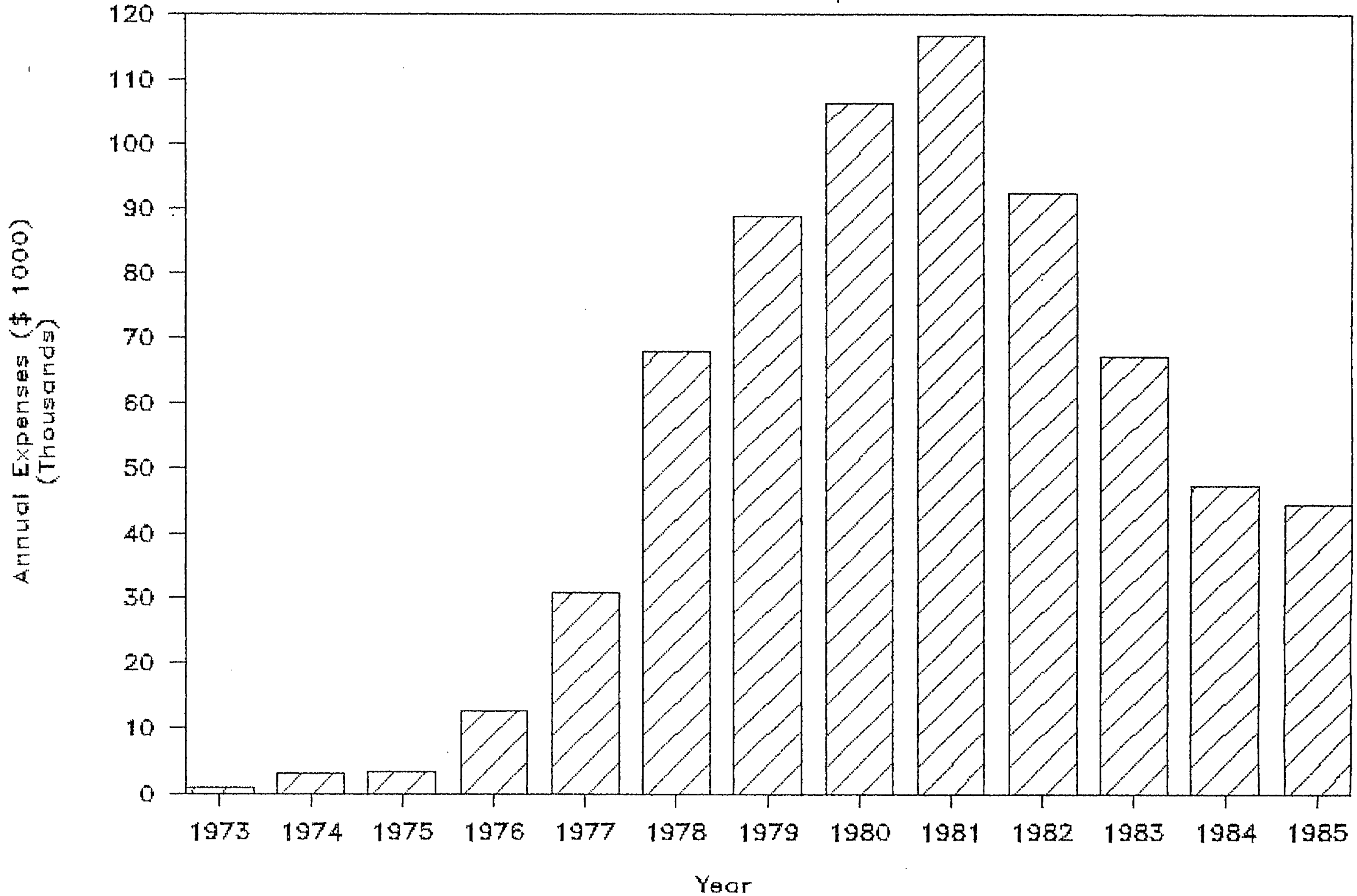
