Touche Ross & Co.

OKLAHOMA CORPORATION COMMISSION

BLACK FOX STATION

ECONOMIC VIABILITY

STUDY

TOUCHE ROSS & CO.

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# I. INTRODUCTION

This report has been prepared by Touche Ross & Co. for the Oklahoma Corporation Commission (the Commission) and presents the results of our review of the economic viability of the Black Fox Station. The findings, conclusions, and recommendations which comprise this report were developed based upon our review and analysis of factors related specifically to the Black Fox Station and the nuclear industry as a whole. Our conclusions and recommendations relate solely to the Public Service Company of Oklahoma (PSO) and should not be construed as applicable to other electric utilities. Further, our conclusions and recommendations are, in part, based upon the results of projections and numerous underlying assumptions. As discussed further in this section and in this report, these projections are based upon the best information publicly available and are to be utilized solely for the purposes defined within the objectives of this study. Accordingly, our projections, conclusions, and recommendations are limited to the determination of the economic viability of the Black Fox Station and should not be relied upon by external parties as a basis for economic decisionmaking related to PSO as a whole.

This report has been structured to reflect our overall approach to the conduct of this engagement and to facilitate review by interested parties. In this section, we provide a general perspective of the purpose of the study and our approach to the conduct of this analysis. Further, we set forth the basis upon which this report was prepared and the limitations upon its use by external parties. The remaining contents of this report are organized as follows:



## BACKGROUND

### History of the Project

In January 1973, PSO announced its intent to build a 1,100 Mw nuclear generating facility scheduled to be available for commercial operation within ten years. This decision was based in part on an earlier planning study prepared for PSO by Black and Veatch Consulting Engineers which recommended that the nuclear generation alternative be seriously considered for the future. In early 1974, PSO notified the Atomic Energy Commission of its intent to submit an application for construction permit for two 950 Mw units by March 1975. In January 1975, PSO accepted the participation of Associated Electric Cooperative, Inc. (Associated) and increased the size of the proposed generating facility to two 1,150 Mw units to accommodate this participation and that of others.

In August 1975, PSO submitted its application for license to construct and operate the Black Fox Station. This submission resulted in the docketing of the application by the

Nuclear Regulatory Commission (NRC) in December of that year which initiated the formal environmental and safety review processes by the agency. In July 1976, PSO announced the participation of Western Farmers Electric Cooperative, Inc. (Western) in the project which delayed the expected issuance of a Final Environmental Statement (FES) by the NRC. To mitigate the impact of this delay on the overall project schedule, PSO applied for a Limited Work Authorization (LWA) which would allow for the initiation of nonsafety-related construction work at the site prior to receipt of a full Construction Permit (CP). Shortly after this application, the NRC issued the FES (February 1977) and the Safety Evaluation Report (SER - June 1977). Hearings were then initiated in August 1977 with the record initially closed during November of that year; however, it was subsequently reopened in May 1978 to consider generic issues related to the environmental effects of radon releases associated with the mining of uranium. The record was again closed resulting in the issuance of a Partial Initial Decision by the Atomic Safety and Licensing Board in July 1978. Upon receipt of this decision - which allowed issuance of the LWA - nonsafety-related construction work at the Black Fox Station site commenced.

At this point, preparation for the safety hearings was intensified and hearings were conducted over the period October 1978 to February 1979. At the conclusion of these hearings, all requirements for receipt of the CP had been fulfilled and issuance of full authority to construct was expected in the near future. However, during March 1979, the events of Three Mile Island Unit 2 (TMI) occurred, which eventually resulted in a moratorium on issuance of CPs by the NRC.

The events summarized above provide a general perspective of the historical milestones achieved by PSO up to the occurrence of TMI. These events, however, do not provide a total perspective of the effect of the passage of time upon such factors as construction cost and expected commercial operation. Consequently, we have prepared Table I-1 which summarizes these factors by selected milestone dates:

Table I-1
Summary of Project Changes

| Date | Units/Size | Completion Cost | Commercial Operation |
|---|---|---|---|
| January 1973 | 1/1,100 Mw | \$450 million | 1982 |
| January 1974 | 2/950 Mw | \$800 million | 1982/84 |
| January 1975 | 2/1,150 Mw | \$1.200 billion | 1983/85 |
| August 1975 | 2/1,150 Mw | \$1.550 billion | 1983/85 |
| November 1977 | 2/1,150 Mw | \$1.780 billion | 1984/86 |
| February 1979 | 2/1,150 Mw | \$2.388 billion | 1985/88 |

Source: Testimony of Vaughn L. Conrad

Since the close of the safety hearings in February 1979, PSO has been unable to obtain a CP from the NRC and has attempted to obtain sufficient definition of additional safety requirements which will be mandated as a result of TMI. Immediately after the occurrence of TMI, action was initiated by PSO to review and assess the developments related to this accident and prepare adequate documentation to ensure that the lessons learned from TMI were effectively considered and corrective action, if necessary, successfully implemented at the Black Fox Station. Concurrent with this action, PSO initiated discussions with the staff at the NRC to attempt to define the basis for further licensing requirements; however, the issuance of the Kemeny Report in October 1979 effectively created an extended moratorium on the processing of applications and the

issuance of CPs. As a result of continued inactivity and increasing uncertainty, PSO sharply curtailed the level of site activity related to the Black Fox Station. As licensing and safety requirements continued to lack specificity and definitive direction, financial commitments were further reduced and cash flow requirements minimized.

Since the implementation of this operational mode, PSO has further modified its approach to the project from a proactive to a reactive posture. In effect, PSO entered into a caretaker status with respect to the project in the fall of 1980 by adopting a more passive role in the development of specific initiatives or responses related to proposed rules. In March 1981, the NRC published proposed final rules related to additional safety requirements and the licensing process; however, these rules have not been enacted to date (although they have been adopted as policy) by the NRC and could be subject to additional revision. PSO nonetheless has indicated that it will formally respond to these requirements at some time during the fall of 1981 in an effort to take advantage of a special NRC task force established to process CP applications.

### Industry Experience

In addition to the background presented above with respect to the Black Fox Station project history, we believe that it is equally important to provide a brief perspective on the experience of the nuclear industry as a whole. A more detailed discussion is presented later within this report; therefore, this section will only provide a general overview of this area.

The decade of the 1970s saw a significant change in the experience of the electric utility industry in constructing nuclear generating facilities within planned cost and duration estimates. Design changes and regulations mandated by the NRC during this period substantially exceeded previous experience and resulted in a pronounced compounding of requirements upon the industry during the latter half of the decade. These additional design changes and regulations significantly affected both estimated completion costs and anticipated project duration. Various studies have indicated a total current planning horizon of approximately twelve years based on six to eight years construction duration previously experienced. These construction durations have varied due to numerous factors such as:

- Design changes
- Rework/retrofit
- Labor productivity
- Financing delay
- Demand reduction
- Regulatory uncertainty

Consequently, actual duration for construction of units currently in commercial operation has shown almost continuous increase as illustrated in **Table I-2**. These periods were calculated and published by the NRC and represent elapsed time from groundbreaking to the fuel load date. The power ascension stage to commercial operations would add an average of six months to these durations.

Table I-2
Summary of Construction Duration to Fuel Load

| Year of Commercial Operation | Units | Average Duration |
|---|---|---|
| 1970 | 4 | 47.6 mos. |
| 1971 | 5 | 55.7 mos. |
| 1972 | 6 | 60.9 mos. |
| 1973 | 12 | 71.1 mos. |
| 1974 | 14 | 72.1 mos. |
| 1975 | 3 | 78.7 mos. |
| 1976 | 7 | 94.3 mos. |
| 1977 | 4 | 90.0 mos. |
| 1978 | 3 | 102.7 mos. |
| 1979 | - | - |
| 1980 | 4 | 130.4 mos. |

Source: Nuclear Regulatory Commission, "Construction Status Report," NUREG-0030, January 1981

Although the construction durations that occurred in the later years of this period were heavily influenced by increasing regulatory requirements and related construction delays, it is clear that total durations to the fuel load date have significantly increased.

The construction durations shown above must also be reviewed in terms of their impact on completion cost. An analysis prepared for the National Regulatory Research Institute indicated that costs for completed units and current estimates for units under construction exceeded original estimates by a ratio of from 1.58 to 5.08 times. Although this listing purportedly represented only approximately one-third of current installations, it is nonetheless indicative of the problems experienced by the electric utility industry. A report prepared by the DOE indicates that cost per kilowatt for light water reactors (LWR) will continue to escalate into the 1980s by substantial margins. **Table I-3** illustrates these projections:

Table I-3
Average LWR Plant Capital Costs
1,000 Mw and Larger

| Year of Commercial Operation | Units in Sample | Average Unit Cost ($/kw) |
|---|---|---|
| 1981 | 5 | $ 933 |
| 1982 | 7 | 949 |
| 1983 | 10 | 1,335 |
| 1984 | 6 | 1,132 |
| 1985 | 7 | 1,405 |
| 1986 | 10 | 1,837 |
| 1987 | 4 | 1,880 |
| 1988 | 2 | 1,654 |
| 1989 | 2 | 1,875 |

Source: Department of Energy, Office of Nuclear Reactor Programs, "Update," March/April 1981

As this table shows, capital cost per kw is projected to double between the period 1981 through 1987, which translates to an average compound annual growth rate in excess of 12%. Finally, an article published in 1980 states that current estimates for nuclear generating facilities to be available in 1992 are more than ten times as large as estimates made in 1969 for facilities to be available in 1976. By any standard, the actual and projected costs of nuclear generating facilities have been significantly affected by the passage of time, continuing inflation, and the increase in regulatory requirements.

This significant escalation in costs to complete a nuclear generation facility as well as the lengthening elapsed project duration have had a serious impact on the commitment of the electric utility industry to nuclear power. In fact, during the period 1975 through 1980, cancellations of nuclear reactor orders substantially exceeded new orders. Table I-4 illustrates this occurrence:

Table I-4
Summary of Orders and Cancellations
of Nuclear Reactors

| Year | Orders | Cancellations |
|---|---|---|
| 1972 | 38 | 6 |
| 1973 | 38 | - |
| 1974 | 34 | 9 |
| 1975 | 4 | 10 |
| 1976 | 3 | 5 |
| 1977 | 4 | 10 |
| 1978 | 2 | 11 |
| 1979 | - | 11 |
| 1980 | - | 12 |

Source: Department of Energy, Office of Nuclear Reactor Programs, "Update," March/April 1981

The impact of the factors discussed above on the growth of nuclear power in the United States has been devastating and has significantly altered the prospects for substantial additional nuclear generation as a part of our total energy mix for the 1980s.

## OBJECTIVES OF THE STUDY

### Request for Proposal Requirements

As a result of these historical trends in nuclear generating facility construction and concern regarding the potential effect of construction of the Black Fox Station on PSO and its customers, the Commission issued a Request for Proposal (RFP) seeking assistance in the review of the application of PSO for a general increase in rates. The assistance requested by the Commission was broadly categorized as follows:

- Analysis of PSO's forecasting, projected generation requirements, planning efforts, and current reliability

- Assistance to staff in analysis of reserve capacity of current electric generating facilities

- Economic analysis of Black Fox Station construction

The results of these specific analyses were to be provided as direct testimony at the conclusion of the investigation.

Based on our review of the RFP and discussions with Commission staff, we determined that the major areas of inquiry were to be directed toward:

- Review of demand forecasts and generating capability requirements

- Comparative analysis of the construction and operating costs of nuclear and coal-fired generating plants

- Assessment of the estimated impact of completion of the Black Fox Station on PSO and its customers

Subsequent to the completion of our analysis, staff requested that the scope of our review be expanded to include potential capital recovery alternatives for the amounts expended on the project to date should it be decided to cancel or convert the site to a coal-fired generating facility. Consequently, we developed an overall approach to the conduct of the engagement which would enable the concerns of the Commission to be effectively addressed through an integrated analytical process.

Approach to Analysis

To facilitate the successful completion of the project, we separated the overall requirements into individual analyses. These discrete reviews were designed to provide a logical sequence to our work activities from an assessment of the need for power through the determination of the economic viability of Black Fox Station and related recommendations. These separate analyses, which are discussed in greater detail in this section, are listed below:

- Assessment of the Need for Power
- Development of Economic Comparisons
- Determination of Financial Impact
- Assessment of Economic Viability
- Evaluation of Capital Recovery Alternatives

In addition to these discrete analyses, several other areas were reviewed and analyzed to provide an essential background perspective on the nature and magnitude of the project and potential problems and constraints.

**First,** review of the chronological history of the project was initiated to develop an appropriate understanding of the efforts taken to date regarding planning, licensing, and construction of the Black Fox Station. This analysis included the review of available information regarding the application for construction permit, identification of factors or events which negatively affected the licensing phase, and the current status of licensing and construction activities and prospects.

**Second,** review of the historical financial condition of PSO was conducted as a basis for determining the underlying financial strength of the Company. Selected financial ratios were identified and PSO's performance reviewed and evaluated in light of other external constraints such as size of construction program, general economic conditions, and regulation. Review of historical and current rate case experience and

filings was also conducted to develop an appropriate understanding of the regulatory process within the state of Oklahoma.

Third, a review was conducted of the historical experience of the electric utility industry in constructing nuclear generating facilities. This review was performed to develop an understanding of the recent history of nuclear power and its prospects for the future. In this analysis we reviewed historical construction duration and cost experience and current projections for expected performance. Underlying reasons for negative performance were identified and evaluated in terms of the degree of their effect on schedule and costs and the likelihood of recurrence in the future. Current projections related to construction duration and costs were obtained and underlying assumptions evaluated to provide a range of alternatives against which the estimates developed by Touche Ross & Co. could be compared.

The performance of these activities provided valuable information related to industry problems and specific experience at PSO. The discrete analyses previously discussed, however, provide the cornerstone of this report and are briefly discussed below.

**Need for Power** - The initial analytical activity performed was to conduct a review of the most recent demand forecast prepared by PSO. The purpose of conducting this analysis was to evaluate whether current generating capabilities were adequate in light of anticipated peak demand requirements. The projections prepared by PSO were reviewed and discussed with appropriate Company personnel and compared to other available forecasts for PSO and members of the Southwest Power Pool. The methodology utilized to prepare these forecasts was also evaluated and underlying assumptions identified and challenged. At the conclusion of this analysis, the impact of peak demand requirements on system generating capabilities was reviewed. The conduct of these particular analyses is essential to an evaluation of the economic viability of the Black Fox Station. However, it should be noted that we did not perform a comprehensive, independent determination of projected demand upon the PSO system. Our analysis was limited to the review of existing material and the evaluation of the reasonableness of underlying assumptions

**Economic Comparisons** - The next major analysis conducted was the development of estimated construction and operating costs for nuclear and coal-fired alternatives. These estimates were based upon generic plants rather than a site specific analysis since such an analysis would have exceeded our available study period and specific estimates for the Black Fox Station had not been updated by PSO since TMI. These generic estimates, however, were based upon information or assumptions specific to PSO where applicable, i.e., in the use of expected construction st : dates, commercial operation dates, and interest during construction rates. The analysis was based upon roughly equivalent generating capacity to ensure comparability of the alternatives. Assumptions regarding all factors were based upon the best information available and input to the Concept Model, a construction cost model developed by the Oak Ridge National Laboratory. Multiple assumptions were reviewed and a range of estimates developed for both the nuclear and coal-fired alternatives.

**Financial Impact** - At the conclusion of the previous analyses, the impact of estimated construction and/or operating costs upon both PSO and its ratepayers was reviewed. These analyses were based upon utilization of our generic construction cost estimates and input, along with additional factors developed by Touche Ross & Co., into a corporate financial performance model developed and maintained by PSO. Several scenarios were utilized reflecting alternative treatments of construction work in progress (CWIP) to derive financial results and requirements. These results

and requirements were analyzed to determine the effect of each alternative upon the financial condition of PSO and the potential impact upon the ratepayers.

**Economic Viability** - Based on the results of the analyses previously conducted and our review of other related factors such as economic conditions, financial requirements and regulatory uncertainties, a determination was made of the overall economic viability of the Black Fox Station. This analysis integrated the results of our previous evaluations and assessments and scrutinized the effect of these factors upon the viability of the project as it currently is conceived. A significant portion of this analysis considered nonfinancial factors such as regulatory requirements and construction experience. These analyses combined with economic comparisons, financial impact, and our professional experience and judgment serve as the basis for our conclusions and recommendations.

**Capital Recovery** - The final analysis conducted was the identification of several capital recovery alternatives and the determination of the effect of each should it be decided to cancel or convert the project. Scenarios related to the treatment of costs to date were developed to demonstrate potential impact upon PSO as well as the ratepayers. These scenarios were developed based upon our previous analyses and input into PSO's corporate financial performance model and were supplemented by manual calculations as necessary. These estimates are presented to the Commission to provide as much financial information as possible for use in deliberation upon the issues within the related proceeding. This information should be used in connection with other financial integrity parameters previously developed to determine the relative merits of potential Commission responses. Each of the major areas of analysis described above is discussed in greater detail elsewhere in this report.

## UTILIZATION OF PROJECTIONS AND REPORT

The information presented in this report contains a substantial number of projections related to the cost of construction, operating costs, and the effect of the occurrence of several events on both PSO and its ratepayers. These projections are limited to the analysis of the Black Fox Station and do not attempt to consider all financial, legal, or operational factors or decisions which may affect the operations of PSO.

In developing the projections contained within this report, we evaluated numerous assumptions related to cost, performance, and impact and selected those assumptions we considered reasonable. However, since projections are based on assumptions about circumstances and events that have not yet taken place, they are subject to variations that may arise as future operations actually occur. Accordingly, assurance cannot be given that the projected results will actually be attained. It should be understood that the underlying assumptions are based on present circumstances and information currently available. Because circumstances may change and unanticipated events may occur subsequent to the date of this report, the reader must evaluate the assumptions and rationale in light of circumstances then prevailing.

Further, it should be understood that this report was prepared for use by the Oklahoma Corporation Commission in its review of the Black Fox Station. The scope of this analysis was not intended to evaluate all aspects of PSO performance or operations nor was such analysis undertaken. All information contained within this report must be evaluated in terms of the objectives of the study and should not be relied upon for any purposes other than those expressly stated herein. Accordingly, this report should not be used as a basis for the development of financial or operational decisions by outside parties.

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# II. EXECUTIVE SUMMARY

This section of our report contains a brief summary of the contents of the total report and is intended to provide the reader with an overview of the ensuing sections of our study.

## SUMMARY OF RESULTS

### Need for Power

Our analysis of the historical and projected load growth forecasts of PSO indicated that although there is a decrease in the rate of growth over the periods analyzed, the projected load increases will require the addition of generating capability at the end of this decade. Review of the current load projections of PSO, over the period 1982-1990, indicate a growth in peak load of 3.6% before consideration of the load management program and 2.9% after consideration of the potential effects of this program. We believe that the load growth projections of PSO are conservative particularly in light of their aggressive load management estimates. Alternative analyses indicate that greater than expected growth or failure of the load management program to accomplish its stated objectives would necessitate additional generating capability, assuming a 15% reserve margin, prior to 1990. It is important to note here that despite the cooler temperatures experienced to date in the summer of 1981 compared to that of 1980, PSO exceeded the 1980 peak of 2,839 Mw and reached 2,930 Mw on July 20, 1981, an increase of approximately 3.2%. Consequently, it is clear that projections even under the most sophisticated of models are subject to wide variation due to weather sensitivity and that adequate reserve capability must be maintained to ensure reliability of service. Therefore, we believe that a legitimate need for power exists for PSO and that there is adequate demand to support the addition of the proposed facility. In fact, our analyses indicate that a need for additional power exceeding that provided by the Oklaunion facility could exist as early as 1988.

### Cost Comparison

We have developed an economic comparison of generic nuclear and coal-fired alternatives based on a range of assumptions established under low, mid, and high cases and adjusted for specific factors pertinent to PSO. The assumptions in each case were varied to reflect various economic and construction conditions over the period of 1981 - 1994. We have utilized two 1,150 Mw nuclear units with anticipated commercial operation of mid-1991 and mid-1994, respectively, except in our high case where commercial operation dates of mid-1992 and mid-1995 were used, and compared these

costs with those for three 770 Mw coal-fired units with commercial operation dates anticipated in mid-1991, early 1993, and mid-1994, respectively. The following table summarizes the results of our capital cost projections:

Table II-1
Summary of Capital Cost Comparisons

| Case | | Dollars (billions) | Dollars/kw |
|---|---|---|---|
| Low - | Nuclear | $ 8.177 | $ 3,555 |
| | Coal | 5.009 | 2,168 |
| Mid - | Nuclear | 9.078 | 3,947 |
| | Coal | 5.353 | 2,317 |
| High - | Nuclear | 10.120 | 4,400 |
| | Coal | 5.789 | 2,506 |

As this table illustrates, the nuclear units substantially exceed the cost of the coal-fired units and in the mid case are 70% greater than the coal-fired alternative. These projections were made utilizing the Concept Model developed by the Oak Ridge National Laboratory and reflect our judgment of certain variable input elements such as escalation rates and AFDC.

An analysis of comparative operating costs for the nuclear and coal-fired alternatives was also conducted to develop a ten-year levelized bus bar cost comparison. At the conclusion of the development of our fuel cycle and other operating costs, we combined these elements with the carrying costs for each facility and arrived at a total bus bar cost comparison based on our mid case and assuming a capacity factor of 65%.

Table II-2
Ten-Year Levelized Bus Bar Cost Comparison
(mills/kwh)

| | Nuclear | Coal |
|---|---|---|
| Carrying costs | 137.73 | 80.85 |
| Operating and maintenance cost | 14.08 | 12.33 |
| Fuel cost | 22.66 | 61.20 |
| Insurance cost | .25 | - |
| Decommissioning cost | 1.23 | - |
| Total | 175.95 | 154.38 |

As this table illustrates, the combination of high capital and nuclear fuel cycle costs results in the determination that the Black Fox Station nuclear project would be less economical than a coal-fired alternative by approximately 14% on a ten-year levelized cost basis.

### Impact on Financial Condition

Our analysis also reviewed the effect that construction of a nuclear facility would have on the financial condition of PSO. Historical analysis indicated that although PSO is currently rated AA, several factors measuring financial condition are poor even in a

period of minimal construction activity. Utilizing our low case capital cost projections, we provided cash construction curves for the corporate financial performance model maintained by PSO to determine the effect of construction on financial condition. The results of our projections indicated that without the inclusion of CWIP in rate base, when construction activity increases, the financial condition of PSO would quickly deteriorate to unacceptable levels. The analysis showed that even with total inclusion of CWIP in rate base, an important minimum financial parameter, i.e., internal cash generation, could not be achieved. Our analysis was only performed for the low case since it is obvious that increasing the financial commitment of PSO would only create further financial deterioration.

### Impact on Customers

In addition to our analysis of the financial condition of PSO, we also reviewed the potential impact of construction of a nuclear facility on the customer. Based upon the Company's corporate financial performance model, customer costs are estimated to increase 57% from 1982 to 1990 excluding any consideration of the Black Fox Station nuclear facility. When 1991 revenue requirements for the Black Fox Station nuclear facility at the low capital costs are included, customer costs are estimated to increase by 159% assuming inclusion of CWIP for ratemaking purposes. Exclusion of CWIP for ratemaking purposes results in an estimated increase in customer cost of 306%.

### Economic Viability

Based on our development of the ten-year levelized bus bar cost comparison and our assessment of the risks associated with continued construction of a nuclear facility, we have recommended that the Black Fox Station project as it is currently conceived be cancelled and converted to a coal-fired facility. Although a pure economic comparison would generally provide a basis for determination of overall economic viability, it is also important to understand the nature and degree of risks associated with construction of a facility of this type and magnitude. Our analysis of various construction, financial, regulatory, and political risks all indicate substantial uncertainty related to these areas. The experience of the electric utility industry in constructing nuclear facilities has exhibited the effect of these risks. Extended construction duration due to reduced demand, limited financing capabilities, poor construction experience, and reduced need for power has resulted in substantially larger financial commitment than anticipated. Additionally, the regulatory and political risk at both the state and federal levels indicate substantial uncertainty with respect to requirements and treatment. Even if the Black Fox Station had proven economically superior, we do not believe this calculated future advantage would overcome the additional risks to the ratepayer and PSO associated with project continuance, many of which would in the end negatively affect any calculated future economic advantage.

### Capital Recovery

In the event the Commission concurs that cancellation of the Black Fox Station project is justified, we believe that some form of capital recovery must be provided for PSO to maintain financial integrity. We have analyzed several alternatives which are available to the Commission and do not believe that full absorption of the write-off by PSO is in the best interests of the ratepayers since financial condition would deteriorate to unacceptable levels. We believe that the concept of risk sharing would require the absorption of the write-off by both PSO and its ratepayers. We have evaluated several risk sharing scenarios and have concluded that the most viable alternative in terms of maintaining financial integrity for PSO and minimizing the effect upon the ratepayer is to allow for recovery of the sunk costs to date including cancellation charges and net of

conversion value over a ten-year period. This figure, reduced by the realized gain from recent sale of certain oil and gas leases held by PSO, would amount to a write-off of approximately $142 million. During the amortization period, a return equivalent to the actual embedded cost of debt and preferred stock as determined in this proceeding would be allowed to compensate these classes of investors. However, to minimize the impact on the ratepayer and to recognize that the risk of project cancellation is one of many assumed by the stockholder, no return would be granted to the equityholder. We believe that this sharing of risk satisfies standards of equity and provides for reasonable and fair treatment of both PSO and its ratepayers.

# III. NEED FOR POWER

The purpose of this section is to summarize the results of our review of PSO's projected load growth and capacity requirements. The scope of our review was limited to assessing the reasonableness of PSO's forecasts based upon a review of the current demand and capacity situation, the Company's forecasting methodology, and the assumptions underlying the forecast. Our conclusions derived from this review are not based upon a comprehensive, independent determination of projected demand upon the PSO system but rather upon our analysis of currently projected conditions tempered with a prospective evaluation of the potential impact on PSO's load growth due to alternative assumptions related to load growth forecasts.

To accomplish the objectives of this review, we structured an approach consisting of the following key elements:

- Review of historical growth patterns
- Review of previous load growth forecasts
- Review of the current PSO load growth forecast
- Review of capacity planning
- Analysis of alternative load growth scenarios

The results of our analysis are discussed in the following pages of this section and have been organized in the following manner to facilitate reader understanding:

- Historical Perspective
- Current Forecasts
- Alternative Load Growth Scenarios
- Alternative Capacity Sources

## HISTORICAL PERSPECTIVE

The purpose of this analysis is to provide a perspective of PSO's historical experience with respect to previous load forecasting efforts, actual growth, and existing generating facilities.

**Exhibit III-1** shows the growth in PSO's peak load for the period 1963-1981. The actual peak load has increased from 862.6 Mw in 1963 to 2930.0 Mw in 1981, a three-fold increase over the period analyzed. While the annual increases have varied from essentially no increase in 1975 to a high of 15.6% in 1980, the change in compound growth rates shown on the exhibit clearly indicates a declining trend in peak load growth.

**Exhibit III-2** was prepared to provide a perspective of the growth in customers and consumption for the same time frame as peak load growth. As this exhibit shows, consumption has increased four-fold over the period 1963-1980 while customers have only increased 1-1/2 times. The following table summarizes the compound growth rates in the growth in peak load, consumption, and customers.

Table III-1
Compound Growth Rates in Load, Consumption, and Customers

| Period | Actual Load | Weather Normalized Load | Consumption | Customers |
|---|---|---|---|---|
| 1963-1980 | 7.3% | 6.9% | 8.4% | 2.6% |
| 1965-1980 | 7.2 | 6.6 | 9.3 | 2.6 |
| 1970-1980 | 6.2 | 5.8 | 5.9 | 2.8 |
| 1975-1980 | 6.5 | 4.2 | 6.2 | 3.0 |
| 1977-1980 | 5.7 | 4.1 | 5.0 | 3.0 |

**Source:** Calculated From Company Response to TR-11, TR-29, and TR-45

PSO has prepared various load forecasts during the 1970s, each of which incorporated PSO's best estimates of future load requirements based upon evolving statistical modeling techniques and recognition of declining load growth rates. Our review of recent forecasts indicates a reasonably accurate estimation of peak load on a short-term basis, i.e., between one and three years. The following table illustrates recent forecasts compared to actual load.

Table III-2
Load Growth Forecast Comparison

| Year | Actual Load | Weather Normalized Load | Company Estimates 1977 | 1978 | 1979 | 1980 |
|---|---|---|---|---|---|---|
| 1977 | 2,405 | 2,350 | 2,314 | - | - | - |
| 1978 | 2,527 | 2,480 | 2,484 | 2,544 | - | - |
| 1979 | 2,456 | 2,517 | 2,665 | 2,660 | - | - |
| 1980 | 2,839 | 2,655 | 2,858 | 2,808 | 2,642 | - |
| 1981 (7/20) | 2,930 | N/A | 3,064 | 2,967 | 2,766 | 2,800 |

**Source:** Company Response to TR-11, TR-29, and Exhibit FJM, Schedule 2, Revised 6/25/81

A recent study performed on behalf of the Commission utilized an end use approach to estimating load growth. The best case scenario results are compared to actual loads in the following table.

Table III-3
Best Case Forecast Compared to Actual Load

| Year | Actual Load | Weather Normalized Load | Best Case Forecast |
|---|---|---|---|
| 1979 | 2,456 | 2,517 | 2,580 |
| 1980 | 2,839 | 2,655 | 2,640 |
| 1981 (7/20) | 2,930 | N/A | 2,680 |

Source: Volume I, The Best Case Forecast, Energy Systems Research Group, Inc., 1980 and Company Response to TR-11 and TR-29

As this table shows, the ability to accurately forecast peak load requirements even in the very short run can be compromised due to extreme weather conditions.

To accommodate the increase in demand placed on the system, PSO has continually built and placed into service additional generating capacity. During the 1970s, PSO brought the following plants on line:

Table III-4
Capacity Additions

| Plant | Capacity (Mw) | Fuel Type | Service Date |
|---|---|---|---|
| Riverside 1 | 450 | Gas | 1974 |
| Riverside 2 | 475 | Gas | 1976 |
| Comanche | 230 | Gas | 1974 |
| Welleetka 1 | 60 | Oil | 1975 |
| Welleetka 2 | 108 | Oil | 1976 |
| Northeastern 3 | 450 | Coal | 1979 |
| Northeastern 4 | 450 | Coal | 1980 |

Source: PSO 1980 Form 1 Report to the FERC

As of December 1980, PSO's generating capacity consisted of 70.8% gas, 5.1% oil, and 24.1% coal. PSO has also entered into contractual arrangements to essentially lease generating capacity to other utilities and maximize the use of current facilities. Finally, PSO has contractual agreements with the Tennessee Valley Authority (TVA) and the Southwest Power Authority (SPA) to purchase additional capacity of approximately 208 Mw for serving peak load requirements when necessary.

## CURRENT FORECASTS

The current load forecasting model represents the latest effort to estimate future load growth on an econometric modeling basis. The key elements of the model include variables for:

- Customer growth
- Real gross state product
- Temperature

- Air conditioning saturation
- Conservation and efficiency

The model developed by PSO in conjunction with outside consultants separates peak load into two components, base load and temperature sensitive load. Each component is modeled separately and then summed to produce an estimate of total peak load.

Exhibit III-3 shows the results of the load forecast for the period 1982-1990 after adjusting for decreases in Western loads currently served by PSO. The forecast assumes a compound growth rate in peak load of approximately 3.6% before the load management program and approximately 2.9% after adjustment for the load growth program.

The inclusion of load management gains represents PSO's initial effort toward reducing peak requirements through load management techniques. PSO's program was initiated in June 1981 and concentrates on the installation of remote radio controlled devices on residential air conditioning units. As peak load periods occur, PSO can begin cycling the air conditioning loads thus reducing peak load. While this program is still in the experimental stages at PSO, other utilities have implemented similar programs with varying degrees of success. Results from these programs indicate an approximate diversified peak demand reduction per customer of 1 kw.

To achieve the 1985 targeted load management benefits of 120 Mw will require a significant effort on the part of PSO to install and operate load control devices. Based upon information made available, PSO will have to install approximately 69,000 load control devices by 1985. This assumes PSO's estimate of an approximate diversified peak demand reduction per customer of 1.7 kw. The need for effective load management is critical to PSO's capital constrained load limits which essentially recognize the inability to maintain adequate reserve margins through the 1980s without load management gains.

