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APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES §§§

APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVIEW OF THE SALE AND LEASEBACK OF PALO VERDE NUCLEAR GENERATING STATION UNIT 2 §§§§

DOCKET NOS. 7460 AND 7172

June 16, 1988

Stipulation of some parties, as amended, adopted by the Commission; El Paso Electric Company request to change rates approved in part and denied in part.

[1] RATEMAKING - INVESTED CAPITAL - PLANT IN SERVICE - GENERATING UNITS - PRUDENCE OF PARTICULAR INVESTMENTS

The Commission order in this docket does not resolve issues of decisional prudence arising after the effective date of the Commission's order in Docket No. 1981 insofar as such decisional prudence may affect the regulatory treatment of Palo Verde Unit 3; those issues shall remain open in future proceedings. All issues of decisional prudence arising prior to the effective date of the Commission's order in this docket have been resolved as to the regulatory treatment of Palo Verde Units 1 and 2. "Decisional prudence" specifically includes any decisions, acts, or omissions relating to El Paso Electric Company's decision to become or to remain a 15.8% participant in the Arizona Nuclear Power Project, including but not limited to the prudence of El Paso Electric Company's load forecasting methodologies and practices.

[2] RATEMAKING - COST OF SERVICE - RATE MODERATION/PHASE-IN PLANS
RATEMAKING - INVESTED CAPITAL - DEFERRED ACCOUNTING TREATMENT

In this docket, El Paso Electric Company is granted a Texas base rate increase of $45,694,691; of this amount, $20,769,479 is to be immediately incorporated into rates, and $24,925,212 is to be deferred for later recovery, as specified in the rate moderation plan (RMP) approved in this case. The terms of the RMP are consistent with the requirements of Statement of Accounting Standards No. 92 (FASB 92) dated August 1987 and are set out in more detail in Paragraph 5 of the Amended and Restated Stipulation.

[3] PROCEDURE - STIPULATION AND SETTLEMENT

It is the policy of this Commission to encourage the settlement of proceedings before this Commission, for the following reasons: (1) settlements usually reduce the expense to ratepayers and taxpayers of resolving the issues presented; (2) settlements usually conserve the resources of the Commission available for ratemaking; (3) settlements allow the parties to the settlement to avoid the risk that a litigated resolution to the issues may produce results that are unacceptable to such parties; and (4) settlements promote peaceful relations among the parties.

[4] PROCEDURE - STIPULATION AND SETTLEMENT

Even where some parties to a proceeding do not agree to a stipulated result, it is reasonable to adopt such a stipulation if: (1) the parties opposing the stipulation have notice that the stipulation may be considered by the Commission and an opportunity to be heard on their reasons for opposing the stipulation; (2) the matters contained in the stipulation are supported by a preponderance of the credible evidence in the case; (3) the stipulation is in accordance with applicable law; (4) the stipulation results in just and reasonable rates; and (5) the results of the stipulation are in the public interest, including the interest of those customers represented by parties opposing the stipulation.

[5] SALE OF PROPERTY AND MERGERS - PUBLIC INTEREST FINDING - TIME OF PUBLIC INTEREST FINDING

The issue of whether El Paso Electric Company's sale and leaseback transactions relating to Palo Verde Unit 2 are in the public interest is reserved for decision in El Paso Electric Company's next rate case after Docket Nos. 7460 and 7172.

[6] RATEMAKING - INVESTED CAPITAL - TAXATION-RELATED ITEMS

In Docket Nos. 7460 and 7172, the rate base treatment of accumulated deferred income taxes (ADFIT) relating to future tax depreciation associated with the disallowance was not resolved and shall remain an open issue to be addressed in the next rate case, except as specified in Paragraph 2 of the Amended and Restated Stipulation. If the treatment of ADFIT in the next rate case results in a lower Texas revenue requirement, the "overcollection" during the first year of the rate moderation plan (RMP) will be flowed back to the ratepayers in the revenue requirement for the second RMP year. The amount of this "overcollection" will be calculated as if the treatment of ADFIT used in the next rate case had been used in the calculation of the revenue requirement in this docket.

[7] RATEMAKING - RATE DESIGN - ELECTRIC - FUEL AND PURCHASED POWER - FIXED FUEL FACTORS

In Docket Nos. 7460 and 7172, the Commission established a new Texas system fuel factor for EPEC with differences for different voltage levels of service. All fuel-related costs remain subject to reconciliation, including the appropriate regulatory ratemaking treatment to be afforded El Paso Electric Company's involvement in the Palo Verde Uranium Venture.

[8] RATEMAKING - INVESTED CAPITAL - CWIP AND AFUDC - RECLASSIFICATION TO PLANT-IN-SERVICE

Palo Verde Unit 3 does not meet the Commission's current in-service criteria as set forth in P.U.C. SUBST. R. 23.21(c)(2)(E), and will remain under construction until completion of the Arizona Interconnection Project

(AIP). If PURA requires a Certificate of Convenience and Necessity (CCN) for AIP, the signatories to the stipulation agree not to oppose the grant of that CCN.

[9] RATEMAKING - INVESTED CAPITAL - USED AND USEFUL PROPERTY - EXCESS CAPACITY

The only issues remaining open on the Palo Verde plant arising under either the prudence or "used and useful" standard are: (1) the appropriate application of the "used and useful" test (the resolution of the decisional prudence issues in Docket Nos. 7450 and 7172 cannot be used as evidence in a Unit 3 case except to demonstrate that such issues have been resolved); (2) whether excess capacity actually exists on El Paso Electric Company's system with regard to Unit 3 (excess capacity issues relating to Units 1 and 2 may be raised once the phase-in described in Paragraph 5 of the Amended and Restated Stipulation is concluded, but not before); (3) where the prudence of a utility's forecasting and decisional processes leading to the construction of plant is not at issue, whether it is permissible to exclude such plant from rate base as excess capacity on the theory that it is not used and useful in providing utility service; (4) if so, what is the appropriate regulatory and accounting treatment for excess capacity (this issue might include whether deregulation is an appropriate regulatory alternative and, if so, a determination of the terms on which deregulation should be implemented); (5) the reasonableness of Unit 3 operation and maintenance (O&M) expenses; (6) the reasonableness of Unit 3 construction costs except any costs directly related to the construction or startup of Units 1 and 2, as delineated in Exhibit A of the Amended and Restated Stipulation.

[10] RATEMAKING - COST OF SERVICE - NUCLEAR DECOMMISSIONING COSTS

The decommissioning fund for El Paso Electric Company's share of decommissioning expense for Palo Verde shall be held in an irrevocable trust; the contingency percentage shall be ten percent.

[11] RATEMAKING - RATE DESIGN - ELECTRIC - SPECIAL TARIFFS AND RIDERS - ECONOMIC RECOVERY RIVERS

As part of the rate moderation plan, El Paso Electric Company's Economic Recovery Rider (ERR) shall continue to be available for those classes and at the demand charge discount level approved by the Commission in Docket No. 6350 through the end of the initial four-year phase-in period for the base rate increases agreed to in Paragraph 5 of the Amended and Restated Stipulation. Thereafter, the continuation of the ERR shall be subject to reevaluation in light of the then prevailing economic circumstances and such other factors as the Commission shall deem relevant at the time. The disposition and allocation of any revenue shortfall resulting from application of the ERR shall be resolved in El Paso Electric Company's next general rate filing with this Commission.

DOCKET NOS. 7460 AND 7172

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION
APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVIEW OF THE SALE AND LEASEBACK OF PALO VERDE NUCLEAR GENERATING STATION UNIT 2	§ § § §	OF TEXAS

EXAMINERS' REPORT

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Acronyms and Abbreviations

ABFUDC -	Allowance for Borrowed Funds Used During Construction
ACD -	Automatic Call Director
ACRS -	Accelerated Cost Recovery System
ADFIT -	Accumulated Deferred Federal Income Tax
A&E/4CP -	Average and Excess - Four Coincident Peak
AEFUDC -	Allowance for Equity Funds Used During Construction
AFUDC -	Allowance for Funds Used During Construction
A&G -	Administrative and General
AIF/NESP	Atomic Industrial Forum/National Environmental Studies Project
AIP -	Arizona Interconnection Project
ANPP -	Arizona Nuclear Power Project
APA -	Administrative Procedure and Texas Register Act
APS -	Arizona Public Service Company
BBRT -	Big Bend Resources Trust
CAR -	Corrective Action Report
CAT -	Construction Appraisal Team
CE -	Combustion Engineering
CF -	Capacity Factor
CLM -	Conservation and Load Management
CP -	Coincident Peak
CWIP -	Construction Work in Progress
DCF -	Discounted Cash Flow
DECON -	Prompt removal/dismantling decommissioning of a nuclear generating facility
D&O -	Directors and Officers
DOD -	Department of Defense
DOE -	Department of Energy
EAF -	Equivalent Availability Factor
EEI -	Edison Electric Institute
ENTOMB -	Safe storage entombment decommissioning of a nuclear generating facility

EPEC -	El Paso Electric Company
EPFC -	El Paso Funding Corporation
EPGM -	El Paso Gas Marketing
EPGT -	El Paso Gas Transportation Company, Inc.
EPHC -	El Paso Hydrocarbons Company
EPNG -	El Paso Natural Gas Company
EPRI -	Electric Power Research Institute
ERR -	Economic Recovery Rider
EUU -	Equivalent Unplanned Unavailability
FASB -	Financial Accounting Standards Board
FCNB-H -	First City National Bank of Houston
FERC -	Federal Energy Regulatory Commission
FL&R -	Franklin Land & Resources
FNB-B -	First National Bank of Boston
GSU -	Gulf States Utilities Company
HL&P -	Houston Lighting and Power Company
IBES -	Institutional Brokerage Estimate Service
IID -	Imperial Irrigation District
IRS -	Internal Revenue Service
ITC -	Investment Tax Credit
KSB -	Klein, Schanzlin & Becker
kW -	kilowatt
kWh -	kilowatt-hour
LESOP -	Leveraged Employee Stock Option Plan
LPSI -	Low Pressure Safety Injection
MMBTU -	million British thermal units
MW -	megawatt
MWH -	megawatt-hour
NERC -	North American Electric Reliability Council
NRC -	Nuclear Regulatory Commission
NSSS -	Nuclear Steam Supply System
O&M -	Operations and Maintenance
OPC -	Office of Public Utility Counsel
PNM -	Public Service Company of New Mexico
PROMOD -	Computer program simulating system dispatch of EPEC's generation resources and purchase of off-system power
PURA -	Public Utility Regulatory Act
PVD -	Primary Voltage Discount
PVNGS -	Palo Verde Nuclear Generating Station
PVUV -	Palo Verde Uranium Venture
QPE -	Qualified Progress Expenditure
RCNLD -	Reproduction Cost New Less Depreciation
RCS -	Reactor Coolant System; also Residential Conservation Service
RFI -	Request for Information
RGRT -	Rio Grande Resources Trust
SAFSTOR -	Safe storage mothballing decommissioning of a nuclear generating facility
SALP -	Systematic Assessment of Licensee Performance
SFAS -	Statement of Financial Accounting Standards
S&P -	Standard & Poor's
SPS -	Southwestern Public Service Company
T&D -	Transmission and Distribution
TMI -	Three Mile Island
TNP -	Texas-New Mexico Power Company
TRA -	Tax Reform Act
TRASOP -	Tax Reduction Act Stock Option Plan
TSA -	Texas State Agencies
WRF -	Water Reclamation Facility

DOCKET NOS. 7460 AND 7172

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EXAMINERS' REPORT

I. Procedural History

El Paso Electric Company (EPEC or the Company) filed this request for a change in rates in all unincorporated areas in Texas in which it serves on April 6, 1987. As originally filed, the effect of the proposed changes was a base rate increase (including miscellaneous revenues) of $83,488,886, or 55.24 percent, over adjusted non-fuel revenues for the test year ended September 30, 1986; as amended at the hearing on the merits, a base rate increase of $76,476,924. In addition, the Company requested a fuel revenue decrease of $12,199,878. EPEC simultaneously filed identical requests for rate increases within the municipalities retaining original jurisdiction over electric utility rates. The ratemaking ordinances of the City of El Paso and the Towns of Clint, Socorro, Vinton, Anthony and Van Horn were timely appealed to the Commission by the company, and were consolidated with the environs docket. All Texas customers and rate classes are affected by the requested changes.

Also consolidated with this docket was Docket No. 7172, the Company's application under section 63 of the Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987) (PURA or the Act) for Commission review of the sale and leaseback of its share of Unit 2 of the Palo Verde Nuclear Generating Station.

The first prehearing conference in the rate application was convened on April 22, 1987, with Mary Ross McDonald and Cornelia M. Adams presiding. (Howard V. Fisher was assigned to the docket in October 1987.) A procedural schedule was established and motions to intervene were granted. Following the first prehearing conference, other motions to intervene were granted; two intervenors later withdrew. One intervenor, the Texas State Agencies, was dismissed by oral order on October 22, 1987, on the motion of EPEC and with the concurrence of the general counsel. TSA appealed that oral order to the Commission on October 28. On November 6, the examiners issued an oral ruling staying the October 22 order pending Commission action on the appeal. The time for acting on TSA's appeal was extended by the Commission several times; it remained pending before the Commission at the time this report was issued and was to be taken up at the Commission's first regularly scheduled final order meeting in February 1988.

The parties and their representatives in the rate proceeding are:

El Paso Electric Company (EPEC or the Company)	David H. Wiggs, Jr. Michael D. McQueen Mitzi Turner Terry Bassham Eduardo A. Rodriguez Carmen L. Gentile David Carroll George Lyons
Office of Public Counsel (OPC)	Geoffrey M. Gay Barbara Day
City of El Paso (City)	Norman J. Gordon Nanette G. Williams Tom Diamond
ASARCO Incorporated	J. Alan Holman Dennis P. Reis Sandra Neisser Boone James W. Checkley, Jr.
W. Silver, Inc.; Chevron, U.S.A.; American Convertors; & Allen Bradley	Martha V. Terry Marianne Carroll
Phelps-Dodge Refining Corp.	Wayne Shirley Alton Hall
Department of Defense (DOD)	Dellon E. Coker David. A. McCormick

Border Steel Rolling Mills & El Paso Iron & Metal	C. Michael Ginnings
United Steelworkers of America	Juan Aranda
Providence Memorial Hospital	Malcolm Harris
Mrs. Rosie Wallin	
Town of Clint	The Honorable Michael Goodwin, Mayor
Town of Socorro	Richard Contreras
Town of Vinton	Tom Diamond
Town of Anthony	The Honorable Jerry M. Montgomery, Mayor
Town of Van Horn	
General Counsel	Bret J. Slocum Alfred R. Herrera George M. Fleming

The procedural history of Docket No. 7172 is discussed in Section VIII below.

Prehearing conferences were convened in Austin on May 29, June 16, June 24, July 10, and July 27, 1987, for the purpose of resolving discovery disputes among the parties and ruling on requests for modification of the procedural schedule. Several of these prehearing conferences were recessed and reconvened by telephone conference call to follow up on the status of the negotiations of outstanding disputes. The examiners issued written orders ruling on those discovery disputes not resolved by the parties through negotiation, and on other contested matters.

The hearing on the merits convened on August 13, 1987, and adjourned on December 9, 1987. Appearances were entered, at various times, by David H. Wiggs, Jr., Michael D. McQueen, Mitzi Turner, Terry Bassham, Eduardo A. Rodriguez, Carmen L. Gentile, David Carroll and George Lyons for EPEC; Norman J. Gordon, Nanette G. Williams, and Tom Diamond on behalf of the City of El Paso; J. Alan Holman, Sandra Neisser Boone, and James W. Checkley, Jr. representing ASARCO, Incorporated; Martha V. Terry and Marianne Carroll for W. Silver, Inc., et al.; Alton Hall representing Phelps-Dodge; Michael Ginnings for Border Steel; David A. McCormick on behalf of the Department of Defense; W. Scott McCollough and Karen E. Young for the Texas State Agencies;and Bret J. Slocum, Deputy General Counsel for Electric, Alfred R. Herrera, Assistant General Counsel, and George M. Fleming, Assistant General Counsel, representing the Commission staff and the public interest.

Originally, the hearing and briefing schedule were roughly divided into four phases. Phase I concerned most of the revenue requirement issues, and briefs on those issues were filed October 20, 1987, by EPEC, the City of El Paso, DOD, the Texas State Agencies, and general counsel. Phase II was devoted to nuclear plant/prudence issues for the most part, and briefs were filed December 4, 1987, by EPEC, the City of El Paso, ASARCO, and general counsel. Phase III encompassed cost allocation, revenue distribution, and rate design issues; briefs were filed December 16, 1987, by EPEC, the City of El Paso, Phelps-Dodge, ASARCO, Border Steel, W. Silver, Inc., the Texas State Agencies, DOD, and general counsel.