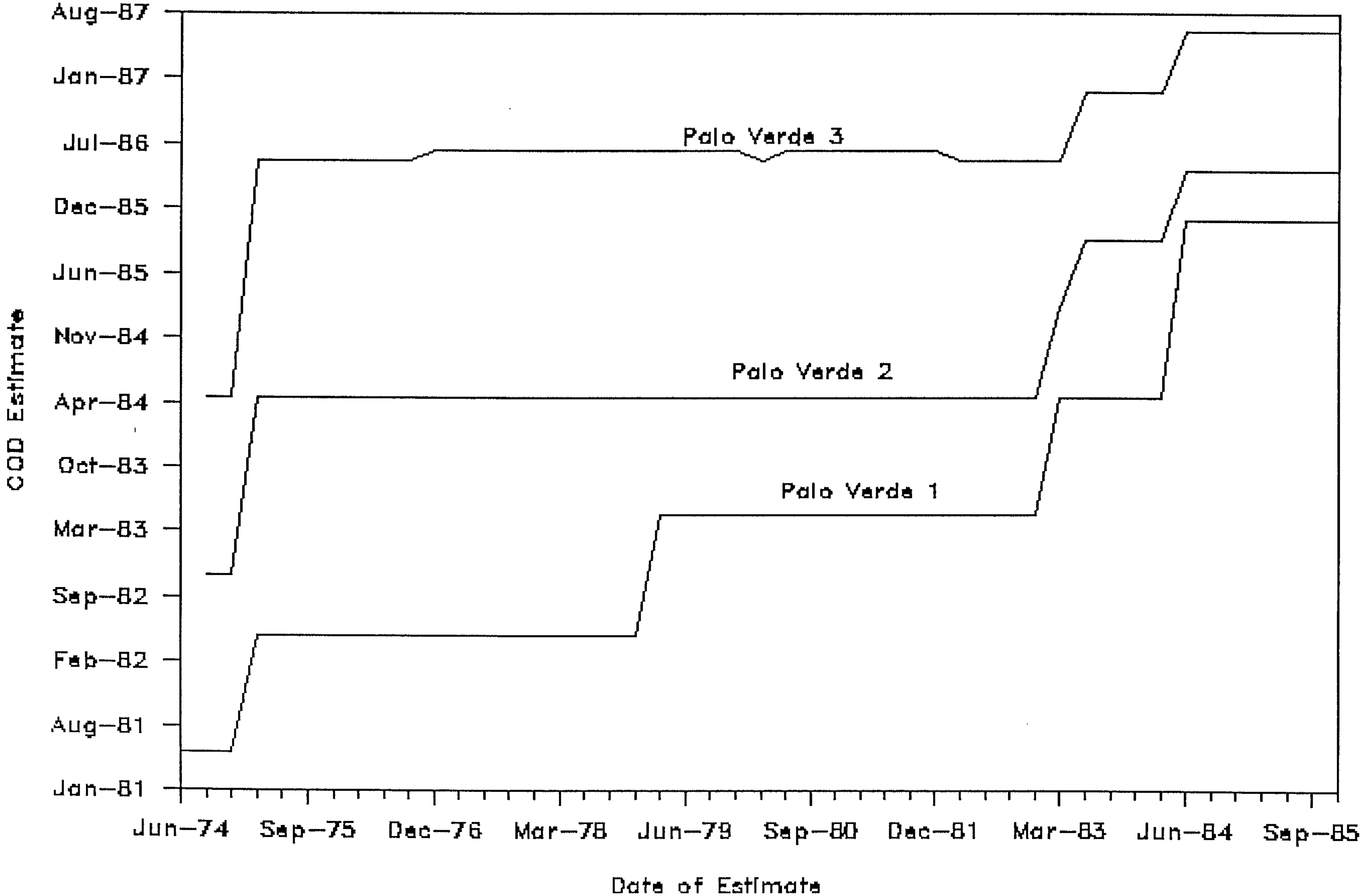