To supplement the load management techniques discussed above, PSO has identified several other approaches to enhance load reductions or supplement capacity including:

- Supplemental energy sources
- Rate design
- Conservation
- Cogeneration

Supplemental energy sources include small hydro units, solar power, and wind generation. Current efforts to develop supplementary energy sources are still in the research stage.

To date, the economics of solar and wind generation have not proven to be cost-effective on a large scale. Potential for small hydro production is limited within the state and faces many legal and economic barriers. Most of the supplemental energy sources represent long-term goals and provide little or no prospects for near-term implementation. Rate design approaches to peak load control center primarily around time-of-use rates for residential service and increased demand charges and interruptible rates for industrial customers. There are a considerable number of pilot programs among various states offering time-of-use rates for residential customers which have resulted in reductions of peak load demand, although they may not be as effective in a weather

sensitive service area such as PSO's. However, the implementation of time-of-use rates faces many regulatory and legal barriers including:

- Design and justification of rate levels
- Rating period determinations
- Equipment requirements
- Cost/benefit considerations
- Customer acceptance

Increased demand charges for industrial customers represent an incentive for load reduction through pricing mechanisms. PSO has indicated that large industrial customers are in fact making significant efforts to reduce overall energy consumption although little has been achieved in reducing peak load requirements; however, PSO believes load reductions could be encouraged through higher demand charges. According to PSO, a general consensus of the industrial group was that interruptible rates were undesirable and would present a significant hardship on the individual companies.

PSO, along with other major Oklahoma utilities, is participating in the State's residential conservation program (ECHO). This program provides for home energy audits by major utilities, the purpose of which are to identify existing energy saving potentials within residential dwellings and to educate consumers about conservation opportunities. To date, the response in PSO's service area has been disappointing. Approximately 1 percent of the customers have responded to the offer to perform an audit.

As a part of the Public Utility Regulatory Policies Act of 1978 (PURPA), provisions were included to provide for cogeneration and small power producers' interaction with public utilities. To date, PSO has identified two new potential cogeneration projects with near-term opportunity involving the use of waste gas as a potential boiler fuel and would require the installation of small units in areas where waste gas is available. The potential for generation from this source ranges from .07 Mw to 7.5 Mw. The long-term opportunity for cogeneration considers the possibility of siting a plant near an industrial facility requiring steam thus utilizing by-product steam from electric generation.

The PSO load forecast reflects current expectations [illegible] respect to capacity additions and retirements. With the exception of the Black [illegible] tion units scheduled for service in 1991 and 1994, the only other additional apa[illegible]duled is the Oklaunion facility. This facility is a joint ownership project within the Central and South West Corporation (C&SW) system, with which PSO has contracted for 175 Mw available in 1987. Scheduled retirements are planned for obsolete or inefficient facilities in 1981, 1985, and 1988 totaling [illegible] Mw. Two critical assumptions included in the capacity forecast are shown below:

- The PSO system will be able to interconnect with Texas; and
- Appropriate exemptions from the Fuel Use Act will be obtained.

The failure to achieve either of these assumptions will place PSO in jeopardy of not being able to maintain adequate reserve margins to meet anticipated load growth.

For planning purposes, PSO targets a 1[illegible]% reserve margin which includes consideration of the following factors:

- System reliability
- Plant size

- Scheduled outages
- Unscheduled outages
- Weather variations

Considering the factors listed above, the impact on PSO's ability to provide reliable service can be illustrated by assuming a forced outage during the peak summer period of Northeastern Units Nos. 3 or 4 in 1982. The impact of such an occurrence would reduce PSO's reserves from 596 Mw to 146 Mw or a reduction in reserve margin from 22% to 5%.

There are many production planning models which attempt to quantify optimal levels of reserve margins based upon, among other things, loss of load probabilities; however, it is clear from the example shown above that a 15% target reserve margin for the PSO system is not unreasonable. As larger base load plants are constructed, reserve levels in excess of 15% may be necessary to provide system reliability.

## ALTERNATIVE LOAD GROWTH SCENARIOS

The purpose of presenting alternative load growth scenarios is to provide the Commission with a perspective of the potential impact on reserve margins and the need for power under different load growth assumptions. As explained previously, these alternatives do not represent definitive estimates of future load growth expectations but are presented as a basis for evaluating the impacts associated with the uncertainty in projecting load growth. Each alternative includes a calculation of reserve margins with and without load management gains to illustrate the importance of this program. The load management gains are highly dependent on PSO's ability to successfully implement various progams and the levels of customer acceptance associated with each program. Exhibits III-4 through III-9 were prepared using the following assumptions:

| | |
|---|---|
| Exhibit III-4 | PSO's load estimate for 1982 compounded at an annual growth rate of 2% |
| Exhibit III-5 | PSO's load estimate for 1982 compounded at an annual growth rate of 2.5% |
| Exhibit III-6 | PSO's current load estimate |
| Exhibit III-7 | PSO's load forecast growth assumptions adjusted for a 3% weather adjustment |
| Exhibit III-8 | PSO's load estimate for 1982 compounded at an annual growth rate of 4.0% |
| Exhibit III-9 | PSO's load estimate for 1982 compounded at an annual growth rate of 4.5% |

The following table summarizes the results of the alternative load growth scenarios:

Table III-5
Results of Alternative Load
Growth Scenarios

| Load Growth Scenario | Year Reserves Fall Below 15% Target With Load Mgmt. | Year Reserves Fall Below 15% Target Without Load Mgmt. |
|---|---|---|
| 2% growth | After 1990 | After 1990 |
| 2.5% growth | After 1990 | 1989 |
| PSO estimate | 1988 | 1983 |
| 3% weather variation | 1985 | 1983 |
| 4% growth | 1985 | 1984 |
| 4.5% growth | 1985 | 1984 |

Source: Calculated From Exhibit FJM, Schedule 2, Revised 6/25/81

The 2% and 2.5% alternatives do not eliminate the need for additional capacity in 1991 but do indicate that additional capacity could be postponed until a later date.

## ALTERNATIVE CAPACITY SOURCES

In the event PSO discontinues the Black Fox Station or load growth exceeds current expectations, there are a number of alternatives available for obtaining additional generating capacity. These include but are not limited to the following:

- Construction of a coal-fired facility at another site
- Conversion of the Black Fox Station site to a coal-fired generation site
- Pursuing co-ownership opportunities with Western at the Hugo site
- Pursuing co-ownership opportunities with other C&SW companies
- Rely on other utilities for purchased power availability

Conversion of the Black Fox Station site to a coal-fired generating station appears to be a reasonable alternative in the event the nuclear option is foregone. Much of the effort expended to date for site preparation would apply to converting the site to coal thus enhancing the prospects of conversion rather than developing a new site. Abandonment of the site will be costly since PSO would have to restore the site to its original condition. Additionally, the other members of the Black Fox Station project may be interested in joint participation in a coal alternative at the original site.

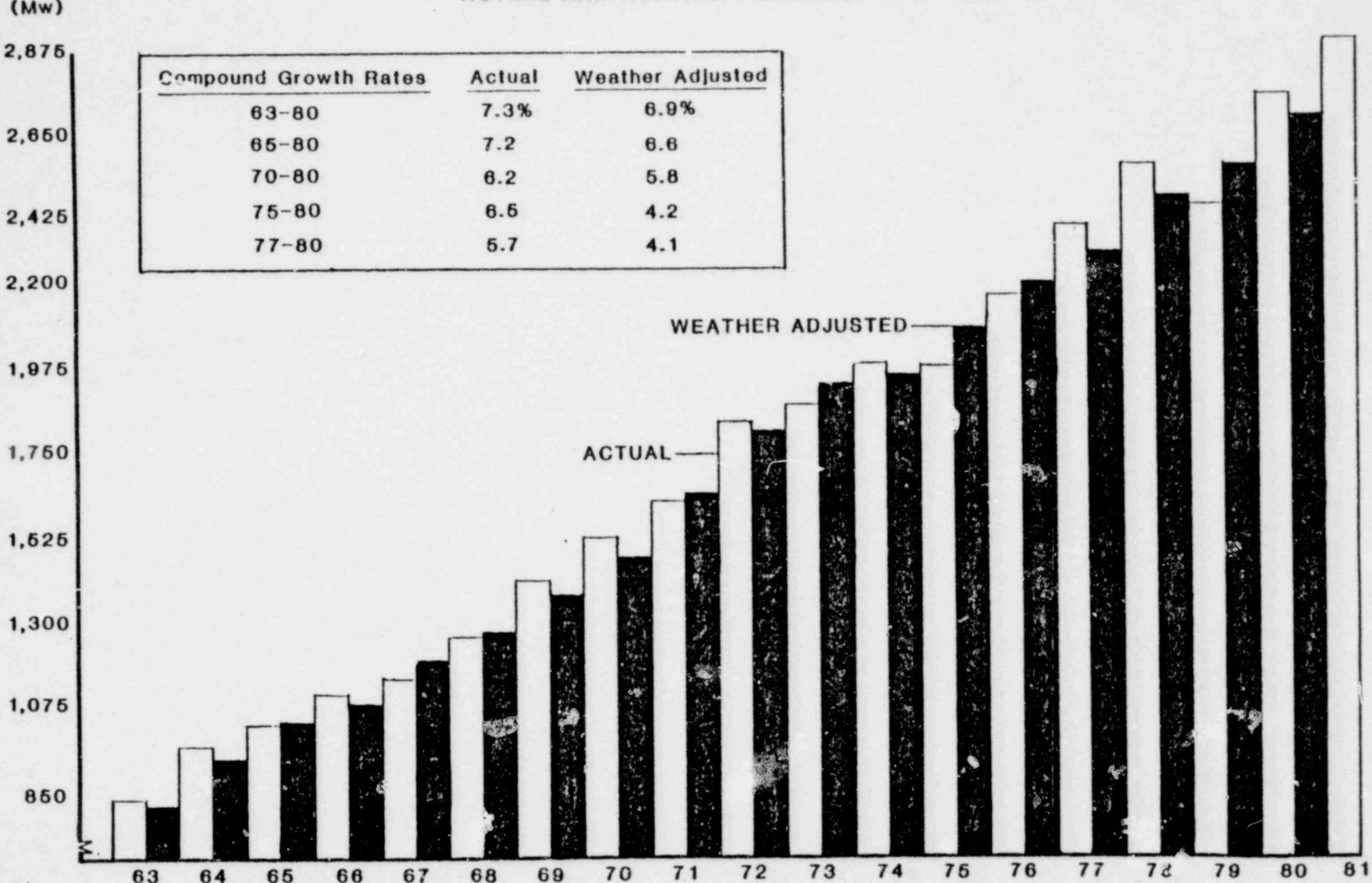
The possibility exists that PSO would choose to construct a coal-fired facility at another site such as Northeastern where an established site is available. A decision such as this may allow PSO to construct an alternative generation facility over a shorter time frame. Other potential sites may also exist which would allow for rapid construction of alternative facilities. Utilizing this alternative would, of course, require a decision regarding the potential use of the Black Fox Station site.

The opportunity of co-ownership ventures provides flexibility in the sizing of plants thus allowing for the construction of large plants and economy of scale benefits. In the future, additional generating capability will be planned within the C&SW system thereby attaining the parent's goal of a fully integrated system; however, current

expectations for additional C&SW plants beyond the addition of the Oklaunion facility are unknown at this time and may not arise until the 1990s.

The last alternative, reliance on other utilities for purchased power, contains a high degree of risk and would not be appropriate. Not only will the cost of future purchased power be high, but current estimates of surplus power in the State of Oklahoma indicate that this power may not be available when PSO's load exceeds generating capacity. In any event, reliance upon purchased power should be limited to very short time periods prior to the addition of generating capacity. As recently as 1977, the Grand River Dam Authority (GRDA) returned to a policy of providing for sufficient capacity to meet its own system requirements recognizing that reliance on purchased power was not cost-effective and in the best interest of its customers.

## PSO
## ACTUAL AND WEATHER ADJUSTED PEAK LOAD

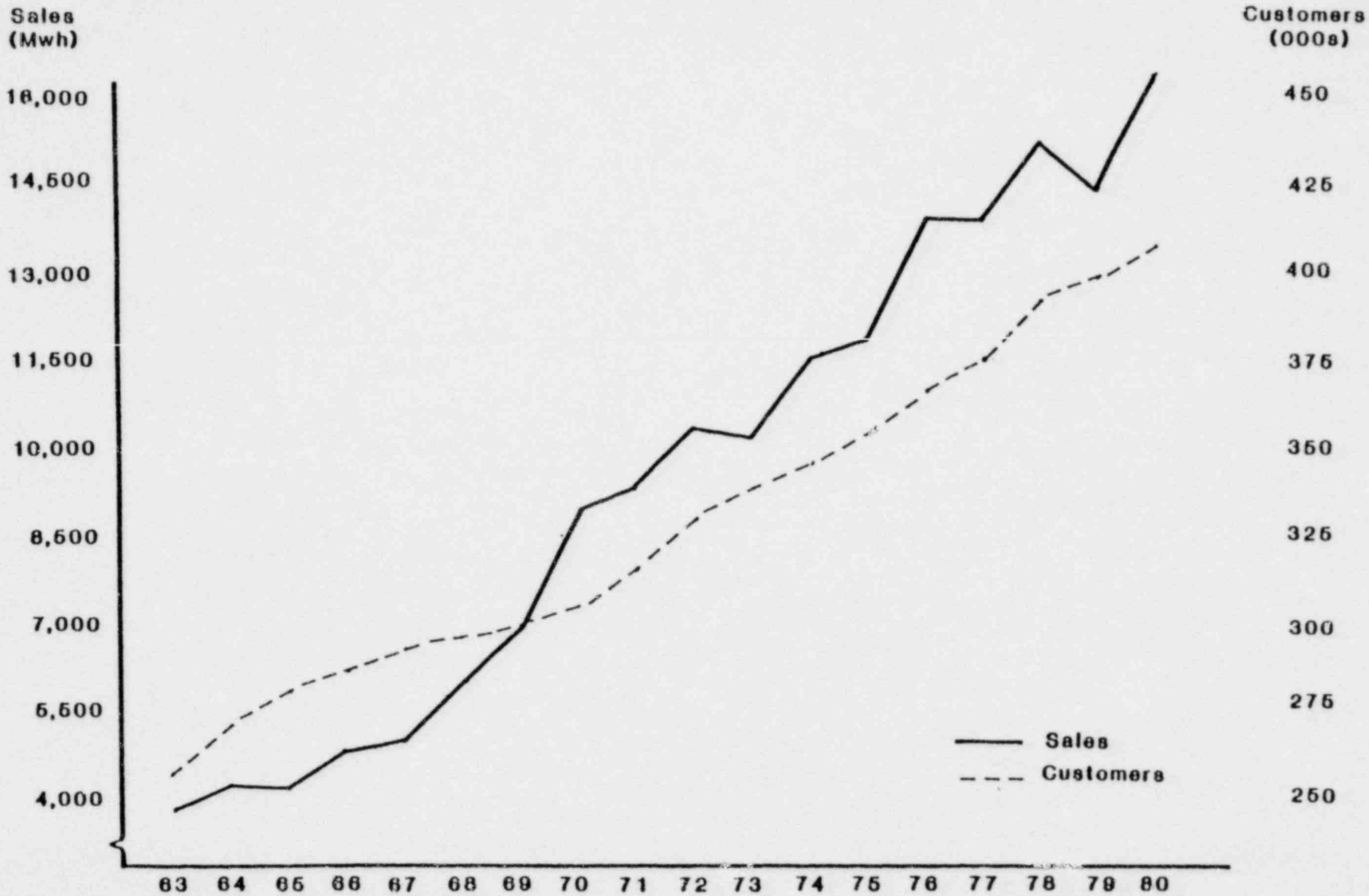



| Compound Growth Rates | Actual | Weather Adjusted |
|---|---|---|
| 63-80 | 7.3% | 6.9% |
| 65-80 | 7.2 | 6.6 |
| 70-80 | 6.2 | 5.8 |
| 75-80 | 6.5 | 4.2 |
| 77-80 | 5.7 | 4.1 |

Source: Company Response to TR-11

Exhibit III-2

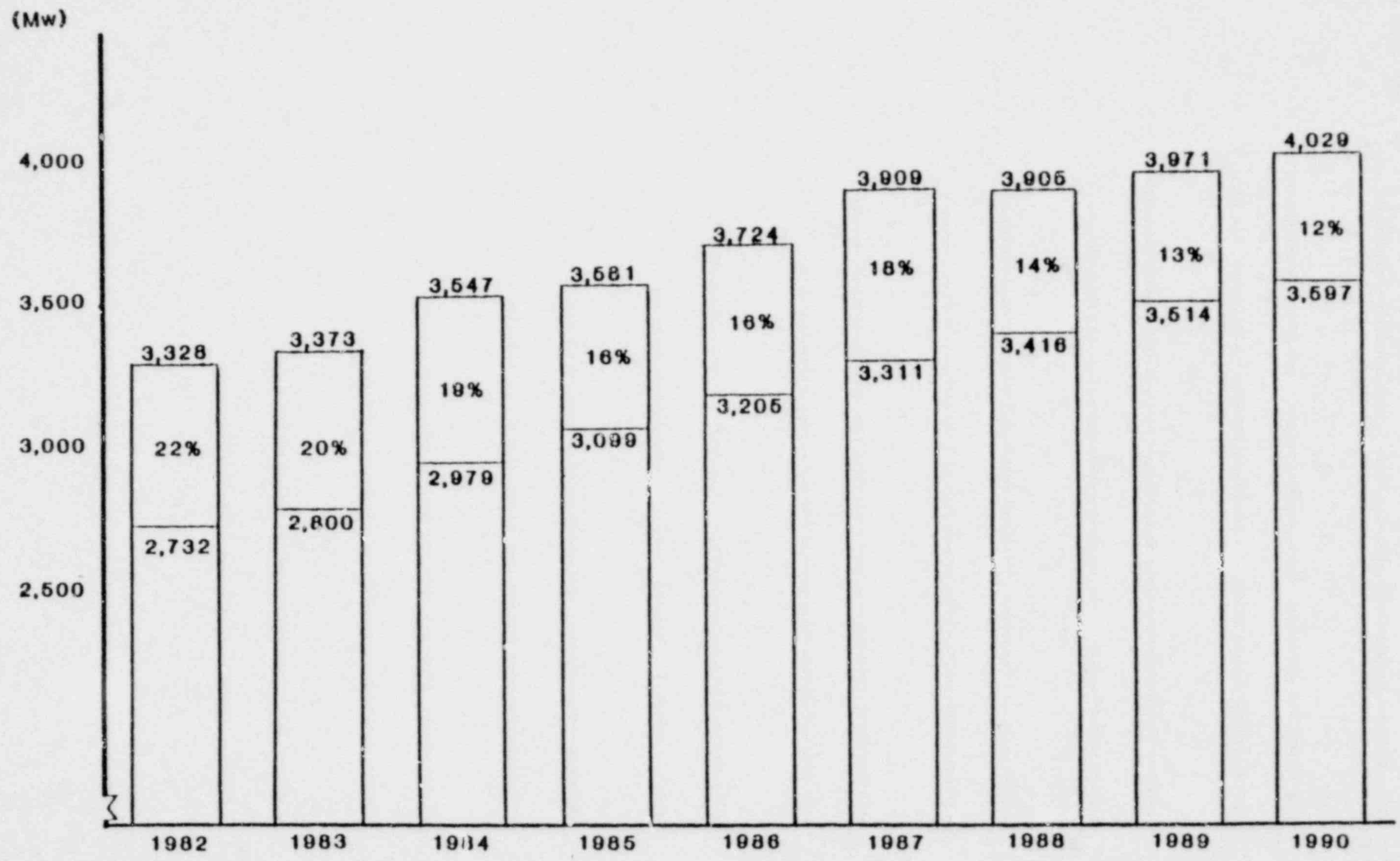
PSO
Number of Customers and kwh Sales




Source: PSO 1979-1980 Annual Report

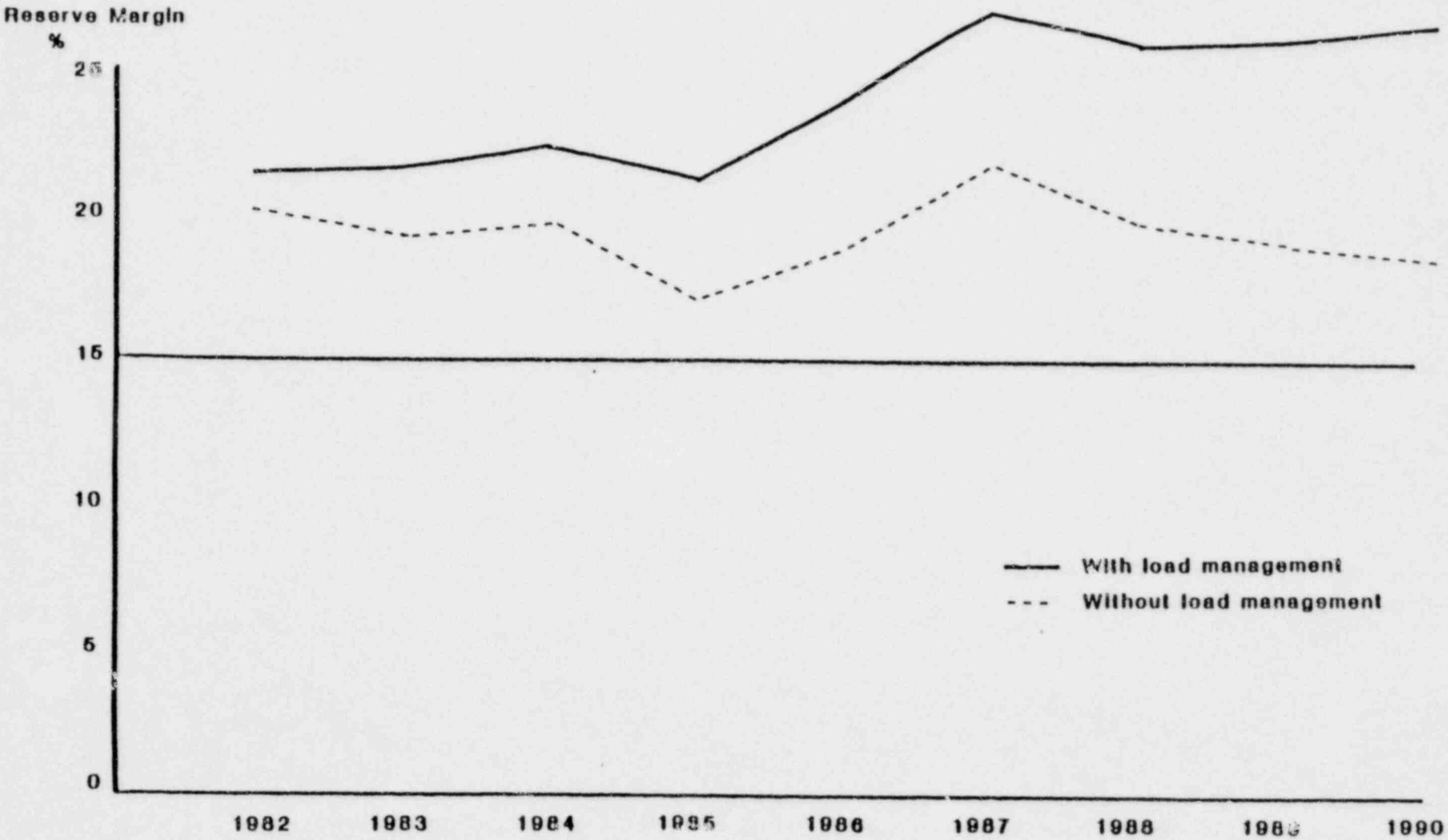
PSO

CURRENT LOAD FORECAST




Source: Exhibit FJM-2 Revised 6-25-81

PSO
Alternative Load Growth Scenarios
Impact on Reserve Margins
2% Load Growth




Source: Calculated from Exhibit FJM, Schedule 2, Revised 6-25-81

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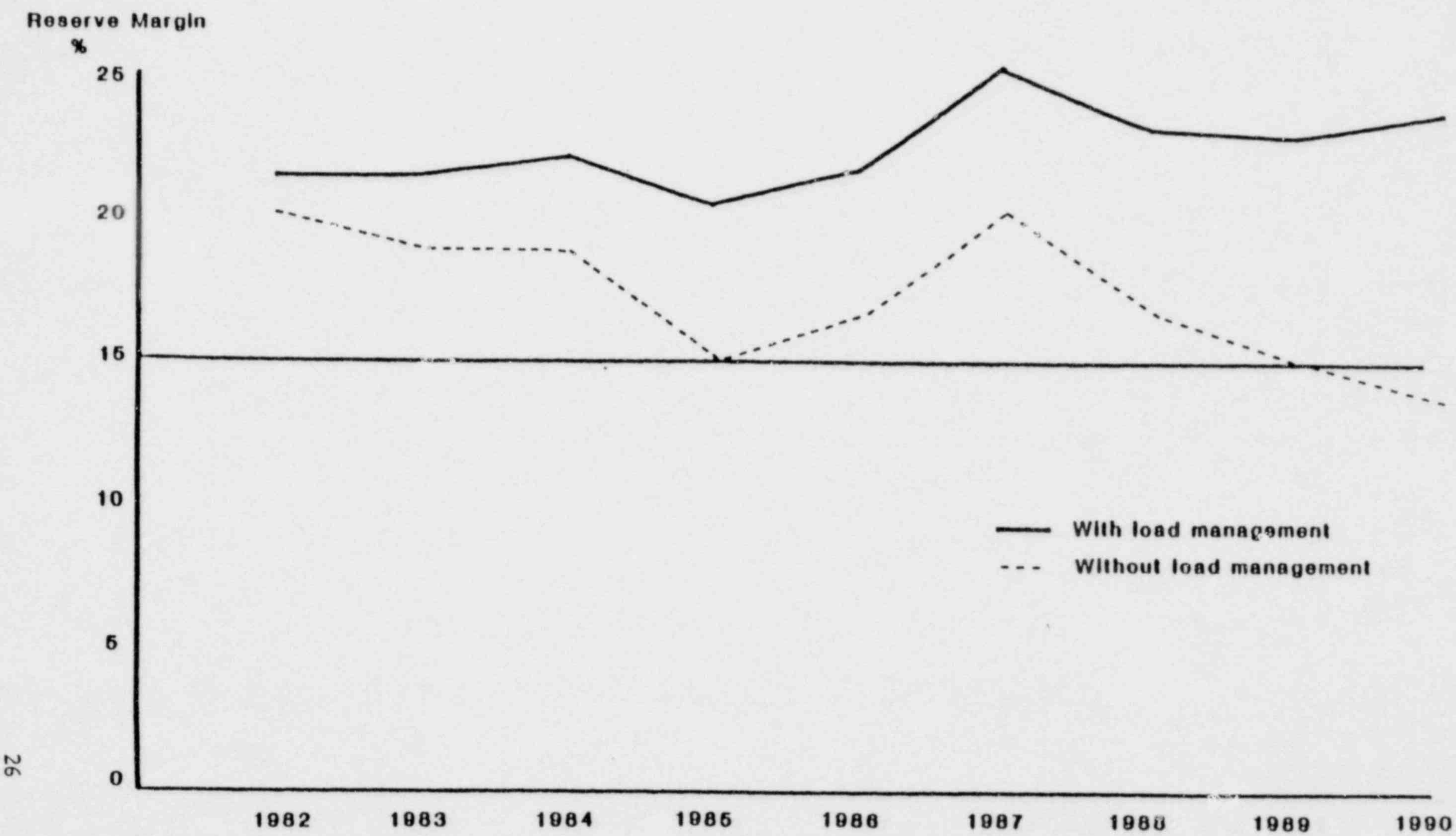
Exhibit III-4

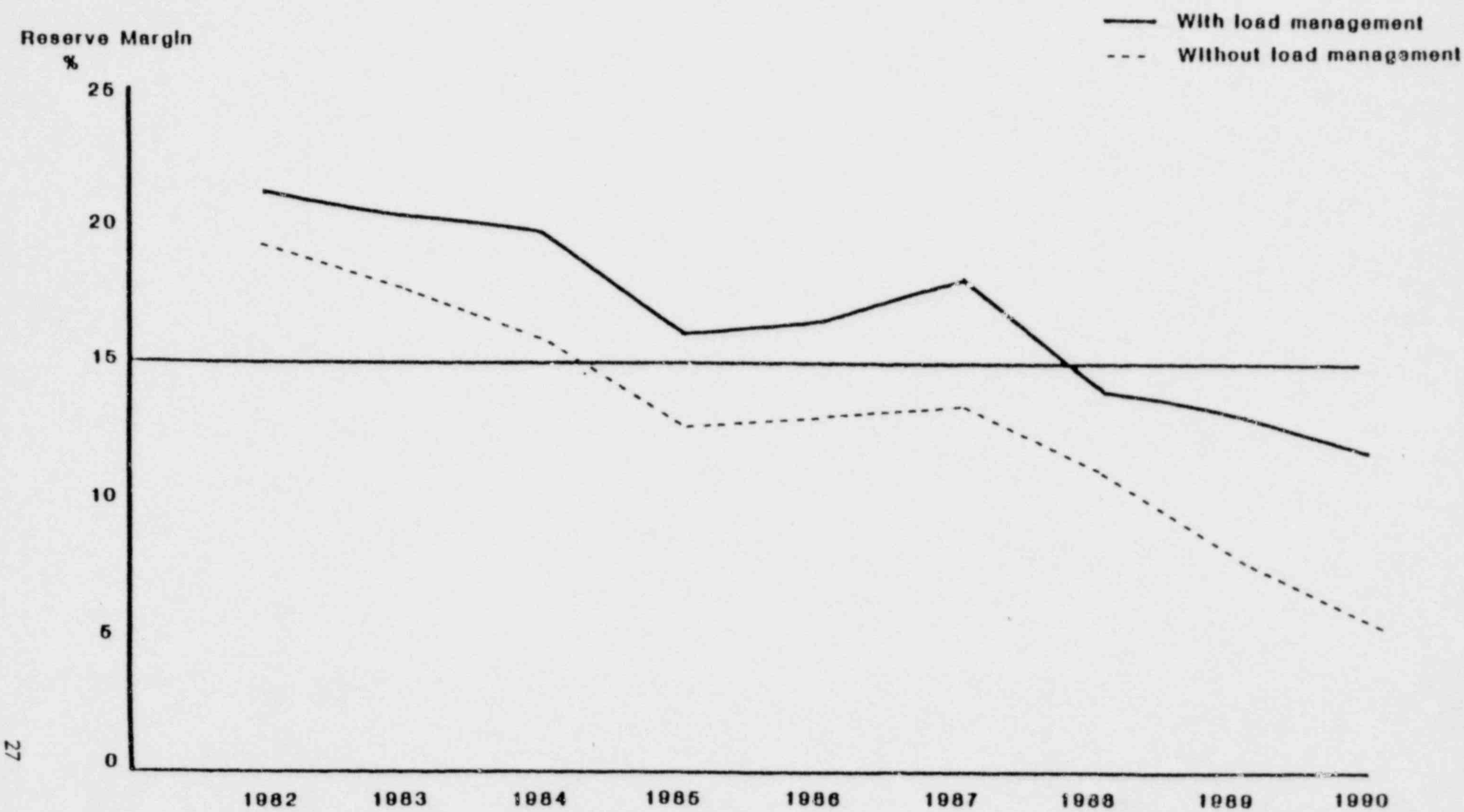
PSO
Alternative Load Growth Scenarios
Impact on Reserve Margins
2.5% Load Growth