Reply briefs on all issues in all three phases, due December 23, 1987, were filed by EPEC, the City of El Paso, ASARCO, W. Silver, Inc., Texas State Agencies, and general counsel.

A stipulation among some of the parties was filed on October 22, 1987, so a fourth phase concerning the stipulation was added. Supplemental testimony regarding the stipulation was filed by EPEC, Border Steel, the City of El Paso, OPC, and the Commission staff. A hearing on the stipulation was conducted following the close of Phase III. Briefs on the stipulation were filed December 23, 1987, by EPEC, the City of El Paso, ASARCO, W. Silver, Inc., Phelps-Dodge, Border Steel, OPC, Texas State Agencies, and general counsel. Stipulation reply briefs were filed January 8, 1987, by EPEC, the City of El Paso, Border Steel, Phelps-Dodge, OPC, Texas State Agencies, and general counsel.

The Company's original effective date in the rate application, May 12, 1987, was suspended by the examiners for the statutory period of 150 days until October 9, 1987. The Company extended that effective date; it is now June 24, 1987. Because there were 68 days of actual hearing on the merits of the rate proceeding, the suspension period has been extended 106 days from November 17, 1987, until March 6, 1988, by operation of PURA §43(d).

Due to time constraints, not every point raised by every participant in this case has been expressly discussed in this Examiners' Report. The examiners have read the entire record and considered every issue raised by the evidence and in the briefs and reply briefs. To the extent that arguments have not been addressed in this Report, they are rejected for lack of merit.

II. Jurisdiction

EPEC is an electric utility as defined in PURA §3(c)(1), and thus is subject to the jurisdiction of the Public Utility Commission of Texas under PURA §§2 and 16(a). The Commission has jurisdiction of the rate application pursuant to PURA §§17(d) and (e), 27, 37, and 43, and of the notice of the sale and leaseback transaction under PURA §63.

The Company published notice of its requested rate increase four times in newspapers of general circulation in each county in which it serves, as follows: El Paso Times/Herald Post (El Paso County), April 11, 18, 25, and May 2, 1987; Van Horn Advocate (Culberson County), April 16, 23, 30, and May 7, 1987; Hudspeth County Herald & Dell Valley Review (Hudspeth County), April 17 and 24 and May 1 and 8, 1987. The Company also provided notice of its filing to the appropriate officer of each affected municipality simultaneously with its filing at the Commission. EPEC has substantially complied with the requirements of P.U.C. PROC. R. 21.22(b)(1) and (3).

Although the Company included in its rate filing package a copy of the notice (EPEC Ex. No. 1, Vol. 8, Schedule T), there is no affirmative statement that individual notice to customers was provided as required in P.U.C. PROC. R. 21.22(b)(2). It would be helpful for the Company to state in its exceptions where such proof appears in the record or, if it has been omitted, to submit with its exceptions an affidavit or other appropriate proof of compliance with P.U.C. PROC. R. 21.22(b)(2).

EPEC gave notice of its filing in Docket No. 7172 by publishing once each week for two consecutive weeks in newpapers of general circulation in each county served by EPEC notice of the sale and leaseback transaction, as ordered by the examiner under P.U.C. PROC. R. 21.25. The required notice was published in the El Paso Times (El Paso County) on December 8 and 15, 1986; in the Van Horn Advocate (Culberson County) on December 11 and 18, 1986; and in the Hudspeth County Herald-Dell County Review (Hudspeth County) on January 9, 1987.

III. Description of the Company

El Paso Electric Company is an investor-owned electric utility which generates, purchases, transmits, distributes and sells electricity in a service area of approximately 10,000 square miles in Texas and New Mexico. At test year end, EPEC provided electric service to 173,079 customers in Texas, and 46,180 customers in New Mexico. The Company's service area extends 110 miles from the City of El Paso northwesterly to the Caballo Dam in New Mexico, and 120 miles southeasterly to Van Horn, Texas. The area includes the municipalities of El Paso, Van Horn, Anthony, Socorro, and Clint in Texas; and Las Cruces, Hatch, and Sunland Park in New Mexico. EPEC also serves the White Sands Missile Range in New Mexico.

During the test year ending September 30, 1986, EPEC's generation mix consisted of 32 percent natural gas; 12 percent coal; 13 percent uranium; and 43 percent purchased power. Approximately 50 percent of the fuel and purchased power costs incurred in meeting EPEC's demand was for purchased power. The remaining 50 percent of the cost of fuel was incurred at EPEC's generating units, with a breakdown of 37 percent for natural gas, 7 percent for uranium, and 6 percent for coal.

EPEC and Texas-New Mexico Power Company (TNP) are two-thirds and one-third participants, respectively, in the Eastern Interconnection Project, which consists of a 125-mile, 345-kilovolt transmission line from the White Sands Missile Range in New Mexico to Artesia, New Mexico, and a back-to-back direct current terminal at Artesia. Put in service on September 21, 1984, this interconnection ties together two National Electric Reliability Councils: the Western Systems Coordinating Council and the Southwestern Power Pool.

EPEC is a participant in the Arizona Nuclear Power Project (ANPP), which built and operates the Palo Verde Nuclear Generating Station (PVNGS). Located 50 miles west of Phoenix, Arizona, ANPP is a joint effort of several southwestern companies which built the 3,810-megawatt nuclear generating station. Arizona Public Service Company (APS) is the operating agent for the project. EPEC owns a 15.8 percent undivided interest in Units 1 and 3 (200 megawatts from each unit). Although EPEC sold its 15.8 percent ownership interest in Unit 2 in two sale/leaseback transactions (the first agreement, completed in August 1986 sold 73.5 of EPEC's share in Unit 2; the second sold the remaining 26.5 percent in December 1986), the Company still receives power from Unit 2. The Commission determined that Unit 1 was in commercial operation for ratemaking purposes as of February 24, 1986, and that Unit 2 was in commercial operation for ratemaking purposes as of September 22, 1986. At test year end, Unit 3 was 99.9 percent complete, and the entire project was 99.8 percent complete.

EPEC also owns and operates or has interests in four other electric generating stations, three of which are in the El Paso area. The fourth is a 7 percent undivided interest in two units of the Four Corners Generating Station near Farmington, New Mexico. The total nominal generating capacity of the company's generating units and interests in Four Corners and PVNGS Units 1 and 2 is 1303 megawatts.

IV. Quality of Service

The Company provided information regarding the quality of its service in the rate filing package. (EPEC Ex. No. 1, Vol. 8, Schedule L-1.) The adequacy and reliability of EPEC's service to its customers was not an issue in this docket. For that reason, this report concludes that the quality of service offered by EPEC is adequate, and that the quality of service should not be considered either favorably or adversely in fixing a reasonable return on invested capital, as permitted under section 39(b) of PURA.

V. Conservation and Load Management

Michael C. Conley, Manager-Energy Management for EPEC, presented testimony on the Company's Energy Efficiency Plan, the extent to which the goals of the Plan have been met, the status of all conservation and load management programs, and the studies being undertaken in this area. (EPEC Ex. No. 1, Vol. 5, Tabs 38 and 39, and Vol. 6, Tab 39; Tr. at 556-618.) His prefiled direct testimony included a copy of the Energy Efficiency Plan submitted by EPEC on December 31, 1985 (EPEC Ex. No. 1, Vol. 5, Tab 39 at MCC-1), and an updated version of that plan, prepared in January 1987, which superseded the one filed December 31, 1985 (EPEC Ex. No. 1, Vol. 5, Tab 39 at MCC-2).

Staff witness Nat Treadway, Regulatory Analyst and Economist, testified about his review of the conservation and load management portion of EPEC's Energy Efficiency Plan. He also offered his recommendations on the appropriate treatment of conservation and load management expenses and the consideration conservation efforts should be given in setting EPEC's rate of return. (Staff Ex. No. 7; Tr. at 1466-1572.) Rebuttal testimony was given by Wayne N. Brown, founder and president of Planergy, Inc., an energy management and consulting firm. (EPEC Ex. No. 41, Tab 1; Tr. at 2128-2178.)

This issue was addressed in the initial briefs of EPEC (Applicant's Brief - Phase I - Revenue Requirement, pp. 130-141) and the City of El Paso (Brief of the City of El Paso - Phase I - Revenue Requirements, pp. 23-26) and in the reply briefs of EPEC (Applicant's Reply Brief, pp. 9-11) and the general counsel (General Counsel's Reply Brief [Phase I and Phase II], pp. 11-13).

A. Discussion of the Evidence

Mr. Conley and Mr. Treadway offered definitions of terms which bring into focus the discussion of conservation and load management. To Mr. Conley, the term "conservation" means the efficient use of an energy source which could be achieved through time of use, good insulation, conservation methods, and use of efficient appliances. He conceded that "conservation" could, in some cases, be used to mean that a person, through conservation efforts, can, in effect, maintain the same level of lifestyle but at a lesser cost of electricity, but he said he would not make a generality of that statement. Mr. Treadway testified that efficient use of energy in customer-owned end-use devices permits exising comfort levels at a lower total system cost, and, like Mr. Conley, pointed out that conservation of resources occurs by reducing heating and cooling losses in buildings, raising equipment efficiencies, and reorganizing processes to use waste heat. Mr. Treadway further distinguished conservation programs, which reduce the demand and energy use measured at the customer's meter, from load management programs, which have an impact on demand but little or no impact on energy use.

Mr. Treadway summarized the Electric Power Research Institute (EPRI) classification of the various demand management programs into six load shape modification objectives. Those load shape objectives directed toward reducing the rate of growth of peak demand are:

- Peak clipping (reduction of the system peak loads);
- Load shifting (shifting load from on-peak to off-peak periods);
- Strategic conservation (reducing sales and changing patterns of use); and
- Flexible load shape (a concept related to reliability and a planning constraint).

Those related to increasing sales are:

- Valley filling (building off-peak loads); and
- Strategic load growth (general increase in sales beyond valley filling increases; may include electric vehicles, industrial process heating, and automation).

Mr. Brown agreed with Mr. Treadway that some load shape objectives legitimately relate to increasing sales.

Mr. Treadway also pointed out that the terms "conservation and load management," "demand-side management," "end-user programs," or "end-use efficiency" may be used interchangeably, but that "energy efficiency" does not refer to utility controlled options, such as generation, transmission, or distribution system efficiency improvements or purchases from renewable energy suppliers and independent power producers.

Mr. Conley's discussion of EPEC's Energy Efficiency Plan for 1986-1987 includes two major types of programs, residential and commercial/industrial. The 1985 Plan was updated for this rate case to reflect EPEC's shift in emphasis from residential customers to commercial and industrial customers. According to Mr. Conley, the unique consumption patterns within EPEC's service territory mean there are fewer potential gains to be made in energy savings in the residential class. More than 85 percent of all EPEC residential customers have evaporative cooling, which uses substantially less electricity than refrigerated air conditioning, and 94.9 percent of residential customers use gas heating. EPEC's average monthly residential consumption is only 478 kWh per customer (down from 525 kWh in 1977) compared to 1,027 kWh average monthly residential usage per customer for all investor-owned electric utilities in Texas. (EPEC Ex. No. 1, Vol. 5, Tab 39, at MCC-3, MCC-4, MCC-5; Vol 6, Tab 39 continued, at MCC-8.) Commercial and industrial customers provide 77 percent of EPEC's revenue; this usage thus provides the greatest opportunity for energy savings. Mr. Conley explained that, because of the low level of residential usage, EPEC has shifted its emphasis from residential programs to commercial and industrial programs where larger demand and energy services per dollar spent for conservation and load management programs are more likely.

It was Mr. Treadway's opinion that EPEC satisifed the requirements of Rule 23.22 for stating its energy efficiency goals. He agreed that the goals are measurable, but warned that it is often difficult to distinguish among the possible causes of year to year changes in load factor. Mr. Treadway was critical of EPEC's updated Plan for listing only the number of participants in each program and not relating these program participation levels to the stated goal of increasing load factor by one percent. Because EPEC made no estimate of savings for each program, Mr. Treadway could not evaluate the extent to which prior goals had been reached. Another shortcoming he identified was EPEC's failure to relate the extent to which the Energy Efficiency Plan achievements have offset EPEC's need for new generating facilities or permitted its reduced reliance on less efficient generating facilities. In addition, Mr. Treadway faulted EPEC for making no attempt to screen a comprehensive set of alternatives in either the residential or the commercial and industrial sectors, and he disagreed with Mr. Conley's view that EPEC has fewer conservations options than other utilities.

Mr. Conley also explained the criteria for selection of the conservation and load management (CLM) programs included in EPEC's Energy Efficiency Plan. The overriding consideration is the unique situation of EPEC and its service territory: currently, it is forecasted that EPEC has adequate capacity for a period six years into the future. Because CLM benefits are derived primarily from avoidance of expensive new generating plants, typical criteria for program selection are not, in Mr. Conley's opinion, appropriate for EPEC. That there is adequate capacity dictates a CLM strategy aimed at retaining customers on the EPEC system and improving the system load factor, because the spread of fixed costs over more kWh sales reduces the need for rate increases and improves the operating efficiencies of the system, according to Mr. Conley.

A second criterion for program selection is the equity within a customer class: the weatherization program and Project CARE were selected mainly for equity and community interest reasons. It was Mr. Treadway's opinion, however, that inclusion of Project CARE is for information only, since it is a redistribution program and not an end-user program. He further observed that common measures of equity include the rate impact of resource additions and the availability of customer services. One measure of equity is whether customers have the opportunity to participate in a particular program; another is whether a high percentage of customers actually do participate. Mr. Treadway suggested that EPEC evaluate the impact of refrigerator and small commercial lighting programs to determine whether they could satisfy the "equity and community need" criterion for program selection.

The third criterion for including a program is customer need. For example, the walk-through residential and commercial energy audits, information programs, and workshops are offered because, in Mr. Conley's view, EPEC customers expect and demand such services.

Finally, the fourth criterion is the "window of opportunity." Under typical cost/benefit analysis, some programs would not have a positive benefit ratio for all ratepayers. But if it is determined that a valuable opportunity for the participant and EPEC will be lost if no action is taken, then the "benefit for all ratepayers" test is not used. This standard was used for selection of the new construction programs for single family residences, apartments, and commercial buildings.

Staff witness Treadway did not agree that Mr. Conley's summary of program planning and selection met the requirements of Rule 23.22. In his opinion, given a goal of improving the load factor by one percent in 1987, EPEC should develop preliminary savings and cost estimates for proposed programs that relate to its energy efficiency goal, analyze barriers to program success, estimate each program's contribution to the goal, and develop a ranking procedure for the programs. Further, in his opinion, the Energy Efficiency Plan should contain an explanation of this ranking process and the rationale for the selected set of programs. Mr. Treadway provided a detailed explanation of the steps necessary for conservation resource planning and implementation, regardless of the regulatory requirements in Texas.

Mr. Treadway further criticized EPEC for failing to estimate the total potential for conservation and load management in its service territory and instead relying on load growth to satisfy its goal of improving load factor. He considers this a short-run view of resource planning, and opined that a comprehensive analysis of alternatives and an estimate of the potential impact of conservation and load management in EPEC's service territory would allow EPEC to select the best set of programs and justify the timing of implementation over the resource planning period. Another shortcoming of EPEC's updated Energy Efficiency Plan was the omission of a statement of capacity and/or energy savings for some programs. Mr. Treadway admitted on cross-examination, however, that P.U.C. SUBST. R. 23.22 does not require a utility to estimate the total potential for conservation and load management.

Further, Mr. Brown believed that Mr. Treadway undermined his own evaluation by offering conflicting testimony. For example, he believes it is inconsistent for Mr. Treadway to criticize EPEC for implementing programs without estimates of savings or costs when his direct testimony states that conservation resource planning and implementation begins with an intuitive analysis and data collection, and that certain conservation activities may be obvious and warranted at the point at which the collective experience and evidence of the utility provides overwhelming justification for action.

Three of EPEC's conservation and load management programs deserve detailed discussion here. First, the Apartment Construction Program was added to EPEC's Energy Efficiency Plan in 1986 because in 1985, 8.8 percent of all-electric residences were multi-family units. Certain energy efficiency measures are only economical when a structure is being built, that is, construction presents a "window of opportunity" for economical installation or implementation of some energy efficiency measures. In multi-family units, very few measures are economical at all for a renter who might be in an apartment for less than two years. The Apartment Program provides rebates to builders for energy efficient water heaters, space heaters, air conditioners, and programmable thermostats. To qualify for rebate, the equipment must be energy efficient; most importantly, the apartment structure itself must meet energy efficiency standards for ceiling and wall insulation, windows, doors, fireplaces, vapor barriers, and dampers. In 1986, 912 apartment units were built according to EPEC's energy efficiency standards. The expense for this program is $416,309.