FIGURE 1.4: PVNGS COD ESTIMATES



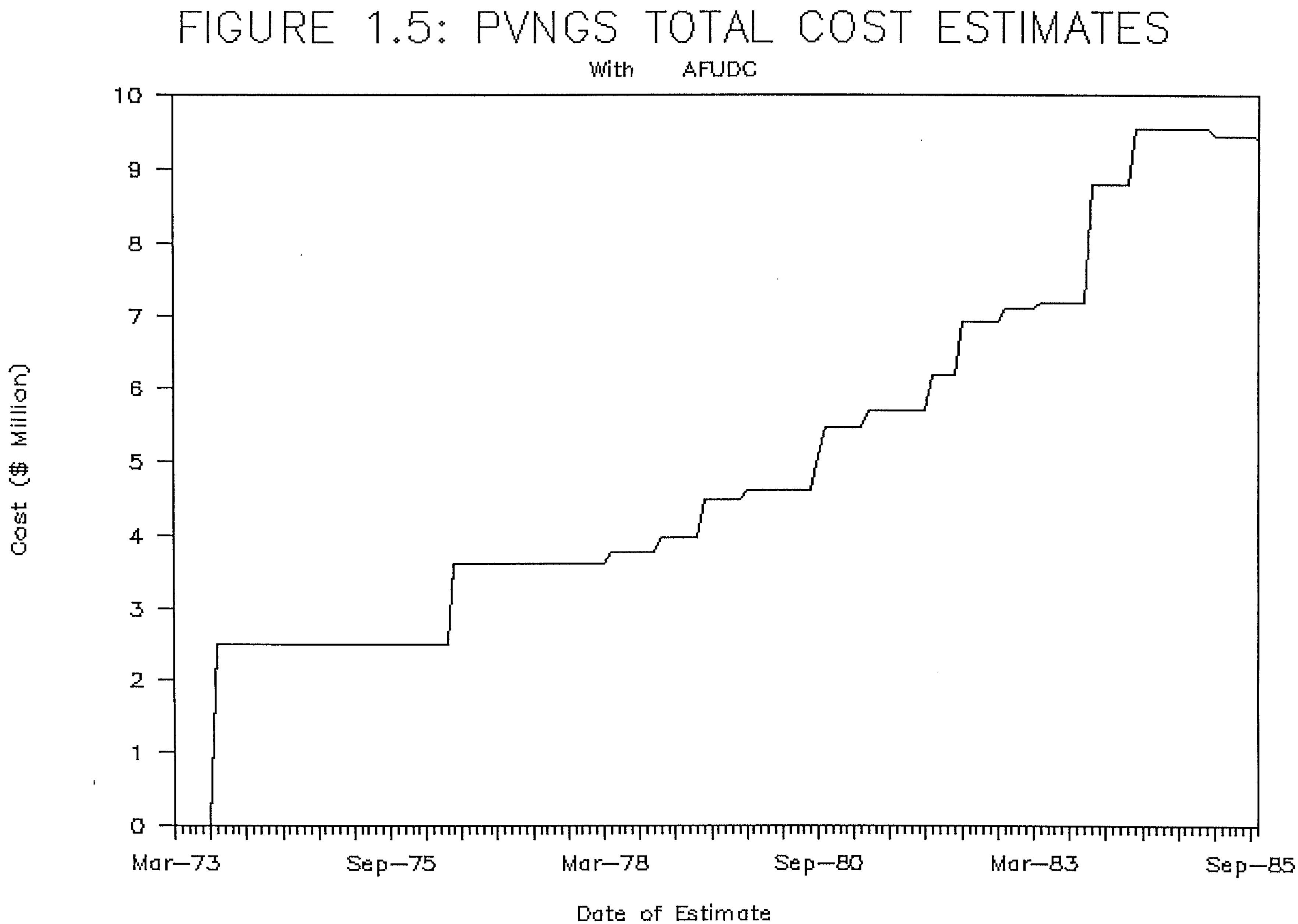


FIGURE 1.5: PVNGS TOTAL COST ESTIMATES
With AFUDC
Cost ($ Million)
10
9
8
7
6
5
4
3
2
1
0
Mar—73
Sep—75
Mar—78
Sep—80
Mar—83
Sep—85
Date of Estimate