Source: Calculated from Exhibit FJM, Schedule 2, Revised 6-25-81

Exhibit III-6

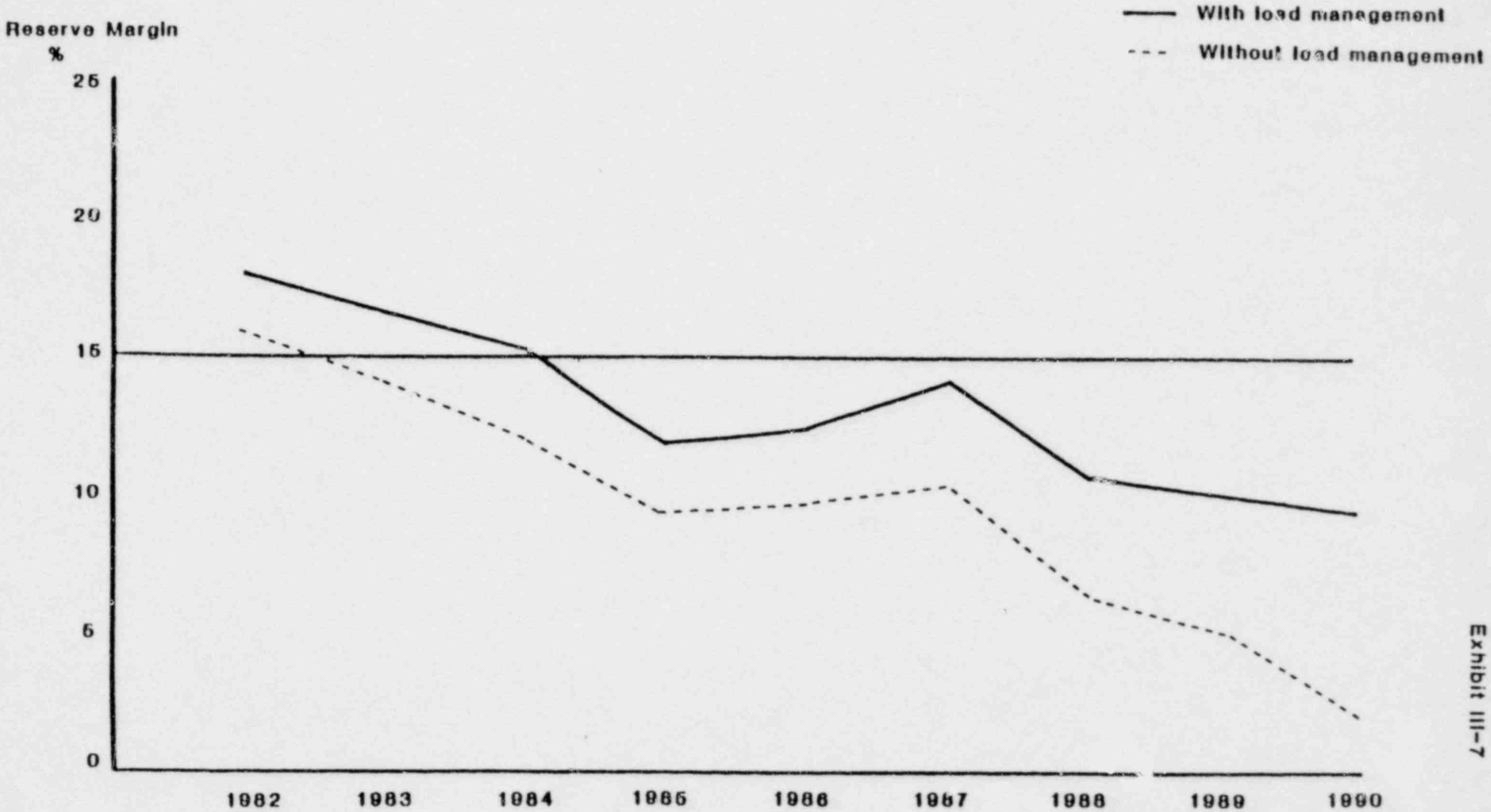
PSO
Alternative Load Growth Scenarios
Impact on Reserve Margins
PSO Load Forecast




Source: Calculated from Exhibit FJM, Schedule 2, Revised 6-25-81

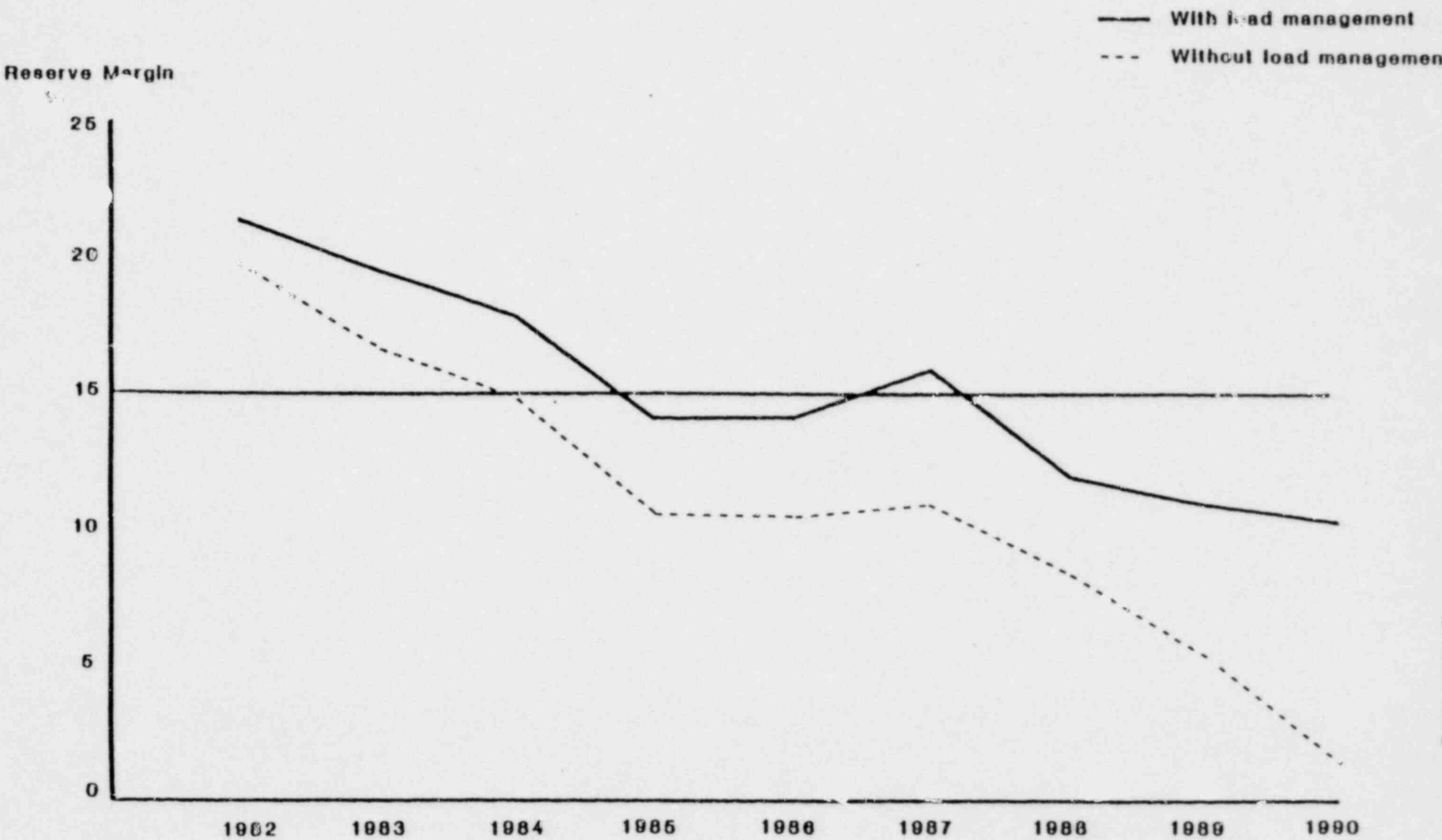
Exhibit III-7

PSO
Alternative Load Growth Scenarios
Impact on Reserve Margins
3% Weather Adjustment




Source: Calculated from Exhibit FJM, Schedule 2, Revised 6-25-81

PSO
Alternative Load Growth Scenarios
Impact on Reserve Margins
4% Load Growth

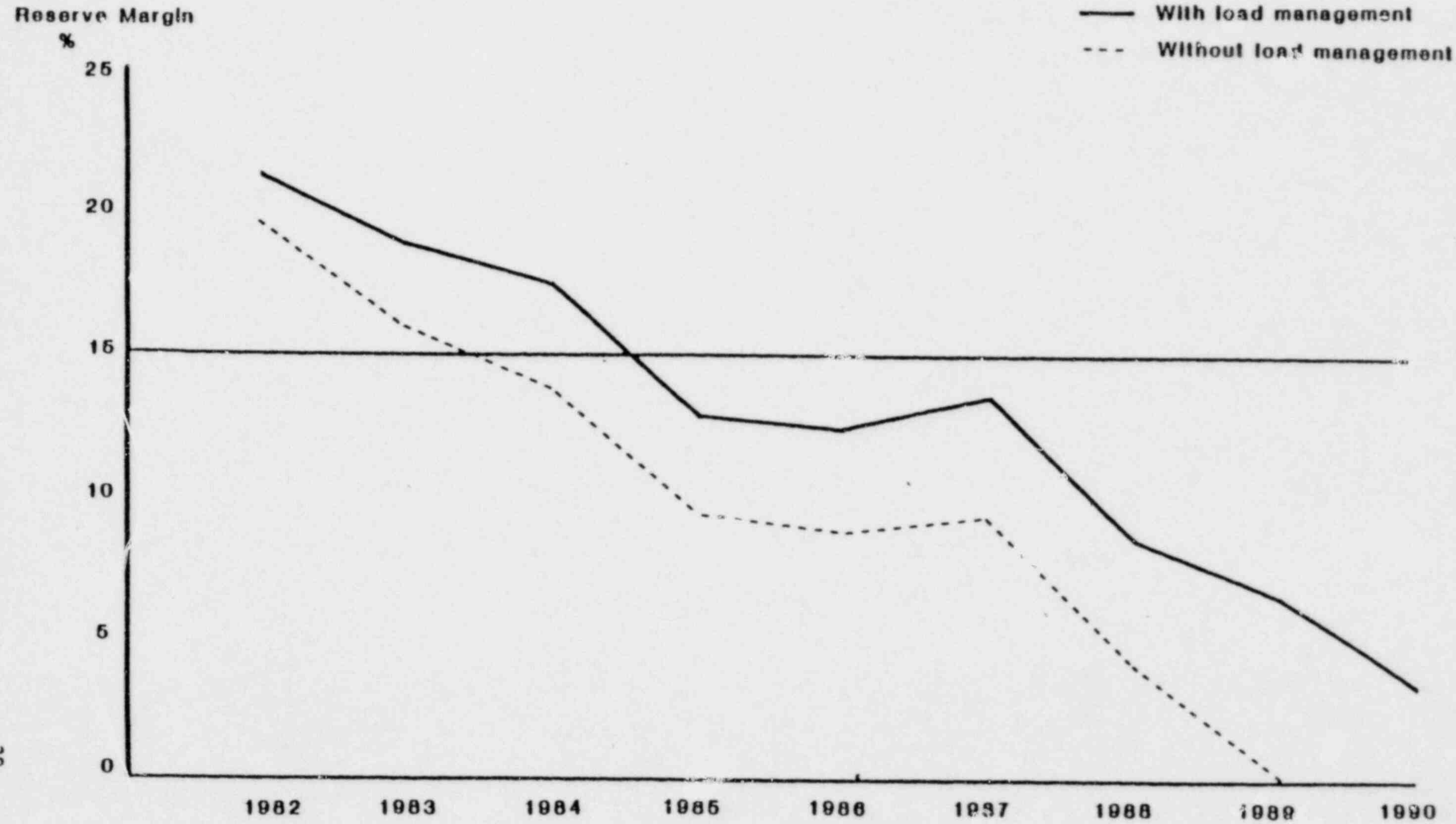



Source: Calculated from Exhibit FJM, Schedule 2, Revised 6-25-81

Touche Ross & Co.

Exhibit III-8

PSO
Alternative Load Growth Scenarios
Impact on Reserve Margins
4.5% Load Growth




Source: Calculated from Exhibit FJM, Schedule 2, Revised 6-25-81

Exhibit III-9

Touche Ross & Co.

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# IV. INDUSTRY EXPERIENCE

This section presents an overview of the processes that occur in the licensing and construction of nuclear facilities as well as the actual experience of the industry to date in constructing and operating facilities. Finally, additional areas requiring resolution will be identified. The topical areas that will be covered are:

- Application and License Process
- Construction Process
- Construction Duration and Schedule Slippage
- Historical Industry Experience
- NRC Requirements

## APPLICATION AND LICENSE PROCESS

The NRC is the primary agency responsible for the licensing of all nuclear facilities in this country and has established stringent procedures and regulations for industry compliance prior to construction or operation of proposed facilities.

Subsequent to the decision to build a nuclear facility, an applicant must initiate filing for necessary permits and licenses required to construct and operate the facility. While the NRC is the primary licensing agency, there are numerous other permits and licenses which must be received from other state and federal agencies. To fully comply with all construction requirements, there are approximately 26 permits or licenses required. An additional seven permits or licenses are required for operation.

The initial step in the construction permit stage for NRC consideration is the submission of an environmental report which considers the probable impact the proposed facility will have on the environment and any irreversible impacts due to construction and operation of the facility. Other portions of the submission deal with cost/benefit analyses, analysis of other viable alternatives to the proposed project, and analysis of the relationship between the environment and its productive use. After evaluation of the environmental report, the NRC issues a draft environmental impact statement that includes a cost/benefit analysis which considers the effects on the environment from the proposed facility and related alternatives to the facility. Once the draft environmental impact statement is distributed, comments are requested and response to these comments is incorporated in the final environmental statement (FES). The FES also contains a final cost/benefit analysis and addresses any issues that the Commission deems to have been insufficiently dealt with in the draft statement.

Concurrent with the filing of the environmental report, the applicant may file a preliminary safety analysis report. Basic issues that are addressed within the report are:

- Description and safety assessment of the site

- Description and discussion of facility design and operating characteristics

- Analysis and evaluation of design and performance of facility structures, systems, and components

- Preliminary plan for training and operation of personnel

- Description of quality assurance program

- Technical qualifications of applicant to be involved in project

- Preliminary plan for coping with emergencies (emergency plan)

The NRC response to the safety analysis report is the safety evaluation report (SER) which may later be supplemented if necessary. The applicant must also file an antitrust report to the Department of Justice which generally is not of major consequence in the licensing process.

After completion of both reports, hearings are held before the Advisory Committee on Reactor Safety (ACRS) related to the application content and issues arising from the applicant's preliminary safety analysis report and the NRC safety evaluation report. The findings of the hearings are provided by letter to the Atomic Safety and Licensing Board (ASLB) which holds adjudicatory hearings to separately address environmental and safety issues. During every phase of the hearing process intervenors are allowed to present arguments against the awarding of the permit or license.

Upon completion of the environmental and site suitability hearings, an LWA may be granted which allows work to be performed in nonsafety-related areas. The safety hearings will address remaining safety related issues, and upon successful completion a construction permit is awarded.

Approximately two to three years prior to completion of construction, the applicant must file for an operating license. During the operating licensing stage, the applicant must resubmit the environmental and safety analysis reports. These reports are updated and contain a more detailed discussion of the issues previously mentioned. Additional reports that are required include:

- Technical specifications report which deals with safety limits, limiting safety system settings, and control settings, limiting conditions for operations, surveillance requirements, design features, and administrative controls

- Security or Safeguard Contingency Plan dealing with plans for threats, thefts, industrial sabotage relating to the nuclear material, and nuclear facilities

Once the various reports have been submitted for NRC review and approval is granted, the applicant is awarded an operating license.

In the operating license stage, hearings are not mandatory but may occur if intervenors or federal or state agencies have points of contention. Only upon the awarding of an operating license may the applicant proceed with the fuel load process. Since TMI there have been additional hearings pertaining to operating and safety issues resulting from the accident. Currently, these hearings must be held before a nuclear facility may go into service; however, in the future, these issues will be incorporated into the application process.

## CONSTRUCTION PROCESS

The construction process includes all major activities from mobilization to fuel load and is initiated prior to the awarding of the LWA or CP. There are approximately 13 key milestones in the construction process which are listed on **Table IV-1** with projected time intervals.

**Table IV-1**
Milestones in the Construction Process

| Milestone | Time Interval | Time Elapsed |
|---|---|---|
| Mobilization | - | - |
| Site Preparation | 11.5 mos. | 14.5 mos. |
| Reactor Building Foundation | 7 | 18.5 |
| Installation of Drywell Bioshield and Pedestal | 23 | 41.5 |
| Set Reactor Within Intervals | 2 | 43.5 |
| Installation of Piping Connected to Primary System Component | 12 | 55.5 |
| Initial Flush of Systems | 13 | 68.5 |
| Performance of Reactor Cold Hydronics Test | 2 | 70.5 |
| Completion of Base Line Inspections | 2 | 72.5 |
| Performance of Leak Rate Test | 3 | 75.5 |
| Integrated System Test | 1 | 76.5 |
| Submission of Applicant Test Results | 1 | 77.5 |
| Fuel Load and Power Ascension | 6 | 83.5 |

**Source:** Nuclear Regulatory Commission, "Construction Status Report," NUREG-0030, January 1981

When discussing construction duration, it is usually expressed in terms from the first safety related concrete pour in the reactor building foundation to fuel load and generally has been estimated to be 65-87 months in duration. The time intervals and milestones will vary according to the specific design of the individual project and actual construction experience.

## CONSTRUCTION DURATION AND SCHEDULE SLIPPAGE

**Exhibit IV-1** is a graphic representation of construction duration experience from groundbreaking to fuel load. The graph shows that the last time a 77-month construction duration was actually achieved, which is the median of the 65-87 months shown above, was in 1976 (89 months for chart purposes; 77 construction plus 12 site preparation).

This exhibit also shows an increase in the construction duration over time, which indicates increasing schedule slippage over projected durations. Several reasons for this slippage are a reduced need for power, financial constraints, lengthened regulatory process, and, in the recent past, TMI.

The effect of these factors on nuclear generating capacity has been a net reduction in additions to installation of nuclear capacity in the last few years. **Exhibit IV-2**, which is a reproduction from the March/April 1981 "Update," Nuclear Power Program Information and Data, prepared by DOE, shows that since 1975 there have been more generating capacity cancellations than additions.

The projected need for power has affected generating capability placement due to reduced load growth expectation brought on in part by customer conservation. The financial requirements of nuclear projects have added to the overall uncertainty in relation to the viability of these projects. The combination of a current prime rate of approximating 20%, new long-term debt rates generally in excess of 15%, and higher perceived risk associated with nuclear projects has posed significant financial constraints which in many cases have led to the delay or cancellation of projects. In some cases, scheduled construction of existing projects has been delayed to reduce the annual financial outlay. Delay will inherently increase the overall cost of the project due to the compounding of AFDC, which also increases as capital costs rise.

The regulatory process and climate along with TMI have also contributed to the extension of the construction period through the proliferation of new rules and regulations which have caused applicants to retrofit or redesign in order to comply.

## HISTORICAL INDUSTRY EXPERIENCE

### Current Nuclear Facilities

Currently, in the United States, there are 174 nuclear facilities in various stages of licensing and operation. Approximately 76 units have received operating licenses; of these units, 68 are licensed for commercial operation, 3 are licensed for commercial operation in the power ascension stage, 1 has a low-power license, and 4 units are shut down indefinitely. With respect to construction of new units, **Table IV-2** shows progress to date for units possessing construction permits.

Table IV-2
Stages of Completion

| Percentage Completion | Number of units |
|---|---|
| 0 % | 6 |
| 1-24 | 26 |
| 25-49 | 11 |
| 50-74 | 17 |
| 75-99 | 21 |
| Total | 81 |

**Source:** Atomic Industrial Forum, "Reactor Information Report," July 15, 1981

Of the remaining 17 facilities, two have LWAs with an additional 15 units on order. For those units which have been completed and are currently operating, information is available with respect to capacity factors, capital cost, and total bus bar costs which provides a perspective on the historical experience of these facilities. These factors are discussed below.

**Capacity Factors** - Substantial differences have existed between projected and actual performance with respect to unit capacity factors and availability. Various industry studies for both BWR and PWR reactors indicate average capacity factors for units of 400 Mw or greater have ranged from a high of 73% to a low of 54% over a period from 1969 to 1980. Additionally, available information shows

that since 1978 the average capacity factor for similarly sized units has dropped from approximately 70% in 1978 to approximately 59% in 1980.

**Capital Costs** - Total completed costs in the nuclear industry have experienced an annual compound growth rate of approximately 17% since 1972 based on 45 units completed between 1972 and 1978. Based on a 1978 average cost of $687/kw, simple compounding of this growth rate to 1980 would result in an average cost of $945/kw. The DOE has performed a similar analysis on nuclear capital costs and projects a 14.5% annual increase over the period 1980-1987. This compares with a 13.1% projected increase for June 1980 data and a 12.1% projected increase for December 1979 data. This indicates continuing higher escalation rates for nuclear capital costs. These projections are based on utility supplied estimates, which have historically tended to be understated.

**Bus Bar Costs** - The total operating cost or bus bar cost includes capital costs, operating and maintenance costs, fuel costs, decommissioning, fuel disposal, etc. Historical studies have indicated that on a bus bar basis nuclear facilities are generally cheaper than coal-fired alternatives. Industry results available for 1979 show that nuclear power cost 1.9¢/kwh with coal at 2.3¢/kwh or a 17.4% advantage for nuclear over a 30-year period. However, other industry statistics show that nuclear power maintains only a marginal advantage with nuclear costs of 2.1¢/kwh versus 2.2¢/kwh for coal or a 4.5% advantage for the same period.

These increases in capital costs and the narrowing of the historical nuclear bus bar cost advantage are due to numerous factors but primarily are related to inflation and increased regulatory requirements. **Exhibit IV-3** illustrates the reasons for increase between 1969 and 1978 estimates for both nuclear and coal-fired facilities as developed by Ebasco Services Incorporated.

## NRC REQUIREMENTS

Requirements to be mandated by the NRC comprise one of the major uncertainties to be considered when evaluating the future viability of nuclear energy. Since the NRC essentially defines and establishes design and safety requirements and how these requirements must be met to operate a nuclear facility, they can effectively delay or postpone award of a permit or require substantial redesigns or retrofits to the point where viability of the nuclear facility is significantly affected. We believe that mention must be made of some of the major unresolved issues that may affect the industry. Public concern over environmental safety and the desire of the NRC to maintain nuclear energy as a safe, viable alternative has led to the proliferation of more stringent regulatory guides. This is illustrated by the fact that in 1971 there were approximately 21 regulatory guides while today there are approximately 150 regulatory guides. **Exhibit IV-4** provides a perspective on the growth of statutory and regulatory requirements as developed by Ebasco Services Incorporated.

### Three Mile Island

The TMI occurrence exposed many areas that had previously been dealt with insufficiently and caused the NRC to take a more cautious and critical approach to nuclear regulation. Areas for potential review and additional regulation are emergency core cooling, radiation protection, emergency management, decay heat removal, and instrumentation and control, all of which are equipment or design change related.

An entirely different issue surfaced by TMI was the validity of the NRC's approach to safety through the single failure criterion approach. This approach, in determining safety requirements, is based on the criterion that a system which is designed to carry out a specific safety related function has to accomplish this function even if a part of that system or a support system fails. Another problem identified with the NRC's approach is that the single failure criterion only applies to what the NRC considers safety related, which is subject to considerable debate.

The effect of TMI will be to cause reconsideration of existing regulations and the addition of new regulations resulting from the NRC expanding its authority into broader areas. The potential impact of TMI on the industry has been estimated at between $15 million and $150 million per unit depending on design and construction completion. It has also caused delays in licensing, estimated to cost between $2.4 and $3.2 billion for the reactors delayed.

**NRC Unresolved Issues**

The NRC has developed a standardized set of procedures and criteria that all safety concerns or issues must satisfy before being classified as an unresolved safety issue. All concerns or issues are evaluated in an initial screening process where any of the following criteria will result in elimination of the issue from further consideration:

- The issue is not related to nuclear power plant safety.
- An NRC staff position is being developed or exists on the issue.
- The issue is not generic.
- The issue is only indirectly related to nuclear power safety.
- The issue requires long-term or exploratory research.
- The issue is related to an unresolved safety issue and can be incorporated into the existing unresolved safety issue.
- The issue requires a policy decision versus a technical solution.
- The issue is related to safety improvements where existing protection is adequate.
- The issue includes programmatic matters involving the implementation of issue resolutions already achieved.
- The issue include collections of related issues in lieu of critical issues.

After the initial screening, a determination is made of whether the issue involves an existing deficiency or a proposed improvement related to either operations, equipment, or emergency response and of the potential associated risk. Based on the results of this second set of criteria, a determination is then made on the continued classifications as an unresolved safety issue.

Currently, the NRC has recognized 17 unresolved safety issues. **Table IV-3** is a list of those unresolved safety issues.

Table IV-3
Unresolved Safety Issues

Water Hammer

Steam Generator Tube Integrity

Mark I Containment Long-Term Program

Mark II Containment Pool Dynamic Loads - Long-Term Program

Anticipated Transients Without Scram

Reactor Vessel Materials Toughness

Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports

Systems Interaction in Nuclear Power Plants

Qualification of Class 1E Safety-Related Equipment

Determination of Safety Relief Valve (SRV) Pool Dynamic Loads and Temperature Limits for BWR Containments

Seismic Design Criteria - Short-Term Program

Containment Emergency Sump Performance

Station Blackout

Shutdown Decay Heat Removal Requirements

Seismic Qualification of Equipment in Operating Plants

Safety Implications of Control Systems

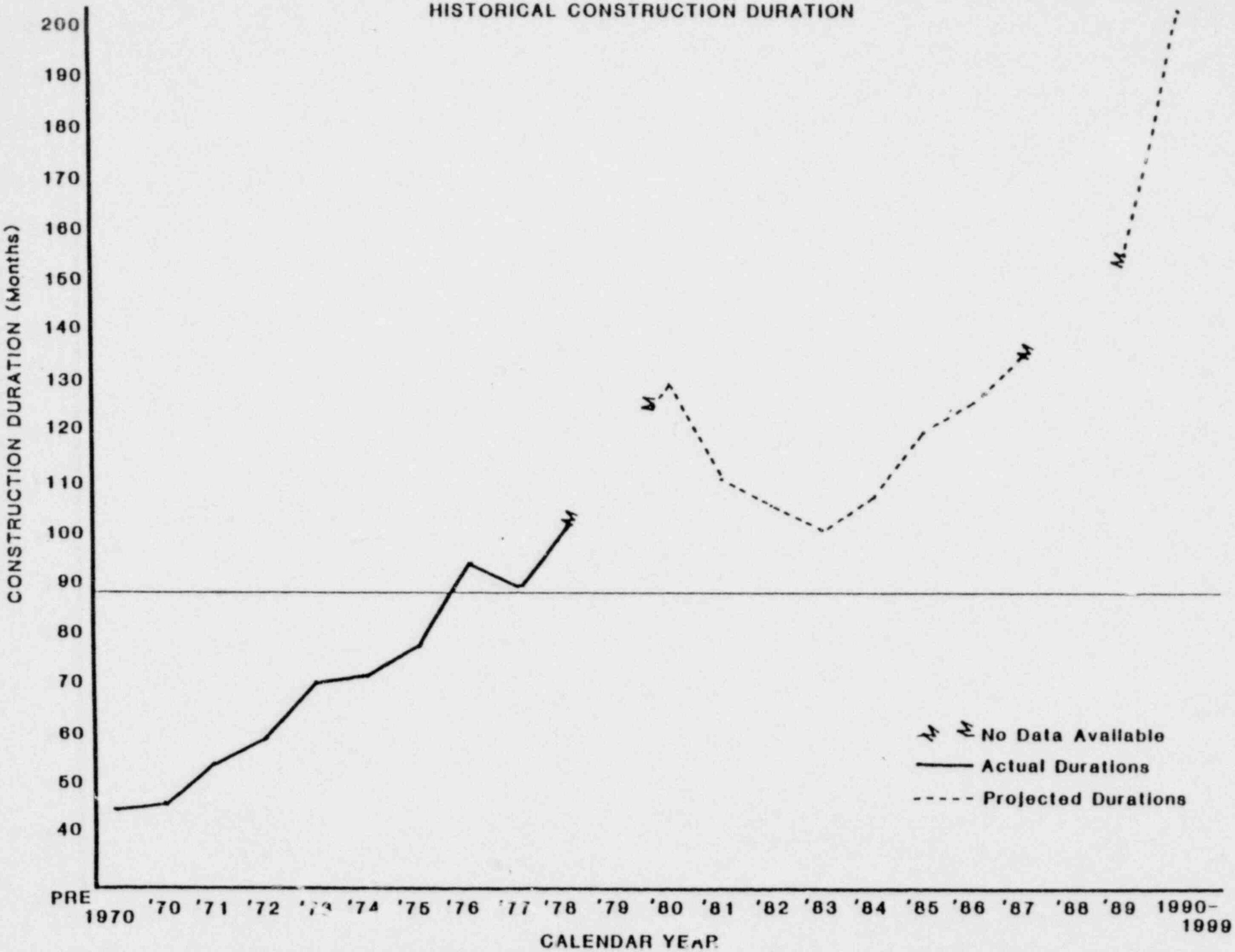
Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

Source: Nuclear Regulatory Commission, "Unresolved Safety Issue Summary," NUREG-0606, May 15, 1981

Of the unresolved safety issues listed, two are directly related to the TMI incident, those being Shutdown Decay Heat Removal Requirements and Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment. Once an issue has been given unresolved safety issue classification (USI), the NRC prepares an action plan for the resolution of the USI including both the technical resolution as well as the definition of future guidelines.

PSO

HISTORICAL CONSTRUCTION DURATION

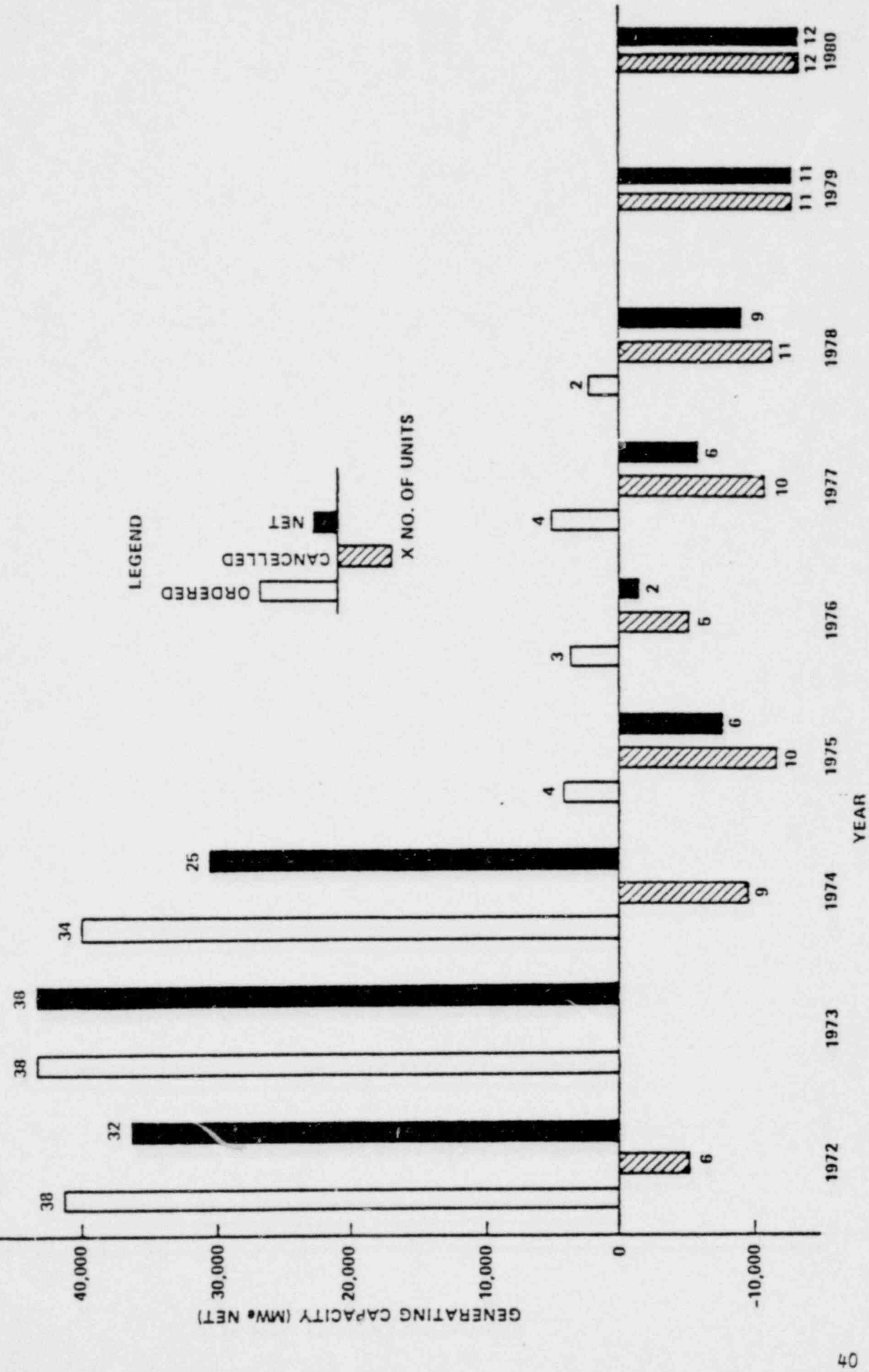



Source: Nuclear Regulatory Commission, "Construction Status Report," NUREG-0030, January 1981.