Mr. Treadway recognized the possible benefits of specifying efficiency standards in new apartment construction and installation of original equipment, but, again, faulted EPEC for failing to provide any estimates of savings resulting from the New Apartment Program. He recommended that EPEC quantify the "window of opportunity" and present a detailed analysis in its next Energy Efficiency Plan. In addition, he suggested that the best way for EPEC to promote all-electric construction is to insure the construction of housing which has low life-cycle costs. EPEC should investigate heat pump water heaters, heat recovery water heaters, radiant barriers, increased thermal integrity, and passive solar heating; should perform rigorous engineering analyses of a variety of building design standards and equipment options; and should analyze the impact of various standards and equipment efficiencies on system load factor, under Mr. Treadway's recommendation. He believes that no rebates are justified under the current program, because rebates are more effective at promoting the long-lasting building efficiency standards rather than specific appliance types; however, he recommended that EPEC continue this program and present an improved evaluation of it in the next Energy Efficiency Plan.

Mr. Brown discussed heat pump water heater and heat recovery water heater technology and explained that, based on company-specific data, EPEC has concluded that these are low priority options. The reasons are as follows. Heat recovery water heaters require a refrigerated air conditioning system, and do not work well with evaporative coolers which account for 90 percent of the residential cooling in EPEC's service area. Mr. Treadway's criticism of the builder rebate program is of questionable value when, by his own admission, the Company would have to promote refrigerated air conditioning in order for the heat recovery water heaters to have a heat source.

According to Mr. Brown, a residential size heat pump water heater costs approximate $1,000, compared to $200-$300 for installed electric resistance water heaters of varying efficiencies, a factor which explains the low penetration of heat pump water heaters. Since natural gas, bottled gas, and solar with gas backup provides 82 percent of the residential water heating in EPEC's service area, Mr. Treadway's criticism of the builder rebate program loses credibility because heat pump water heaters rely almost exclusively on electric resistance elements for backup.

The High Efficiency Appliance Information and Demonstration Program informs customers about energy efficient appliances and equipment and attempts to influence them to purchase high efficiency units through the use of rebates, for both customer and dealer, on energy efficient water heaters, window air conditioners, freezers, dryers, and ovens. The goal for 1986-1987 was to have 20 appliance dealers and 2,674 customers participate in the program. EPEC has 24 participating dealers and 6,154 customers have participated in the program. In addition, Mr. Conley stated that 688,967 pieces of literature on life-cycle costs of energy-efficient equipment as compared to less efficient models were purchased and distributed. This program is budgeted for $497,868, but EPEC is asking that only $265,299 be included in the cost of service. Shareholders will pay for $232,569 of the costs of this program.

On cross-examination, Mr. Conley denied that increasing sales is a major goal of the Energy Efficiency Plan, but he conceded that an increase in the off-peak electrical sales is a direct part of EPEC's Plan. He defended that aspect of the Plan by stating that such an increase in off-peak sales improves system efficiencies and thereby benefits all ratepayers. Although he would not admit that EPEC has excess capacity, he finally agreed that even increased on-peak sales would spread fixed costs over more kWh.

Mr. Treadway aimed his most detailed criticism at EPEC's current appliance marketing effort, characterizing it as being based on an intuitive analysis which concludes that off-peak sales will spread fixed costs over a larger number of kWh, but goes no further. There is no data on each option to demonstrate that these end uses will increase off-peak sales, however, air conditioners and heat pumps are weather-sensitive load and will increase residential on-peak use. The minimum efficiency standards specified are low, and there is no reasoned analysis of the long-term load shape impacts of this program. In Mr. Treadway's view this is not an energy efficiency program but an appliance marketing program.

Mr. Treadway believes that EPEC is promoting air conditioning in contradiction to its stated goal of increasing the system load factor. Based on EPEC's Demand and Energy Forecast (EPEC Ex. No. 1, Vol. 1, Tab 9, Exhibit JEG-1) which states that more air conditioners should have the effect of decreasing the overall system load factor, Mr. Treadway concludes that EPEC's activities may aggravate the peaking impact of residential air conditioners. He recommended that EPEC terminate the High Efficiency Appliance Program for two reasons. First, participants lose because the cost of buying and operating electric appliances is greater than the natural gas equivalent. Second, although the remaining customers may benefit from the short-run revenue increases, there are negative long-term aspects to increasing air conditioning saturations, as noted in EPEC's Demand and Energy Forecast (JEG-1).

Third, the recently begun Commercial Cool Storage Program is designed to promote the concept of Cool Storage in new buildings (under the "window of opportunity" analysis) and in existing buildings where retrofit is possible and economical. Cool Storage is a load shifting technique in which a building's air conditioning system is operated during the hours of the day the building is unoccupied (off-peak) to make either chilled water or ice. During the hours the building is occupied (peak), the building is cooled either partially or totally from this chilled water or ice, reducing the electrical demand requirements on the main air conditioning system. This benefits both EPEC and the participant by shifting air conditioning load from peak to off-peak periods. EPEC realizes an improved daily load factor, and the demand portion of the customer's bill is reduced. Mr. Conley testified that EPEC has shifted (and has contracts to shift) 1,100 kW from on-peak to off-peak. Using Palo Verde fixed costs of $2,500 per kW, Mr. Conley calculated the savings to ratepayers from this one program as $3 million. However, because it is a pilot program he had no cost data on it; he said cost data would be filed with the Energy Efficiency Plan due December 31, 1987.

By the time Mr. Brown testified on rebuttal, EPEC had shifted 1,256 kW from on-peak to off-peak, and had contracts to shift an additional 390 kW to off-peak. He noted, however, that the total potential for the number of installations is limited because of the low level of commercial growth in EPEC's service area. But EPEC is pursuing the retrofit market; there have been four retrofit installations (shifting 603 kW, already included in the total), and projects which would shift another 160 kW are under consideration.

Mr. Treadway found EPEC's supporting documentation for its programs and program cost-benefit data inadequate and insufficient for him to perform an independent analysis of the programs. For example, his first analysis of the

Cool Storage Program (based on EPEC's current data) led him to conclude that it fails the cost-benefit test in every respect, a recalculation (using what he termed more realistic assumptions) resulted in a more favorable appraisal of the program. He recommended that EPEC continue to evaluate this program, and redesign it as necessary.

EPEC is in the process of conducting a load research study for the commercial and industrial sector. Mr. Conley explained that it takes 18 to 24 months to collect and analyze data, and that the commercial/industrial survey is in the initial stages. The goals of this survey are as follows:

- to determine the status of existing commercial class in terms of energy use;
- to estimate the additional realizable market potential in the commercial customer class;
- to provide data for forecasting the electric end use of commercial and industrial sectors;
- to develop an energy utilization index-energy use by square footage, number of employees, age of building;
- to group EPEC's commercial customers by Standard Industrial Codes (SIC);
- to determine the type and amount of energy consumed by space conditioning equipment by building types;
- to identify what other major electrical loads are being utilized by the commercial and industrial sectors;
- to examine how electricity is used in manufacturing processes, including electric motors;
- to determine the amounts and types of electric load which commercial and industrial customers may, with appropriate incentives, shift or may allow EPEC to interrupt; and
- if sufficient interruptible and shiftable load is found to be available, to determine the level of incentives needed to induce commercial and industrial customers to shift load or allow EPEC to interrupt it.

In discussing the load shape objectives of EPEC's programs, Mr. Treadway noted that the audit programs are stated to achieve strategic conservation and the Cool Storage Program has a load shifting objective. The Company's four remaining programs report both strategic load growth and strategic consumption objectives. In the opinion of this witness, it is possible, although not sensible, for separate elements of a program to have different load shape objectives. The conflicting objectives indicate to Mr. Treadway that EPEC is trying to use the Energy Efficiency Plan to market electricity over alternate fuels. Conceding that promotion of electricity need not be contradictory to its energy efficiency plan goals, Mr. Treadway nevertheless recommended that the Company remove conflicting objectives from all its programs.

The overriding criticism of EPEC's updated Energy Efficiency Plan was the absence of any forecast of savings from conservation and load management programs. Both Mr. Conley and Mr. Treadway cited the Commission's August 1986 adoption of the <u>Long-Term Peak Demand and Capacity Resource Forecast for Texas 1986</u> in support of his position. Mr. Treadway noted that that forecast included a conservation and load management savings in EPEC's service area of 96 megawatts from 1986 to 1995. Significant capacity resource savings (about 14 megawatts per year) were predicted starting in 1989, even accounting for EPEC's anticipated excess capacity appears the statement that the special treatment for EPEC (the grant of an additional year to gather data) was not a license for delay in implementing long-term conservation. In Mr. Treadway's opinion, EPEC has not made a reasonable estimate of the potential for conservation and load management within its resource plan and has made little progress in preparing estimates of future conservation and load management savings. He offered several specific methods by which EPEC could improve its measures of the impact of conservation and load management, and he listed 27 items which EPEC should include in its next Energy Efficiency Plan, due December 31, 1987. On cross-examination, however, Mr. Treadway acknowledged that under P.U.C. SUBST. R. 23.22, EPEC is required to comply with only 14 of the items on his list.

On cross-examination, Mr. Conley explained that the absence from the updated Plan of estimated kWh peak demand reductions associated with each program was justified by EPEC having been granted, in the State Energy Efficiency Plan, an additional year (*i.e.*, through 1988) to collect data for its conservation and load management programs. Mr. Brown elaborated on EPEC's data collection activities. With respect to residential data, the Company is conducting another appliance saturation survey, following up the one done in 1985; and an on-site commercial and industrial end-use survey was planned for the fall of 1987. Mr. Brown opined that the Company is well within the December 31, 1988, time frame for collecting data, evaluating conservation and load management potential, and developing and implementing programs.

Mr. Treadway also pointed to the need for EPEC to improve its accounting for conservation and load management costs. He noted confusing and unexplained budgeting and accounting procedures. For example, the RCS (Residential Conservation Service) and Walk-Through Audit Programs are reported separately but budgeted together; likewise, the Commercial and Industrial Lighting, Commercial and Industrial Audit, and Commercial and Industrial Energy Management Programs are reported separately but budgeted together. He also suggested that EPEC record in a deferred debit account the incremental expenditures incurred to carry out the recommendations of the Commission regarding its Energy Efficiency Plan. To be includable in this account, such expenditures would have to be directly related to Mr. Treadway's recommendations for EPEC's Energy Efficiency Plan, and reasonable and necessary costs of service. These expenses would be submitted and reviewed in EPEC's next rate case. The account would not be used to record the costs of any conservations programs, end-use data collection, or other conservation related expenses currently included in EPEC's revenue requirement.

More specifically, Mr. Treadway recommended disallowance of $131,345 of the requested $569,064. The disallowed amounts are from two programs, neither of which is in the best interests of EPEC and its customers, in the opinion of this witness: the discontinued Water Heater Program ($2,133), which he believes promoted energy use, not conservation, and the High Efficiency Appliance Information and Demonstration Program ($129,212), which in Mr. Treadway's view has many negative aspects, detailed above. The $129,212 disallowance is the sum of the direct program costs ($75,081) and a prorated 29.58 percent of EPEC's Energy Management Department supervisory costs ($54,131). The percentage is based on the High Efficiency Appliance Program's share of personnel costs as budgeted in the Energy Efficiency Plan.

Finally, Mr. Treadway recommended a downward adjustment of $400,000 (approximately 5 basis points) to EPEC's overall return, based on his view that EPEC's present emphasis is on marketing, not conservation. The appliance rebates expensed below the line and his disallowed expenses total $406,211 in the test year, and represent expenditures made without investigation of the long term effects of the programs. He also recommended that the Commission discourage EPEC from expensing marketing programs below the line. Even if these expenses are outside the Commission's purview, these marketing activities have an impact on electrical resource planning in Texas; some have negative long term consequences.

B. Analysis and Recommendation

PURA §39(b) mandates that the Commission consider a utility's efforts to comply with the statewide energy plan and its efforts and achievements in the conservation of resources. Under P.U.C. SUBST. R. 23.22(c), in the filing of an application for a major rate change, an electric utility is required to submit its most recent Energy Efficiency Plan, along with testimony specifying the extent to which the goals of the utility's Energy Efficiency Plan have been met, summarizing the status of all programs and studies, identifying all costs expended and benefits achieved as of the filing date and indicating the extent to which the utility's energy efficiency achievements have offset the need for new generating facilities or permitted the utility to reduce reliance on less efficient generating facilities. Subsection (d) of this rule sets forth the various ratemaking treatments which the Commission may order.

The evidence on the conservation and load management issue in this docket was voluminous and cross-examination extensive, most likely because the Commission staff recommended disallowance of some expenses and a downward return adjustment. The evidence demonstrates that, overall, EPEC has improved its performance in the area of conservation and load management. The record reveals that EPEC is devoting more personnel and money to conservation and load management efforts than it was at the time of the previous rate case, Docket No. 6350. The Company also appears to be gathering the kind of data needed to make accurate projections of the kW peak demand reductions and kWh savings, and the costs and benefits of specific conservation and load management activities and programs. In summary, the credible evidence supports the Company's contention that because of limited residential consumption and demand, the opportunity for significant savings is negligible, and the change in emphasis in EPEC's conservation and load management programs from residential to commercial and industrial appears justified.

It is difficult to evaluate the effectiveness of individual programs, however, because of the absence of cost-benefit information and estimates of kW peak demand reductions and kWh savings resulting from their implementation. While the staff found such omissions fatal to EPEC's attempt to comply with Rule 23.22(c), a fair reading of the Long-Term Peak Demand and Capacity Resource Forecast for Texas 1986 supports EPEC's report of zero estimated kW peak demand reductions and kWh savings through 1988 for the programs it has implemented.

On the other hand, staff testimony has offered cogent criticism of the overall planning of EPEC's conservation and load management programs. It is quite possible and even reasonable for some of EPEC's programs to include load shape objectives for both conservation and growth; there is not necessarily the need to eliminate what staff perceives as "conflicting" objectives from those programs which include both. However, those programs which *do* promote increased sales should be carefully planned and thoroughly justified as complying with the load shape objectives recognized by the Commission. Even excusing the omission of projected kW peak demand reductions and kWh savings per customer resulting from particular programs because the data are still being collected, EPEC must at least justify the expected results from those programs it does implement.

The most extreme example of EPEC's failure in this regard is its High Efficiency Appliance Program. The rationale for this program appears to be that it is desirable for customers and the Company for electrical appliances to operate efficiently, and that this program will increase off-peak sales. Granted, if consumers are intent on purchasing electrical appliances, encouraging their purchase of high-efficiency models is laudable, and appliance dealers are the logical and most efficient point of contact. But as the record demonstrates, while increased saturation and use of electrical appliances probably does increase off- peak sales, even increased on-peak sales allows fixed costs to be spread over a larger number of kWh. In addition, air conditioners and heat pumps are weather sensitive load and will increase residential on-peak use.

There is some justifiable concern that such a program actually encourages customers to purchase equipment and appliances which replace those fueled by gas, or to purchase an air conditioner to replace an evaporative cooler. Even if these are purchases of efficient electric appliances and equipment, this kind of replacement may increase not only off-peak sales (a desirable result) but also on-peak sales (an undesirable result) and are virtually certain to increase the monthly electrical consumption (and bills) of the purchasing customer. A program which promotes the *indiscriminate* consumption of electricity does not further energy efficiency goals and cannot be justified on any basis.

Furthermore, the Company's assertion that the Commission has no authority over below-the-line expenses simply misses the point. Clearly, the Commission cannot disallow expenses not claimed in the Company's cost of service, but the Commission's sanctions are not limited to disallowance of expenses. Conservation and energy efficiency activities and programs, regardless of their funding source, must be considered by the Commission in fixing a return on invested capital under PURA §39(b). Any activity which frustrates or thwarts the statewide energy plan, even if funded solely by shareholders, could be considered a negative factor in fixing the return on invested capital.