Figure 3.1: Plant Cancellations:

With, and Without Construction Permit

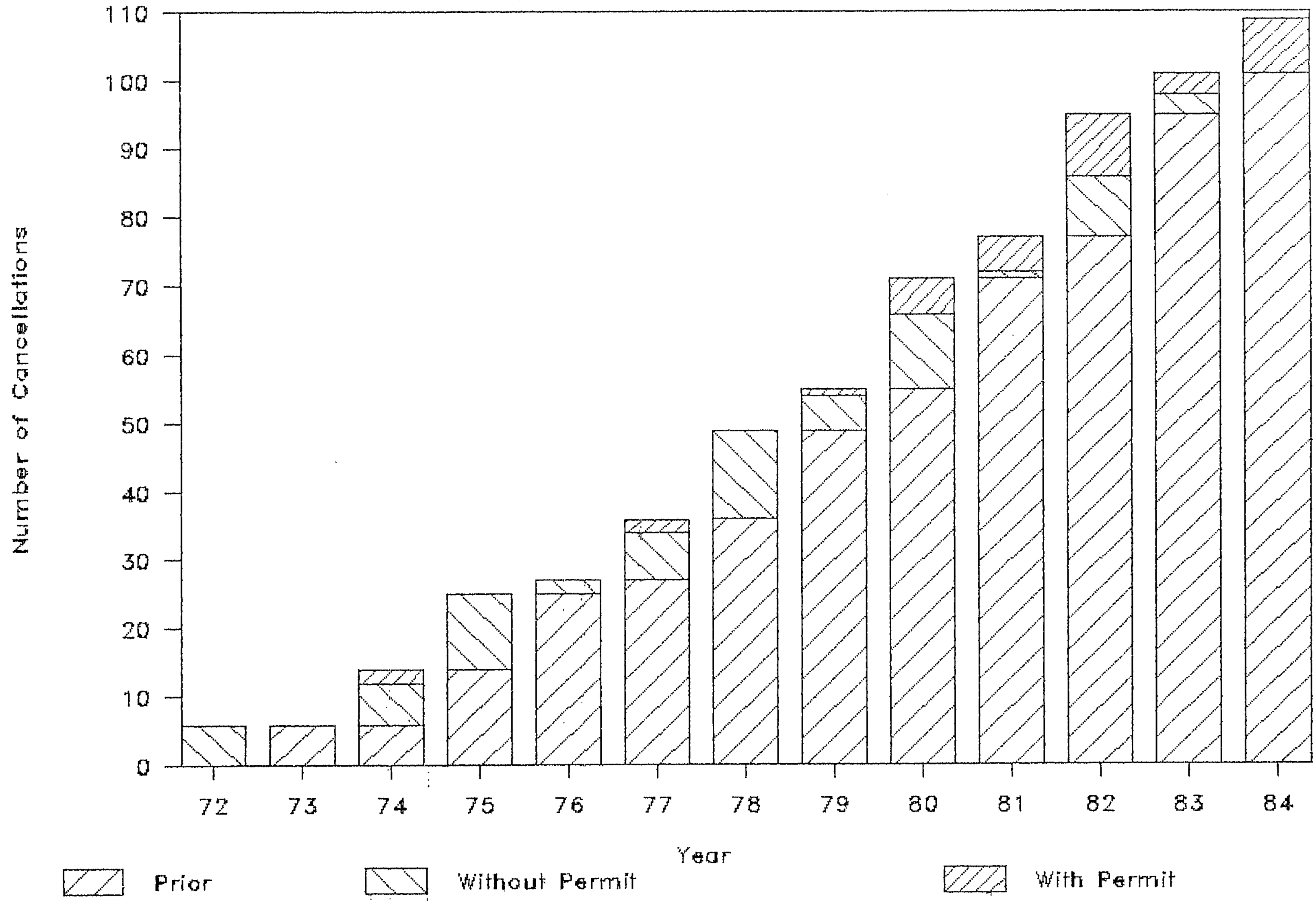


Figure 3.2: NET NUCLEAR ORDERS