Touche Ross & Co.

Exhibit IV-1

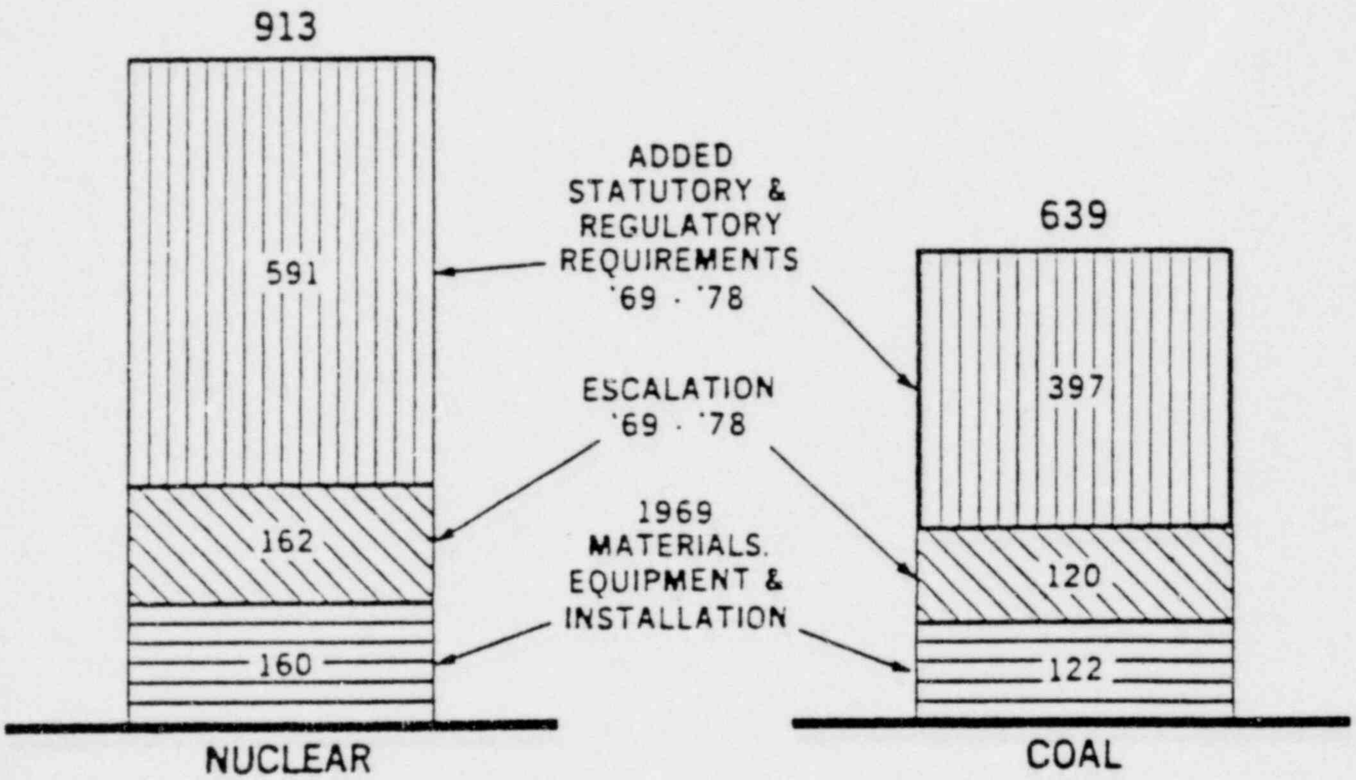
ANNUAL ORDERING AND CANCELLATION OF NUCLEAR GENERATING CAPACITY BY U.S. UTILITIES




Source: "Update," Department of Energy, Office of Nuclear Reactor Program, March/April, 1981

Exhibit IV-3

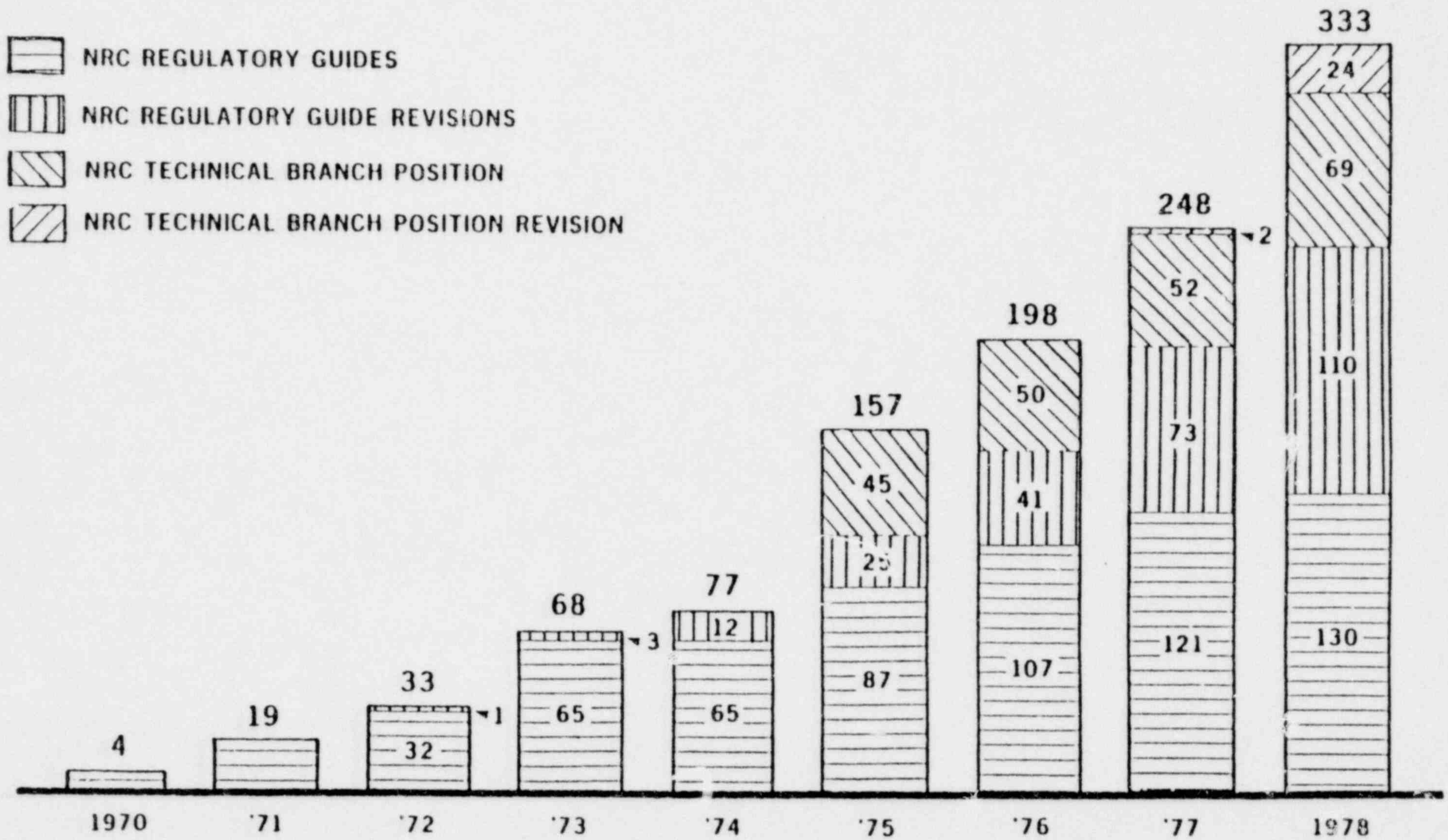
# PLANT COST BREAKDOWN, '69 -'78 ESTIMATES
(DOLLARS PER KW)




Source: Ebasco Services Incorporated

# ADDED STATUTORY & REGULATORY REQUIREMENTS, '69 - '78 ESTIMATES

(CUMULATIVE NUCLEAR PLANT GUIDES)




Sources: Ebasco Services Incorporated

Exhibit IV-4

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## V. PROJECT COST ASSUMPTIONS

The purpose of this section is to set forth the basic capital cost and operating assumptions relied upon in the development and comparison of total estimated bus bar energy costs for nuclear and coal-fired generating alternatives. As previously mentioned, the assumptions contained within this section were utilized to develop a generic rather than a site specific economic comparison. This was necessary because of the time constraints involved and the lack of a current baseline estimate from PSO or its Architect/Engineer (A/E - Black and Veatch). As discussed in the Introduction section, PSO has sharply curtailed the level of continuing project activity due to the lack of direction related to the licensing process. These uncertainties effectively precluded the development of a meaningful current baseline estimate and necessitated our use of the generic comparison.

In developing our assumptions, however, we attempted to consider certain factors related to the Black Fox Station or PSO to reflect as closely as possible the actual parameters of the project. For example, our analysis is based upon a commercial operation date of mid-1991 for the first unit which is generally consistent with information obtained during our analysis related to anticipated commercial operation. Similarly, the rates used for allowance for funds used during construction (AFDC) are based upon actual and projected amounts for PSO. By utilizing specific factors such as these, we believe that the results of our generic study more accurately reflect the likely experience at the Black Fox Station.

### OVERALL PARAMETERS

In developing our overall comparisons, there are certain basic parameters which must be established and maintained to improve the validity of the analysis. These parameters differ from the general assumptions in that they provide the foundation for additional analyses by defining the nature of the project itself. These parameters are described below.

**Generating Capability** - In developing an economic analysis of generating plant alternatives, we believe it is essential that roughly equivalent generating capability be utilized. Analysis of alternatives with significantly different total generating capability would bias against the alternative with lower generating capability since it would reduce the economics of production and increase the cost/kw. Since the Black Fox Station as it is currently envisioned would consist of two 1,150 Mw units, we have accepted this plant size and utilized three 770 Mw coal-fired generating units for comparative purposes. This results in total equivalent generating capability of 2,300 Mw for the nuclear alternative and 2,310 Mw for the coal units which we believe would provide a valid basis for economic comparison. Although PSO might as a practical matter build smaller sized coal units, our comparison does not attempt to analyze or differentiate between these sizing options or to limit the analysis to generation capability equivalent to PSO's ownership participation in the Black Fox Station.

**Coal Source** - In the evaluation of alternative generating sources, PSO would have numerous possibilities regarding the type of coal to be used. These sources would include high sulfur eastern coal, low sulfur western coal, high sulfur midwestern coal, or a mixture of several sources. Based on current contracts which PSO has for its

Northeastern units, we believe that a realistic alternative source for our coal-fired alternative would be the Powder River Basin in Wyoming. Although this source would result in the burning of low sulfur coal, it is generally believed that current environmental regulations and potential particulate omissions would necessitate the inclusion of scrubbers at the unit.

**Plant Site** - As previously mentioned, we have utilized the Concept Model to perform our capital cost calculations. This model identifies 22 specific locations for generating plants and resulting cost indices. Since the Concept Model does not include Tulsa as a specific location, we have utilized the Dallas location which more closely resembles the actual Black Fox Station site in terms of cost comparions. Although utilization of Dallas as a site would slightly understate the costs of construction compared to a Tulsa site, we believe that it is a reasonable selection since site specific information is not available at this time.

**Levelization Period** - The generating life of a facility will extend over several decades, and the longer the time frame the more difficulty in accurately forecasting economic conditions. Consequently, it is necessary to evaluate certain prospective operating costs over a shorter, more reasonable period to avoid the uncertainties associated with projections over an extended period. Therefore, fuel and operation and maintenance expenses have been levelized over a ten-year period to allow for a more reasonable representation and comparison of prospective costs.

## DATA BASE DEVELOPMENT

To develop an adequate data base for use in selection of appropriate assumptions, numerous utilities, publications, governmental agencies, consulting firms, and trade groups were contacted to identify and obtain pertinent information. A listing of sources for information is presented at the conclusion of this section in **Exhibit V-1** to demonstrate our broad approach to data collection.

The information collected included studies, manuscripts, articles, speeches, and various other analyses with respect to nuclear and coal-fired generating plants, the licensing process, energy demand, and prospective economic conditions. These documents were reviewed and analyzed to determine the bases for conclusions therein and to evaluate the reasonableness of these conclusions and their applicability to the instant situation. A wide divergence of opinion emerged between the documents in several subject areas which required a more detailed analysis of the reasons for differences and resulted in the identification of those particular studies upon which greater reliance could be justified.

The information drawn from these sources was assimilated and compiled by major area of analysis, e.g. nuclear capital cost, and further reviewed to develop a realistic data base to support our assumptions. To the extent that more current information could be identified and obtained to supplement the historical nature of our data base, it was obtained from publicly available sources and included as part of the overall data base. The assumptions selected were then input to the Concept Model and numerous sensitivity analyses performed to determine the effect of assumption modification.

## DESCRIPTION OF THE CONCEPT MODEL

The Concept Model was developed by the Engineering Technology Division of the Oak Ridge National Laboratory (ORNL) to provide conceptual cost estimates for nuclear and fossil-fired generating plants. The current version of the model, known as Concept-5, was updated during 1978 with a new users manual available in 1979. At the time of preparation of this report, ORNL was in the process of updating Concept-5 to reflect more current data into 1980. The cost estimates that are generated by the model are a function of plant type, size, location, and date of initial operation, all of which are defined by the user. This information, combined with other data files containing cost-model data and historical cost data, will generate conceptual cost information based on the parameters as defined. The basic input to the Concept Model is listed below:

- Plant net capacity

- Plant type

- Plant location

- Date of purchase of nuclear steam supply system (NSSS) or fossil-fired steam generator (FSSS)

- Date of receipt of construction permit

- Date of initial commercial operation

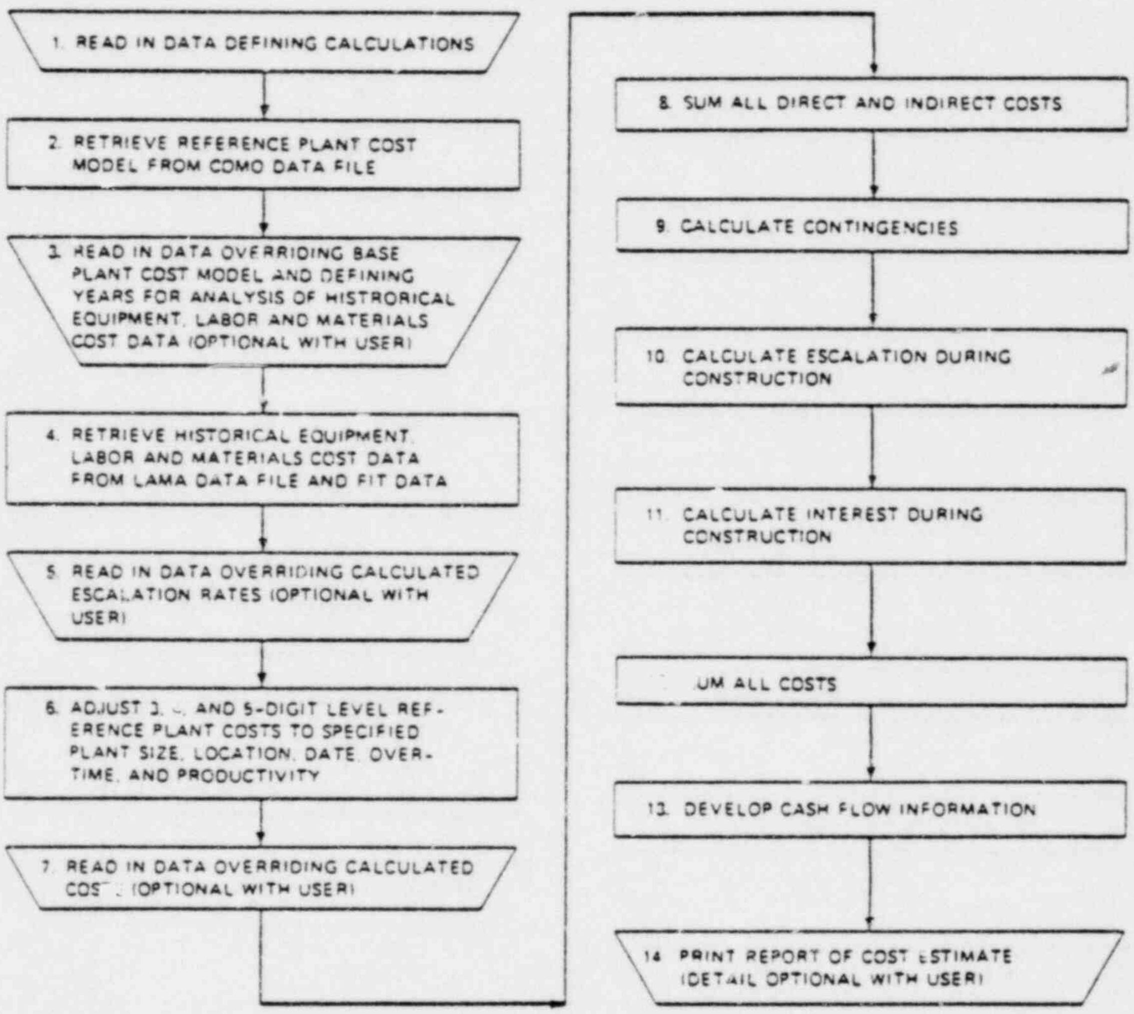
- Interest rate

In addition to this basic input requirement, other variables can be modified to override the stored input. These variables include, but are not limited to:

- Escalation rates
- Contingency
- Direct labor man-hours/kw
- Productivity
- Overtime premium
- Overhead burden

The model follows a logical progression of calculation based on the basic input requirements and other variables summarized above. The calculation sequence allows for overriding of basic stored data and for the conduct of sensitivity analyses by direct user access. The general flow of calculations is schematically displayed below in **Table V-1**.

TABLE V-1
Flow of Concept Calculations




**Source:** Concept-5 Users Manual, ORNL-5470

The output of the model includes the breakdown of costs into various capital cost accounts and summarizes this information into the following major categories:

- Direct costs
- Indirect costs
- Direct and indirect costs

- Contingency allowance
- Total direct and indirect costs
- Escalation during construction
- Total escalated direct and indirect costs
- Allowance for funds used during construction
  - On direct and indirect costs
  - On escalation during construction
- Total allowance for funds used during construction
- Total plant capital investment

Direct and indirect costs and the related contingency are stated in current dollars at the specified date. Escalation is stated in mixed dollars based upon the specified dates for initiation and commencement of calculation and the stated rates of change. Allowance for funds used during construction is stated in mixed dollars since it is a function of both total direct and indirect costs and escalation on these amounts. Absolute values for each of the major categories above are also provided on a dollar/kw basis to facilitate comparison between generating plant size and type alternatives. The model also provides for the development of cash expenditure curves based on the construction duration and other cost factors as defined. During the latter stages of the conduct of our analysis, ORNL indicated that an update of Concept-5 had been made to reflect more recent experience. The results of the update, though preliminary in nature, were obtained and manually input into the model to reflect the most recent experience. It is expected that a new Concept Model tape will be available sometime this fall.

## ACCURACY OF ASSUMPTIONS

The capital and operating cost projections contained within this report are based upon the best information publicly available. However, since projections are based upon assumptions about circumstances and events which have not yet taken place, they are subject to variations that may arise as future operations actually occur. Accordingly, assurance cannot be given that the projected results will actually be attained. It should be understood that the underlying assumptions are based on circumstances and information currently available. Because circumstances may change and unanticipated events may occur subsequent to the date of this report, the reader must evaluate the assumptions and rationale in light of circumstances then prevailing.

Given the general uncertainity related to projections of any kind, particularly with respect to capital and operating costs of nuclear and coal-fired facilities, we developed a range of assumptions, where appropriate. The effect of each of these cases was determined and compared to establish a general indication of a low case, a mid case, and a high case. From these cases a base case was selected to measure the sensitivity of modification to the underlying assumptions. This sensitivity analysis was then used to identify and evaluate the degree of change related to a particular assumption variance and establish an overall indication of the reasonableness of our end results. Finally, our end results were compared to published information as a further test of the validity of the cases developed.

## CAPITAL COST ASSUMPTIONS

The actual assumptions relied upon as the basis for developing our conceptual cost projections are provided below. As discussed above, we developed several cases based upon varying the critical assumptions by category. We have referred to the extremes of our cases as the low and high cases. However, these cases do not reflect either the lowest or the highest dollar value of conditions possible. Clearly, these conditions are not definable or estimable. Our low and high cases therefore represent what we believe to be the more optimistic and pessimistic results within a narrowly defined range of assumptions. Consequently, we have set these cases to represent achievable results in the low case and possible results with respect to the high case.

The low and high cases provide the boundaries or parameters of our analysis. To supplement these extremes, we have developed a mid case which slightly modifies one or more of the critical assumptions. We have presented this case to provide a broader perspective of potential results and to demonstrate the effect of changing various assumptions.

## NUCLEAR

The following series of assumptions were developed for use in our projection of the completed construction costs of a generic nuclear generating facility:

**Commercial Operation:** The anticipated commercial operation of the nuclear facility has been defined as July 1, 1991, for the first unit and July 1, 1994, for the second which is generally consistent with information obtained from PSO. We have specified a midyear commercial operation date to ensure that the units are available in time to provide baseload energy during the peaking season.

**NSSS:** Current estimates for planning, licensing, and constructing a nuclear facility have ranged between eleven and thirteen years by industry sources. To meet this schedule, we have selected July 1, 1979, as the date of award of the nuclear steam supply system (NSSS). This schedule would provide for a total elapsed time of twelve years from this date to commercial operation of the first unit.

**Construction Start:** Current estimates for construction duration from groundbreaking to commercial operation have ranged between six and seven years by industry and regulatory sources. Although PSO currently expects the NRC to issue a CP sometime early in 1983, it is not believed that full mobilization would be achieved until early in 1984. In consideration of the need to remobilize an intensive construction effort and to allow for a seven-year construction schedule, we have selected July 1, 1984, as the date of construction initiation for Unit No. 1 and July 1, 1987, for Unit No. 2.

**Labor Hours/kw:** Recent experience in direct craft construction labor hours and estimates of the growth in this factor have ranged from 14 man-hours/kw to 18 man-hours/kw. To recognize the historical experience within the industry, we have utilized a range of labor hours consistent with the above amounts.

**Contingency:** The purpose of our contingency allowance is to provide for consideration of unanticipated problems within the defined scope of the project, such as materials and spare parts shortages and minor productivity problems. The projections contained in the next section are based upon contingency allowances ranging from 15-17%, which are generally consistent with published estimates. These amounts

were subsequently adjusted upward to a range of 18%-24% to reflect our estimated TMI costs discussed below.

**Escalation:** We have utilized estimates of the implicit price deflator as the basis for our escalation factors. Published information indicates a range of estimates in this factor from 8.1%-8.7% over the period 1980-1989. Comparison to the Handy Whitman Construction Index also indicates that historically the implicit price deflator has been exceeded by inflation within the construction industry. In recognition of this experience and actual escalation with respect to the construction of nuclear facilities, we have selected a general inflation factor of 8.5% over the life of the project and utilized total escalators in the range of 9.5%-10.5% for application to our conceptual costs.

**Allowance for Funds Used During Construction:** In developing this element, we have reviewed the actual experience of PSO and internal projections developed for purposes of the current rate case. Based on this data, we have utilized the actual AFDC rates of 10% in 1979, 11% in 1980, and a range of 12.25%-12.50% during the remainder of construction.

**Three Mile Island (TMI):** Various estimates are available for determining the effect that TMI will have on regulatory requirements and eventual facility design. We have based our estimate on information which indicates costs may range between $15 million to $150 million/unit in 1980 dollars. Utilizing this range, we have selected a range of $25 million to $60 million/unit as a basis for comparison to reflect the minimal construction progress and ability to redesign. These amounts were combined with our initial contingency allowances to account for TMI costs within the model.

## COAL

The following series of assumptions were developed for use in our projections of the completed construction costs of a generic coal-fired facility:

**Commercial Operation:** The anticipated commercial operation date for the first of our three coal-fired units has been defined as July 1, 1991, consistent with our nuclear assumption. Unit No. 2 commercial operation has been defined as the midpoint of all three units or January 1, 1993. Finally, July 1, 1994, was selected to be the commercial operation date of Unit No. 3, which is also consistent with our nuclear assumption. We have spaced the commercial operation of these three units to allow for maintenance of a construction sequence and minimize remobilization of on-site resources.

**FSSS:** Current estimates for planning, licensing, and constructing coal-fired facilities range between seven and eight years. To meet the assumed need for power date of 1991 and maintain this overall schedule, we have selected July 1, 1985, as the date of boiler award for all three coal-fired units.

**Construction Start:** Current estimates for actual construction duration from groundbreaking to commercial operation have ranged between four and five years. To meet the expected commercial operation dates established earlier, we have established a 51-month construction schedule which results in construction starts of April 1, 1987, for Unit No. 1; October 1, 1988, for Unit No. 2; and April 1, 1990, for Unit No. 3.

**Labor Hours/kw:** Recent construction experience and current estimates indicate a range in this factor of 6 man-hours/kw to 9 man-hours/kw. We have selected a range for labor hours for our analysis of between 9 and 10 man-hours/kw to allow for potential additional environmental requirements.

**Contingency:** Our review of contingency allowances for coal-fired plants generally indicates a range between 5%-14%. We have utilized a range of 10%-12% in our analysis.

**Escalation:** We have based our escalation rates for our coal-fired plants on the same general inflation index described above - the implicit price deflator. In developing our generic costs, we have utilized total escalation in the range of 9%-10% for coal-fired units.

**Allowance for Funds Used During Construction:** Our rates of AFDC for this analysis are again based on the actual and expected rates of PSO of 10% in 1979, 11% in 1980, and a range of 12.25%-12.50% during the remainder of construction.

As previously discussed, our base cases for both nuclear and coal are designed to provide a representation of optimistic and pessimistic results within a narrowly defined range of assumptions. In developing the total conceptual cost projections, we did not make specific assumptions for all possible factors due to time and information constraints; however, the range of assumptions used in our cases would provide for some consideration of many of the items listed below:

- Minor regulatory modifications/requirements
- A/E experience
- Construction management organization and experience
- Indirect changes
- Labor rates
- Productivity
- Historical escalation experience
- Extended construction delays
- CP delay
- Financing delays
- Previous site work
- Interrupted unit sequence
- Sunk cost carrying charges
- Costs to existing units

We were unable to adjust for all of these potential factors within the Concept Model given the time constraints involved. We do believe, however, that these factors would impact the nuclear units to a greater extent than the coal-fired units. As previously discussed, regulatory requirements have significantly affected nuclear projects. We have not assumed any specific allowances for continuation of historical experience in our contingency. Should such frequent regulatory revisions occur, our estimates would be understated. Additionally, should adverse local regulatory treatment occur, the cost of capital could increase, further raising the amount of capitalized AFDC.

## OPERATING COST ASSUMPTIONS

The operating cost assumptions discussed below were developed from a review of publicly available studies and reports. For the major ten-year levelized life cycle cost components, i.e., nuclear fuel, coal, coal transportation, and operating and maintenance cost, ranges are presented in order to evaluate the impact of alternative assumptions.

## NUCLEAR

The following assumptions were developed for use in our projections of the life cycle operating costs of a generic nuclear generating facility:

**Capacity Factor:** For purposes of this analysis, capacity factor is defined as the ratio of actual annual generation (kwh) to net plant rating (Mw) times 8,760 hours. A review of historic capacity factors for BWR reactors of 1,000 Mw or greater indicates a cumulative average capacity factor of 57% ranging from 51.2% to 66.8%. Life cycle capacity factors of 55%, 65%, and 75% are used for this analysis.

**Nuclear Fuel Cycle Cost:** The nuclear fuel cycle consists of a number of separa.e and distinct cost functions. These include:

- Uranium ore $UF_3O_8$ (yellowcake)
- Conversion $UF_6$
- Enrichment U235
- Fabrication
- Spent fuel cooling/storage
- Spent fuel shipping
- Spent fuel disposal

**Exhibit V-2** illustrates the nuclear fuel cycle components. For purposes of our analysis we have excluded any consideration of reprocessing spent fuel since there is currently a ban on the reprocessing of spent fuel in the United States.

PSO currently has contracts for uranium ore, conversion, and fabrication with various vendors. For purposes of this analysis, we have utilized contract prices and quantities. To the extent the contract quantities are less than the amount necessary for 10 years' operations, we have estimated the market price of additional supplies.

To calculate the levelized nuclear fuel cycle cost, we have used a computer model (GACOST) maint.ned by PSO for this purpose. **Exhibit V-3** shows the input assumptions requir for this model.

**Operating and Maintenance Expenses:** Operating and maintenance expenses include all expenses associated with operating and maintaining the nuclear fuel facility. The primary cost components included in operating and maintenance expenses are:

- Labor
- Labor related costs
- Security costs
- Routine maintenance materials
- Coolants and water

A review of 1,000 Mw and above nuclear reactor operating and maintenance experience for 1978 indicates an average operating and maintenance (O&M) expense

of between 1.5 mills/kwh to 4.3 mills/kwh for plants with capacity factors ranging from 47% to 75%. We have increased O&M costs for inflation and the additional cost due to the impact of TMI. For purposes of this analysis, operating and maintenance expense levels of 3.5, 4.0, and 4.5 mills/kwh have been utilized. An escalation rate of 8.5% was used to estimate future operating and maintenance expense.

**Insurance:** Nuclear liability insurance premiums are assumed to be $500,000 per year for each unit based upon current industry estimates and considering the requirements of the Price-Anderson Act. An escalation rate of 8.5% was used to estimate future premium cost.

**Decommissioning:** Currently there are several alternatives available for decommissioning nuclear plants; these include:

- Mothballing/caretaker status
- Entombment/caretaker status
- Immediate dismantling
- Deactivation/delayed dismantling
- Entombment/delayed dismantling

A recent study of decommissioning costs estimates the range of decommissioning cost for each alternative. **Table V-2** presents the alternative cost ranges.

**Table V-2**
**Decommissioning Cost**
**($ millions)**

| Alternative | Cost Estimate | | |
|---|---|---|---|
| | Low | Mid | High |
| Mothballing | $ 3.5 | $ 11.1 | $ 24.9 |
| Entombment | 10.9 | 33.3 | 47.5 |
| Immediate Dismantling | 36.8 | 75.4 | 146.2 |
| Mothballing/Delayed Dismantling | 20.3 | 45.5 | 60.5 |
| Entombment/Delayed Dismantling | 11.1 | 49.8 | 97.0 |
| Annual Caretaking Cost | .236 | .336 | .436 |

**Source:** Analysis of Nuclear Power Reactor Decommissioning Cost, National Environmental Studies Project, May 1981

Of the alternatives listed above, immediate dismantling is the least costly despite the higher initial capital cost. This is due to the extended annual caretaking cost associated with the other alternatives. Both the initial and delayed entombment alternatives are more costly than the mothballing alternatives; however, in all cases the costs are affected by the funding and tax treatment to be provided by regulatory agencies to annual sinking fund provisions. For purposes of our analysis, we have chosen immediate dismantling as preferable to all others when considered on a present value dollar basis. An escalation rate of 8.5% was used to estimate future decommissioning cost.

## COAL

The following assumptions were developed for use in our projections of the life cycle operating costs of a generic coal-fired generating facility.

**Capacity Factor:** The coal capacity factors utilized for our analysis are equivalent to the factors used in the nuclear cost assumptions, i.e., 55%, 65%, and 75% although historical experience would indicate that these factors would generally exceed nuclear capacity factors.

**Coal Fuel Cycle Costs:** The coal fuel cycle costs consist of the following cost components:

- Mine mouth coal cost
- Transportation
- Coal unit trains
- Coal car maintenance

As stated previously, we have assumed the use of Wyoming Powder River Basin coal for this analysis. A review of current mine mouth costs indicates a cost/ton ranging from $6.75 to $7.50.