This report will not make recommendations with respect to specific conservation and load management programs, except to observe that EPEC's Cool Storage program appears promising and that the shift in emphasis of its conservation and load management programs toward the commercial and industrial sectors appears justified. Further, EPEC faces an extremely difficult task: it must simultaneously comply with legislative expectations as expressed in PURA and interpreted by this Commission regarding conservation of resources *and* demonstrate the need for the capacity represented by its investment in the Palo Verde Nuclear Generating Station. Understandably, EPEC will be more interested in pursuing energy efficiency programs which include increased sales. Such programs are not only not forbidden by the Commission's Substantive Rule, they are recognized as legitimately having a place in the efficient use of resources. While the Commission staff should not substitute their personal conservation preferences for the requirements of the Substantive Rule, conversely, EPEC *must* demonstrate that the pursuit of increased sales is a benefit to its ratepayers and is consistent with state energy efficiency policy.

EPEC has attempted to justify many of the omissions in its updated Energy Efficiency Plan by claiming to operate under a unique set of circumstances and to have been granted an additional year to gather the data, evaluate it, and implement appropriate conservation and load management programs for which there are measurable projected kW peak demand reductions and kWh savings. The report acknowledges that position, but cautions EPEC that much will be expected of the Energy Efficiency Plan to be filed by December 31, 1989.

With respect to the requested expenses for conservation and load management expenses, this report proposes that the Commission adopt the staff's recommendation and disallow $131,345 (Texas) of expense from the cost of service, as explained above. The report does not recommend adoption of the staff's proposed downward adjustment to return, primarily because it does not seem fair to have given EPEC a year longer than other Texas investor-owned utilities to gather data for its conservation and load management programs and then penalize it for reporting zero conservation savings in the test year. However, as stated above, much has been justified on the basis of this company's unique circumstances, and much has been promised for future Energy Efficiency Plans for this utility. It seems only fair that EPEC be allowed the full measure of time to gather data and prepare to demonstrate solid energy efficiency achievements and at the same time be given notice that it is expected to make very good use of that extra time - or suffer potentially the full range of remedies at the Commission's disposal.

VI. Quality of Management

A. Introduction

Under PURA §39(b), the Commission must consider the quality of a utility's management in fixing a reasonable return on invested capital. In addition, the final order in Docket No. 6350 directed EPEC to address the eight recommendations concerning Franklin Land & Resources (FL&R) contained in the management audit conducted by Touche Ross & Co. This audit, performed in 1985 and completed in August of that year, had been required by the Commission pursuant to PURA §16(h). The final order in Docket No. 6350 permitted EPEC to recover the $600,000 cost of the audit over three years.

William J. Johnson, Vice President/Treasurer-Chief Financial Officer of the Company, testified on the status of implementation of the FL&R recommendations. (EPEC Ex. No. 1, Vol 4, Tab 21, pp.19-21; Tr. at 244-260.) Staff witness Diane Friday, management analyst in the Operations Review Division of the Commission, presented testimony on the Company's progress in implementing not only the FL&R recommendations but also other recommendations from the Touche Ross Management Audit. (Staff Ex. Nos. 13 and 13A; Tr. at 1934-2025.) In rebuttal to Ms. Friday's testimony, EPEC presented the testimony of four witnesses: Gregg Forszt, Manager-Materials Management for the Company (EPEC Ex. No. 41, Tab 2; Tr. at 2179-2202); Robert V. Keyes, Manager of Customer Operations for the Company (EPEC Ex. No. 41, Tab 9; Tr. at 2306-2332); Robert N. Hackett, Assistant Vice President and Executive Consultant in charge of EPEC's Management Support Services Department (EPEC Ex. No. 41, Tab 4; Tr. at 2332-2386); and Ignacio Troncoso, Vice President, Engineering, Transmission, and Distribution (EPEC Ex. No. 41, Tab 12; Tr. at 2387-2402).

This issue was addressed in the initial briefs of the Company (Applicant's Brief-Phase I-Revenue Requirements, pp. 117-129) and the City of El Paso (Brief of the City of El Paso-Phase I-Revenue Requirements, pp. 18-23); and in the reply briefs of the Company (Applicant's Reply Brief, pp. 6-9) and the general counsel (General Counsel's Reply Brief [Phase I and Phase II], pp. 5-11).

B. Background

Ms. Friday's testimony included a summary of the Commission's management audit program, which has been in operation since September 1983, following the amendment to PURA which added §16(h). That section requires the Commission to conduct a management audit of each utility it regulates at least once every ten years. Audits of investor-owned utilities are conducted by management consultants selected through a request-for-proposal process. The Commission staff administers and participates in the audit, monitoring the progress of the audit, making sure that the goals and objectives of the audit are met, approving payments to the consultants, and monitoring the issues as they are developed by the consultant.

Ms. Friday described a management audit as a diagnostic examination of how well an organization is managed, an evaluation of the efficiency and effectiveness of a company's management and operations at a particular time. An audit report contains a series of findings and observations about a utility's management and operations in each functional area audited. Important elements of a management audit report are the identification of opportunities for improvements to a company's management operations and the inclusion of recommendations developed to guide the company in making those improvements. An audit report also includes a short implementation plan for each of the recommendations, comprised of action steps, a recommended time line, and estimated costs and benefits of implementing the recommendation. Ms. Friday opined that a management audit, which reviews the quality of a utility's management at the time of the audit, can help the Commission in evaluating whether a utility's decision-making processes and its performance are reasonable.

Following the issuance of a final audit report, a utility has the opportunity to approve, reject, or except to each recommendation. The company also has the opportunity to develop its own implementation plans and schedules for the recommendations. The Commission staff reviews the reasonableness of the acceptance status and of the implementation plans to see that the most important aspects of the audit recommendations will be addressed. The staff's evaluation is premised upon the notion that a utility has a responsibility to its ratepayers to pursue aggressively the most efficient and effective management practices reasonably possible, a responsibility the staff views as particularly compelling when a company has had the opportunity to receive expert management advice at the expense of its ratepayers. The staff then monitors a company's progress by tracking the quarterly progress filings it is required to submit. (Staff Ex. No. 13 at 2-6.)

On cross-examination, Ms. Friday acknowledged that what is "reasonably possible" for a company is affected by its financial condition, the need to provide services to ratepayers, and the number of employees available to work on recommendations. She further agreed that it is not reasonable for a utility to ignore its day-to-day operations and focus only on implementing audit recommendations, and that "agressively pursue" does not mean hiring lots of new employees just to implement recommendations within a few months. (Tr. at 1958-1959; 1983.)

C. The Touche Ross Management Audit of EPEC

1. Background and Implementation Status

The specific objectives for the EPEC audit, explained Ms. Friday, were to:

- identify opportunities for cost reduction in the present and cost savings in the future;

- evaluate the adequacy, efficiency, and effectiveness of utility management and operations;

- assess the impact to the utility's ratepayers of the operations and financial transactions of the Franklin Land & Resources subsidiary and its subsidiaries;

- assess the impact to the utility's ratepayers of the utility's trust arrangements for fuel and electric generation; and

- prepare for the Public Utility Commission of Texas, its staff, and the ratepayers an objective written report on the management and operations of the utility.

The Touche Ross audit of EPEC reviewed the areas of executive management and organization, system planning and design, engineering and construction, fuels management, power supply, transmission and distribution, financial management, customer service and public relations, corporate support services, human resource management, and Franklin Land & Resources. The audit report comprises two volumes, and contains an executive summary, a company profile, 298 findings and observations, and 187 recommendations. The third volume contains an implementation plan. (Staff Ex. No. 13 at 6-7.)

On cross-examination, Ms. Friday explained that in March 1986, two months after beginning her employment with the Commission, she was assigned responsibility for monitoring EPEC's progress in implementing the audit recommendations. (Tr. at 1955.) The first thing she did was to read the audit, review statistical data on implementation status, and look at implementation reports. She did not talk to anyone at EPEC; did not check on any complaints the Company had had during the course of the audit; and did not review any audit text page reviews or recommendation review forms submitted by EPEC before the final report. (Tr. at 1956.) She made no independent verification of the accuracy of the Touche Ross findings and did not review any drafts of the Touche Ross report or task force report. Ms. Friday was aware that the Company had been so concerned about factual errors and inconsistencies in the draft that the Company held two meetings with Touche Ross to discuss those problems, but she had no specific knowledge about what transpired at those meetings because they had taken place prior to her coming to the Commission. (Tr. at 1957.)

Following issuance of the audit report in August 1985, EPEC had 90 days to review the recommendations, point out errors of fact or analysis in the report, and revise its own implementation plans. (Tr. at 1937.) EPEC approved 157 of the recommendations, excepted to 29, and rejected one. The Commission staff reviewed the original implementations plans submitted by EPEC in November 1985 and found they were generally adequate in addressing the audit recommendations. (Staff Ex. No. 13 at 11; Tr. at 1939.) The staff's monitoring of the Company's progress consisted of eight letters (three of which were transmittal letters for forms, one of which informed the Company of the staff members working on the audit review, and the latest of which was sent in April 1986); several telephone calls from Ms. Friday to EPEC personnel; and three meetings, all of which probably took place prior to Ms. Friday's employment at the Commission. (Tr. at 1961-1962; EPEC Ex. Nos. 23, 24, 25, 27, 28, 29, 30 and 32.)

After EPEC had filed its first quarterly report, the Commission staff sent a letter to EPEC in January 1986 requesting clarification of 205 items (EPEC Ex. No. 25; Tr. at 1963-1964); EPEC responded with answers for each request. (Tr. at 1965; 1972-1973.) Ms. Friday admitted on cross-examination that although she found some of the Company's responses inadequate, she did not follow up on them, and that until she sent Requests for Information to EPEC in the course of this rate proceeding (eventually sending more than 200 RFIs [Tr. at 1988]), there had been no communication from the staff to EPEC about any potential problems in its implementation process in more than one year. (Tr. at 1978-1979.)

In March 1986, however, EPEC had filed a progress report stating that the Company was delaying its implementation of 53 recommendations for two years or more and of 22 recommendations for a period of less than two years because of the Commission's final order in Docket No. 6350. According to EPEC Vice President Robert Hackett, who filed the report, that order "forced the Company to institute a Contingency Plan to keep it in a cash survival mode." In making the decision to delay implementation of certain recommendations, EPEC reported that the estimated costs (both annual and recurring) were developed for each recommendation on the departmental or division level. If a recommendation required either hiring additional personnel or making a cash outlay, it was delayed. Further, the Company characterized this decision as "black and white," meaning that if the recommendation required cash outlays, no matter what Touche Ross projected benefits to be, it could not and would not be implemented until the Company had available funds. EPEC decided to wait until it had funds for implementation before determining benefits associated with those recommendations requiring cash outlays. (Staff Ex. No. 13 at 11-12.) This information was conveyed to the Commission staff. (EPEC Ex. No. 35.)

Ms. Friday's testimony criticized this methodology because EPEC did not account for the potential benefits, either quantifiable or non-quantifiable, of implementing these recommendations even though in some cases Touche Ross had developed such estimates. This methodology was not a legitimate one to use in deciding to delay implementation of some recommendations, in Ms. Friday's opinion, because in considering to take action on any issue a company should take into account both the estimated costs and the estimated benefits. She believes that EPEC took into account only the cost side of the equation and ignored the benefit aspect altogether. In addition, her review indicated that not all of the delayed recommendations would have required hiring additional personnel or making cash outlays. She identifies 31 delayed recommendations for which EPEC had made no estimates of the costs of implementation. (Staff Ex. No. 13 at 12-13 and at Schedule 2.)

But when reminded during cross-examination that the final audit report by Touche Ross had quantified benefits for only 42 out of 187 recommendations, Ms. Friday responded that she was not surprised. She conceded that the validity of the Touche Ross cost and benefit numbers, two years old at the time she testified at the hearing, could have been affected by intervening events, by the passage of time, and by changes in the economy, the Company's financial condition, and the implementation plans. (Tr. at 1959-1960.)

Ms. Friday's testimony pointed to a March 26, 1987, memorandum from Evern Wall to EPEC executive officers, indicating that the sale/leaseback had improved the Company's cash situation dramatically. According to her, the Company decided not use that cash to resume implementation of the delayed audit recommendations. She relied on a September 23, 1986, memorandum from Mr. Wall to the EPEC Board of Directors which indicated that no money from the sale/leaseback would be used directly for implementing those recommendations costing money; EPEC's position was that appropriate rate relief was necessary to implement those recommendations. A memorandum from Mr. Wall to the Executive Committee of the Board of Directors dated February 6, 1986, stated that the minimum delay of two years was based on appropriate rate relief to begin January 1987, and should include the $5 million estimated by EPEC as required for expenditures on the recommendations. (Staff Ex. No. 13 at 13-14.) This is essentially the same information which had been given to the Commission staff in March 1986. (EPEC Ex. No. 35.)

It was Ms. Friday's opinion that, had EPEC been seriously committed to securing the $5 million as a precondition to implementing the audit recommendations, it would have had to request that money in the current rate case and demonstrate that the costs it would incur are known and measurable, according to standard ratemaking principles. She believes that EPEC's actions in not implementing certain audit recommendations were in response to what it considered unfavorable rate treatment from this Commission in Docket No. 6350. (Staff Ex. No. 13 at 14.) The evidence establishes that EPEC has implemented between 108 and 117 of the 187 audit recommendations made by Touche Ross. (Tr. at 1987.)

Mr. Hackett's testimony on rebuttal explained in some detail, and from a different perspective, the Company's actions during the audit and following the issuance of the final audit report. EPEC had generated two volumes of proposed revisions to the text of the audit; these were presented for discussion with Touche Ross and the Commission staff. According to Mr. Hackett, these revisions offered corrections of factual misrepresentations in the audit, but only a few were accepted by Touche Ross. On cross-examination, he conceded that some of the disputes concerned not just facts but also the interpretation of those facts and the conclusions drawn from them by Touche Ross. (Tr. at 2381-2382.) A second meeting (apparently not contemplated by the contract under which the audit was performed) was held in which EPEC attempted to convince the consultants to reconsider the items which the Company had pointed out. In Mr. Hackett's view, the general attitude of the auditors was that the document had been written and would not be changed.

Because of the factual errors in the text, EPEC believed there were inaccurate costs and benefits in the implementation plan. According to Mr.

Hackett, EPEC has been reviewing each recommendation to see if there is cost or benefit or opportunity for improvement. That is the reason EPEC did not reject recommendations immediately. The Company informed the Commission in its open meeting on September 13, 1985, that EPEC would not reject any single recommendation without further review, but would review and evaluate them before deciding to accept or reject them. Ms. Friday agreed on cross-examination that it made sense for EPEC to work on recommendations before deciding to reject them. (Tr. at 1961.)

Mr. Hackett also pointed out that the Company was operating under cash constraints at the time the audit was conducted. The Cash Retention Plan, adopted in February 1985, included several cost containment measures designed to protect the integrity of the Company's cash position. Hiring, wage increases, overtime pay, and other employee benefits were frozen until EPEC's cash situation improved, but the Company lost employees. In late 1985, Mr. Hackett stated, the cash condition of the Company worsened, and the Short-Range Contingency Plan adopted by the Company mandated cancellation or deferral of activities requiring a cash outlay, including implementation of audit recommendations.

The decision-making process concerning whether to delay implementation of audit recommendations did not include using the potential benefit as an offset to the cost of implementation, as Mr. Hackett described it. For example, if a recommendation would produce a benefit of $500 after incurring a cost of $200, it was delayed for the sole reason that the Company did not have the $200 to invest to initiate the recommendation. Mr. Hackett stated that the implication that EPEC never developed estimated benefits for the delayed recommendations is not correct. The original implementation plan included information on all of the benefits which were then quantifiable. However, once the Short-Range Contingency Plan was in place, if a recommendation required extra personnel, EPEC did not attempt to determine any associated benefits since the decision had already been made not to implement any recommendations requiring the use of extra personnel. Nevertheless, Mr. Hackett testified on cross-examination, EPEC continued to work on those recommendations which did not require out-of-pocket expenditures (Tr. at 2384), and he believed that the Commission staff was aware that not all implementation activities had ceased. He also testified that upon receipt of cash from the sale and leaseback of PVNGS Unit 2, EPEC resumed its work on the previously delayed audit recommendations. (Tr. at 2338.)

In addition, EPEC met with members of the Commission staff to discuss the delay in implementing audit recommendations; according to Mr. Hackett, EPEC's representatives sought feedback from the staff but got none. At this meeting, staff announced plans to visit EPEC in late 1986 to monitor the implementation progress, but the visit did not take place. Further, Mr. Hackett asserted that EPEC has received only sparse feedback on its quarterly reports, and had no communication from the staff from April of 1986 until the staff began filing RFIs in this docket. Mr. Hackett charged that the Company had received no indication that it was not doing an adequate job in complying with the audit recommendations until the filing of the staff's testimony in this docket. (EPEC Ex. No. 41, Tab 4, pp. 5-9.)

Finally, Mr. Hackett explained why there was no request in the rate filing package in the instant application for $5 million for implementing the audit recommendations. Since EPEC worked on the audit implementation during the test year, the expenditures are included in the test year per books figures. Since EPEC plans to continue working on audit implementation, those amounts were not removed. This means that the Company will continue implementing audit recommendations within its normal budgetary cash flow under which expenses are booked as they are incurred. (EPEC Ex. No. 41, Tab 4, p. 12.)

2. Franklin Land & Resources

Much of the testimony on the quality of EPEC's management centered on the eight recommendations contained in the Touche Ross audit report relating to FL&R. Section 14 of that audit report discusses FL&R, then a wholly owned subsidiary of EPEC, and makes recommendations based on the findings and observations in the Touche Ross audit report. Section 14 is included in the record as Staff Ex. No. 1; the eight recommendations are set forth below in full, along with a summary of the testimony regarding the implementation status of each one.

14.1 FL&R should strengthen the cost allocation methodology used to transfer costs between EPEC and FL&R in order to minimize the potential for any cross-subsidization by EPEC.

Mr. Johnson testified that the allocation methodology used to transfer costs between EPEC and FL&R has been in place since July 1983, and includes executive and administrative time as well as allowance for overheads and burdens. The methodology is reviewed at least annually; further refinement of the methodology is pending. EPEC is conducting studies to determine an appropriate methodology, and is working with its outside accountants, Peat Marwick and Mitchell. (Tr. at 252-253.) In his prefiled direct testimony, Mr. Johnson stated that he anticipated a final decision by the end of 1987, but on cross-examination he testified that he hoped to have the new methodology in place in nine months to a year, meaning June to August of 1988. (Tr. at 253.)

Ms. Friday pointed out that the merit of the Touche Ross recommendation is reinforced by a May 1985 FERC audit of EPEC, which found that EPEC does not maintain detailed records to adequately support the charges for lease payments and administrative services. The FERC audit recommended that the Company change its procedures to provide for adequate documentation of expenses relating to transactions with FL&R which are charged to utility operating expense. According to Ms. Friday, EPEC has not strengthened the cost allocation methodologies, and has reported having taken only preliminary steps toward addressing this recommendation, namely, polling five other utilities about their cost allocation procedures. (Staff Ex. No. 13 at 8.) On cross-examination, Mr. Johnson agreed that the FERC audit in 1985 was critical of the documentation on allocation procedures. (Tr. at 253-254.) He also acknowledged that no refinement in the allocation methodology had been implemented since the audit report was issued in August 1985. (Tr. at 253.)

14.2 FL&R and EPEC should modify the joint tax allocation agreement so that the terms and conditions of the agreement accurately reflect the current practices for execution of the agreement. Additionally, a procedure should be established for EPEC to charge a carrying cost to FL&R for the prefunding of tax benefits until such time when EPEC can use the tax benefits to offset a portion of its tax liability.

Mr. Johnson reported this recommendation as having been completed. FL&R and EPEC finalized and executed a new joint tax allocation agreement effective March 1987 which incorporates modifications reflecting current practices. He reported that execution of the tax allocation will be consistent with the agreement itself, thereby increasing management control. On cross-examination, however, Mr. Johnson revealed that EPEC had not implemented the second part of this recommendation because the only effect of placing those interest charges on the tax benefits that are transferred earlier would be to increase interest income for EPEC (a below-the-line item) and increase interest expense for FL&R. The Company is still considering whether this particular recommendation should be implemented, just to make sure everything between the companies is as accurate as it can be. (Tr. at 255.) Ms. Friday testified that the Company reports that it is presently in the process of discussions pursuant to the recommendation but provides no other detail. (Staff Ex. No. 13 at 9.)

14.3 FL&R should develop a set of more clearly defind investment criteria and standards.

FL&R has had in place since 1981 a policy for investment selection, according to Mr. Johnson. Following the recent restructuring, however, PasoTex Corporation will be the primary entity involved in making unregulated investments. The three main goals in the selection of investments for PasoTex are: 1) the creation of employment opportunities; 2) the ability to maintain after-tax earnings equivalent at least to the embedded cost of capital of EPEC; and 3) the creation of additional energy consumption to spread fixed costs of production over a greater kWh base. On cross-examination, Mr. Johnson conceded that the investment criteria suggested in this Touche Ross recommendation were more specific than the three goals developed by PasoTex, but pointed out that the report did not require EPEC to adopt all of them. (Tr. at 250-251.) Mr. Johnson also admitted that the PasoTex Board of Directors reviewed the criteria suggested by the Touche Ross audit report. The PasoTex Board adopted the three criteria in December 1986 or January 1987, according to Mr. Johnson, and they did not come from FL&R. The PasoTex criteria for investment are different from those of FL&R, in that PasoTex is trying to acquire companies to move to El Paso; FL&R, in his recollection, was not ever in a position of going out and acquiring companies. (Tr. at 251-252.) Ms. Friday testified that EPEC had taken no action on this recommendation. (Staff Ex. No. 13 at 9.)

14.4 FL&R should develop a specific policy statement which delineates the timing and amount of FL&R earnings which would be used to offset revenue requirements in the ratemaking process.

Mr. Johnson testified that the nature of FL&R's investments makes the development of the recommended policy statement difficult. Any such policy would necessarily be two-edged, in that losses as well as earnings should logically be included in the revenue requirement calculation. Such a provision would insulate the stockholder against imputed earnings to revenue requirements in periods in which FL&R may actually be in a loss position. Conversely, the present policy would tend to include only actual earnings as part of the revenue requirement and thereby protects the ratepayer against any cross-subsidization.

On cross-examination, Mr. Johnson acknowledged that the Boards of Directors of EPEC and FL&R were aware at the time of the management audit of the difficulties of projecting the budget and the results of FL&R, and the EPEC and PasoTex Boards of Directors are aware of that now. (Tr. at 256.) It is his personal opinion that it would be impossible to comply with this recommendation at the present time. When asked why EPEC accepted that audit recommendation, Mr. Johnson replied that it gave EPEC the opportunity to see if valid and usable projections of this nature could be made. (Tr. at 257.) Again, Ms. Friday testified that EPEC had simply taken no action on this recommendation. (Staff Ex. No. 13 at 9.)

14.5 FL&R should regularly update the financial projections for its various investments to identify the impact of changes in costs and other market conditions. Furthermore, a more formalized form of contingency planning should be implemented to identify those assumptions and conditions which have the greatest potential impact on the success of FL&R's investments.

Mr. Johnson reported that recommendation will be implemented through PasoTex Corporation, although he was unable to state with particularity what steps had been taken to accomplish this. (Tr. at 257-258.) Ms. Friday's testimony was that no action had been taken on this recommendation. (Staff Ex. No. 13 at 9.)

14.6 EPEC should be required to annually demonstrate the continuing economic advantage of leasing versus owning the Mills Building.

Mr. Johnson's testimony indicated that this had been done by updating the Touche Ross study results for 1986. Ms. Friday agreed that the Company reports having completed implementation of this recommendation. (Staff Ex. No. 13 at 9.)

14.7 FL&R should continue its policy of buying variable rate preferred equities in its levered financial transactions.

Not only is FL&R presently complying with this recommendation, according to Mr. Johnson, it will continue to do so as long as it is economically viable. Ms. Friday stated that this recommendation requires no new action by EPEC, since it simply recommends continuation of an existing investment policy. (Staff Ex. No. 13 at 9.)

14.8 FL&R should consider expanding its Board of Directors to include outside directors who are not or have not been employees of EPEC.

In reviewing this recommendation, Mr. Johnson testified, it was determined that the Joint Investment Review Committee, formed in January 1984, met the intent of expanding FL&R's Board of Directors to include outside members. This committee includes three officers of FL&R and three outside directors representing, in Mr. Johnson's view, diversified backgrounds and interests. On cross-examination, however, Mr. Johnson agreed that Touche Ross would probably have been aware of this Joint Investment Review Committee. (Tr. at 259-260.) He also testified that the PasoTex Board of Directors is made up entirely of outside directors, except for Evern Wall, President, Chief Executive Officer, Chairman of the Board and a Director of EPEC. (Tr. at 259.) In Ms. Friday's opinion, since Touche Ross was aware of this committee and its membership at the time of the audit and still made recommendation 14.8, EPEC had, in effect, rejected this recommendation by not taking any further action. (Staff Ex. No. 13 at 10.)

Ms. Friday further concluded that since EPEC had taken no action or inadequate action on six of the eight recommendations regarding FL&R, the Company had not satisfactorily implemented them. What she viewed as a lack of effort in this area was relevant to other issues she raised in her testimony, discussed below, and the calculation of her recommended management penalty. (Staff Ex. No. 13 at 10.)

3. Other Audit Recommendations

In describing how EPEC's failure to implement certain recommendations deprived it of benefits, Ms. Friday provided examples in three areas: materials management, financial management, and staff reductions/productivity improvements.

With respect to materials management, Ms. Friday testified that the Touche Ross audit had found that EPEC's policies and procedures were not effective and that they failed to incorporate modern materials management techniques. Specifically, the audit concluded that responsibility for warehouse and stockroom operations was fragmented, resulting in insufficient control over materials and supplies, and that the material inventory appeared excessive, particularly the transformer inventories. The recommendation from Touche Ross was that EPEC replace the current stores system with a more comprehensive, automated inventory and materials management system; reduce the materials and transformer inventory investment by approximately $1,956,000; and consolidate the responsibility for managing the various warehouses and stockrooms to one central department within materials management.

Granting that the implementation of this recommendation would require EPEC to make some expenditure, Ms. Friday nevertheless concluded that in order to make a responsible and informed decision, EPEC management should investigate the various features available in materials management systems, compare their costs, and determine which would be most appropriate and beneficial. According to the information reviewed by Ms. Friday, EPEC has delayed implementation of these recommendations by two years or more. The ratepayers would receive a readily calculable benefit from an inventory reduction of $2 million, but in Ms. Friday's opinion, the long-term benefits of additional improvements and higher efficiencies possibly resulting from the changes in materials management are inestimable. (Staff Ex. No. 13 at 15-16.)

In the area of financial management, Ms. Friday reported that Touche Ross offered the following six recommendations regarding EPEC's budget process:

- Require top managemement to provide improved planning assumptions to cost center managers so that those managers would be able to make better budget decisions. Such information would include growth in the company's customer base, inflation, new programs, corporate goals, and productivity levels.

- Challenge base expenditures in the budget process, rather than building future budgets on past expenditures.

- Develop decentralized on-line budget data entry to provide more timely, accurate budget information to cost center managers.

- Incorporate cost reductions from the company's corporate planning documents into actual budgets.

- Require cost center managers to provide written explanations of budget variances.

- Reduce the company's tolerance levels of budget overruns.

According to Ms. Friday, EPEC estimated that only one of these recommendations would require a cash outlay, that being a one-time cost of $42,200 to adopt zero-based budgeting. Even though the benefits of improved budgeting techniques are impossible to quantify (because they appear as avoided cost overruns and elimination of needless spending), EPEC chose to delay the implementation of these recommendations for two years or more. (Staff Ex. No. 13 at 16-17.)

Finally, with respect to staff reductions/productivity improvements, Ms. Friday stated that the Touche Ross audit report had identified three areas in which there were opportunities for staff reductions. She summarized the potential annual savings in each of these areas as follows:

11.1.3	Customer telephone inquiry staff	$ 60,000
12.2.4	Warehouse stock handlers	55,000
12.5.3	Garage staff	100,000
	Total savings from reduction	$215,000

Ms. Friday reported that in each case, Touche Ross conducted a productivity or comparative staffing analysis demonstrating that overstaffing existed in a specific function or location and resulting in the recommendations to reduce staff levels. In some cases, not specified by Ms. Friday, Touche Ross recommended that EPEC develop its own productivity measures to monitor its staffing levels and identify additional oppotunities for reductions. In her opinion, EPEC has approached these recommendations backwards: its stated reason for not completing the staff reductions was that it lacked the cash to perform its own productivity studies (in the areas Touche Ross had already studied). Thus, the illogical conclusion: EPEC claims it has insufficient cash to reduce its staffing levels. These are recommendations which EPEC chose to delay implementation for two years or more. (Staff Ex. No. 13 at 17-18.)

4. Comparison with Other Utilities

Ms. Friday compared the quantitative results of EPEC's implementation of the Touche Ross management audit recommendations with the implementation efforts of two other Texas utilities using three meaures: 1) the number of recommendations made by the auditor in each audit; 2) the actual costs and benefits reported as a result of implementation efforts; and 3) the percentage completion rate for each audit. She compared the EPEC audit, completed in November 1985, with the HL&P audit, completed in November 1984, and the GSU audit, completed in February 1986.

As for the first measure, the audit for HL&P contained 83 recommendations; the audit for GSU made 124 recommendations; and the EPEC audit had 187 recommendations. The costs and benefits resulting from the three utilities' implementation efforts, as of their April 1987 reporting dates, were as follows:

Utility/ Audit Date	One-Time Cost	One-Time Benefit	Recurring Cost	Recurring Benefit
HL&P (11/84)	$6,524,600	$23,553,600	$1,307,300	$84,459,500
GSU (2/86)	$ 323,100	$ 634,000	$ 261,500	$ 3,650,900
EPEC (11/85)	$ 105,000	$ 902,000	$ 280,000	$ 244,000

The third measure, "percentage complete," is tracked by the Commission staff and updated quarterly based on the utility's progress report. Ms. Friday explained that there are two elements in this analysis. One is the percent of recommendations for which the completion date is unknown. This is the number of recommendations for which progress is indeterminate and for which the company has not adopted target completion dates. According to Ms. Friday, a large number of recommendations with this status may indicate that a company's planning is inadequate or that it has de-emphasized the audit recommendations. The second part of this analysis is the percent of progress made toward implementing recommendations for which there is an estimated completion date. This is expressed as the ratio of days elapsed to total days required for implementation.

In Ms. Friday's view, this third measure is most useful when audits are compared on an equivalent time-elapsed basis, that is, comparing the percentage completion status of two utilities as of the same quarterly filing. For example, EPEC had made six quarterly filings at the time Ms. Friday's testimony was filed, and she compared EPEC's progress with that of HL&P as of its sixth quarterly filing: HL&P reported 1.2 percent complete unknown compared to EPEC's 16 percent complete unknown; HL&P reported 73 percent progress on known completion targets versus 61 percent for EPEC. Ms. Friday explained that GSU's progress could not be compared as of a sixth quarterly report because GSU had only reached its fourth quarterly filing date as of the time her testimony was prepared. (Ms. Friday apparently did not compare the relative progress of the three utilities as of the fourth quarterly reporting date, which would have enabled her to include GSU in the comparison.)

Acknowledging that no two audits are alike and that audit results cannot be expected to be equivalent, Ms. Friday nevertheless maintained that these quantitative measures can be a benchmark against which to assess the quantity of recommendations and the aggressiveness with which management has pursued the improvements recommended in the audit. Ms. Friday found the number of recommendations in the EPEC management audit particularly high and she noted that the estimated benefits ranged from $26,643,000 to $33,051,000 annually. It was her opinion that it was reasonable to use the audits of HL&P and GSU as comparisons to the EPEC audit, because they were performed by competent, unbiased management consulting firms and presented a fair evaluation of the management and operations of these utilities. Her conclusion was that of the three utilities for which comprehensive management audits had been performed to date, EPEC had demonstrated the slowest progress and the poorest performance, had not aggressively pursued the most efficient and effective management practices reasonably possible, had not considered well its decision to delay implementation of the audit results. She believes that these actions are not in the best interests of EPEC's ratepayers. (Staff Ex. No. 13 at 18-21.)

However, on cross-examination Ms. Friday conceded that different auditors make different numbers of recommendations; that recommendations of different auditors might differ in complexity and thus might vary in the ease with which costs and benefits can be quantified; that the size of the costs and benefits depends upon what the recommendations are; that certain recommendations lend themselves to greater costs and benefits than others and that there is no way to make that comparison across the board; that the actual costs and benefits reported are affected by the number of recommendations for which costs and benefits can be quantified; and that there may be legitimate circumstances preventing a company from initially determining costs and benefits. Nevertheless, use of different auditors was not a factor in her comparison, nor was the complexity of the recommendations, and she agreed that her measure only compares actual costs and benefits and does not take into account the reasons for the differences. (Tr. at 1981-1982.)

In his rebuttal testimony, Mr. Hackett faulted the staff's comparison because it fails to consider operational differences between HL&P, GSU, and EPEC. In his opinion, HL&P has enormous resources available for implementing its audit recommendations; for example, it has more than ten times as many employees as EPEC and revenues not quite ten times greater than EPEC. The customer to employee ratio for EPEC is much larger than for HL&P: EPEC has 86 more customers per employee than HL&P. From this, he concluded that HL&P's manpower and resources for planning and implementing audit recommendations are much greater than those of EPEC.