Transportation costs are based on a 2,200-mile round trip. Current transportation costs for this haul distance are approximately $12.00 to $18.00 on a per ton basis.

The transportation of coal from Wyoming will require approximately six unit trains per coal plant at a 65% capacity factor. A unit train is assumed to consist of 100 cars with a 100-ton capacity per car.

A review of current maintenance cost indicates an average price of approximately 3.0¢ to 3.5¢/haul mile.

The following table summarizes the assumptions for the coal fuel cycle costs.

Table V-3
Coal Fuel Cycle Cost Assumptions

| Cost Component | Cost | Escalation |
|---|---|---|
| Mine Mouth | $ 7.25/ton | 8.5%, 9.5%, 10.5% |
| Transportation | $ 15.00/ton | 9.5%, 10.5%, 11.5% |
| Coal Car | $ 40,000 each | 10% |
| Coal Car Maintenance | 3.25¢/haul mile | 8.5% |

**Operating and Maintenance Costs:** A review of 1978 expenses for large coal units indicated that operating and maintenance costs were slightly lower than those of large nuclear reactors. However, the additional requirements due to the TMI incident will result in higher costs for future nuclear facilities. Accordingly, we have assumed operating and maintenance costs of 3.0, 3.5, and 4.0 mills/kwh for the coal comparisons. An escalation rate of 8.5% was used to estimate future operating and maintenance expense.

**Life Cycle Costs:** The economic comparison of nuclear versus coal is based on an analysis of the cost of the plants over the operating life of the plant. For purposes of this analysis, a plant operating life of 30 years is assumed for both nuclear and coal

plants. As discussed earlier, both alternatives are levelized over a ten-year period. The life cycle cost components used in this analysis include the following:

- Levelized fixed investment carrying cost or fixed charge factor
- Levelized fuel cost
- Levelized operating and maintenance expenses
- Levelized insurance expenses
- Levelized decommissioning expenses (nuclear only)

The following sections discuss the methodology and assumptions used to develop the fixed charge and levelization factors.

**Fixed Charge Factor:** The fixed charge factor represents the fixed cost associated with the capital investment in a nuclear or coal-fired plant. The components of the fixed charge factor include:

- Return
- Sinking fund depreciation
- Annual income taxes
- Property taxes
- Property insurance

The return component of the fixed charge factor represents the overall cost of capital. The sinking fund depreciation component provides a lump sum amount at the end of the plant life equal to the original capital investment. Levelized annual income taxes represent taxes which must be considered for the common and preferred equity return components.

Property taxes are levied on the capital investment of nuclear and coal plants. Property insurance represents the insurance associated with investment to protect the utility in the event of property damage. Liability insurance is included as a component of operating and maintenance expenses.

Table V-4 details the assumptions used for development of the fixed charge factor for the coal and nuclear comparisons.

Table V-4
Fixed Charge Factor Assumptions

| Component | Nuclear | Coal |
|---|---|---|
| Debt Ratio | 48% | 48% |
| Debt Cost | 10.8 | 10.8 |
| Preferred Stock Ratio | 10 | 10 |
| Preferred Stock Cost | 10 | 10 |
| Common Equity Ratio | 42 | 42 |
| Common Equity Cost | 15 | 15 |
| Overall Cost of Capital | 12.5 | 12.5 |
| Federal and State Income Tax Rate | 48.0 | 48.0 |
| Property Taxes | 2.0 | 2.0 |
| Property Insurance | .1 | .1 |

**Levelization Factor**: To compare the life cycle cost of a nuclear plant with a coal-fired plant, a present value approach is necessary due to the length of the period analyzed. In simple terms, the use of a levelization factor results in a fixed amount to be charged over the period selected. When summed, this fixed amount is equal to the present value of the nominal amounts necessary to pay the expenses of the item under consideration. The following levelization equation was utilized for calculating levelized fuel, operating and maintenance, insurance, and decommissioning costs:

$$\text{Levelization factor} = \frac{1+e}{1+d} \times \frac{\frac{1+e}{1+d} \times 1 - \left(\frac{1+e}{1+d}\right)^{n}}{1 - \frac{1+e}{1+d}} \times \text{CRF}$$

where:

e = escalation rate
d = discount rate
CRF = overall cost of capital + sinking fund depreciation

Exhibit V-1

# INFORMATION SOURCES

## Federal Agencies

Department of Labor
Energy Information Administration
Nuclear Regulatory Commission
Interstate Commerce Commission
National Coal Association
American Nuclear Society
Federal Energy Regulatory Commission

## State Agencies

Wyoming Geological Survey
Wyoming Department of Economic Planning and Development

## Utilities

Long Island Lighting
Cincinnati Gas & Electric
Ohio Edison
Public Service Company of Indiana
New England Power
Northern States Power
Power Authority for the State of New York
Washington Public Power Supply System
Houston Lighting & Power
West Texas Utilities
Commonwealth Edison
Texas Power and Light
Kansas Gas and Electric
Union Electric

## Publications

Coal Age
Coal Week
Electrical World
Coal Outlook
Nuexco
Coal Technology
Keystone News Bulletin
Wall Street Journal

## Private Industry

Wharton Econometrics
Chase Econometrics
E. F. Hutton
Salomon Brothers
Morgan & Stanley
Merrill Lynch, Pierce, Finner, and Smith
Data Resources, Inc.
ICF, Inc.
Peabody & Associates
Ebasco Services Incorporated
Black & Veatch Consulting Engineers
Burns & Roe, Inc.
Atomic Industrial Forum (AIF)
Oak Ridge National Laboratory
Edison Electric Institute
Komanoff Energy Associates
Sargent and Lundy Engineers
Marsh and McLennon
Electric Power Research Institute
Institute of Nuclear Power Operations
PLM, Inc.

NUCLEAR FUEL CYCLE

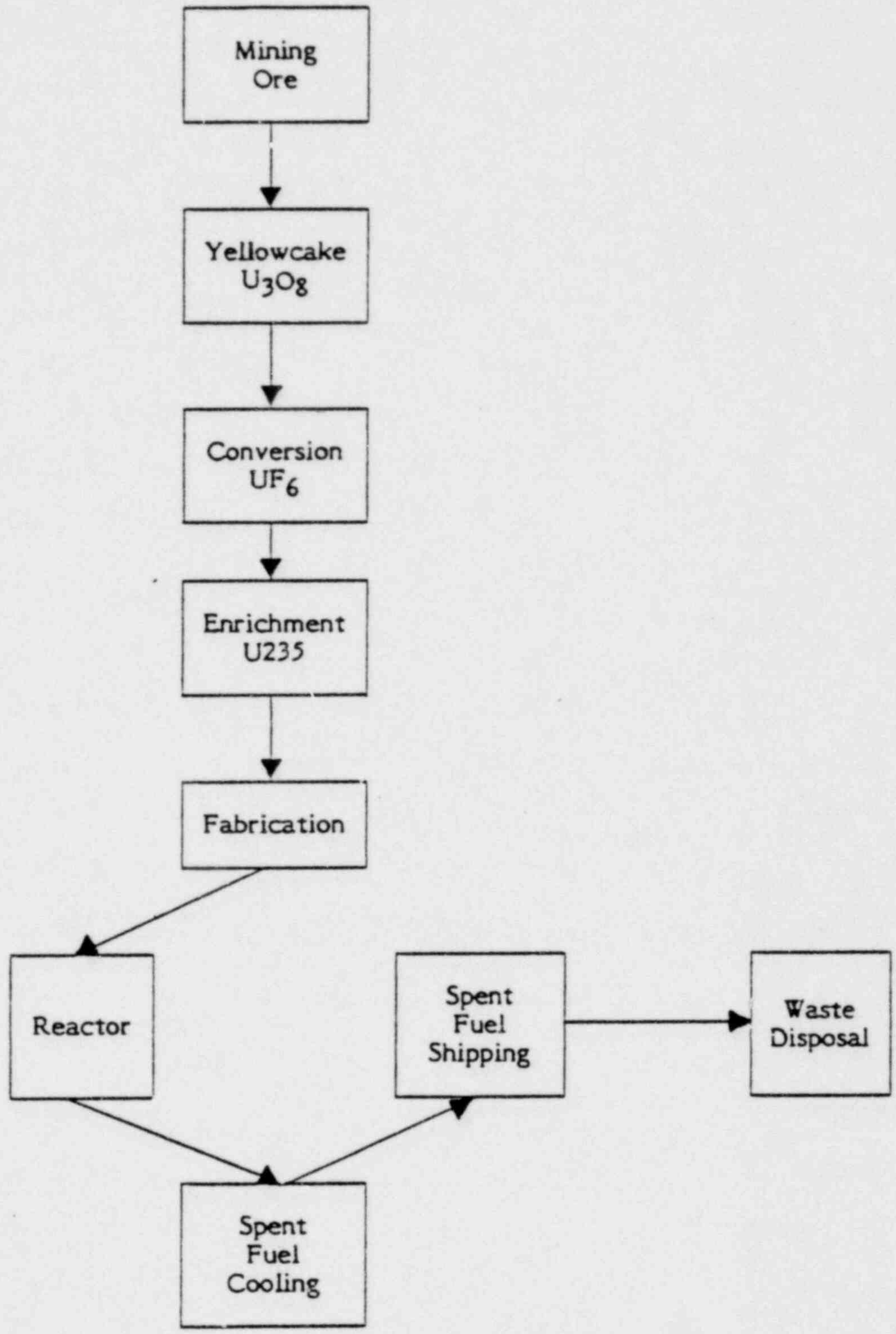


Exhibit V-3

# LEVELIZED NUCLEAR FUEL COST
## ASSUMPTIONS

| | |
|---|---|
| Reactor Type | General Electric BWR |
| Rating | 3,579 Mw Thermal<br>1,150 Mw Electrical |
| Net Heat Rate | 10,600 Btu/kwh |
| Mwd/Mt | 29,000 |
| Capacity Factor | 55%/65%/75% |
| Fuel Cycle Length: | |
| 1st Cycle | 17 months |
| 2nd Cycle | 11 months |
| Remaining | 18 months |
| Enrichment Tails | 0.20% |
| Salvage Value | None |
| Refueling Interval: | |
| 1st Cycle | 12 weeks |
| Remaining | 6 weeks |

| | Base Price | Date | Escalation Rate |
|---|---|---|---|
| Fuel Cycle Costs: | | | |
| Uranium Ore Under Contract | $ 46.30 lb. | 1/1981 | 8.75% |
| Current Uranium Ore | 25.00 lb. | 6/1981 | 0 - 1st five years<br>8.5% thereafter |
| Conversion (1) | 5.00 Kgu | 1/1980 | 8.5 |
| Enrichment (2) | 130.75 Swu | 1/1982 | 10.0 |
| Fabrication (1): | | | |
| Initial Core | 177.00 Kgu | 1/1985 | 8.5 |
| 1st Reload | 158.70 Kgu | 1/1985 | 8.5 |
| 2nd Reload | 144.70 Kgu | 1/1985 | 8.5 |
| 3rd Reload | 143.50 Kgu | 1/1985 | 8.5 |
| 4th Reload | 134.20 Kgu | 1/1985 | 8.5 |
| 5th Reload | 125.10 Kgu | 1/1985 | 8.5 |
| Remaining | 225.00 Kgu | 1/1985 | 8.5 |
| Spent Fuel Shipping (3) | 55.00 Kgu | 1/1985 | 10.5 |
| Spent Fuel Disposal (3) | 328.20 Kgu | 1/1985 | 8.5 |

**Sources:** (1) Base Prices Are Company Estimates Based Upon Existing Contracts
(2) U.S Department of Energy
(3) Company Estimate of Base Price

# VI. COMPARISON OF NUCLEAR AND COAL

The purpose of this section is to present and discuss the results of our development of nuclear and coal-fired generating alternative capital and operating costs. These projections were developed based on the assumptions defined in the previous section and represent the results of application of a range for most assumptions. We have presented the projections in three cases - low, mid, and high - to provide a perspective of potential results to the Commission. Each of the cases is discussed separately within this section to provide a comparison between our nuclear and coal-fired generating options.

## CAPITAL COSTS

Each of the resulting capital cost projections for both the nuclear and coal-fired generating alternatives was developed by the Concept Model discussed earlier. In each case, we have provided an illustrative breakdown of the following cost categories, expressed in dollars/kw:

- Direct and Indirect
- Contingency
- Escalation
- Allowance for Funds Used During Construction

The results of each of these cases are presented in **Exhibit VI-1.**

### Low Case

In developing our low case, we adopted certain assumptions which would provide projected completed construction cost based upon favorable construction and economic conditions. The specific assumptions relied upon for this case are set forth for both the nuclear and coal-fired generating alternatives in **Table VI-1**:

**Table VI-1**
**Low Case Assumptions**

| | Nuclear | Coal |
|---|---|---|
| Units/Size | 2 x 1,150Mw | 3 x 770Mw |
| NSSS/FSSS | *79.50 | *85.50 |
| Construction Start | 84.50, 87.50 | 87.25, 88.75, 90.25 |
| Commercial Operation | 91.50, 94.50 | 91.50, 93.00, 94.50 |
| Escalation | 9.5% | 9% |
| Contingency | 15% | 10% |
| Labor Hours/kw | 14 | 9 |
| TMI | $25mm | - |
| AFDC (Coal and Nuclear) | 1979 - 10%, 1980 - 11%, 1981-94 - 12.25% | |

* July 1, 1979, July 1, 1985, etc.

The total construction costs shown on Exhibit VI-1 were developed using the Concept Model for a Dallas site which, as previously mentioned, most closely approximates the conditions existing in the Tulsa area.

For the nuclear alternative, total projected construction costs are $8.177 billion in mixed dollars or approximately $3,555/kw. This projection assumes that escalation will generally reflect the average for the construction industry with a slightly higher rate for nuclear construction. Favorable construction experience is also assumed with no significant impact on productivity and the construction sequence. Finally, an allowance for TMI is provided based on the low end of published ranges. The total projected capital costs for the coal-fired alternative are $5.009 billion in mixed dollars or approximately $2,168/kw. These projections assume the same relationship of escalation as the nuclear alternative and the same favorable construction experience. We have reduced the applicable contingency allowance to account for the historical and prospective disparities between nuclear and coal-fired plants. Comparison of the nuclear and coal-fired alternatives results in a capital cost ratio of approximately 1.63:1.00.

### Mid Case

The development of our mid case considered the effect of somewhat less favorable escalation and construction experience. The specific assumptions relied upon for this case are set forth below:

Table VI-2
Mid Case Assumptions

| | Nuclear | Coal |
|---|---|---|
| Units/Size | 2 x 1,150 Mw | 3 x 770 Mw |
| NSSS/FSSS | 79.50 | 85.50 |
| Construction Start | 84.50, 87.50 | 87.25, 88.75, 90.25 |
| Commercial Operation | 91.50, 94.50 | 91.50, 93.00, 94.50 |
| Escalation | 10% | 9.5% |
| Contingency | 15% | 10% |
| Labor Hours/kw | 16 | 9.5 |
| TMI | $45 mm | - |

AFDC (Coal and Nuclear) 1979 - 10%, 1980 - 11%, 1981-85 - 12.25%, 1986-94 - 12.50%

The total construction cost projected for the nuclear alternative in this case is $9.078 billion or approximately $3,947/kw. In this projection, escalation rates are assumed to be slightly higher than the low case and direct craft labor hours/kw are increased to more closely reflect historical experience. The amount provided for TMI has also been increased to reflect greater expectation of the effect of this occurrence on design and safety requirements.

For the coal-fired alternative, capital costs are projected at $5.353 billion or approximately $2,317/kw. Assumptions similar to those in the low case were relied upon with the exception of escalation which was increased to reflect higher inflation. Direct craft labor hours/kw were not increased to reflect the general historical experience in coal-fired plant construction. Comparison of the nuclear and coal-fired alternatives results in a capital cost ratio of approximately 1.70:1.00.

## High Case

The final case developed in our capital cost comparison was based on somewhat pessimistic, although not entirely improbable, assumptions related to escalation and the occurrence of unplanned events. The specific assumptions relied upon for this are provided below:

**Table VI-3**
**High Case Assumptions**

| | Nuclear | Coal |
|---|---|---|
| Units/Size | 2 x 1,150Mw | 3 x 770Mw |
| NSSS/FSSS | 79.50 | 85.50 |
| Construction Start | 84.50, 87.50 | 87.25, 88.75, 90.25 |
| Commercial Operation | 92.50, 95.50 | 91.50, 93.00, 94.50 |
| Escalation | 10.5% | 10% |
| Contingency | 17% | 12% |
| Labor Hours/Kw | 18 | 10 |
| TMI | $60mm | - |

AFDC (Coal and Nuclear) 1979 - 10%, 1980 - 11%, 1981-85 - 12.25%, 1986-94 - 12.50%

The projected capital cost for the nuclear alternative in this case is $10.120 billion or approximately $4,400/kw. In this projection, construction escalation is assumed to exceed general inflation by a higher margin with increases in labor, materials, and equipment for nuclear construction again outpacing those for coal. The contingency percentage has been increased to allow for unexpected events, and the costs for TMI are increased to provide for a more substantial effect of this event on design requirements and construction costs. Most importantly, however, the scheduled commercial operation dates of both units are slipped one year to determine the effect of unanticipated delays due to productivity, financing inability, or reduced demand.

The total projected construction costs for the coal-fired alternative are $5.789 billion or approximately $2,506/kw. Escalation, contingency, and direct craft labor hours/kw have been increased over the previous cases to allow for higher inflation in the construction industry, unanticipated construction problems, and increased environmental requirements. Scheduled commercial operation dates were not extended for the coal-fired alternative since we do not believe that the type or magnitude of problems potentially confronting the nuclear alternative would similarly affect the coal alternative. Comparison of the nuclear and coal-fired alternatives indicates a capital cost ratio of approximately 1.75:1.00.

Table VI-4 summarizes the previous analyses and highlights those factors of major importance.

Table VI-4
Summary of Capital Cost Comparisons

| Case | | Dollars | Dollars/kw | Ratio |
|---|---|---|---|---|
| Low - | Nuclear | $ 8.177 | $ 3,555 | 1.63 |
| | Coal | 5.009 | 2,168 | 1.00 |
| Mid - | Nuclear | 9.078 | 3,947 | 1.70 |
| | Coal | 5.353 | 2,317 | 1.00 |
| High - | Nuclear | 10.120 | 4,400 | 1.75 |
| | Coal | 5.789 | 2,506 | 1.00 |

In considering these capital cost projections, it is also helpful to identify the sensitivity of these amounts to changes in various underlying assumptions. For example, utilizing our nuclear mid case including the effect of TMI, a one percentage point increase in the rate of escalation from 10% to 11% results in an increase of approximately $747 million or $325/kw which amounts to approximately an 8% increase. Similarly, a one-year slippage in the scheduled commercial operation date results in an increase of approximately $1.066 billion or $463/kw which amounts to approximately a 12% increase in total cost. An increase in man-hours/kw from 16 to 18 would increase total cost by $335 million or $146/kw which is approximately a 4% increase. Exhibit VI-2 illustrates the results of varying certain assumptions in the projection of capital costs. It is clear from this exhibit that even minor changes in certain assumptions can have significant effects on actual capital expenditures.

In evaluating these capital cost projections, it is important to note two factors. First, we have not attempted to determine the cost of capital for PSO and have generally utilized a 15% return on equity. Should PSO experience negative construction related events which would increase the uncertainty regarding timely completion or should adequate regulatory relief not be forthcoming, this factor would increase and obviously force the cost of the project upward. Second, no major regulatory changes have been assumed. Should these occur they may have a significant effect on project costs.

## OPERATING COSTS

Each of the operating cost projections for both the nuclear and coal-fired generating alternatives was developed from the assumptions discussed previously and are levelized on either a ten- or thirty-year basis. Included with each major operating cost category are sensitivity charts to illustrate the impact of varying assumptions.

## NUCLEAR

### Operating and Maintenance Expense (O&M)

The following table summarizes our projected levelized operating and maintenance cost for the various capacity factor assumptions levelized over a 10-year period.

Table VI-5
10-Year Levelized O&M Expenses

| Capacity Factor | Mills/kwh |
|---|---|
| 55% | 15.84 |
| 65 | 14.08 |
| 75 | 12.33 |

**Nuclear Fuel Cost**

Our projected nuclear fuel cost levelized over a 10-year period is 22.66 mills per kwh.

**Decommissioning Cost**

Decommissioning costs are based upon a levelized annual sinking fund payment which, when summed over the life of the facility, will provide sufficient funds for immediate dismantling. Since the annual payment is a fixed amount, changes in capacity factor can significantly affect the cost in mills per kwh. **Table VI-6** summarizes decommissioning cost at various capacity factor levels.

Table VI-6
Thirty-Year Levelized Decommissioning Cost

| Capacity Factor | Mills/kwh |
|---|---|
| 55% | 1.45 |
| 65 | 1.23 |
| 75 | 1.06 |

**Nuclear Insurance**

Nuclear insurance costs are levelized over a 10-year period and include premiums for Price-Anderson Act coverage. Property insurance premiums are not included here since they are a component fo the fixed charge factor. **Table VI-7** summarizes nuclear insurance cost for various capacity factor levels.

Table VI-7
Ten-Year Levelized Insurance Cost

| Capacity Factor | Mills/kwh |
|---|---|
| 55% | .29 |
| 65 | .25 |
| 75 | .21 |

### Capital Carrying Cost

Capital carrying costs represent the cost to be incurred on a levelized basis with an assumed plant life of 30 years. The following table summarizes nuclear capital carrying cost for each captial cost assumption at various capacity factors for our low, mid, and high capital cost cases.

Table VI-8
Thirty-Year Levelized Capital Carrying Costs

| Capacity Factor | Capital Cost (mills/kwh) Low | Mid | High |
|---|---|---|---|
| 55% | 146.60 | 162.77 | 181.45 |
| 65 | 124.05 | 137.73 | 153.53 |
| 75 | 107.51 | 119.36 | 133.06 |

## COAL

### Operating and Maintenance Expense

The following table summarizes our projected levelized operating and maintenance costs for the various capacity factor assumptions levelized over a 10-year period.

Table VI-9
10-Year Levelized O&M Expenses

| Capacity Factor | Mill/kwh |
|---|---|
| 55% | 14.08 |
| 65 | 12.33 |
| 75 | 10.56 |

### Fuel Cost

**Coal Mine Mouth and Transportation** - Coal fuel costs are levelized over a 10-year period with varying rates of escalation. **Table VI-10** summarizes levelized coal mine mouth and transportation cost under our low, mid, and high cases.

Table VI-10
Ten-Year Levelized Coal and Transportation Cost

| | Escalation (mills/kwh) | | |
|---|---|---|---|
| | Low | Mid | High |
| Mine Mouth | 14.29 | 16.59 | 19.24 |
| Transportation | 34.30 | 39.79 | 46.12 |
| Total | 48.59 | 56.38 | 65.36 |

**Exhibits VI-3 and VI-4** present the sensitivities of mine mouth and transportation cost for additional escalation rates.

**Coal Cars** - Levelized coal car costs represent the carrying cost associated with the investment in coal unit trains and vary with plant capacity factors. Coal unit train costs are levelized over a 16-year period to reflect PSO's current depreciable life for coal unit trains. **Table VI-11** summarizes the fixed carrying cost and annual operating and maintenance expense of coal unit trains for each capacity alternative.

Table VI-11
Levelized Coal Unit Train Cost

| | Capacity Factor (mills/kwh) | | |
|---|---|---|---|
| | 55% | 65% | 75% |
| Carrying Cost | 2.86 | 2.90 | 2.93 |
| Operating and Maintenance Cost | .03 | .03 | .03 |
| Total Coal Car Cost | 2.89 | 2.93 | 2.96 |

**Coal Inventory**

Coal inventory costs represent the fixed carrying cost associated with maintaining a 90-day coal pile and vary with coal mine mouth and transportation escalation rates. **Table VI-12** summarizes coal inventory carrying costs at our assumed escalation rates in each case.

Table VI-12
Levelized Coal Inventory Carrying Cost

| | Escalation (mills/kwh) | | |
|---|---|---|---|
| | Low | Mid | High |
| Inventory Carrying Cost | 1.73 | 1.89 | 2.07 |

**Capital Carrying Cost**

Capital carrying costs represent the costs to be incurred on a levelized basis with an assumed plant life of 30 years. The following table summarizes coal capital carrying

cost for each capital cost assumption at various capacity factors for our low, mid, and high capital cost cases.

Table VI-13
Levelized Coal Capital Carrying Cost

| Capacity Factor | Capital Cost (mills/kwh) Low | Mid | High |
|---|---|---|---|
| 55% | 89.40 | 95.54 | 103.34 |
| 65% | 75.65 | 80.85 | 87.44 |
| 75% | 65.56 | 70.07 | 75.78 |

## LEVELIZED BUS BAR COST

A comparison of levelized bus bar cost over a ten-year period provides a means to evaluate the economics of nuclear and coal-fired generating alternatives after combination of each cost component on a present value mills/kwh basis. For purposes of comparison, we have selected our mid case at a 65% capacity factor and have included additional sensitivity analyses for capital carrying costs and fuel costs.

The following table summarizes the assumptions used for these analyses.

Table VI-14
Ten-Year Levelized Bus Bar Cost Assumption

| | Nuclear | Coal |
|---|---|---|
| Capital Cost/kw | $ 3,947 | $ 2,317 |
| Capacity Factor | 65% | 65% |
| Fixed Charge Factor | 20.16% | 20.16% |
| Coal Mine Mouth Escalation | - | 9.5% |
| Coal Transportation Escalation | - | 10.5% |
| Discount Rate | 12.5% | 12.5% |

Operating and maintenance expense, insurance, and decommissioning costs are based upon the costs previously derived at a 65% capacity factor. Exhibit VI-5 presents the results of this comparison stated in 1991 mills/kwh. As this exhibit shows, ten-year levelized coal bus bar costs are 21.57 mills/kwh less than levelized nuclear bus bar costs or a coal advantage of approximately 14%.

In interpreting the results of this analysis, the reader must keep in mind the following key assumptions which can significantly affect the results presented. These are:

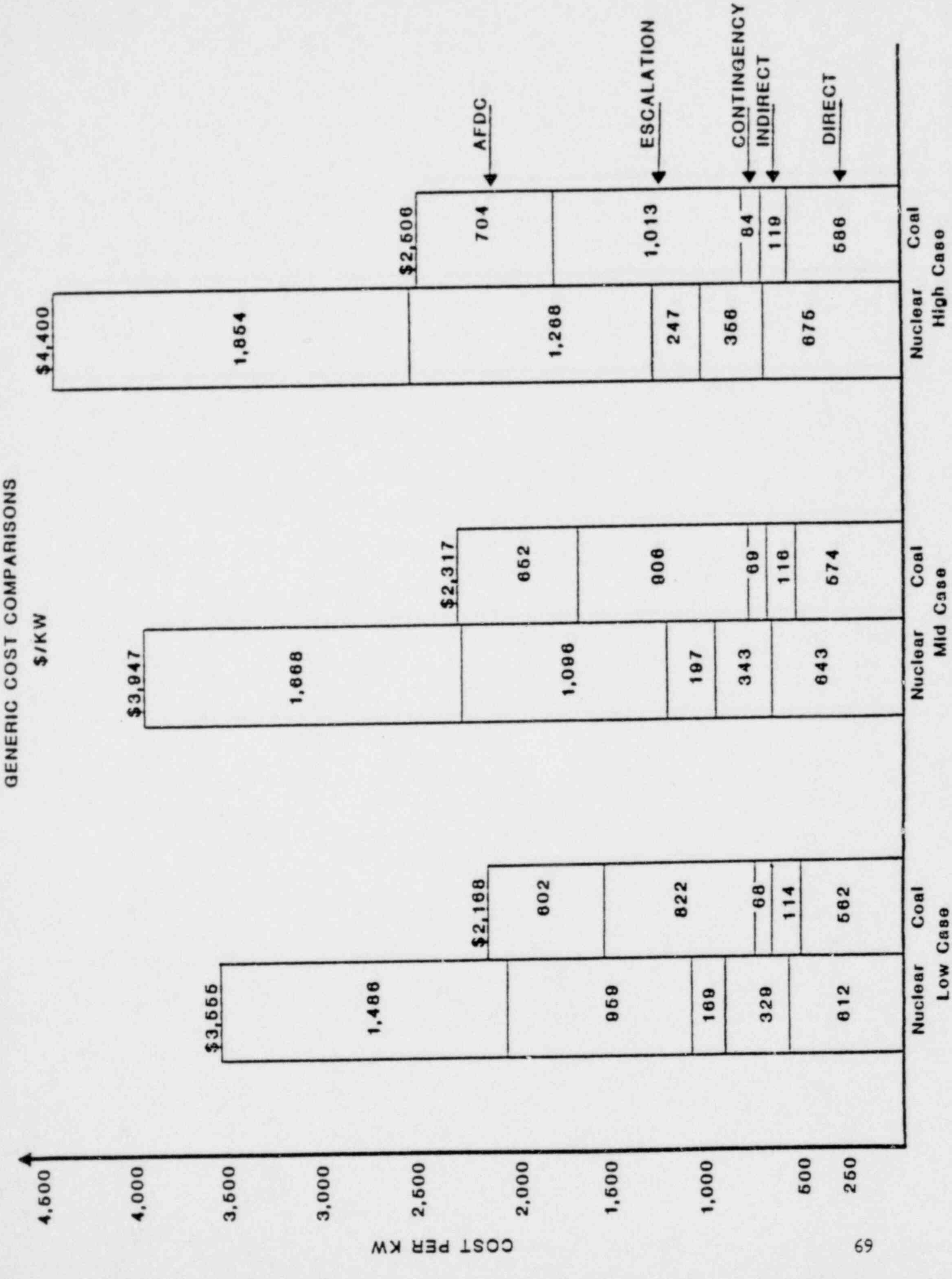
- Fuel costs are levelized over a ten-year period. Since coal fuel costs are a large portion of the levelized coal bus bar cost, escalation of mine mouth and/or transportation cost can have a significant impact on the comparison.

- Nuclear fuels costs are predicated on existing PSO contracts. The base price for yellowcake contained within the contract is significantly higher than current market prices. Therefore, the levelized nuclear fuel cost shown on Exhibit VI-5 are not appropriate for generic comparisons.

- Our levelized bus bar costs are based upon those assumptions we consider appropriate for a 10-year period. We do not believe that it is appropriate to speculate over an additional 20 years to develop levelized 30-year costs. Consequently, our assumptions should not be applied to an extended period.