He also challenged a comparison based on number of recommendations completed, asserting that the number of recommendations is meaningless because the audits were performed by three different auditors, using different scopes of review. The scope, manpower, time of duration and other activities are all different for the recommendations of each company; the difference in size, location, population density, economic conditions, and lifestyle of a service territory, in Mr. Hackett's opinion, would be contributing factors which make audit recommendation completion status unique to each utility. Touche Ross itself had recognized problems inherent in attempting to compare audits of different companies. Mr. Hackett pointed out that during the selection process for this audit, a Mr. Flaherty of Touche Ross stated that HL&P should not be used as a benchmark when comparing audits, that the level of detail to which Touche Ross was committed would be greater, and that it would not be fair to compare the proposed audit of EPEC with the HL&P report. If a comparison is to be done, reasoned Mr. Hackett, all events must be normalized so that there is a reasonable basis for comparison.

Mr. Hackett opined that corporate performance indicators are a better measure of the Company's efficiency and effectiveness than is completion status of audit recommendations. In his view, well-defined corporate performance indicators give a quick comparison of a company's previous status with its current status; measure performance against established goals and provide a means for measuring performance against expectations; provide valuable input to the short- and long-range planning process; promote and renew awareness of managers; and create a positive influence toward improvement of performance and productivity. The corporate performance indicators developed by Touche Ross for EPEC revealed first that the number of customers per employee was substantially higher than for the average of the Texas investor-owned utilities, indicating efficient use of manpower; second, that the Company's costs were lower for 13 out of 20 cost categories for the years 1979 through 1983. Mr. Hackett presented the same statistics for the years 1984 and 1985 (developed by EPEC using the same source documents as Touche Ross) showing that the relative performance of EPEC remains unchanged and that it performs exceptionally well against other Texas investor-owned utilities. (EPEC Ex. No. 41, Tab 4 at pp. 9-12.) The cross-examination of Mr. Hackett revealed, however, that these comparisons are not particularly informative either, because they do not include the reaons for the differences among the utilities. Further, Mr. Hackett used the same information used by Touche Ross and admitted that he did not check for errors in the data. (Tr. at 2346-2377.)

5. Computation of Management Penalty

Based on her evaluation and comparison, Ms. Friday recommended that the Commission assess a management penalty to EPEC in fixing its rate of return. Although she agreed that it is impossible to measure the additional costs which EPEC imposed on its ratepayers or the benefits forgone as a result of the Company's lack of attention to the potential improvements identified in the audit, she still recommended imposition of a penalty quantified through surrogate means derived from the estimated costs and benefits developed by Touche Ross in the management audit report. (She recommended use of those estimates simply because EPEC did not develop its own.) These cost estimates will produce a more conservative penalty, according to Ms. Friday, because the Touche Ross figures included estimated man-hour costs of implementation, although man-hour costs generally do not translate into actual out-of-pocket expenses for a company. (Staff Ex. No. 13 at 22-23.)

Ms. Friday defended her calculation - admittedly based on estimated costs and benefits and not an exact measure of the benefits forgone by ratepayers - as appropriate because her purpose was not to make a traditional cost of service adjustment. She also pointed out that no other figures are available and that use of the Touche Ross numbers produces a conservative estimate since it is based only upon the delayed recommendations for which there are quantified benefits. Even though it is reasonable to assume that EPEC's ratepayers would benefit from implementation of other recommendations, she recognized that there are no means of quantifying those benefits. (Staff Ex. No. 13 at 21-23.)

Ms. Friday's criteria in selecting recommendations for assessing the management penalty were first, that implementation had been delayed; second, the recommendation had net benefits quantified by Touche Ross; and third, the recommendation was incomplete at the time she prepared her prefiled direct testimony. Only seven of the 75 delayed recommendations had benefits which were quantified by Touche Ross and were incomplete at the time Ms. Friday's testimony was prepared. The following chart shows Ms. Friday's computation:

Recommendation Number	One-Time Cost ($)	One-Time Benefit ($)	Recurring Cost ($)	Recurring Benefit ($)
11.1.3	7,300	0	0	60,000
11.3.1	7,300	165,000	0	0
11.3.3	3,600	25,000	0	0
12.2.3	15,000	209,000	0	482,000
12.2.4	0	0	0	55,000
12.2.5	1,000	0	0	160,000
12.5.3	2,000	0	0	100,000
TOTAL	36,150	398,960	0	857,000

One-time benefit less one-time cost = net one-time benefit	= $ 362,809
Recurring benefit less recurring cost = net recurring benefit	= $ 857,000
TOTAL MANAGEMENT PENALTY	$1,219,809

(Staff Ex. No. 13 at 23-24 and at Schedule 3.)

At the time she took the witness stand during the hearing on the merits, however, Ms. Friday had reviewed information furnished by EPEC in its July 1987 quarterly filing. Based on that information, she decided that two of the seven recommendations had been completed (12.2.3 and 12.2.4), and she removed them from the calculation of the management penalty. After removing the dollar amounts for the two completed recommendations, the revised calculation of the management penalty is as follows:

One-time benefit	$190,000	
Less one-time cost	21,150	
Net one-time benefit		$ 168,850
Recurring benefit	$320,000	
Less recurring cost	0	
Net recurring benefit		$ 320,000
TOTAL MANAGEMENT PENALTY		$ 488,850

(Staff Ex. No. 13A at Revised Schedule 3.)

On cross-examination, Ms.Friday testified that she had not done an independent review of the costs and benefits of the delayed recommendations upon which she based the calculation of her management penalty. (Tr. at 1989.) She did not agree, however, that if EPEC established that the Touche Ross cost and benefit numbers were inaccurate, the amount of her management penalty would or should change. (Tr. at 1990-1991; 1998-1999; 2003-2004; 2016-2017; 2022.)

In his rebuttal testimony, Mr. Hackett flatly asserted that the surrogate measures for quantifying a management penalty should not carry any weight because the staff had not demonstrated the validity of the Touche Ross benefits even though the Company had demonstrated that much of the Touche Ross cost and benefit analysis was incomplete and not based upon facts. He also asserted that a management penalty against EPEC is inappropriate for two reasons. First, the seven recommendations used to derive the dollar amount of the penalty are either complete, well on the path to completion, or impossible to complete because of errors in the Touche Ross recommendations. Second, since the Commission is not authorized to direct the means by which recommendations are implemented by the Company, it is not appropriate to penalize the Company for not implementing them in the manner recommended by Touche Ross. Finally, Mr. Hackett charged that the staff should be more positive when approaching the conduct of an audit, since the lapse of 15 months between the last communication from the staff and the filing of the testimony proposing a penalty is a disservice to the Company, its ratepayers, and its stockholders. (EPEC Ex. No. 41, Tab 4, pp. 12-13.) All other factors being equal, had there been open and timely communication between the staff the the Company regarding the audit and the manner in which it was to be implemented, it might be justifiable to consider imposing a penalty, but not under the circumstances in this case. (Tr. at 2345.)

The five specific delayed recommendations, the computation of costs and benefits by Touche Ross, and the implementation status were discussed in the cross-examination of Ms. Friday, and in the rebuttal testimony of Mr. Forszt, Mr. Keyes, and Mr. Troncoso.

a. Recommendation 11.1.3

The recommendation was to reduce customer telephone inquiry staffing levels at the Mills Building. In his rebuttal testimony, Mr. Keyes explained that he disagreed with some of the facts underlying the Touche Ross recommendation. For example, Touche Ross stated that the existing 18 Customer Services Representatives are fully dedicated to incoming telephone calls. Mr. Keyes stated that this is incorrect, as these employees perform other duties and are not on the telephone a full eight hours per day. He also stated that the call volume per employee was understated by Touche Ross. On cross-examination, Mr. Keyes was unable to state whether the Company had formally excepted to this recommendation, although he thought an exception had been filed. (Tr. at 2322-2326.)

Mr. Keyes believed that further study of the recommendation was warranted, and pointed out that Touche Ross acknowledged that the simple solution of reassigning or terminating employees should not be taken without better data. EPEC has begun to develop the necessary data and is in the process of determining appropriate staffing levels for this function. He went into some detail regarding the information EPEC has developed about this function, and how it has used these data to make decisions about the direction further study should take. One step the Company took in July 1986 was to investigate various Automatic Call Director (ACD) systems available on the market and to recommend that an ACD system be installed. The installation was completed in March 1987, at a cost of $200,000.

The ACD provides statistics regarding the type of call, length of call by type, variations of length of call by experience of personnel, the time factor involved with the wrap-up of each call after disconnecting, and the number of calls handled and abandoned by time of day. Mr. Keyes testified that without such information, any study of appropriate staffing levels would be suspect, and that EPEC will review the ACD statistics and expand and improve performance standards after obtaining six months of data. Mr. Keyes also offered some rather detailed statistical information about the time within which incoming calls are answered, the average waiting time for customers calling in, the number of abandoned calls and the time within which they were abandoned. The Company has used this information to redefine its performance standards and to begin determining employee productivity.

The costs involved in taking these steps has been considerably in excess of $200,000, as compared to the $10,550 estimated by Touche Ross. Even though Mr. Keyes agreed that the Touche Ross estimate of a $60,000 savings resulting from a reduction of the Customer Services Representative staff is probably correct, he could not yet agree that a reduction is appropriate. He anticipated that further changes would be implemented by January 1, 1988. (EPEC Ex. No. 41, Tab 9, pp. 9-15.)

Ms. Friday testified on cross-examination that she was aware that EPEC had taken some steps to establish performance measurements, and had in fact sent RFIs to the Company specifically addressing some of the steps in this recommendation. (Tr. at 2005-2006.)

b. Recommendation 11.3.1

The second delayed recommendation, 11.3.1, was to further reduce the time between bill generation/receipt and service termination on unpaid accounts. Touche Ross had recommended that, in addition to the Company's planned reduction from 42 to 28 days, the delay be further reduced to 25 days, with 23 days set as the regulated minimum. (City Ex. No. 14.)

Mr. Keyes's rebuttal testimony explained the sequence of events by which EPEC had achieved a series of reductions in the time span. One of the steps EPEC took, in September 1985, was to implement major modifications in its automated collection system, including statistical and tabulation reports to be used as evaluation tools for system and procedure performance. EPEC also instituted improved customer notification policies. Additionally, through approved revisions to its tariff, EPEC was able to change the time for delinquency notification from 16 working days to 16 calendar days. Speedier payment posting procedures also reduced this lag time, as did elimination of the two day field notification procedure.

A reroute project, recommended by Touche Ross, was implemented in March and April of 1987. This changed the meter reading, billing, and due date for 155,000 customers in the El Paso area. Most customers had no more than a three-day change in these dates, but for some, the change was significant (up to two weeks). The final impact of this project was a one-day reduction in the time from meter reading to bill generation. Other system modifications, which require significant planning and testing to insure reliability and and accuracy, are being incorporated. Finally, the Company is planning to notify its customers about changes in the bill due date.

The Company's disagreement with the Touche Ross recommendation is based on its interpretation of Commission rules regarding disconnection of customers. According to Mr. Keyes, these rules prohibit disconnection if the bill is paid within 26 days. The rules also provide that EPEC cannot issue late notices or disconnect notices earlier than the first day the bill becomes delinquent. Since the due date for a bill is 16 days after issuance, the termination notice cannot be sent until the 17th day following issuance. The rules further state that the notice must be mailed or hand delivered at least ten days prior to the date of termination. Mr. Keyes concludes that if the bill is paid 27 days from issuance, service cannot be disconnected. The earliest disconnection could be made is the 28th day following issuance of the bill. (EPEC Ex. No. 41, Tab 9, pp. 2-6.)

On cross-examination, however, Mr. Keyes confirmed that as of September 1985, EPEC was not able to accomplish disconnection until 55 days had elapsed from bill generation. (Tr. at 2309-2310.) The current lag between billing and termination is 39 days. (Tr. at 2311.) Implementing the approved tariff change from 16 working days to 16 calendar days would reduce the lag by eight days, according to Mr. Keyes. (Tr. at 2311.)

Ms. Friday conceded on cross-examination that if a reduction in the collection period from 28 days to 25 days were legally impossible, then the benefit estimated by Touche Ross (based on three extra days of interest income on available funds) is not correct. (Tr. at 2001-2002.) While acknowledging that EPEC had taken steps to reduce the collection time, Ms. Friday pointed out that these were not actions set forth in the action plan. (Tr. at 2003.)

c. Recommendation 11.3.3

The third recommendation used for Ms. Friday's management penalty calculation was that EPEC should send commercial bills to the individual responsible for making the payment rather than to the company name. (City Ex. No. 14.) Again, Mr. Keyes testified on rebuttal about the action EPEC has taken on this recommendation. He could not recall whether EPEC had formally excepted to this recommendation, but an implementation plan was filed. In October 1986, EPEC filed a Step Status Report showing that five of the six action steps for this recommendation had been completed. According to Mr. Keyes, EPEC is instituting this recommendation only for those customer accounts which require collection attention; however, this is not a new practice, as EPEC has had the ability to direct a bill to a particular person or department since 1976. The Company's experience is that the function of bill payment can shift to different employees or departments several times a year. If the recommendation were implemented for all commercial accounts, EPEC would need to verify the responsible party at least once a year, at an estimated cost of $11,131 for implementation and $13,900 for annual recurring costs. Touche Ross had estimated an implementation cost of $3,600.

Mr. Keyes also found flawed the Touche Ross estimate of benefits of $25,000 in interest income on increased daily receipts available for funds investment. According to his calculation, implementation of this recommendation would have to yield $416,667 in expedited daily revenues, assuming a six percent interest rate. As of June 1986, the average daily revenues were $1,542,545. Thus, the benefit is based on an assumption that 27 percent of the average daily revenues would be affected by such changes, an impact Mr. Keyes's experience informs him is not likely. Given the Company's current procedures, the other modifications to the collection system, and fact that estimated costs of implementation are greater than potential benefits, Mr. Keyes believes that this recommendation has been implemented in the most cost-effective manner. (EPEC Ex. No. 41, Tab 9, pp. 6-9.)

On cross-examination, Mr. Keyes denied that implementation of this recommendation had ever been totally delayed, even though it had been included in the list of delayed recommendations submitted to the Commission staff. He further stated that there had been no decision not to implement this recommendation, although he agreed that it had not yet been fully implemented. (Tr. at 2327-2331.)

Ms. Friday testified on cross-examination that she was aware of the actions EPEC had taken on this recommendation, but in her opinion EPEC had not explored all the options available for implementing it; however, she was not aware of any other ways in which this recommendation could have been implemented. (Tr. at 1991-1995.) She further agreed that if the Company's analysis of the costs and benefits were correct, then the Touche Ross estimates were flawed. Even so, she declined to agree that if the Touche Ross numbers were wrong her management penalty was also wrong. (Tr. at 1997-1999.)

d. Recommendation 12.2.5

This recommends reconfiguring the El Paso main warehouse operations to support reporting depot facility consolidation within the Transmission and Distribution (T&D) Department in order to reduce yard time losses. EPEC witness Gregg Forszt testified on rebuttal about the implementation status of each action step under this recommendation.

The first action step required reassigning the T&D Department materials delivery person to the El Paso warehouse. EPEC has not done and will not do this, because even though the materials delivery person works closely and often with warehouse personnel, the primary function and supervision of this position is still within T&D.

The second action step was the redefining of all warehouse employees' job descriptions to include material handling and vehicle material loading and unloading. Under EPEC's agreement with IBEW Local 960, no job descriptions exist for Union classification; however, in the latest negotiated settlement with the Union, the position of Senior Warehouseman was created. Since it was a new position, job responsibilities were designated. The Company intends to make yard locations at Carnegie, Altura, Scotsdale, and Santa Fe separate warehouse locations all serviced by one Senior Warehouseman. (EPEC Ex. No. 41, Tab 2, at pp. 8-9; and at Exhibit GAF 13.) On cross-examination, however, Mr. Forszt admitted that creation of the Senior Warehouseman position was not mentioned in EPEC initial implementation plan submitted to the Commission in November 1985. (Tr. at 2198.)

The next step recommended that the warehouse personnel should be reclassified to tool and material handlers or other appropriate category, if necessary. Because of the creation of the position of Senior Warehouseman, EPEC decided that reclassification was not necessary. Further, Touche Ross had suggested developing procedures for material requisitioning and related loading and unloading of materials for the vehicles at Copper. Accordingly, a "Stores Issue and Return" procedure was written and implemented; the same procedure will be used at the yard warehouse locations. (EPEC Ex. No. 41, Tab 2, at Exhibit GAF-14.) Again, Mr. Forszt conceded that the Company's initial implementation plan had not included development of a "Stores Issue and Return Policy." (Tr. at 2199.)