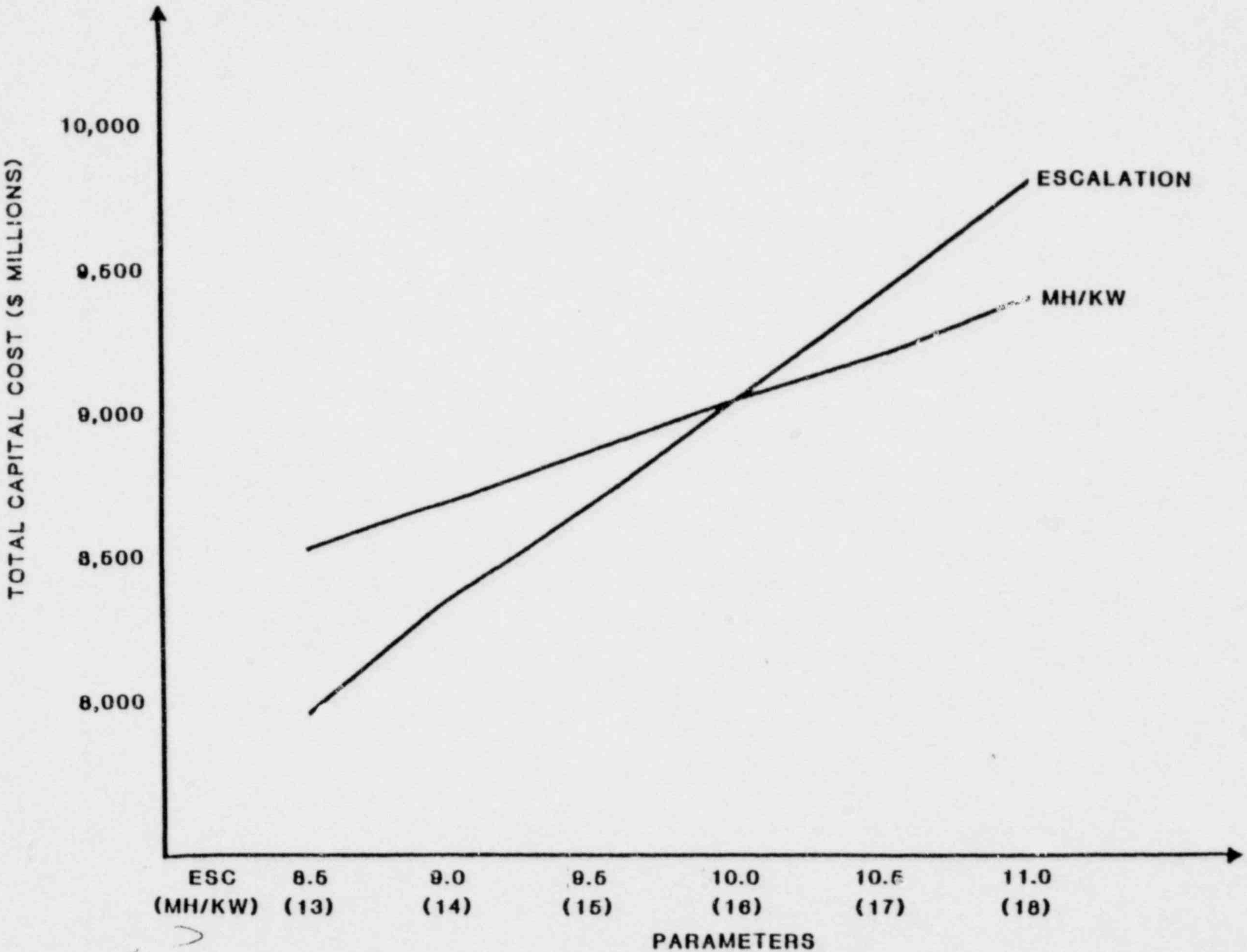
To evaluate the impact of these assumptions along with the assumptions for capital cost and fuel cost, sensitivity analyses were performed. Exhibits VI-6 and VI-7 present the sensitivities of levelized bus bar cost due to changes in fuel cost and capital cost.

Exhibit VI-1


GENERIC COST COMPARISONS
$/KW
COST PER KW
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
250
AFDC
ESCALATION
CONTINGENCY
INDIRECT
DIRECT
$3,555
1,486
959
169
329
612
$2,168
602
822
68
114
562
Nuclear Coal
Low Case
$3,947
1,668
1,096
197
343
643
$2,317
652
906
69
116
574
Nuclear Coal
Mid Case
$4,400
1,854
1,268
247
356
675
$2,506
704
1,013
84
119
586
Nuclear Coal
High Case

PSO

NUCLEAR SENSITIVITY ANALYSIS



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MINE MOUTH COAL COST

SENSITIVITY ANALYSIS

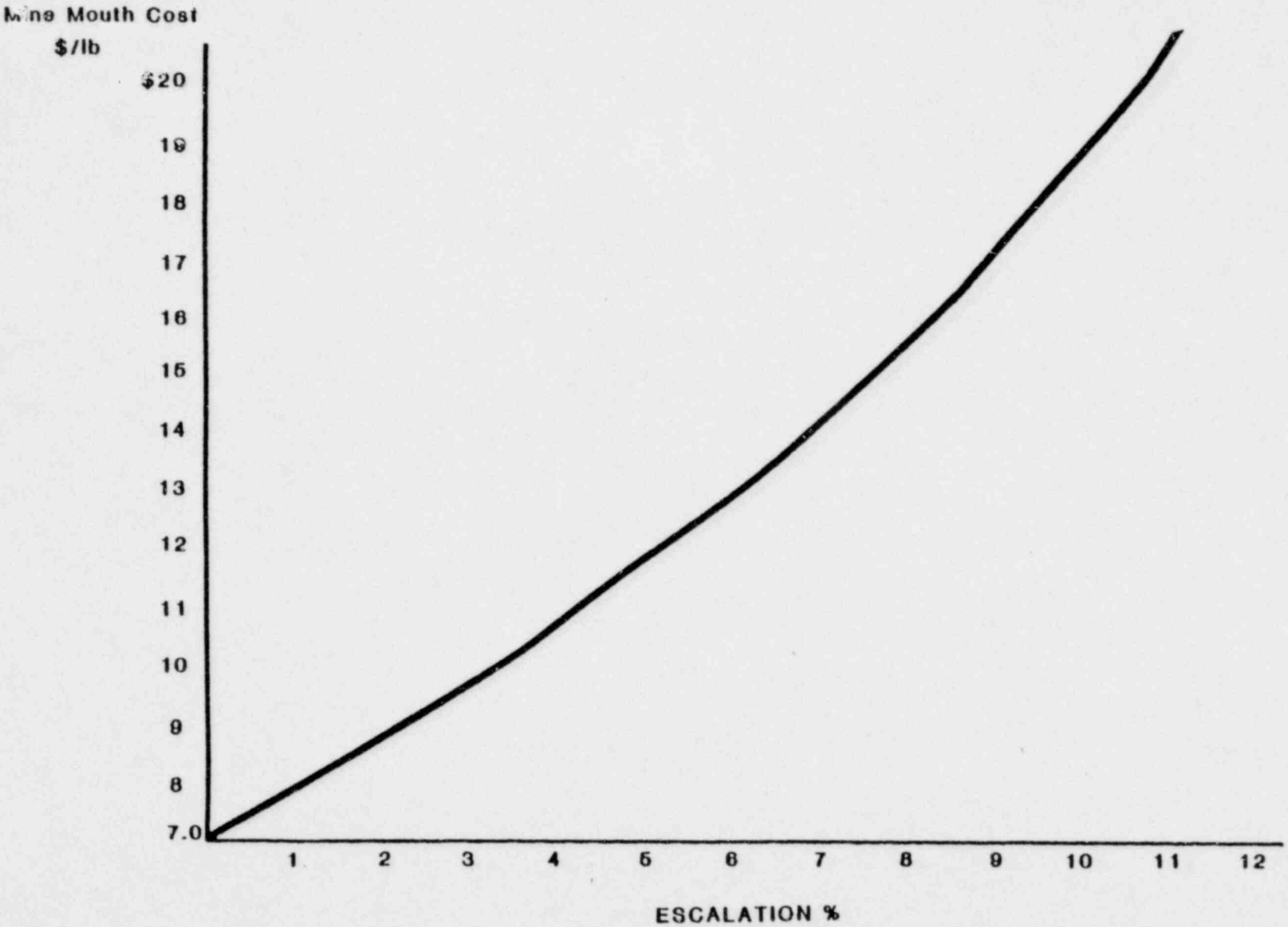


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Exhibit VI-3

# PSO
# TRANSPORTATION COST
# SENSITIVITY ANALYSIS

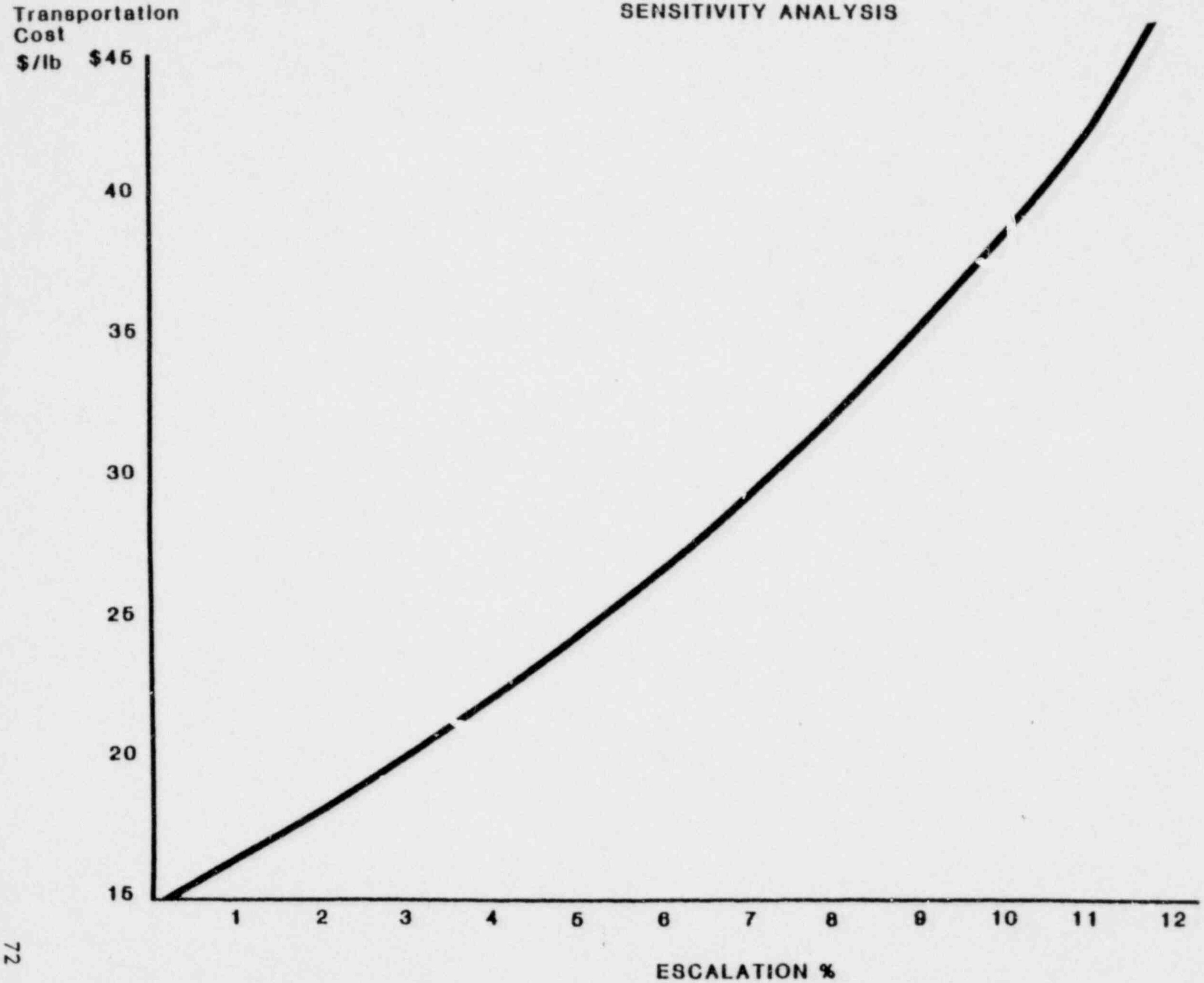
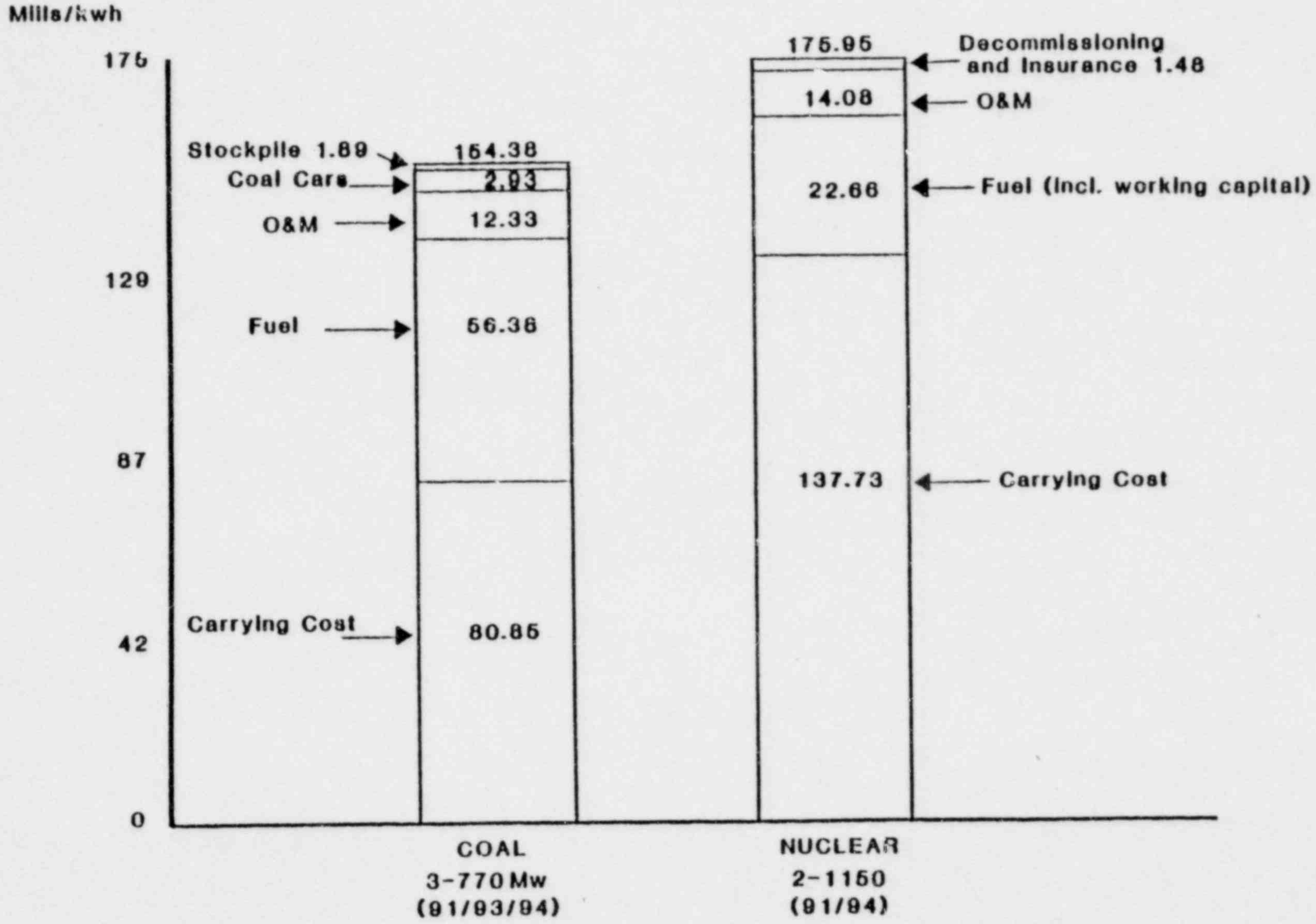



Exhibit VI-4

Touche Ross & Co

Exhibit VI-5

PSO
LEVELIZED BUS BAR COST
65% CF, MID CAPITAL COST, MID COAL ESCALATION



PSO
SENSITIVITY ANALYSIS
COAL COST

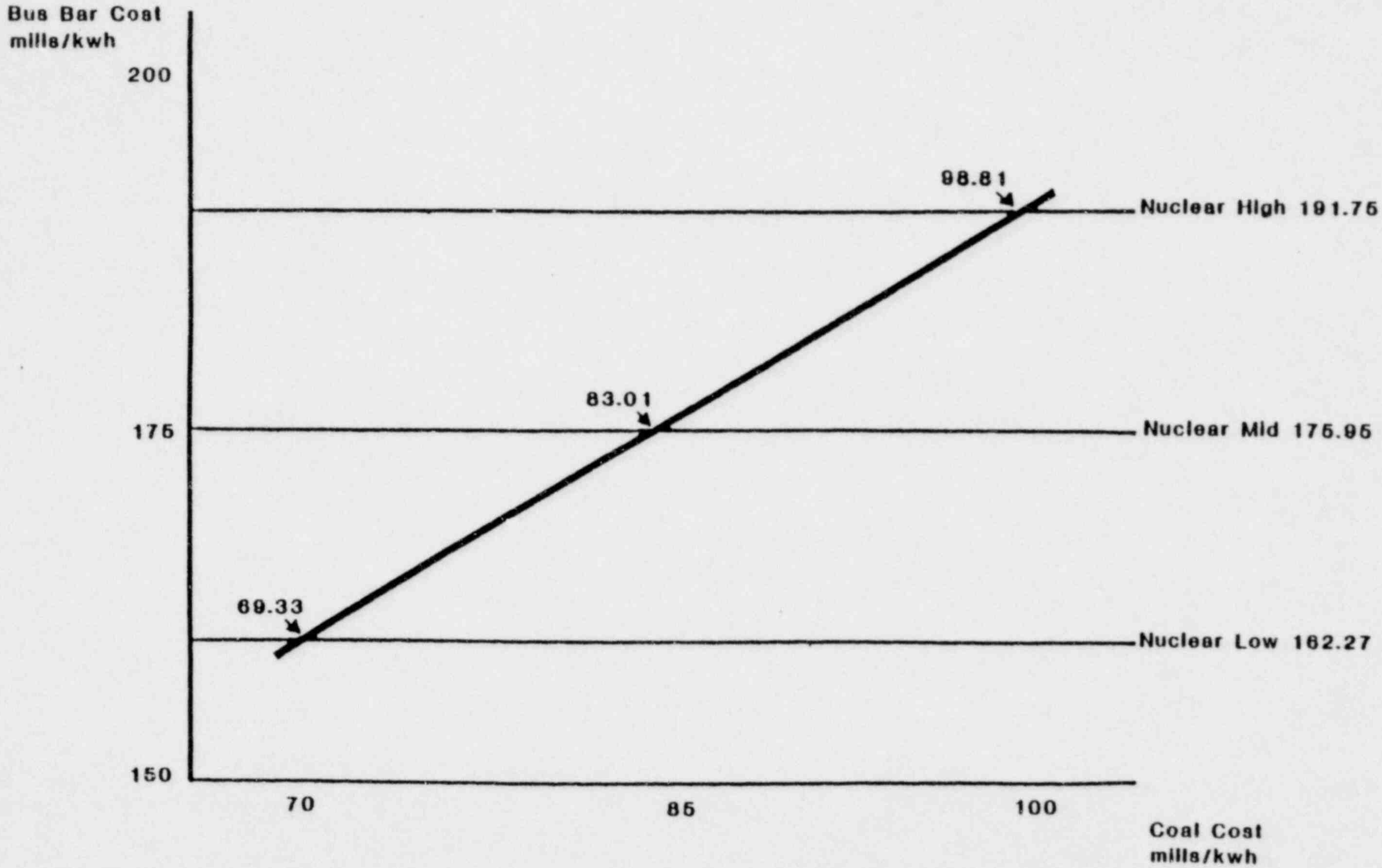



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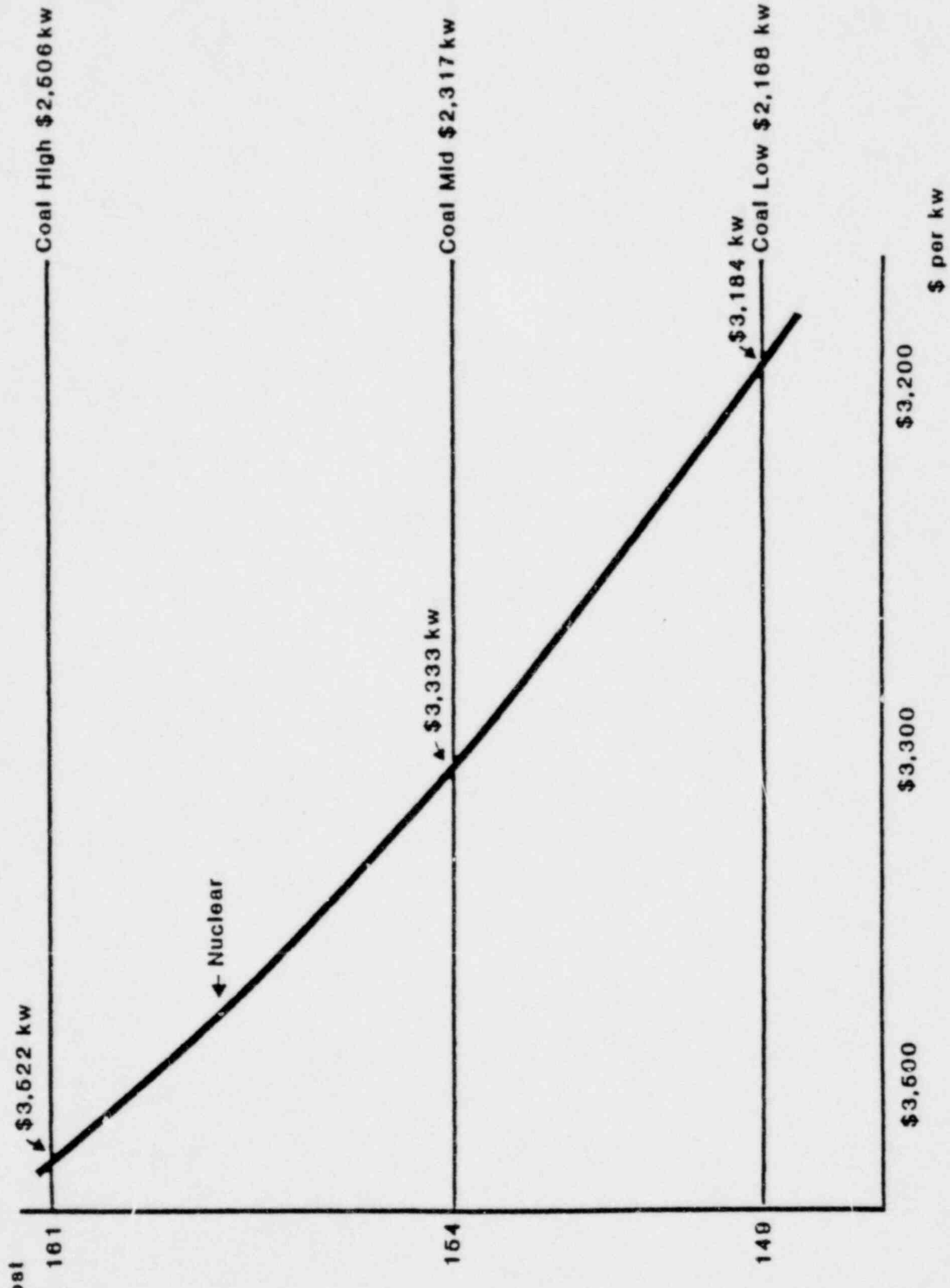
Exhibit VI-6

Exhibit VI-7

PSO
SENSITIVITY ANALYSIS
NUCLEAR PLANT INVESTMENT



# VII. IMPACT ON FINANCIAL CONDITION

The purpose of this section is to describe the historical financial condition of PSO and to discuss the potential effect construction of major generating capacity additions would have on prospective financial results. Although PSO is a member of the C&SW system, this discussion is limited to PSO only and does not consider events which could occur as a result of this affiliation.

## HISTORICAL REVIEW

In evaluating the ability of a company to undertake or continue a major project requiring significant capital outlay and external financing, it is imperative that the underlying financial strength of the entity be assessed as a basis for determining the potential occurrence of circumstances which would adversely affect the ability of the company to successfully complete the undertaking. We have identified several key financial integrity measures and reviewed the historical performance of PSO with respect to each of these measures. The particular indicators of financial strength reviewed were:

- Pretax Interest Coverage
- AFDC as a Percentage of Net Income Available for Common
- Internal Cash Generation as a Percentage of Construction Expenditures
- Average Common Equity as a Percentage of Average Total Invested Capital

We believe that these key measures are generally indicative of financial health of a utility and are heavily relied upon by rating agencies and the investment community in evaluating overall financial condition. Each of these measures is discussed more fully below.

**Pretax Interest Coverage** - This measure provides an indication of the safety or security of leveraged investments and is a critical factor in the evaluation of regulated utilities by the investment community. Standard & Poor's has indicated that appropriate coverage for a AA rated electric utility should be in the range of 3.00x to 3.50x and recently has indicated that this coverage should be 3.25x or better. **Exhibit VII-1** shows the historical pretax interest coverage for PSO for the period 1970-1980 and indicates that with the exception of 1980, the 3.25x criterion has been exceeded. However, this exhibit also shows that the historical coverages achieved have substantially declined over the period analyzed.

**AFDC as a Percentage of Net Income Available for Common** - As a result of continuing and extended construction programs, the utility industry has adopted an accounting convention which accrues and capitalizes the annual carrying cost of devoted capital as part of the construction cost while recognizing these carrying charges in the form of an addition to net income. This component of net income, known as AFDC, is available as part of reported earnings but provides no cash flow to the utility. Consequently, the investment community has come to recognize earnings comprised of significant amounts of AFDC to be of less quality than cash earnings. **Exhibit VII-1** shows that PSO has generally been able to maintain a minimal amount of AFDC as a portion of net income until 1979 and 1980 when this measure exceeded 40% of earnings. It is important to note that AFDC is a function of three elements of a utility's operation - the AFDC rate, magnitude and duration of construction expenditures, and regulatory treatment of CWIP - and can be significantly affected by each of these elements individually as well as collectively.

**Internal Cash Generation as a Percentage of Construction Expenditures** - Due to the significant construction programs maintained by most major electric utilities, substantial capital funds are required to finance these major generating additions. Standard & Poor's has indicated that AA rated electric utilities should generate better than 40% of total annual construction expenditures through internal sources to reduce external capital market reliance. **Exhibit VII-1** indicates that for the period 1970-1980, PSO has generally exceeded the level stated by Standard & Poor's although in certain years actual internal cash generation was below this level. The high internal cash generation achieved by PSO, however, must be analyzed in terms of the actual construction expenditures required. **Exhibit VII-1** also shows that construction expenditures were generally less than 20% of existing net plant which would not indicate that annual cash expenditures requirements are proportionally large. In fact, although 1980 internal cash generation was almost 50% of construction expenditures, the total annual cash capital outlay was only approximately 11% of net plant.

**Average Common Equity as a Percentage of Average Total Invested Capital** - This indicator is generally recognized as a key measure of financial risk since it measures the amount of total capitalization derived from the owners of the company as opposed to lenders to the company. The greater the balance of common equity as a percentage of total invested capital the lower the financial risk since greater security is provided to the lenders. **Exhibit VII-1** illustrates that the equity ratio of PSO has ranged between 37.5% and 44.9% and that in recent years has continually exceeded 40%. Although this is somewhat higher than historically achieved by the electric utility industry as a whole, it is still below the target equity ratio of 42% that has been set by PSO, again in periods of minimal construction activity and financial requirements.

The above summarization indicates that while PSO's financial performance as indicated by these measures appears satisfactory, the overall trend, with the exception of the equity ratio, indicates continued deterioration, particularly in those years where the construction expenditure requirements for Northeastern Unit Nos. 3 and 4 may have peaked. More importantly, however, these measures are impacted by the minimal construction activity at the Black Fox Station. Had major construction activity been initiated, these measures would likely show substantially poorer results.

## PROJECT FINANCING REQUIREMENTS

A previous section of this report has dealt with the development of projected capital costs for generic nuclear and coal-fired alternatives. These projections may be utilized to determine the effect of estimated cash construction expenditure requirements on the financing requirements of PSO. Based on our earlier projections, we have utilized the corporate financial performance model of PSO and attempted to simulate the cash curves necessary to construct a nuclear generating facility. These simulations are based on the anticipated cash outlay requirements as developed by the Concept Model and modified to reflect the fact that a substantial amount of the initial planning, design, and site related work has been performed at the Black Fox Station site. We have not developed cash curve or financing projections for a coal-fired facility at this point since such requirements would obviously be affected by a write-off of sunk costs for the nuclear facility. Our analysis of alternative capital recovery scenarios contained later in this report includes projections of this nature based on treatment of the sunk costs to date associated with the Black Fox Station. Although our original projections were developed for a generic nuclear facility, we believe that the projections can be utilized to predict and assess the effect of construction on the financial condition of PSO.

It is important to note that we have not evaluated the assumptions underlying the corporate financial performance model. Although we are aware of the major underlying assumptions, we have not attempted to modify the basic corporate financial and operating plan assumed in the model. For example, the model assumes that the Transok Pipe Line Company will be spun off to C&SW and does not reflect the results of operation for this Company. We recognize that this change is under scrutiny by the Commission; however, for our purposes we did not modify management's plans.

**Exhibit VII-2** sets forth the required cash outlays for the generic nuclear facility as developed under our low case by the Concept Model. We have limited our analysis to the low case since the results of these amounts of construction requirements are illustrative of the effect of the magnitude of investment on the financial results of PSO. The total cash curve outlays have been reduced by \$135 million to reflect the actual cash expenditures made through 1980 for the Black Fox Station. As this exhibit shows, the cumulative cash expenditures for the nuclear facility are \$2.118 billion and \$2.957 billion for all construction projects during the period 1981-1990. Although additional cash outlays would be necessary during the period 1991-1994, the PSO corporate financial model is only designed to utilize and calculate ten years of financial results.

To determine the amount of external financing requirements on PSO, certain assumptions must be made regarding the treatment of CWIP as part of the rate base for ratemaking purposes. We have utilized the extremes of alternatives available, i.e., full inclusion without capitalization of AFDC or exclusion and continued AFDC capitalization. These two extremes provide a broad perspective of the range of results for PSO and demonstrate dramatically the disparate conditions which may be achieved.

Based on the cumulative cash requirements developed earlier for the low nuclear case, we have utilized the corporate financial performance model to calculate the amount of external financing required to meet these cash curves and maintain the construction sequence. **Exhibit VII-3** shows the annual and cumulative external financing requirements under the two alternative CWIP treatment scenarios for the nuclear alternative. As this exhibit shows, PSO would be required to finance more than \$2.829 billion of construction when CWIP is excluded and more than \$1.840 billion even when CWIP is included under the nuclear alternative. The relative amounts of external financing requirements are demanding even under our low case which assumes favorable economic and construction experience.

As we discussed briefly above, the PSO model does not extend beyond 1990 and we have not attempted to review the financing requirements associated with either our mid or high case. Based on our review of the results through 1990 under our low case, we do not believe such additional analysis is either required or meaningful.

## PROJECTED FINANCIAL INTEGRITY MEASURES

The financial integrity projections developed under our low case are intended to provide a general perspective of the likely results of construction of approximately 1,400 Mw (60.87% of 2,300 Mw facility) of additional capacity for PSO from a nuclear source. We have developed these projections solely for purposes of demonstration of the effect of significant capital outlay on certain financial measures. These projections are not provided for, or intended for use by, any party for any purpose other than expressly stated herein.

We have utilized the results of the corporate financial performance model based on our cash construction requirements to assess the projected financial condition of PSO under the alternatives described above. These projected results are based on numerous other assumptions made by PSO regarding overall economic conditions and operations. The results of these construction financings significantly affect the financial condition of PSO as measured by the financial integrity parameters reviewed earlier. **Exhibit VII-4** illustrates these results, which assume rate relief sufficient to maintain at least a 15% return on common equity and a target equity ratio of 42%.

**Exhibit VII-4** presents the results of our nuclear alternative assuming CWIP is excluded from rate base. As this exhibit demonstrates, each of the financial integrity measures reviewed gradually deteriorate over time to unacceptable conditions. By 1984, internally generated funds are less than 30% and become negative, which implies no contribution from earnings, in 1989. AFDC grows to more than 50% of earnings by 1983 and actually provides all earnings in 1986 and thereafter. This exhibit also illustrates the effect on PSO if CWIP was included in rate base. Although pretax interest coverage remains high and AFDC is a minor amount of earnings, the amount of internally generated funds is still less than 40% of the Standard & Poor's guideline from 1985 through the end of the decade.

In analyzing these results, it is important to keep five factors in mind.

**First,** these financial results are predicated upon favorable market rates and costs of capital which would be entirely unrealistic under the exclusion of CWIP scenario and would generally increase which would result in even further deterioration.

**Second,** the requirements for cash construction outlays extend into 1994, which would indicate continued severe deterioration with respect to internal cash generation even with full inclusion of CWIP in rate base.

**Third,** these projections assume adequate rate relief to maintain a 15% realized return on common equity. We have not made a capital cost analysis of PSO and have merely selected this level of return for illustrative purposes.

**Fourth,** these projections are based on our low case for construction expenditures which assumes generally favorable economic and construction conditions.

**Fifth,** the parameters previously discussed are those currently maintained and are subject to change as overall economic conditions vary. Therefore, it should not be assumed that projected favorable results under current rating agency requirements would be as favorably perceived in future time frames.

Exhibit VII-1

PSO

HISTORICAL FINANCIAL MEASURES

| Year | Pretax Interest Coverage | AFDC as a % of Net Income Available for Common Equity | Internal Cash Generation as a % of Construction Expenditures | Construction Expenditures as a % of Net Plant | Average Common Equity as a % of Total Average Invested Capital |
|---|---|---|---|---|---|
| 1970 | 5.48x | 8.1% | 60.8% | 10.4% | 44.9% |
| 1971 | 5.38 | 2.1 | 71.2 | 9.0 | 40.5 |
| 1972 | 4.92 | 5.9 | 40.7 | 15.8 | 38.6 |
| 1973 | 4.51 | 17.9 | 41.3 | 14.4 | 40.7 |
| 1974 | 4.43 | 10.9 | 45.0 | 14.9 | 37.5 |
| 1975 | 4.18 | 11.5 | 58.5 | 12.0 | 38.6 |
| 1976 | 4.13 | 5.3 | 64.6 | 12.1 | 37.6 |
| 1977 | 4.64 | 9.8 | 44.6 | 17.4 | 38.9 |
| 1978 | 4.76 | 23.8 | 37.1 | 21.5 | 42.0 |
| 1979 | 3.97 | 44.7 | 33.8 | 20.9 | 40.9 |
| 1980 | 2.84 | 40.4 | 48.9 | 10.9 | 41.6 |

Source: Company Response to TR-13

Exhibit VII-2

PSO

PROJECTED CASH EXPENDITURES
($000)

| Year | Nuclear Project Cash Expenditures | All Projects Cash Expenditures |
|---|---|---|
| 1982 | $ 21,518 | $ 97,019 |
| 1983 | 22,559 | 112,760 |
| 1984 | 72,311 | 197,737 |
| 1985 | 177,692 | 284,551 |
| 1986 | 222,741 | 335,188 |
| 1987 | 302,185 | 381,705 |
| 1988 | 589,300 | 660,816 |
| 1989 | 360,831 | 443,919 |
| 1990 | 348,734 | 443,769 |
| Total | $ 2,117,871 | $ 2,957,464 |

Source: Corporate Financial Performance Model

Exhibit VII-3

PSO

PROJECTED FINANCING REQUIREMENTS
($000)

| | Nuclear | |
|---|---|---|
| Year | Without CWIP | With CWIP |
| 1982 | $ 22,769 | $ - |
| 1983 | 58,619 | 33,689 |
| 1984 | 138,638 | 102,624 |
| 1985 | 229,902 | 173,639 |
| 1986 | 302,636 | 217,448 |
| 1987 | 364,587 | 251,362 |
| 1988 | 627,198 | 47[illegible]90 |
| 1989 | 523,992 | 305,740 |
| 1990 | 560,522 | 285,103 |
| Total | $ 2,828,863 | $ 1,840,295 |

Source: Corporate Financial Performance Model

PSO

PROJECTED FINANCIAL MEASURES



| | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 |
|---|---|---|---|---|---|---|---|---|---|
| **Nuclear Without CWIP:** | | | | | | | | | |
| Pretax Interest Coverage | 4.30x | 4.01x | 3.68x | 3.44x | 3.26x | 3.12x | 3.01x | 2.91x | 2.82x |
| AFDC as a % of Net Income Available for Common | 44.95% | 53.19% | 68.81% | 89.21% | 108.62% | 124.04% | 132.21% | 147.25% | 157.68% |
| Internal Cash Generation as a % of Construction Expenditures | 63.48% | 49.51% | 27.22% | 16.27% | 9.04% | 2.85% | 1.82% | (13.37)% | (25.01)% |
| **Nuclear With CWIP:** | | | | | | | | | |
| Pretax Interest Coverage | 4.61x | 4.37x | 4.11x | 3.97x | 3.88x | 3.80x | 3.72x | 3.70x | 3.67x |
| AFDC as a % of Net Income Available for Common | 3.27% | 4.87% | 5.61% | 5.96% | 5.88% | 6.52% | 5.06% | 3.16% | 2.72% |
| Internal Cash Generation as a % of Construction Expenditures | 83.75% | 70.99% | 44.49% | 34.83% | 32.55% | 31.47% | 24.18% | 33.48% | 34.81% |

**Source:** Corporate Financial Performance Model

Exhibit VII-4

# VIII. IMPACT ON CUSTOMERS

The purpose of this section is to present the estimated impact on the customer resulting from our low case capital cost projections over the period 1982-1990.

## PROJECTED REVENUE REQUIREMENTS

The analyses conducted in the previous section indicate that a significant amount of cash construction expenditures will be required which will be heavily dependent upon substantial infusions of external capital. To support the required project expenditures as well as all other construction requirements, operating requirements, and capital market costs, continuous rate relief will be necessary to maintain the required cost of capital to PSO and ensure that even the minimum financial measures previously outlined are attainable. We have attempted to determine the amount of annual revenue requirements needed by PSO under the various ratemaking scenarios described for our nuclear alternative. These projected revenue requirements were developed using the corporate financial performance model at PSO and include the results of ongoing operations based upon a 15% return on common equity.

**Exhibit VIII-1** sets forth the amount of projected annual and total revenue requirements under the inclusion and exclusion of CWIP scenarios for the nuclear alternative. As this exhibit shows, annual additional revenue requirements range from approximately $15 million to $97 million based on full inclusion of CWIP and from approximately $1 million to $50 million excluding CWIP. These annual requirements through 1990 total approximately $460 million for the CWIP inclusion case and $143 million assuming exclusion of CWIP.

## CUSTOMER IMPACT ANALYSIS

To gain an understanding of the potential impact on PSO's customers, **Exhibit VIII-2** was prepared to illustrate typical average cost per kwh based upon capital expenditures developed under our low case. This exhibit was developed from PSO's corporate financial performance model and is intended to show **relative impacts** rather than specific cost per kwh. Further, the amounts used to develop the relative comparisons in this section are not appropriate for comparisons to customer impacts shown in the capital recovery section of this report, since we have used our low estimate of the nuclear capital cost for the comparisons in this section. The average cost per kwh includes PSO's estimate of increases in operating and maintenance expenses and fuel cost during the period and are not limited solely to the effect of the cost of the nuclear facility.

**Exhibit VIII-2** shows the estimated cost per kwh for the period 1982-1990 for the nuclear facilities without CWIP rate base treatment. As shown on this schedule, the estimated cost increases from 4.68¢/kwh in 1982 to 7.35¢/kwh in 1990. This is a total increase over the period shown of 2.67¢/kwh or 57%.

**Exhibit VIII-2** also shows the estimated cost per kwh for the period 1982-1990 for the nuclear facilities with CWIP rate base treatment. As shown on this schedule, the estimated cost increases from 4.99¢/kwh in 1982 to 9.84¢/kwh in 1990. This is a total increase over the period shown of 4.85¢/kwh or 97%. The effect of this treatment when

compared to the without CWIP case is an increase in cost per kwh from 68¢/kwh to 9.84¢/kwh or 110%.

Since the corporate financial performance model does not extend beyond 1990, customer impacts subsequent to this date were not available. However, the relative impact on the customer in 1991 can be estimated by determining the capital carrying cost of Unit No. 1 when it goes into service in 1991. We have not attempted to reflect changes in fuel mix or operating cost for this comparison. The following table illustrates this impact based upon our low estimated capital cost for Unit No. 1.

Table VIII-1
Customer Impacts
1991 Nuclear Investment Carrying Cost

| | Without CWIP | With CWIP* |
|---|---|---|
| Total Investment (Millions) | $ 3,789 | $ 732 |
| Fixed Charge Factor | 20.16% | 20.16% |
| Total Carrying Cost (Millions) | $ 764 | $ 148 |
| Cents/kwh Increase at 65% CF | 11.67¢ | 2.26¢ |
| 1990 Cents/kwh | 7.35 | 9.84 |
| Total | 19.02¢ | 12.10¢ |
| % Increase Over 1990 | 159% | 23% |
| % Increase Over 1982 | 306% | 159% |

* Includes 1991 Cash Expenditures for Unit No. 2.

In summary, it is clear that the customer will experience an increase of 57% from 1982 to 1990 in rates primarily due to inflationary pressures. Including Black Fox will result in an increase of 110% through 1990 with an overall increase of 159% when the first unit is placed in service in 1991. Excluding Black Fox will result in an overall increase of 306% when the first unit is placed in service in 1991.

Exhibit VIII-1

PSO

ANNUAL REVENUE REQUIREMENTS

NUCLEAR
($000)

| Year | With CWIP | Without CWIP |
|---|---|---|
| 1982 | $ 86,474 | $ 49,967 |
| 1983 | 17,115 | 13,809 |
| 1984 | 14,962 | 1,840 |
| 1985 | 38,890 | 11,674 |
| 1986 | 42,294 | 6,344 |
| 1987 | 79,725 | 41,066 |
| 1988 | 47,536 | 964 |
| 1989 | 96,568 | 17,333 |
| 1990 | 36,719 | - |
| Total | $ 460,283 | $ 142,997 |

**Source:** Corporate Financial Performance Model

Exhibit VIII-2

PSO

CUSTOMER IMPACT ANALYSIS

NUCLEAR
(CENTS PER KWH)

| Year | With CWIP | Without CWIP |
|---|---|---|
| 1982 | 4.99¢ | 4.68¢ |
| 1983 | 5.42 | 5.09 |
| 1984 | 5.81 | 5.37 |
| 1985 | 6.20 | 5.55 |
| 1986 | 6.78 | 5.85 |
| 1987 | 7.36 | 6.15 |
| 1988 | 8.12 | 6.58 |
| 1989 | 9.11 | 7.02 |
| 1990 | 9.84 | 7.35 |

Source: Corporate Financial Performance Model

# IX. OVERALL ECONOMIC VIABILITY

The purpose of this section is to summarize the results of the analyses conducted, to assess the overall risks involved, and to determine the overall economic viability of the Black Fox Station project as it is currently conceived considering all appropriate impacting factors and resulting ramifications.

## REVIEW OF PROJECT EVOLUTION

In developing an overall conclusion on the economic viability of the project, it is helpful to again review the project history and understand the factors that have transpired and affected the project status to date. The initial decision to plan for and participate in a nuclear facility was made based on judgments regarding the supply and reliability of future fuel sources, the economics of alternative fuel sources, existing fuel mix, and the economic and political situations existing in the early 1970s. At that point in time and based on those conditions leading up to that period, nuclear power was thought to be capable of providing cheaper and more reliable energy with a high degree of operating safety. Events that occurred subsequent to the initial decision to proceed such as the oil embargo, severe economic cycles, TMI, and heightened consumer awareness have all combined to change the general perception of nuclear power from a financial, safety, and regulatory perspective. Most factors, however, have been beyond the control of PSO, management despite the significant effects each have had on project evolution.

Our review of the original application and the supporting documents of PSO, as well as the FES prepared by the NRC, indicate that the best information available during this period supported the decision to proceed with construction of a nuclear facility as a means of generating low cost, reliable, and safe energy. Subsequent to this date, several major factors severely affected both the cost and schedule of the project as originally anticipated. These factors, i.e., high and prolonged inflation, increased regulatory requirements, and TMI, have combined to generally render unrealistic and unattainable all original projections for facilities currently under construction or awaiting receipt of a construction permit. As a result of the effect of these events, PSO has substantially reduced on-site work effort to minimum site maintenance activities and adopted a passive posture toward the expenditure of future cash outlays or level of effort. The current posture of PSO appears to be limited to monitoring of NRC developments, response to regulatory initiatives within existing manpower levels, and avoidance of any further significant expenditures until the level of uncertainty is reduced and definitive direction obtained.

Although we have not reviewed in depth the broad expanse of all management actions, we believe that the evolution of the project to date is the result of the execution of prudent management decisions with respect to project initiation and minimization of unnecessary financial commitment. In our opinion, the adverse events which have occurred and affected project costs and schedules have been beyond the control of PSO, and management decisions to date have appropriately considered the interests of the ratepayer in both the short and long term.

## SUMMARY OF RESULTS

Earlier in this report, we developed projected capital costs for a generic 2,300 Mw nuclear facility and a 2,310 Mw coal-fired facility utilizing a conceptual cost model known as Concept-5. The results of this model, based on the specific assumptions underlying each case, are summarized in Table IX-1 on an absolute dollar and cost/kw basis.

Table IX-1
Summary of Capital Costs

| | | $ Billions | $/kw |
|---|---|---|---|
| Nuclear | - Low | $ 8.177 | $ 3,555 |
| | - Mid | 9.078 | 3,947 |
| | - High | 10.120 | 4,400 |
| Coal | - Low | 5.009 | 2,168 |
| | - Mid | 5.353 | 2,317 |
| | - High | 5.789 | 2,506 |

As this table shows, nuclear facility costs are significantly higher in each case and range from 1.63x to 1.75x, the projected capital costs for a similarly sized coal-fired facility.

Review was also made of the prospective financing requirements of PSO under the low nuclear case developed as well as the financial results implicit in the operating projections for the period 1981-1990. Total external financing requirements for the nuclear facility and other ongoing construction projects amount to $2.829 billion during this period if CWIP is excluded from rate base and $1.840 billion if the full amount of CWIP in each period is included. Analysis of the prospective financial condition of PSO assuming the low case and full exclusion of CWIP indicated that internal cash generation and AFDC measures would deteriorate to unrealistic levels after the mid-1980s. More importantly, however, even if CWIP is included in rate base and a full current cash return provided, internal cash generation declines to a level below that currently stated as minimally required for a AA electric utility by Standard & Poor's. Although our projections do not give effect to cost of capital changes, failure to meet minimum standards during heavy construction and with high financing requirements would result in an increase in the cost of capital and an increase in construction cost which would result in further deterioration.

The resulting additional annual revenues required by PSO to meet a 15% return on equity were determined based on our low case. This analysis indicated that with full inclusion of CWIP under the low nuclear alternative, more than $460 million of additional revenues would be necessary over the period 1982-1990 and that even if CWIP were fully excluded from rate base, approximately $143 million additional revenues would be required over the same period.

Based on our projected capital and operating costs, we developed ten-year levelized costs for the generic nuclear and coal-fired generating alternatives. This analysis indicated that it would cost approximately 175.95 mills/kwh on an annual basis for the nuclear facility compared to only 154.38 mills/kwh for the coal-fired facility. This difference yields a 14% advantage to the coal-fired facility.

## ANALYSIS OF MAJOR RISKS

The analyses conducted thus far have been limited to the development of projected costs and the impact of these costs on the financial condition of PSO and the average cost to the customer. These analyses and the related results provide an indication of the potential effects of continuance of the Black Fox Station project; however, they do not provide a complete perspective of the risks involved in either construction or operation. We believe that a complete evaluation of the overall economic viability of the Black Fox Station can only be achieved once the major risks affecting both PSO and the project are identified and assessed. For purposes of this discussion, we have characterized these risks into the following categories:

- Construction
- Financial
- Regulatory
- Political

Each of these risks is discussed below in further detail.

**Construction Risk** - The original baseline construction cost estimates prepared by most utilities involved in nuclear facilities have generally been understated in terms of actual experience. Factors such as unanticipated design problems, regulatory requirements, poor labor productivity, work stoppages, financing inabilities, and faulty craftmanship among others have affected the ability of the owner company to meet original baseline estimates. These problems have then manifested themselves in two ways. **First**, the total cost of the project is increased on an absolute dollar basis for each item which then has a rippling effect on other items such as the escalated cost over time and capitalized AFDC. These changes in various elements of the detailed baseline estimate require a reconstruction of the total baseline estimate and often indicate a need for additional capital financing or increased manpower to maintain the intended construction schedule. **Second**, the cumulative effect of a number of construction related problems may force an extension in the construction schedule which will dramatically affect the escalated costs and capitalized AFDC and which may result in even greater capital market costs than planned, which in a circular fashion exerts even further upward pressure on the baseline estimate. Our review of the historical industry experience in the construction of nuclear facilities indicates that extensions in construction duration have generally occurred as a result of the reasons previously enumerated. In our opinion, the likelihood of the continuance of this phenomenon is high and the effects of this occurrence significant. Utilizing our sensitivity analyses, a one-year slippage in commercial operation for both units from 1991 and 1994 to 1992 and 1995, respectively, would increase the cost of the facility by $1.066 billion.

Increased regulatory oversight of design and safety preparation sequences of the construction phase also increase the likelihood of an interrupted licensing and construction process. Additionally, current conditions indicate that energy consumption growth has declined and that total demand will grow at a lower rate in the future than previously experienced. The possibility of construction problems and schedule slippage at the Black Fox Station are high and add significant risk to PSO's ability to achieve its anticipated commercial operation dates within baseline estimates.

**Financial Risk** - The construction risks previously discussed typically result in an increased financial commitment on the part of the owner company. These increased

financial commitments have generally occurred during a period where overall economic conditions have seriously affected the costs of all labor and materials particularly those devoted to construction where related cost increases have exceeded the overall inflation rate by several percentage points. These higher rates of inflation for the construction industry and for nuclear facilities in particular have resulted in a significant compounding of costs to complete planned facilities despite efforts by the utility industry to control the growth in these costs.

Current economic conditions continue to be marked by protracted periods of high inflation and instability. Recent forecasts from government and major economic consulting and forecasting organizations indicate an improved overall economy with lower rates of inflation in the future; however, economic programs recently enacted by the federal government may have a significant impact on the economy as a whole. Consequently, it is unclear to what extent and over how long a period economic improvement will be achieved. For capital intensive industries, it is still likely that the rate of inflation will exceed the national average, particularly so for nuclear facility construction which requires substantial complements of labor for an intense and concentrated period.

Considering the financial risks facing PSO, the overall risks related to general economic conditions and the impact on costs must also be supplemented by discussion of capital market availability. The construction of a nuclear facility will require massive infusion of external capital regardless of the ratemaking treatment of CWIP or other factors. In the long run, capital market availability at reasonable cost can only be attained by the maintenance of a strong financial condition particularly where frequent market visitations for large capital amounts will be necessary. For PSO, which must maintain a construction schedule to meet the need for demand and minimize the potential for increased cost, adequate and timely access to the capital markets at a reasonable cost is imperative.

The risks facing PSO regarding overall economic conditions and capital market availability should also be evaluated in terms of the concomitant effect each have on the financial condition of PSO. To ensure continued market access at reasonable cost, PSO must maintain the minimum standards of financial health as determined by the investment community, particularly the rating agencies. Consequently, any adverse overall economic conditions which affect PSO will by their nature generally impact the ability of PSO to access the capital markets. This inability will in turn force the construction cost upward due to either higher financing costs or schedule delay related to financing inability. Once this situation occurs the likelihood of a spiraling effect is increased and the commitment to a project of the size of a nuclear facility becomes the point of balance for the company as a whole. In our opinion, the financial risks related to a project of the potential magnitude of the Black Fox Station are significant and are largely beyond the direct influence of PSO management.

**Regulatory Risk** - The risk of increasing regulation over the design, construction, and operation of nuclear facilities originates at the national level at the NRC. In recent years the scope and intensity of review by the NRC has significantly increased and resulted in the issuance of numerous rules and requirements which have impacted facility design and the overall licensing process. Since 1979, the NRC has devoted considerable attention to safety related problems identified as a result of TMI. The lessons learned from the development, occurrence, and handling of this incident will have substantial impact upon future design, construction, and operation requirements. Since PSO does not yet have a CP, it is likely that substantial effort will be expended

when hearings resume to address all potential TMI and safety design problems which could negatively affect the anticipated construction start date currently envisioned. Similarly, significant attention will be directed to the granting of a license to operate the facility and the possibility exists that experience by other nuclear facility operators will give rise to additional unanticipated problems which could negatively affect anticipated commercial operation.

It is extremely important to note that this study does not attempt to quantify the economic impact of significant future regulatory and statutory changes. As exhibited earlier, regulatory and statutory changes have been the primary factors affecting construction cost in the recent past. Although industry studies typically assume a "learning curve" whereby the negative design and construction related problems of the past are assumed to diminish in the future, the potential effects of TMI are unknown and may result in additional restrictions which will significantly affect projects under construction. Consequently, forthcoming regulatory and statutory requirements could substantially affect the projected construction costs of nuclear facilities from those projected today.

At the state level, the most significant risks faced by PSO are those related to overall ratemaking philosophy, particularly that to be afforded the Black Fox Station and the ability of PSO to secure financing approval from the Commission. Our analysis indicated that construction of a nuclear facility by PSO would be undesirable, if not impossible, unless CWIP were included as part of rate base. The financial results indicated by the corporate financial performance model were such that the ability to finance the project would probably be impaired, creating enormous fiscal maintenance difficulties.

Recently, the Commmission refused to approve a proposed long-term debt financing by PSO, a portion of which was to be used to finance generating plant construction. This decision apparently was based on uncertainty relative to the need for power and the requirements for significant new generating capacity. It is our understanding that the Commission decision is under appeal and will be decided sometime during the fall of 1981.

The combination of national and state regulatory risks can significantly impede the construction of the Black Fox Station and the ability to continue and maintain the required financial commitment to the project. In our opinion, there are substantial uncertainties relative to the licensing of the facility on a timely basis and in a manner which will facilitate the maintenance of a timely construction schedule. More importantly in the long run, however, we believe that substantial risks would be assumed related to the overall ratemaking treatment to be applied to PSO in total and the Black Fox Station in particular during construction.

**Political Risk** - The risks associated with the national and state political mood are less tangible in terms of description but are substantially greater in their potential impact on nuclear power and PSO. Despite any national policy which may be forthcoming, the risk remains that a policy favorable toward nuclear power would be ratified and maintained by subsequent policymakers. The incident at TMI served notice that a change in public mood and national perspective can occur within a short time interval and as a result of many different catalysts.

Substantial uncertainties exist with respect to the eventual cost and methods of waste disposal and decommissioning. These processes are significantly affected by the political process and resolution of current problems is uncertain at this time.

Eventual requirements and decisions may have a significant impact on the planning funding, and methods for these processes.

At the state level, the pc.itical risk is extremely volatile and tends to be influenced by the emotions and temperament of the various constituencies which are sensitive to events occurring at a given point in time but may not apply the necessary visionary perspective that is required for decisions where the implications may be permanent. To successfully carry a project through a period in excess of 13 years requires major assumptions related to the stability of the regulatory process and the conviction of future commissioners that the policies of an earlier period be continued in the future. The general rise in inflation will exert upward pressure on the costs of operation to electric utilities which will necessitate continued regulatory relief and potentially encourage increased vocal opposition to the policies of the si ting commission. Factors such as these complicate the Commission's decisionmaking process and m ri the political risk at the state level. In our opinion, significant risks related to political process exist which are beyond the control of PSO yet critical to the viat..ty of nuclear power and the Black Fox Station.

It is clear that all of the above risks are integrated and do not exist entirely independent of one another. Consequently, when evaluating the viability of the Black Fox Station, it is the aggregate or total risk that must be assessed rather than a combination of separate and discrete risks.

## CONCLUSIONS

The approach to our analysis of the overall economic viability of the Black Fox Station was described in detail at the beginning of this report. Our initial analysis was directed toward the determination of the need for power by PSO and the resulting additional generating capacity requirements. The next major activity was the development of the projected capital costs for generic nuclear and coal-fired alternatives with capacity equivalent to the planned Black Fox Station. The development of projected capital costs was then combined with an analysis of projected operating costs to develop total bus bar costs for the nuclear and coal-fired alternatives and to determine the most economic generating option. The total projected capital costs were also utilized to determine the applicable cash curves and required external financing. These projections then yielded prospective financial results for PSO over the period 1981-1990 which are the parameters of the corporate financial performance model. Finally, we assessed the impact on the customer of construction of a nuclear facility and measured this effect.

Based on our previous analyses and our evaluation of the risks associated with continuance and completion of the Black Fox Station, we have developed the following conclusions:

**Need for Power** - We believe that a legitimate need for power exists for PSO and that there is adequate demand to support the addition of the proposed facility. In fact, our analyses indicate that a need for additional power exceeding that provided by the Oklaunion facility could exist as early as 1987, the commercial operation date for this facility.

**Capital Costs** - Utilizing our mid case, we project that the cost to construct a nuclear facility will be approximately 70% higher than for a coal-fired facility. The capital cost projections indicate that a generic nuclear facility would cost \$9.078 billion compared to \$5.353 billion for a coal-fired facility. These projections are

based on numerous assumptions regarding inflation, schedule maintenance, costs to mitigate TMI related problems, and unexpected events. In our opinion, the costs stated above are a reasonable projection when compared to historical experience and expected conditions and may be understated due to future regulatory requirements.

Bus Bar Costs - Based on our mid case and the results of our operating cost analyses, the nuclear alternative is less economical than the coal-fired alternative. Our total ten-year levelized bus bar costs for the nuclear units are estimated at 175.95 mills/kwh compared to 154.38 mills/kwh for the coal-fired facility. This difference provides a 14% advantage to the coal-fired alternative under our mid case assumptions and would indicate no future economic benefit to construction of the nuclear facility notwithstanding the numerous risks that are present in completing the facility.

Impact on Financial Condition - Our analysis of the projected financial results of PSO utilizing our low nuclear case indicate that even optimistic assumptions regarding capital costs and ratemaking treatment of CWIP would not enable PSO to meet all the minimum standards of financial conditions currently stipulated by Standard & Poor's. We have only performed this analysis under our low case since it is obvious that increasing the financial commitment of PSO would only create further financial deterioration.

Impact on Customers - Based on our use of the low nuclear case in determining the additional revenue requirements of PSO, we project that the cost of power to the customer would approximately double between 1982 and 1990 from 4.99¢/kwh to 9.84¢/kwh if the cost of project related expenditures are included as part of the rate base and provided a full current cash return.

Management Prudence - We believe that the management of PSO has on the whole acted with due diligence and executed sound responses to numerous complex and constraining problems. During the course of our review nothing came to our attention that would indicate that the interests of the ratepayers were not considered in the planning of the facility or in the decision to limit future financial commitment to the project until additional regulatory direction is provided.

Economic Viability - Based on our review of the magnitude of the expenditures required to complete the Black Fox Station, the economic comparison of total generating costs, the potential effect of these expenditures on the financial condition of PSO, the cost to the customer, and the relative uncertainty with respect to numerous other factors, we conclude that it would not be in the best interests of either PSO or its customers to continue with construction of the Black Fox Station as presently conceived.

The combination of numerous and substantial uncertainties and the magnitude of the potential investment on the part of PSO would indicate that project continuance would require the absorption of substantial risk regardless of the effect of state regulation on the costs of the project or of any economic benefits which could have existed. We do not believe that optimistic assumptions regarding costs will materialize or that the financial position of PSO is sufficient to absorb the normal, much less the adverse, events which could arise. For these reasons, we believe that the prudent course of action at this time is the cancellation of the Black Fox Station nuclear facility as it is currently conceived and the analysis of alternative generating capacity options.

# X. CAPITAL RECOVERY ALTERNATIVES

In this section we discuss some of the various alternative capital recovery treatments which we believe are available to the Commission in dealing with the costs of cancellation of the Black Fox Station nuclear facility. Each of these alternatives is discussed in detail below.

## IDENTIFICATION OF ALTERNATIVES

We have concluded that as currently conceived the Black Fox Station nuclear facility should be cancelled in recognition of the lack of economic benefits to be derived and the potentially adverse circumstances which may arise during project continuation. Since PSO currently has approximately $200 million of investment in the project including nuclear fuel and AFDC, a methodology must be identified for handling these sunk costs and related contract cancellation charges for ratemaking purposes. We have identified several basic alternatives that are available and that provide a broad range of potential impacts on PSO and the ratepayer. We have utilized these basic alternatives to determine the effect of cancellation and conversion to a coal-fired facility and have further determined the effect that construction of an alternative coal-fired facility would have on total financial condition, financing requirements, revenue requirements, and customer impact under both inclusion and exclusion of CWIP scenarios. The basic cases we have identified are listed below and are based upon the reduction of nontransferable sunk costs by the amount of gain to be realized on the recent sale of certain oil and gas leases:

- Cancellation with a full write-off
- Conversion with amortization of nontransferable sunk costs over a ten-year period with no return applied to the unamortized balance
- Conversion with amortization of nontransferable sunk costs over a ten-year period with a partial return applied to the unamortized balance
- Conversion with amortization of nontransferable sunk costs over a ten-year period with a full return applied to the unamortized balance

Each of these alternatives were then input to the corporate financial performance model assuming the addition of two 670 Mw coal-fired units and under alternative CWIP treatments. These two units were assumed to be available for commercial operation in mid-1991 and -1993, respectively, to avoid the necessity of estimating operating costs and economic dispatch during the period under analysis. As a practical matter, we believe one unit could be required as early as 1988.

In developing the capital recovery scenarios identified above, we have attempted to offer the Commission a broad perspective of the options available as well as the ramifications of each. We have included a worst case scenario, i.e., total write-off, to illustrate the effects of no capital recovery and have also included several options for capital recovery which are based on a sharing of costs between PSO shareholders and the ratepayer. These risk sharing options effectively range from both a return of and return on capital to only a return of capital. Risk sharing is preferred since it will provide an opportunity to maintain a level of financial integrity for PSO by allowing for partial recovery. We have utilized the gain to be realized from recent oil and gas leases to

reduce the amount of write-off to be recovered and to minimize the effect on the ratepayer.

## DEVELOPMENT OF CANCELLATION AND CONVERSION COSTS

PSO's portion of the total project costs subject to cancellation were developed based on information contained in the June 1981 project status report. This information was supplemented by additional analyses prepared by PSO related to cancellation charges and conversion value. **Table X-1** summarizes the total cancellation and write-off costs before consideration of any gain from sale of oil and gas leases.

**Table X-1**
**Summary of Project Write-off**
**(millions)**

| | |
|---|---|
| Site and equipment | $ 155 |
| Fuel | 10 |
| AFDC | 35 |
| Total project cost at June 30, 1981 | 200 |
| Cancellation charges | 41 |
| Total abandonment cost | 241 |
| Conversion value | ( 54) |
| Net project write-off | $ 187 |

The total site and equipment costs of $155 million represent the sunk costs expended through June 30, 1981, for design, licensing, and site related work performed under the LWA. A minimal amount of payments have been made for yellowcake received to date and for prepayments required by DOE for the enrichment of material to be provided after the conversion process.

The most difficult projections of the write-off value of the project relate to the cancellation charges to be incurred as a result of the discontinuance of various labor, equipment, material, and professional services contracts currently maintained by PSO. A value of approximately $13 million was developed for the yellowcake components based on the difference between contract and projected market prices. A charge of approximately $28 million was developed based upon detailed review of various contracts and anticipated success in negotiations.

The conversion value is comprised of two elements, convertible site and related equipment values and the proceeds from the sale of equipment not usable in construction of a coal-fired facility. The values developed for the cancellation charges and conversion value are subject to significant modification depending upon market and other conditions and are intended only to provide an order of magnitude estimate of potential impact. Definitive amounts would be determinable after PSO begins contract negotiations with vendors and suppliers and after a replacement facility is designed.

## THE CONCEPT OF RISK SHARING

As previously mentioned, we have identified and evaluated several capital recovery alternatives which are predicated upon sharing of the costs of cancellation between PSO and the ratepayer. We believe that the Commission should keep in mind the general goal of regulation when determining the appropriate treatment for the total project cancellation costs of the Black Fox Station. These general goals are:

- To provide reliable service to the ratepayer at a reasonable cost
- To maintain the financial integrity of the utility which will assure the availabilty of investor capital at a reasonable cost

Theoretically, these goals will be achieved concurrently through the execution of prudent management decisions and the application of appropriate ratemaking treatment. When this situation exists, benefits accrue to the ratepayer in terms of high quality service and to the utility in the form of maintenance of financial integrity and capital market accessibility. Hence, benefits are derived by both ratepayers and the utility under the traditional maxims of regulation.

Since the attendant benefits derived from regulation are theoretically received and shared by the ratepayer and the utility, it follows that any uncontrollable risks inherent in the ongoing operation of the utility should be shared to some extent between these parties. Many of the decisons required of utility management are subject to a great deal of uncertainty, yet when the results of any prudent decisions are favorable both parties share in the benefits received. Conversely, should adverse conditions arise which are beyond the control of utility management, equity would dictate that the financial burdens created also be shared between the parties. To do otherwise would create the perception of an unequal sharing of risks and benefits by the utility and the ratepayers. We believe such an action should be avoided to maintain a proper equilibrium between the risk/benefit relationship. In the case where a utility and its shareholders are perceived to bear the total risk of adverse, unforeseen, and uncontrollable events, the cost of capital to that utility would by definition increase. Conversely, if the ratepayer were perceived as bearing the full responsibility for such adverse events, subsequent regulatory action would theoretically correct this imbalance in risk sharing by reducing the cost of capital or correction of the specific imbalance to bring the risk/benefit relationship again into equilibrium.