Other action steps in this Touche Ross recommendation include development of procedures to supply materials to the Santa Fe and Altura yards, a change of working hours, and implementation of new procedures and operations. EPEC has determined that the materials for the yard warehouse locations will be transferred from the main El Paso warehouse following current transfer procedures. All appropriate procedures which have been identified have been written and published, and upon completion of all yard warehouse activities, additional procedures will be written as required. Upon final arrangement of all yard warehouse locations and work load studies, the working hours will be changed as appropriate. (EPEC Ex. No. 41, Tab 2, at p. 9.)

Mr. Forszt challenged the accuracy of the Touche Ross cost estimates. For this recommendation, the estimate was approximately $1,000 and no out-of-pocket expenses. EPEC believes that the cost of implementation should include creation of the Senior Warehouseman position at a total cost of $37,000 annually. The estimated benefits in the Touche Ross audit were $160,000 per year based on reduced crew yard time losses through prestaging and supplying of materials to the vehicles. EPEC has found that implementation includes such benefits as improved utilization of warehouse personnel, better inventory control at yard locations, reduced crew yard time, and reduced crew windshield time. Conceding that the exact dollar amount of the benefits could not be quantified, Mr. Forszt believes that it is significantly less than $160,000, even considering only the added cost of a Senior Warehouseman.

Again, in cross-examination Mr. Forszt acknowledged that as of March 1986 EPEC's step status report for this recommendation showed completion of only one step, as of February 1, 1986, with an estimated cost of $100,000. Mr. Forszt could neither confirm nor deny that this was the only step status report EPEC filed for this recommendation, since he does not file the step status reports, but he did agree that as of the March 1986 filing this recommendation was delayed and that it is still incomplete. (Tr. at 2199-22-2.)

Cross-examination of Ms. Friday revealed that none of the information in Mr. Froszt's rebuttal testimony about the steps EPEC has taken to complete this recommendation has appeared in any of the reports EPEC has filed at the Commission. (Tr. at 2013.)

e. Recommendation 12.5.3

Finally, the fifth delayed recommendation was to develop and implement a plan to reduce the garage staff complement. Touche Ross suggested five action steps and estimated implementation costs of $2,000 (for the equivalent of two weeks of work by EPEC personnel) and minimal out-of-pocket costs for employment agency fees or training costs, with benefits of $100,000 annually. (City Ex. No. 15.) EPEC rebuttal witness Ignacio Troncoso testified that the Touche Ross recommendation was based on faulty observations of the practices employed in the garage.

Touche Ross apparently assumed that the Company garage operates exactly like industry averages. The auditor's observations were then compared with the flat-rate standards employed in commercial garage operations and, according to Mr. Troncoso, gave an unfavorable view of the productivity of the EPEC garage operations. This fundamental flaw was the subject of a meeting of representatives from EPEC, the Commission staff, and the auditors in Dallas in July 1985; Touche Ross nevertheless declined to alter its recommendation. (EPEC Ex. No. 41, Tab 12, pp. 2-3.)

Mr. Troncoso reported that EPEC made a determination of how much the reduction in fleet vehicles reduced the work load in the garage, and from there investigated whether it was possible to reduce the garage staff. (EPEC reduced the number of vehicles from 232 in August 1985 to 218 by mid-1986; it was still 218 in September 1987. [Tr. at 2391-2394.]) To substantiate its claim of operational differences between the Company garage and commercial garages, in November 1985 EPEC began a study of in-house garage operations. The study, still in progress, seeks to gather data which would correspond to that in the flat rate manuals, used in commercial garage operations, which specify a standard time for performing certain kinds of repairs on given makes and models of vehicles. Initially, it was estimated that gathering the data would take two man-months, and EPEC designed and implemented a repair order form that captured the data on a day-to-day basis.

It was then determined that a continuing expenditure of 25 man-hours per week would be required to extract and analyze the data manually, an impossibility at the time because of staffing levels. Acquisition of a personal computer for this task was discussed and rejected because of the Company's cash shortage. Now that the cash shortage has passed, EPEC created and filled in the second quarter of 1986 an administrative position charged with the responsibility for acquiring and implementing a personal computer based fleet management and control package. The computer is installed, software is loaded and running, and the accumulation of garage data has begun. (Tr. at 2397.) The analysis may or may not result in eventual compliance with the Touche Ross recommendation to eliminate three persons from the garage staff, according to Mr. Troncoso. When reliable information is available for analysis, however, EPEC will be able to make sound decisions about the number of personnel in the garage section. Mr. Troncoso testified that garage staffing level changes will be postponed until April 1988 when the analysis will be complete. (EPEC Ex. No. 41, Tab 12, at pp. 3-5.)

Mr. Troncoso conceded on cross-examination that his testimony did not address any of the action steps for this recommendation. (Tr. at 2398.)

During cross-examination by Company counsel, Ms. Friday testified that she was aware of the Company's strong exception to this recommendation by Touche Ross and the analysis underlying it. (Tr. at 2019-2020.) However, she did not agree that if EPEC's garage is not operated exactly according to industry averages, then Touche Ross's estimates will be wrong, since averages, however defined, by the nature of what they are, include variations in practices. (Tr. at 2020-2021.) She agreed that EPEC has taken some action on recommendation 12.5.3, but denied that she was penalzing the Company for something it indicated it needs more time to decide whether or not to implement. Ms. Friday based her penalty on the Company having postponed consideration of this recommendation without taking into account the costs and benefits, regardless of the accuracy of the costs and benefit estimates provided by Touche Ross. (Tr. at 2022-2023.)

D. Discussion and Recommendation

The evidence regarding the quality of EPEC's management, overall, does not support the imposition of the management penalty recommended by the staff and the City of El Paso. The credible testimony demonstrates that EPEC, even though struggling with cash problems, was able to implement some of the Touche Ross audit recommendations and, when its cash problems worsened, chose to suspend implementation activities which required initial cash expenditures. As the evidence shows, aggressive pursuit does not mean focusing solely on implementation of audit recommendations. The facts in evidence do not support the staff's conclusions and the general counsel's argument that EPEC's delay in implementing audit recommendations was ill-considered. Nor does the evidence support the contention that implementation was delayed in retaliation for what EPEC considered unfavorable rate treatment from this Commission in Docket No. 6350.

The testimony of Mr. Hackett successfully rebutted that of the staff witness. It shows that EPEC was already operating under cash constraints at the time the audit was conducted, and had suspended a number of cash expenditures. The Company lost employees, and it can be inferred that it thereby lost some of the resources for implementing audit recommendations. The lack of rate relief in Docket No. 6350 simply made a difficult situation worse, and the Company chose to suspend those items requiring a cash outlay. Mr. Hackett further testified, in contradiction to Ms. Friday and the arguments of general counsel, that implementation activities did in fact resume following the cash infusion brought about by the sale and leaseback of PVNGS Unit 2.

This report does not find credible the comparisons with other utilities, neither the comparisons of audit results made by Ms. Friday or the alternative comparison of performance indicators offered by Mr. Hackett. As the testimony from both witnesses established, there is no adjustment which can cause the many dissimilarities in utility operations and in the management audits to be similar enough for the comparisons to be valid and informative.

Further, the evidence regarding implementation status on the five recommendations used by Ms. Friday to calculate the management penalty does not justify its imposition; thus, use of the estimated benefits as a surrogate for calculation of the penalty is unsupported. The assertion that these five recommendations have not been implemented seems to rest on the fact that EPEC has not filed quarterly reports stating that each has been completed. The evidence of record reveals that while the Company may not have kept the Commission staff informed of each action it was taking on these recommendations, there was either some activity toward implementing at least four of the recommendations, or the Company was gathering data to determine if the original recommendation and/or cost and benefit estimates were still valid.

In addition, the record demonstrates that there are a number of factors which can make the numerical calculations of costs and benefits inaccurate, particularly after two years. Ms. Friday even conceded that if EPEC has reassessed the costs and benefits of a particular recommendation the Touche Ross estimates would be wrong. Further, she acknowledged that some costs and benefits cannot be easily calculated, and that initial estimates can later prove to be wrong. The evidence shows that, as for these five recommendations, EPEC did develop its own costs and benefits and implemented part or all of four of them, even though in some cases the actual costs of implementation were higher than originally estimated by Touche Ross or the benefits were lower or unquantifiable. These recommendations may have been delayed by EPEC's cash problems, but EPEC did perform its own analysis of costs and benefits and has taken some or all of the steps (albeit not necessarily those recommended in the Touche Ross audit) for implementing at least four of the recommendations.

It is clear, however, that EPEC has yet to complete the reduction of the time lag between bill generation/receipt and termination of service on unpaid accounts. The Touche Ross recommendation was premised on EPEC's reduction of this lag from 55 days to 28 days; however, the time has been reduced only to 39 days, not 28. While the Company has been inexplicably remiss in not pursuing this recommendation more diligently, the Touche Ross estimate of benefits was based on a further reduction in this time from 28 days to 25 days, a legal impossibility. Thus, while EPEC has been curiously slow in achieving the reduction to 28 days, the penalty is based on a benefit which cannot legally be gained, and there is no other measure in the record.

The one area of the Touche Ross audit which seems crucial in any evaluation of the quality of management concerns Franklin Land & Resources. Yet the relationship between EPEC and this subsidiary received only cursory treatment in the testimony of both the Company and the staff. Ratepayers and regulators alike are curious (and perhaps even a bit suspicious) about whether ratepayers are subsidizing unregulated activities. Although EPEC dutifully complied with the directive in Docket No. 6350 to address these audit recommendations in its next rate case, it did not address specifically the changes in corporate structure which resulted, as well as can be ascertained from the record, in FL&R now being a subsidiary of PasoTex, a subsidiary of EPEC. Unfortunately, there is no explanation of the new corporate structure and relationships, or of how or whether the Touche Ross audit recommendations about FL&R are applicable to PasoTex.

Further, the Company's claims that four of these eight recommendations have been completed are not entirely convincing, yet nowhere is there an analysis of the impact on ratepayers of, for example, the Company's minimal efforts at evaluating or changing the allocation methodologies between EPEC and FL&R, or the Company's stated justification for its failure to begin charging a carrying cost to FL&R for the prefunding of tax benefits. These activities in particular have a significant albeit concealed impact on ratepayers, and the Company's efforts as represented in this record have been minimal. Yet, as noted above, the stated rationale for using the five delayed audit recommendations as a surrogate for calculating a management penalty is not supported by the credible evidence in this record, and there is no alternative suggested by the evidence.

Finally, this report will simply state the obvious: there has been a serious failure of communication between EPEC and the Commission staff. General counsel argues that the Company has failed to show any requirement in the Commission rules or PURA that a utility must be informed of the staff's opinion of the utility's efforts to comply with the management audit, but the converse of that is true as well: there is nothing which requires the staff to withhold that information either. The record is not informative on the questions of how the Touche Ross audit recommendations for EPEC were to be implemented, whether there was a specific or implicit timetable or deadline for implementation, whether the Company had the option of deviating from the recommendations, and if so, by how much, etc.

It is clear that the Company bears the responsibility for implementing audit recommendations and cannot reasonably expect the staff to hold its hand along the way; Mr. Hackett conceded as much when he observed that the Commission is not authorized to direct the means by which the recommendations are implemented. Nevertheless, it seems reasonable to expect that EPEC should notify the Commission staff of deviations from the Touche Ross recommendations, and should offer substantial information justifying those changes, if not in special filings, then at least in the quarterly reports. And although it is true that the staff is not required to babysit the Company, as general counsel asserts, it seems reasonable to expect the staff to offer negative feedback at least, so that EPEC can amend its implementation procedures if necessary, particularly since management performance will be evaluated by the staff in part on how well and completely the Company has implemented audit recommendations. It is ironic that the one instance in which EPEC reported a major shift in implementation plans (the delay due to cash problems), the staff apparently said nothing one way or the other, then used the delay as the basis for imposing a management penalty. This report submits that such treatment is simply unfair.

The recommendation of this report is that no management penalty should be imposed on EPEC in this docket. However, the Commission should direct EPEC to update all implementation plans as of the next quarterly filing following the final order in this docket, and should inform the Company that the quality of its management will be evaluated, at least in part, on its achievements in implementing the Touche Ross audit recommendations.

VII. Palo Verde Nuclear Generating Station

A. Overview of the Prudence Phase

In addition to the briefs and the prefiled testimony of intervenors and staff, the EPEC submitted approximately 31, three-inch thick volumes of prefiled testimony in this docket. In addition, the hearings in the prudence phase lasted from mid-September to early December producing a very substantial transcript. The writer of the following sections on prudence has not attempted to summarize this testimony; rather she has tried to provide an analytical framework and discuss the evidence and the positions of the parties as they bear on the legal and factual issues that are important under this analysis.

The analysis is fundamentally divided into two parts, "decisional prudence" (which has to to do with EPEC's decision to participate in a 15.8 percent share of Palo Verde) and "construction prudence." Decisional prudence is important insofar as a utility has excess capacity on its system. A utility is entitled to the opportunity to earn a return on an investment that is "used and useful". All investments are not equivalent, however. Some may be very much larger in dollar amount than others and yet produce the same number of megawatts for the ratepayer. If the utility is left to decide which generating units it will count as being needed to meet load requirements, it can, for example, exclude cheap capacity in order to make more of its expensive capacity appear used and useful. Under the analysis adopted in this report, a utility that fails to prove that an investment in new generating capacity was prudent would be subject to having the Commission decide which resources to count towards meeting load requirements in the event there is excess capacity on the system.

Excluding cheap capacity is not the only technique for making more of an expensive investment in generating capacity appear used and useful. A utility can also accomplish this through the use of long-term, firm off-system sales to the extent that the Commission is willing to recognize them in load requirements. Here again, under the analysis adopted in this report, a utility that fails to prove that an investment in new generating capacity was prudent would be subject to having the Commission discount such sales in determining load requirements.

To do otherwise would mean that a utility which contracted unneeded capacity on an imprudent basis could not only force ratepayers to make up the difference between off-system sales revenues and the actual cost of the new capacity, but could enter upon a cycle of building capacity that was not needed but for the off-system load. When the old off-system sales contracts expired, the utility could enter into new off-system sales contracts. Then, when native system load plus off-system load justified building new capacity, the cycle would start over, with the result that the utility would be recovering expenses and earning a return on a system that was always larger and more expensive than it would have been without the off-system load.

The examiners point out that the Commission has an opportunity now, given the decisional prudence issues in this docket, to determine, over the utility's objection, which items belong in loads and resources for purposes of determining excess capacity. If the Commission "stipulates out the prudence issues" relating to Palo Verde as is recommended by the General Counsel in order to dispose of this docket (No. 7460), it may never have this opportunity again. Palo Verde capacity, which will actually not be needed to serve ratepayers until 1997 or beyond, will appear used and useful through a variety of techniques that will appear perfectly acceptable if there are no prudence issues involved.

The examiners conclude in this docket (No. 7460) that EPEC has failed to show that its initial decision to invest in 600 MW of Palo Verde capacity was prudent. Whether, over the years after the decision was made, more or less of the capacity would have appeared likely to be used and useful at the time the units were scheduled to come on line is not important to the analysis. The utility limited forever its range of options when it made the initial commitment. Even if it acted more or less prudently subsequent to making this commitment - which is obviously an area of intense controversy - and, even if it could obtain a CCN for all 600 MW from this Commission as of 1978, it still cannot change the nature of that initial commitment. That EPEC has failed to show that its initial commitment to Palo Verde was made on a prudent basis is the conclusion of staff witnesses Orozco and Rosenblum in this docket (No. 7460). It was also the conclusion reached in the two previous dockets (Nos. 5700 and 6350) which have considered the issue.

The examiners in this docket would find that 25 percent of the capacity Palo Verde Units 1 and 2 does not meet the used and useful test for purposes of being included in rate base. This 25 percent exclusion in no way cuts the utility to the bone. It provides for capacity needs through 1996, with a substantial (142 MW) net resources margin over and above reserve margin in 1996 itself.

The legal argument with respect to Palo Verde expenses would be somewhat lengthy to reproduce in this overview; the bottom line is that the recommendation of the examiners would allow for full recovery of all on-going, out-of-pocket expenses connected with Palo Verde Units 1 and 2, but has given ratepayers the benefit of the lower fuel expense associated with the Palo Verde capacity.