In evaluating a situation which would require the assumption of risk by the ratepayer, it is obviously important to establish whether the conditions which arose were beyond the control of utility management and whether any evidence exists which clearly indicates imprudent decisionmaking by management. In the case where management could in fact exercise significant influence or control over certain events or where evidence points to the execution of imprudent management decisions, such risk sharing would not be appropriate since the implicit responsibility borne by management to their ratepayers would have been foregone. Under these conditions, the risks and results of adverse events should be borne by the utility and its stockholders. During our review, nothing came to our attention that would indicate that the best interests of the ratepayers were not considered by PSO management. We believe that the adverse events which have occurred and have impacted project cost and schedule have been beyond the control of PSO management and that management has acted in a prudent manner. Consequently, we believe that the risk sharing concept previously discussed is applicable to the current situation and that any losses or write-offs to be determined by the Commission be shared between PSO and the ratepayer.

## IMPACT ON FINANCIAL CONDITION

The potential cancellation of the Black Fox Station nuclear facility will require the determination of appropriate treatment of approximately $200 million of sunk costs and $41 million of cancellation charges. These amounts could, of course, be offset by conversion value to a coal-fired facility at the same site and by the effect of the gain to be realized from sale of certain oil and gas leases. Nonetheless, the magnitude of the dollars to be considered - approximately $142 million - requires that several options be evaluated in terms of the effect on PSO and its ratepayers prior to adoption of any particular methodology. To facilitate these overall evaluations, we have identified the following alternatives available to the Commission providing for capital recovery and which embody the principles of risk sharing as previously discussed. Each of these alternatives assumes that the annual amortization of unrecovered costs is included as part of cost of service.

**Full Inclusion With No Return** - Under this alternative, the total amount of unamortized write-off is included in rate base for ratemaking purposes; however, no return on the unamortized balance is allowed. This option effectively allows a return of capital but no return on invested capital and results in the lowest revenue requirement from the ratepayer.

**Full Inclusion With Partial Return** - This alternative allows for inclusion of the unamortized balance as part of rate base and provides for a return on capital equivalent to the actual embedded costs for debt and preferred stock during the amortization period. In effect, this option provides for a return of capital and a return on capital to those classes of investors other than the common stockholders.

**Full Inclusion With Full Return** - The final alternative allows for inclusion of the unamortized balance as part of rate base and provides for a return to all classes of investors. This option creates the greatest revenue requirement for the ratepayer and minimizes the risk to the stockholder. Although this option forces the assumption of major risk on the ratepayer, it does not eliminate risk to the stockholder since he must still absorb the financing requirements and risks attendant with a replacement facility.

We believe that these alternatives based on risk sharing are the most viable options available to the Commission to assist in the maintenance of quality and reliable service at the lowest cost and to maintain the financial integrity of PSO. The results of our analysis of each of these alternatives is presented below along with the results of the full write-off scenarios with no provision for capital recovery.

**Full Write-off Without Lease Gain** - As originally discussed, the total amount of the write-off related to the cancellation of the Black Fox Station nuclear facility amounts to $187 million including the value of sunk costs transferrable to a coal-fired alternative. To determine the impact of a write-off of this magnitude on PSO, we have utilized the Company's corporate financial planning model to project the impact on certain financial results. **Exhibit X-1** illustrates the results of the total write-off assuming no financial compensation in recognition of the sunk investment. As this exhibit shows, the absorption of the full write-off will result in approximately an $81.9 million loss after taxes. The magnitude of this loss would have the effect of creating a deficit in retained earnings of approximately $46.5 million. Since PSO would have a net loss, it is not particularly relevant to review financial integrity parameters; however, to indicate the negative impact on earnings, the projected return on average common equity under this alternative would be approximately (28.17)%.

In analyzing the impact of this write-off on PSO, it is important to recognize the potential ramifications that extend beyond the absolute figures presented above. We believe that the following factors must be considered:

**First,** a utility with negative retained earnings is unable to pay dividends and consequently would not be in a position to attract equity capital.

**Second,** a utility with an inability to attract equity capital is severely hampered in its ability to attract debt capital since the security of the lenders is diminished.

**Third,** a utility that is unable to attract capital at a reasonable cost is unable to finance the necessary system growth and replacement to meet additional demand for power.

**Fourth,** a utility that is incapable of meeting the demands of system growth or maintenance will soon be in violation of its enfranchised responsibility of providing quality, reliable, and safe service.

It is imperative that the Commission understand that a single year write-off of the magnitude related to the Black Fox Station will affect more than the year in which the loss is taken. The confidence of the investment community in PSO and more importantly the confidence in regulation within the state of Oklahoma could be lost and extremely difficult to regain, if indeed it can be restored to an effective level at all. Further, the ramifications of adverse Commission action could affect other utilities with majority operations within the state since the investment community could require the cost of capital to be increased in general for Oklahoma utilities.

**Full Write-off With Lease Gain** - During the conduct of our analysis, PSO negotiated the sale of certain oil and gas leases which were expiring. As a result of this sale, PSO will realize approximately a $45 million gain which would be available to offset the Black Fox Station write-off. We believe that the interests of the ratepayer and PSO would both be advanced by utilizing the amount of this gain to offset the amount of the loss resulting from abandonment of the nuclear facility. Under this scenario, the absorption of the net write-off will result in approximately a $39.7 million loss after taxes as shown on **Exhibit X-1.** Even with the offset of the gain on the sale of leases, retained earnings would still be reduced to a deficit value of approximately $12.0 million. The projected return on common equity under this case would be approximately (12.21)%.

Although this case does not provide as devastating an impact on PSO as the full write-off of the net loss without consideration of the oil and gas lease gain, neither does it ameliorate or improve the financial condition of the Company. The ramifications alluded to above could also prevail in this instance regardless of the absolute dollar differences in each case. The operative factor is the ability to issue dividends which again is compromised with its attendant consequences.

Although we have presented the results of these two scenarios, we do not believe that either of the two are viable options without some form of additional capital recovery. It is obvious that under either of the above scenarios the financial position of PSO is untenable and wholly unacceptable when considered within the bounds of sound and reasoned judgment. Under either of these conditions and regardless of assumed mitigating circumstances, the ultimate cost and risk of these alternatives will be borne by the ratepayer.

In the remaining scenarios we evaluate the potential effect of certain capital recovery alternatives. These alternatives are based upon a ten-year amortization period, during which time the costs of the write-off (net of the gain on the lease sale) would be recovered, and provide for the construction of two 670 Mw coal-fired replacement plants with commercial operation dates of mid-1991 and -1993, respectively. Although the actual costs of debt and preferred stock as determined in this proceeding would be the most appropriate for application to the unamortized balance, we have utilized the projected costs as developed by the corporate financial performance model to demonstrate order of magnitude impact. To provide a better perspective of financing capability, we have developed these cases with and without inclusion of CWIP in rate base which demonstrates the impact on PSO financial integrity measures under each alternative. Exhibits X-2 through X-6 contain summaries of the results of our projections.

**Full Inclusion With No Return** - Under this scenario no return is provided to any class of investor during the amortization of the write-off. Based on our projections, the following results would be obtained under this scenario:

**With CWIP:**

- Pretax interest coverage would range from 3.65x to 4.00x.
- Internal cash generation would range from 23.14% to 86.49% of annual construction expenditures.
- AFDC as a percentage of net income available for common would range from 3.35% to 10.19%.
- Return on average common equity would range from 12.60% to 14.76%.
- Financing requirements would range from zero to approximately $479 million annually.

**Without CWIP:**

- Pretax interest coverage would range from 2.96x to 3.93x.
- Internal cash generation would range from .09% to 81.50% of annual construction expenditures.
- AFDC as a percentage of net income available for common would range from 14.81% to 134.22%.
- Return on average common equity would range from 12.64% to 14.78%.
- Financing requirements would range from zero to approximately $607 million annually.

This scenario provides the worst of conditions for PSO under the alternative capital recovery cases and would minimize the impact on the ratepayer.

**Full Inclusion With Partial Return** - In this scenario a partial return equivalent to the projected embedded costs of debt and preferred stock is provided on the unamortized write-off in each period. The following results would be obtained under this scenario:

**With CWIP:**

- Pretax interest coverage ranges from 3.66x to 4.21x.
- Internal cash generation ranges from 2[illegible].32% to 91.80% of annual construction expenditures.
- AFDC as a percentage of net income available for common ranges from 3.34% to 9.89%.
- Return on average common equity ranges from 13.43% to 14.82%.
- Financing requirements would range from zero to approximately $478 million annually.

**Without CWIP:**

- Pretax interest coverage ranges from 2.97x to 4.14x.
- Internal cash generation ranges from .19% to 86.80% of annual construction expenditures.
- AFDC as a percentage of net income available for common ranges from 13.72% to 133.72%.
- Return on average common equity ranges from 13.45% to 14.84%.
- Financing requirements would range from zero to approximately $607 million annually.

This scenario would reduce the impact of the write-off on PSO but would require somewhat greater payment from the ratepayer.

**Full Inclusion With Full Return** - Under this scenario the full cost of capital is earned on the unamortized balance of the write-off in each period. The results indicated under this scenario are provided below:

**With CWIP:**

- Pretax interest coverage ranges from 3.69x to 4.69x.
- Internal cash generation ranges from 23.70% to 104.00% of annual construction expenditures.
- AFDC as a percentage of net income available for common ranges from 3.[illegible]8% to 9.37%.
- Return on average common equity ranges from 15.00% to 16.01%.
- Financing requirements would range from zero to approximately $476 million annually.

**Without CWIP:**

- Pretax interest coverage ranges from 3.00x to 4.62x.
- Internal cash generation ranges from .49% to 98.98% of annual construction expenditures.
- AFDC as a percentage of net income available for common ranges from 11.73% to 132.32%.
- Return on average common equity ranges from 15.00% to 15.99%.
- Financing requirements would range from zero to approximately $606 million.

In this scenario the impact of the write-off on PSO would be minimized while the effect would be maximized on the ratepayer. As previously discussed, we have not attempted to modify the underlying assumptions of the corporate financial performance model. Our projections are based on management's financial and operating plans, except as affected by our basic assumptions regarding replacement power and capital recovery.

## IMPACT ON CUSTOMERS

The financial results of each of the scenarios for capital recovery indicate the extent to which the financial condition of PSO is affected under the different alternatives. It is equally important, however, to review the potential effect upon the ratepayer of these alternatives since the magnitude of the write-off in combination with the requirements for replacement generating capability are substantial. **Exhibits X-7** through **X-9** summarize this information:

**Full Inclusion With No Return** - As discussed above, this alternative will result in the smallest impact on the customer over the period analyzed.

**With CWIP:**

- Annual revenue requirements for the write-off would be $14.2 million beginning in 1982 as shown on **Exhibit X-7.**
- Annual additional revenue requirements including two 670 Mw coal replacement units range from approximately $24 million to $116 million and total approximately $507 million over the period as shown on **Exhibit X-8.**
- Cents/kwh for all customers increase from 4.86¢ in 1982 to 9.22¢ in 1990 as shown on **Exhibit X-9.**

**Without CWIP:**

- Additional revenue requirements in 1982 for the write-off would be $14.2 million as shown on **Exhibit X-7.**
- Annual additional revenue requirements range from approximately $9 million to $65 million and total approximately $270 million over the period as shown on **Exhibit X-8.**
- Cents/kwh for all customers increase from 4.80¢ in 1982 to 7.51¢ in 1990 as shown on **Exhibit X-9.**

**Full Inclusion With Partial Return** - In this alternative a return equivalent to the debt and preferred stock costs is allowed which increases the revenues to be received by PSO compared to the previous scenario. The results of this alternative are presented below:

**With CWIP:**

- Additional revenue requirements for the write-off would be $21.9 million in 1982 declining to $14.2 million in 1991 as shown on **Exhibit X-7.**
- Annual additional revenue requirements range from approximately $31 million to $119 million and total approximately $551 million over the period as shown on **Exhibit X-8.**
- Cents/kwh for all customers increase from 4.93¢ in 1982 to 9.23¢ in 1990 as shown on **Exhibit X-9.**

**Without CWIP:**

- Additional revenue requirements for the write-off would be $21.9 million in 1982 declining to $14.2 million in 1991 as shown on **Exhibit X-7.**
- Annual additional revenue requirements range from approximately $10 million to $73 million and total approximately $314 million over the period as shown on **Exhibit X-8.**
- Cents/kwh for all customers increase from 4.87¢ in 1982 to 7.51¢ in 1990 as shown on **Exhibit X-9.**

**Full Inclusion With Full Return** - Under this scenario all costs are reimbursed to PSO along with a full return on the unamortized balance in each period. This alternative provides the greatest additional revenue requirement from the ratepayer.

**With CWIP:**

- Additional revenue requirements for the write-off would be $39.5 million in 1982 declining to $14.2 million in 1991 as shown on **Exhibit X-7.**
- Annual additional revenue requirements range from approximately $51 million to $124 million and total approximately $639 million over the period as shown on **Exhibit X-8.**
- Cents/kwh for all customers increase from 5.08¢ in 1982 to 9.25¢ in 1990 as shown on **Exhibit X-9.**

**Without CWIP:**

- Additional revenue requirements for the write-off would be $39.5 million in 1982 declining to $14.2 million in 1991 as shown on **Exhibit X-7.**
- Annual additional revenue requirements range from approximately $14 million to $91 million and total approximately $402 million over the period as shown on **Exhibit X-8.**
- Cents/kwh for all customers increase from 5.02¢ in 1982 to 7.54¢ in 1990 as shown on **Exhibit X-9.**

Exhibit X-1

PSO

# RESULTS OF WRITE-OFFS
($ millions)

| | Without Lease Gain | With Lease Gain |
|---|---|---|
| Net Loss After Taxes | $(81.9) | $(39.7) |
| Retained Earnings | (46.5) | (12.0) |
| Return on Common Equity | (28.17)% | (12.21)% |

Source: Corporate Financial Performance Model

Exhibit X-2

PSO

CAPITAL RECOVERY

PRETAX INTEREST COVERAGE

| Year | No Return With CWIP | No Return Without CWIP | Partial Return With CWIP | Partial Return Without CWIP | Full Return With CWIP | Full Return Without CWIP |
|---|---|---|---|---|---|---|
| 1982 | 4.00x | 3.93x | 4.21x | 4.14x | 4.69x | 4.62x |
| 1983 | 3.89 | 3.80 | 4.07 | 3.99 | 4.46 | 4.37 |
| 1984 | 3.73 | 3.61 | 3.89 | 3.77 | 4.19 | 4.06 |
| 1985 | 3.69 | 3.52 | 3.81 | 3.64 | 4.06 | 3.87 |
| 1986 | 3.71 | 3.49 | 3.81 | 3.58 | 4.00 | 3.77 |
| 1987 | 3.69 | 3.40 | 3.76 | 3.47 | 3.90 | 3.60 |
| 1988 | 3.66 | 3.29 | 3.70 | 3.34 | 3.78 | 3.41 |
| 1989 | 3.66 | 3.11 | 3.69 | 3.14 | 3.74 | 3.18 |
| 1990 | 3.65 | 2.96 | 3.66 | 2.97 | 3.69 | 3.00 |

Source: Corporate Financial Performance Model

Exhibit X-3

PSO

CAPITAL RECOVERY

INTERNAL CASH GENERATION

| | No Return | | Partial Return | | Full Return | |
|---|---|---|---|---|---|---|
| Year | With CWIP | Without CWIP | With CWIP | Without CWIP | With CWIP | Without CWIP |
| 1982 | 86.49% | 81.50% | 91.80% | 86.80% | 104.00% | 98.98% |
| 1983 | 72.36 | 66.55 | 76.40 | 70.79 | 85.19 | 79.49 |
| 1984 | 54.92 | 48.06 | 57.75 | 50.90 | 63.08 | 56.24 |
| 1985 | 61.92 | 49.97 | 64.53 | 52.58 | 69.78 | 57.83 |
| 1986 | 55.55 | 42.03 | 57.51 | 44.00 | 61.25 | 47.67 |
| 1987 | 32.91 | 23.05 | 33.65 | 23.79 | 35.06 | 25.20 |
| 1988 | 25.73 | 16.33 | 26.06 | 16.70 | 26.72 | 17.34 |
| 1989 | 23.14 | 8.78 | 23.32 | 8.97 | 23.70 | 9.33 |
| 1990 | 26.07 | .09 | 26.18 | .19 | 26.47 | .49 |

**Source:** Corporate Financial Performance Model

Exhibit X-4

# PSO

## CAPITAL RECOVERY

## AFDC AS A PERCENT OF INCOME AVAILABLE FOR COMMON

| Year | No Return With CWIP | No Return Without CWIP | Partial Return With CWIP | Partial Return Without CWIP | Full Return With CWIP | Full Return Without CWIP |
|---|---|---|---|---|---|---|
| 1982 | 4.28% | 14.81% | 3.96% | 13.72% | 3.38% | 11.73% |
| 1983 | 6.29 | 19.88 | 5.88 | 18.54 | 5.15 | 16.29 |
| 1984 | 7.31 | 28.88 | 6.87 | 27.14 | 6.16 | 24.38 |
| 1985 | 8.25 | 39.14 | 7.85 | 37.33 | 7.17 | 34.17 |
| 1986 | 8.92 | 47.63 | 8.56 | 45.79 | 7.95 | 42.71 |
| 1987 | 10.19 | 63.41 | 9.89 | 61.68 | 9.37 | 58.63 |
| 1988 | 7.72 | 76.37 | 7.59 | 74.98 | 7.33 | 72.67 |
| 1989 | 4.39 | 110.03 | 4.35 | 109.00 | 4.26 | 107.02 |
| 1990 | 3.35 | 134.22 | 3.34 | 133.72 | 3.30 | 132.32 |

**Source:** Corporate Financial Performance Model

Exhibit X-5

PSO

CAPITAL RECOVERY

RETURN ON AVERAGE COMMON EQUITY

| | No Return | | Partial Return | | Full Return | |
|---|---|---|---|---|---|---|
| Year | With CWIP | Without CWIP | With CWIP | Without CWIP | With CWIP | Without CWIP |
| 1982 | 12.63% | 12.64% | 13.66% | 13.66% | 16.01% | 15.99% |
| 1983 | 12.66 | 12.66 | 13.56 | 13.59 | 15.50 | 15.50 |
| 1984 | 12.60 | 12.63 | 13.43 | 13.45 | 15.00 | 15.00 |
| 1985 | 13.01 | 13.07 | 13.67 | 13.71 | 15.00 | 15.00 |
| 1986 | 13.34 | 13.43 | 13.91 | 13.97 | 15.00 | 15.00 |
| 1987 | 13.78 | 13.85 | 14.20 | 14.25 | 15.00 | 15.00 |
| 1988 | 14.22 | 14.26 | 14.48 | 14.53 | 15.00 | 15.00 |
| 1989 | 14.53 | 14.58 | 14.68 | 14.72 | 15.00 | 15.00 |
| 1990 | 14.76 | 14.78 | 14.82 | 14.84 | 15.00 | 15.00 |

Source: Corporate Financial Performance Model

Exhibit X-6

# PSO

## CAPITAL RECOVERY

## FINANCING REQUIREMENTS

| | No Return | | Partial Return | | Full Return | |
|---|---|---|---|---|---|---|
| Year | With CWIP | Without CWIP | With CWIP | Without CWIP | With CWIP | Without CWIP |
| 1982 | $ -0- | $ -0- | $ -0- | $ -0- | $ -0- | $ -0- |
| 1983 | 31,459 | 36,969 | 27,905 | 33,198 | 20,278 | 25,656 |
| 1984 | 40,622 | 49,901 | 37,084 | 46,405 | 30,714 | 39,994 |
| 1985 | 28,612 | 42,942 | 25,836 | 40,166 | 20,154 | 34,488 |
| 1986 | 43,524 | 62,495 | 40,953 | 59,923 | 36,148 | 55,215 |
| 1987 | 162,560 | 193,130 | 160,547 | 191,117 | 156,680 | 187,248 |
| 1988 | 329,719 | 379,309 | 328,245 | 377,588 | 325,235 | 374,684 |
| 1989 | 479,181 | 587,128 | 478,033 | 586,027 | 475,681 | 583,754 |
| 1990 | 435,829 | 607,742 | 435,335 | 607,247 | 433,710 | 605,565 |
| Total | $ 1,551,506 | $ 1,959,616 | $ 1,533,938 | $ 1,941,671 | $ 1,498,600 | $ 1,906,604 |

Source: Corporate Financial Performance Model

Exhibit X-7

# PSO

## CAPITAL RECOVERY

## REVENUE REQUIREMENTS FOR SUNK COST

| Year | No Return | Partial Return | Full Return |
|---|---|---|---|
| 1982 | $ 14,200 | $ 21,916 | $ 39,480 |
| 1983 | 14,200 | 21,393 | 36,735 |
| 1984 | 14,200 | 20,760 | 33,679 |
| 1985 | 14,200 | 20,006 | 31,211 |
| 1986 | 14,200 | 19,206 | 28,789 |
| 1987 | 14,200 | 18,385 | 26,156 |
| 1988 | 14,200 | 17,470 | 23,489 |
| 1989 | 14,200 | 16,742 | 21,417 |
| 1990 | 14,200 | 15,616 | 18,192 |
| 1991 | 14,200 | 14,200 | 14,200 |
| | $ 142,000 | $ 185,694 | $ 273,348 |

**Source:** Corporate Financial Performance Model

Exhibit X-8

PSO

CAPITAL RECOVERY

REVENUE REQUIREMENTS FOR SUNK COST AND

TWO 670 MW COAL-FIRED UNITS

| Year | No Return | | Partial Return | | Full Return | |
|---|---|---|---|---|---|---|
| | With CWIP | Without CWIP | With CWIP | Without CWIP | With CWIP | Without CWIP |
| 1982 | $ 72,041 | $ 65,416 | $ 79,774 | $ 73,135 | $ 97,322 | $ 90,662 |
| 1983 | 30,372 | 28,548 | 37,334 | 35,857 | 52,495 | 50,904 |
| 1984 | 23,654 | 18,525 | 30,685 | 25,217 | 43,281 | 37,989 |
| 1985 | 33,777 | 26,743 | 39,122 | 32,087 | 50,528 | 43,455 |
| 1986 | 25,549 | 19,789 | 30,813 | 25,054 | 40,368 | 34,458 |
| 1987 | 69,614 | 54,412 | 73,647 | 58,444 | 81,461 | 66,386 |
| 1988 | 41,604 | 15,567 | 44,774 | 19,120 | 50,876 | 25,080 |
| 1989 | 116,3[illegible] | 32,290 | 118,935 | 34,471 | 123,610 | 39,1[illegible]7 |
| 1990 | 94,225 | 8,816 | 95,633 | 10,225 | 93,914 | 13,733 |
| Total | $ 507,195 | $ 270,106 | $ 550,717 | $ 313,610 | $ 638,855 | $ 401,834 |

Source: Corporate Financial Performance Model

Exhibit X-9

PSO

CAPITAL RECOVERY INCLUDING

TWO 670 MW COAL UNITS

CENTS/KWH

| | No Return | | Partial Return | | Full Return | |
|---|---|---|---|---|---|---|
| Year | With CWIP | Without CWIP | With CWIP | Without CWIP | With CWIP | Without CWIP |
| 1982 | 4.86¢ | 4.80¢ | 4.93¢ | 4.87¢ | 5.08¢ | 5.02¢ |
| 1983 | 5.29 | 5.22 | 5.35 | 5.28 | 5.47 | 5.40 |
| 1984 | 5.63 | 5.52 | 5.69 | 5.57 | [illegible] | 5.68 |
| 1985 | 5.87 | 5.70 | 5.91 | 5.74 | 6.00 | 5.83 |
| 1986 | 6.21 | 6.00 | 6.25 | 6.04 | 6.32 | 6.11 |
| 1987 | 6.61 | 6.28 | 6.64 | 6.31 | 6.69 | 6.37 |
| 1988 | 7.22 | 6.70 | 7.24 | 6.73 | 7.28 | 6.78 |
| 1989 | 8.25 | 7.16 | 8.27 | 7.17 | 8.30 | 7.21 |
| 1990 | 9.22 | 7.51 | 9.23 | 7.51 | 9.25 | 7.54 |

Source: Corporate Financial Performance Model

# XI. RECOMMENDATIONS

The purpose of this section is to summarize the results of our analysis of the economic viability of the Black Fox Station nuclear facility and the capital recovery alternatives available to the Commission and to present our recommendations related to these issues. In reviewing the recommendations contained herein it is important to remember that our conclusions and recommendations are related to the Black Fox Station as it is currently conceived and do not contemplate major changes such as modification of project participation between the owners. Additionally, our conclusions are based upon assumptions regarding circumstances and events which have yet to occur and which are subject to change. Accordingly, our recommendations must be considered as based upon the application of our professional judgement and reliance on the best information available.

## SUMMARY OF CONCLUSIONS

Based on the analyses previously conducted, we have reached the following conclusions regarding the Black Fox Station nuclear project, PSO, and the regulatory requirements associated with previous and expected events or conditions:

**Need for Power** - We believe that the requirement for additional generating capability by PSO currently exists and will continue to prevail regardless of the load management program recently implemented. We believe that the need for additional power could arise as early as 1988 and that PSO will be required within the very near future to make appropriate plans for the provision of additional required energy.

**Black Fox Station Project Viability** - Our analyses indicate that the construction of a nuclear facility would not result in the most economical source of energy as measured by total ten-year levelized bus bar costs. The effects of capital cost escalation have resulted in substantial increases to total construction cost which is the single largest component of total bus bar costs. These capital cost increases coupled with projected increases in certain components of the nuclear fuel cycle have effectively resulted in the cost of power from the proposed nuclear facility exceeding that available from a coal-fired generating alternative. Regardless of the economic comparisons, however, there are numerous and substantial uncertainties related to the construction of a nuclear facility. Based on the magnitude of the financing requirements involved and the high degree of uncertainty with respect to various risks, we do not believe that it would have been appropriate to continue with the construction of the nuclear facility as currently conceived, even if marginal economic benefits were shown to prevail.

**PSO Financial Condition** - Although PSO is currently rated AA, our review of the historical and prospective financial condition of the Company indicates that significant difficulties exist with respect to the ability to meet certain minimum financial integrity parameters and to ensure continued capital market access at reasonable cost. We believe that PSO could have future financing difficulties even under the reduced cash requirements of two 670 Mw coal-fired generating alternatives with inclusion of CWIP as part of rate base.

**Cost to Customers** - Our analysis indicate that even with the cancellation of the nuclear facility and replacement with a coal-fired generating alternative, rates are likely to almost double between the current date and 1990. This situation will occur as a result of the high inflation that has historically been experienced and is expected to continue at some level over the decade and the additional construction and operating requirements of PSO. Consequently, even the construction of coal-fired generating facilities which have historically been relatively inexpensive to complete will require significant capital investment and result in continued high escalation in cost to the customer.

**Capital Recovery** - Based on our review of the results of a total write-off scenario, we believe that the Commission must provide for some level of recovery of capital investment if PSO is to maintain any level of financial integrity. To require the absorption of a full write-off by PSO of all costs expended to date plus those cancellation charges to be determined could irreparably impair the financial condition of PSO which would not be in the interest of the ratepayers under any conditions.

**Regulatory Requirements** - As previously noted, the costs of construction of a coal-fired generating facility are projected to rise to a level that will require significant financial commitment on the part of PSO. Since these commitments are substantial and will arise over an extended period of time, it is imperative that continued access to capital markets be provided. We believe that capital market accessibility can be achieved through consideration of CWIP inclusion in rate base at the appropriate time to maintain PSO financial integrity. Indeed, in our analyses, inclusion of CWIP is imperative to allow even the opportunity to achieve minimum standards of financial performance. We believe that the development of a Commission policy with respect to CWIP is necessary to provide some basis for the evaluation of future rate applications and the effects of significant construction programs.

## RECOMMENDATIONS

As a result of these conclusions, we have developed several recommendations to address the problems enumerated above. In developing these recommendations, we have sought to assure that the interests of both the ratepayer and PSO are considered and that neither party is afforded unrealistic treatment at the expense of the other. Our recommendations are designed to enable PSO to continue to attract capital at reasonable cost and to minimize the effect of rate increases on the ratepayers.

### Cancellation/Conversion

We recommend that the Black Fox Station nuclear facility as it is currently conceived be cancelled and that the site be considered as applicable to construction of replacement coal-fired generating facilities. We have utilized the conversion assumption in our capital recovery analysis since it represents a logical choice by PSO. We have not, however, evaluated this choice in economic terms compared to other potential replacement scenarios. Although PSO would be required to restore the Black Fox Station site to its original condition were it to be fully abandoned as a generating site, the Company has several options that are also available. These would include:

- Pursuit of co-ownership opportunities with Western Farmers Electric Cooperative, Inc. at its Hugo site

- Pursuit of co-ownership opportunities with other C&SW companies

- Construction of additional facilities at the Northeastern site

- Construction of additional facilities at other sites

- Purchase of power from other utilities

It was beyond the scope of this study to evaluate these alternatives and PSO itself has not undertaken such an analysis. It is clear, however, that such study will be necessary in the very near future since our analysis of load forecasts indicates that a potential need for additional generating capability could be required as early as 1988. Given the timetable necessary to obtain all necessary permits and to construct required facilities, it is imperative that an economic evaluation of alternatives be conducted at the earliest opportunity.

During our analysis of the Black Fox Station, we also briefly reviewed the possibilities of only constructing a single 1150 Mw nuclear unit which has a projected total cost under our mid case of $4.618 billion. Our analysis indicates that the expenditures associated with this alternative also would place PSO in the position of being unable to meet minimum financial measures as currently maintained by the rating agencies. We have not compared total levelized bus bar costs for this facility with an alternative coal-fired facility since it is unclear as to what size facility PSO would construct, what participation PSO would obtain, and in what period it would be commercially available. In addition to these problems, there are several uncertainties, which we are unable to evaluate and which would have substantial impact on the validity of this alternative.

**First,** cancellation of the second unit would constitute a significant change in the evaluation process administered by the NRC when this agency developed the original FES and would likely necessitate a significant reevaluation of matters previously considered closed. This evaluation could effectively require a reiteration of much of the administrative process accomplished to date notwithstanding the possibility that the NRC could view such change as requiring complete review of all aspects of the licensing process.

**Second,** the magnitude of the dollars involved is still so large as to create difficulties in financing even with inclusion of CWIP rate base. These financial commitments would, of course, be understated due to the numerous risks and uncertainties previously cited.

**Third,** it is unclear how the current project ownership agreement would be affected and to what extent the current partners would choose to participate in a single 1150 Mw unit.

In light of all these uncertainties and the potential for adverse events to significantly affect capital costs, we do not believe that construction of a single 1150 Mw unit would be in the best interests of PSO or the ratepayer.

### Capital Recovery

We recommend that the Commission allow PSO to recover the costs of the Black Fox Station investment to date and that a return equivalent to the actual costs of debt and preferred stock as determined in this proceeding be provided on this level of investment. The total amount of sunk costs and potential cancellation charges, however, should be reduced to reflect the gain on the sale of certain oil and gas leases. The net

amount of the write-off would then be approximately $142 million which we would recommend be returned to PSO over a ten-year period in equal amortization. The average unamortized balance in each period would also be provided a return based on the actual costs of debt and preferred stock as determined in this proceeding. These amounts are, of course, estimated at this time; however, we believe that they reasonably demonstrate the order of magnitude involved. After all cancellation charges are known, the Commission should adjust the remaining unamortized balance to reflect these changes.

We believe that capital recovery is essential to the financial health of PSO and that it is imperative that the investment community retain confidence in the Commission and in PSO. We do not believe that the decision to construct the Black Fox Station nuclear facility was imprudent and we believe that PSO has considered the interests of the ratepayer in its planning and management of the project.

Our analysis of the projected financial condition of PSO under the capital recovery scenario of full inclusion with partial return also included the review of the effect of construction of two 670 Mw coal-fired generating facilities to replace the nuclear units. This analysis clearly indicates that unless CWIP is included in rate base during the years of high construction expenditures, the financial condition of PSO will deteriorate to levels which will not allow the attraction of capital at reasonable cost. Consequently, we believe that CWIP will be required to be included in rate base at some point to allow PSO to maintain a minimum level of financial integrity and assure capital market accessibility. We would suggest that the Commission define the minimum levels of financed integrity to be attained and evaluate each rate application of PSO in light of these parameters.