In the section of the report on construction prudence, the examiners have considered that construction costs may be excluded under two theories. If a utility submits insufficient evidence to show that it was prudent and efficient in managing a project, it would be fair to exclude costs to the extent that they exceed "reasonable costs" for such a facility under all of the circumstances. Additionally, if it can be shown that the utility or its agents were at fault in causing some specific costs to be incurred these costs would be excluded.

City of El Paso and Commission staff presented evidence of costs associated with delays caused by design defects in the RCS (reactor coolant system) and LPSI (low pressure system injection) pumps which were supplied by Combustion Engineering. Neither the City nor the staff provided evidence that, but for some mismanagement on the part of ANPP or any other entity, these problems and delays would not have occurred. The examiners thus found no basis to exclude the delay costs either as estimated by city witness Hubbard at $170 million or as estimated by staff witness Jacobs at $28 million. Furthermore, with the exception of a few areas such as the early phase of start-up activities, as to which staff witness Burns found that the evidence of prudence and efficiency was inconclusive, the evidence overall indicates that the project was prudently and efficiently managed, particularly in the construction phase leading up to the problems encountered in 1983 as a result of design defects in equipment supplied by Combustion Engineering.

In addition, overall project costs appear to be reasonable. Thus, even if there were some problems encountered along the way, or some false-starts with regard to start-up operations that may signal some initial inefficiency, ANPP has overall supplied a facility that is reasonable in terms of its cost and, with the possible exception of some continuing problems with the RCS (which the project last took care of at the time of refueling on Unit 1), gives adequate assurance of safety and reliability. The examiners are not recommending any exclusion of construction costs under a theory of imprudence or inefficiency.

The examiners are nonetheless aware that Arizona Public Service (APS), as operating agent for the Palo Verde participants, has filed suit against Combustion Engineering under a breach of contract theory. This suit represents a very substantial unliquidated claim against a supplier, for which EPEC should not be reimbursed by ratepayers to the extent that it is reimbursed by Combustion Engineering.

The damages that APS stands to recover on behalf of EPEC could be more or less than Mr. Hubbard's estimate of delay costs depending on a variety of factors, one of which would be its legal basis for recovering indirect or consequential damages. Although there is evidence in this docket (No. 7460) bearing the issue of ANPP's damages against CE under a contract theory, it is incomplete at best. This issue could be taken up in a separate proceeding following this docket. Whether it would be taken up depends, to some extent, on the interests and desires of the parties. The examiners are recommending only that, at a minimum, the Commission review any settlement reached with Combustion Engineering to ensure that it is in the public interest. If it is not, this could serve as basis to impute to EPEC a reasonable recovery on the theory that a fiduciary duty to ratepayers had been breached. The examiners are of course recommending that an appropriate percentage of any amounts that are actually recovered be deducted from rate base to prevent double recovery of these costs.

B. Regulatory History of Palo Verde in Texas as it Relates to Prudence Issues

Because regulatory and management decisions are so closely intertwined, the following regulatory history of Palo Verde, which is presented chronologically, is in part a history of management decisions at El Paso Electric Company. As such, it needs to be read as an integral part of the report.

1. 1975-1977

The P.U.C. began operations in September of 1975. In May of 1977, EPEC applied for a certificate of convenience and necessity (CCN) for its Copper Station Unit No. 1, a new gas-fired peaking unit. In reviewing that request, which was assigned Docket No. 478, the Commission became aware that EPEC had not obtained certificates for its out-of-state facilities including Palo Verde. The Commission directed EPEC to apply for certification for those facilities and, in July of 1977, EPEC did so under protest.[1]

In the final Order in Docket No. 478, the Commission concluded that EPEC was entitled to a certificate for Palo Verde under Section 53 of the PURA or, "in the alternative",[2] under Section 54. Section 53 of the PURA is the section that provides for facilities operating or under construction as of the effective date of the Act to have been issued "grandfather" certificates on application to the Commission within six months of the effective date. Section 54 is the section that provides for a grant of certification based on public convenience and necessity after consideration of certain factors specifically set out, among them: adequacy of existing service, need for additional service, lowering of cost to consumers, effect on the recipient and on neighboring utilities, environmental integrity, and so on.

In the final Order in Docket No. 478 in 1977, the Commission found that, prior to September 1, 1975, EPEC had expended $8,266,276 on "Palo Verde Nuclear Generating Station Units 1, 2, and 3".[3] This finding was the basis of the determination that EPEC was entitled to a certificate under Section 53 even though the application did not meet the requirement of being filed within the six-month deadline, as was subsequently noted in Docket No. 1981.

The Commission's deliberations in Docket No. 478 resulted in a finding that, with the addition of Palo Verde--the first unit of which was then expected to come on line in May of 1982, EPEC would have a problem of excess reserves by 1983, which would be exacerbated by the addition of Copper Station. As the Commission nonetheless found that, for the year 1981, there would be a slight reserve deficiency without the power generated by Copper Station, it directed EPEC to initiate negotiations with other utilities for the supply of purchased power to meet its interim reserve requirements.

The decision in Docket No. 478 actually resulted in neither the granting nor the denial of the CCN for Copper Station. The final Order issued August 29, 1977, stated that, at the conclusion of a six-month period, EPEC was to report on the status of its negotiations for purchased power, at which time the Commission would re-examine the need for Copper Station.

2. 1978

City of El Paso and City of Anthony subsequently appealed the decision in Docket No. 478, and the cause was remanded to the Commission in June of 1978 by the district court, with the grant of certification for Palo Verde reversed and set aside in order that there might be "a full hearing on all issues involving the [certification] of the Palo Verde Nuclear Generating Facility."

Meanwhile at the end of the six-month period, EPEC reported in February of 1978 that it was unable to locate satisfactory purchased power. The CCN application for Copper Station was severed from Docket No. 478 and assigned Docket No. 1642. Although the Commission subsequently found in Docket No. 1642 that EPEC could have purchased sufficient power from the Salt River Project (SRP) to cover its requirements as forecasted by staff,[4] it nonetheless granted the certificate for Copper Station. Certification for Palo Verde was pending at the time because of the district court's remand of that cause.

The examiner's report in Docket No. 1642 reflects the existence of a significant difference in 1978 between what EPEC and Commission staff were forecasting in the way of future load growth. The report reflects that, for future year 1984, EPEC was forecasting a peak of 1076 MW. By comparison, Commission staff was forecasting a peak of 876 MW,[5] a difference of some 200 MW, or the equivalent of EPEC's share in one unit of Palo Verde. (Hindsight shows that actual peak for 1984, at 784 MW, was some 92 MW lower than either had forecast.) According to the examiner's report, staff was recommending that "a study be undertaken to determine the feasibility of conditioning certification of Copper Station on the sale of at least a portion of Palo Verde". The report further notes that the City of El Paso was vigorously supporting this proposal. Although the report dismisses the proposal on the basis that the Palo Verde issue would be dealt with in its own separate docket, the existence of the proposal shows that in early 1978 persons outside the company with expertise in load forecasting wanted the company to look into selling a portion of its share. Of course, at that time, Palo Verde Unit 1 was expected to be on line as early as 1982, with Palo Verde Unit 2 to follow in 1984.[6]

In 1978 in Docket No. 1642, staff was forecasting a peak of 813 MW for 1982. Interestingly, in light of lengthened construction schedules for Palo Verde and slower load growth than was anticipated, the peak that was forecast by staff for the year in which Palo Verde Unit 1 was then supposed to be coming on line is in much the same ballpark as the peak actually experienced in the year in which Palo Verde Unit 1 did come on line. (Palo Verde Unit 1 went into commercial operation on February 13, 1986, with Palo Verde Unit 2 to follow in September of that year. Historical native system[7] peak was 790 MW in 1986 and 820 MW in 1987).

In June of 1978, EPEC filed an application for a rate increase, assigned Docket No. 1981. The issue of certification for Palo Verde which was still pending from Docket No. 478 was consolidated with it. In Docket No. 1981, Commission staff took the position, rejected by the examiner, that only 300 MW, or one-half, of EPEC's interest in Palo Verde should be granted a CCN. Based on the examiner's recommendation, the Commission granted a certificate covering EPEC's entire 15.8 percent share. At page 2 of the report the examiner stated:

> [F]ull participation in Palo Verde and idling the gas and oil fired generators or selling their excess generation to other utilities, would probably cost less in the long run. Customers would bear the full brunt of CWIP but would save in the future by avoiding the pass-through of the cost of expensive oil and gas fuel. Also, the Company could profit from sales to other utilities and the revenues earned would allow EPEC's other customers to pay less.[8]

Clearly, the examiner conceived of Palo Verde as a base load plant that would eventually replace oil-and gas-fired generation.

In 1978, EPEC had an interest in a coal unit, the Four Corners plant, which supplied 110 MW (and still does), but the remainder of EPEC's generating capacity was fueled by oil and gas. Although in 1977 and 1978, EPEC's total system load was peaking at 657 and 690 MW[9] respectively, the examiner's view of the ten-year outlook showed that, under staff's forecast, Palo Verde "would represent only 58 percent of [the staff's] forecasted peak of 1031 MW for 1988 and should fit in as a baseload plant for the Company".

Almost in contrast with his conclusion that 600 MW of Palo Verde would "fit in" as baseload capacity even if this meant the idling of some oil and gas units or the selling of excess generation to other utilities, the examiner included the following recommendation at p. 5:

> Due to the enormous cost, the uncertainty involved in the various growth forecasts, and the uncertainty of the construction cost forecasts, the Examiner would recommend that EPEC's management be directed to continually look for alternatives to the Palo Verde Project and keep the lines of communication open to potential buyers of Palo Verde generating capacity.

Arguably, in order to reconcile with the rest of the report this language, and that of Finding of Fact No. 16 which gives EPEC a:

> capital transition allowance of $1,406,653 to permit the Company sufficient time to evaluate its continued level of participation in the Palo Verde Nuclear Project,[10]

one must infer a finding that a 600 MW share of Palo Verde was economically justified as of 1978 in relation to other alternatives even if it meant the idling of some existing oil and gas-fired capacity or the selling of some excess generation to other utilities, but that in future, due to changed circumstances, it might not be.

Perhaps another way to reconcile the two recommendations is by way of reference to what might be called the "grandfather" factor. Palo Verde was, after all, not an abstract proposition in 1978. The project was under construction, and EPEC had a firm commitment to fund a 15.8 percent share of it or else find someone who would. Arguably, under those circumstances, it is very difficult for the regulatory body to proceed as though it were evaluating the need for the project in the abstract before the contracts are signed and the concrete is poured. Moreover, there is probably an understandable reluctance to second-guess and disrupt a project unless the grounds are compelling. In Palo Verde's case, where there are advantages to independence from oil and gas, and the economics of nuclear power versus coal seem favorable, but there is uncertainty about future load requirements, the various recommendations - that EPEC be granted a Section 54 certificate and, having just established the need for its entire 15.8 percent share, also be granted a monetary allowance to give it time to "evaluate" the very same thing - which perhaps seem contradictory, may actually fit together.

Nonetheless, there is a problem with saying that the report and order in Docket No. 1981 both granted the CCN and, in the same breath, called into question the need for this capacity. The problem is that the grandfather factor, though it might have been the legal basis of the certificate had EPEC applied early enough under Section 53, and might even have been a legitimate factor in a Section 54 certificate insofar as the Commission is authorized under the statute to look at effect on the recipient of granting (or denying) the certificate, was nonetheless never explicitly stated as a reason for granting the certificate in Docket No. 1981. Instead, the report indicates that 600 MW of Palo Verde should "fit in" under circumstances of a ten-year forecast showing a peak of 1031 MW for 1988 even if this meant the idling of some oil and gas-fired capacity or the selling of some excess generation to other utilities. The rationale in Docket No. 1981 was not that the investment was worthy of some sort of special consideration that might, because of the grandfather factor, protect it as far as the past was concerned, but rather that the investment was justified on the basis of then-current economics and load forecasts independent of any sort of grandfather factor. Thus, regardless of any reservations about the level of participation in Palo Verde that may have been expressed in the report,[11] the stated rationale for granting the CCN would tend to justify the Company in not selling, if that were its preference, so long as the relationship among the factors relied on the report remained fairly constant. Moreover, certain language in the report would tend to justify the Company in not selling, if that were its preference, even if it were using some excess capacity to make off-system sales. At page 2, the report states:

> Under the Staff position that EPEC will need only 300 of the 600 MW Palo Verde will provide, the Company can either sell one-half of its participation[12] or maintain full participation and idle its expensive oil and gas fired plants or sell its excess energy to other utilities in the form of economy sales.

The examiner appears to be saying here that, if events turn out as staff has predicted and only 300 MW of Palo Verde is needed to serve ratepayers, there is no harm done by having certificated the full 600 MW because, one way or another, 300 MW of something can always be removed or retired from ratebase or sold off-system. The examiner unfortunately appears to assume that one would be indifferent to the alternative chosen, with the decision therefore conveniently being left to the utility.

One problem with this assumption is that the alternatives are not equivalent from the ratepayers' point of view. If Palo Verde turns out to be the most expensive capacity on EPEC's system (which it has), ratepayers would prefer that it had been removed from ratebase through a sale of participation. Another problem is that, aside from fear of regulatory disallowance, there is no particular incentive on the part of the utility to try to effect a sale of participation as opposed to a sale of economy energy; certainly, there is no incentive for the utility to try to effect a sale of participation at anything below book value. In addition, where there is the possibility that, at any future point in time, the utility will need the capacity on its native system, there are probably a number of incentives to retain ownership of the capacity. One incentive would be that, even if the utility could build new capacity during the time that the existing capacity was under contract to an off-system purchaser, the utility might prefer to retain ownership of the existing capacity in order to avoid having to build the new capacity with all of the attendant problems and costs and uncertainties of a new financing and construction project. Insofar as fear of regulatory disallowance would be the real impetus[13] to effect a sale of participation, and insofar as the report and order in Docket No. 1981 indicated the parameters within which 600 MW of Palo Verde would "fit in" (translation: there would probably be no disallowance), the subsequent history of Palo Verde may be fairly predictable. Indeed, for whatever reasons, there has never been any sale of participation in Palo Verde; there is no evidence that there has ever been any offer to sell an interest at below book value; there have been some substantial off-system sales of capacity consummated, one of which lasts through the year 2002; and lastly, some oil and gas fired units have been retired earlier than was anticipated.

Lastly, it might be said about the report and order in Docket No. 1981 that to reject a staff proposal to certify just half of EPEC's share and to grant the certificate for the reasons that were stated is to find that, as of 1978, the decision to participate in 600 MW of Palo Verde was "prudent." Moreover, on that basis, it is arguable that there is no point in inquiring into the quality of the Company's deliberations prior to November of 1978. Good, bad, or indifferent, from whatever standpoint, the prior decisions of the Company culminated in the granting of the certificate in 1978 on the basis of load forecasts and expected net economic benefits for ratepayers. Ironically, considering the basis of the approval given EPEC's full participation in Palo Verde in Docket No. 1981, it may prove to have been rather to the Company's advantage that its protest to having to apply for a CCN for Palo Verde went unheeded, and even that its quasi-grandfather certificate from Docket No. 478 was vacated by the district court.

3. 1979-1983

In June of 1979, EPEC filed a second application for a rate increase. It was assigned Docket No. 2641. The case settled prior to the hearing with the settlement providing that:

> Pursuant to the recommendation of the City Council that EPEC divest itself of 25 percent of its interest in Palo Verde , EPEC shall present evidence at a future. . . date to the Board regarding the continued need for EPEC's current participation in Palo Verde . . .

At that time, PV Units 1 and 2 were expected to be on line in 1983 and 1984 respectively. (The record in Docket No. 2641 does not reflect the date projected for PV Unit 3.) EPEC, which was then maintaining that none of its interest should be sold, was projecting peak loads of 821 and 849 MW, respectively, for those years. (Actual peak for those years was somewhat lower than projected, at 749 and 825 MW, respectively.) To provide a point of reference with Docket No. 1981, it may be noted that the Company was contemplating a peak of 983 MW in 1987, the last year for which it had a forecast. Six hundred megawatts of Palo Verde would have represented approximately 61 percent of that peak which, roughly speaking, would have meant a slightly larger percentage of Palo Verde to peak several years after commercial operation than had been contemplated in Docket No. 1981.

In May of 1980, EPEC filed its third application for a rate increase. It was assigned Docket No. 3254, and it, too, settled. All issues relating to EPEC's level of participation in Palo Verde were, however, severed out and consolidated with Docket No. 3382, which was the petition of EPEC for review of the order of City of El Paso for EPEC to divest itself of fifty percent of its share. Ultimately, Docket No. 3382 also settled prior to the hearing which, due to a series of continuances requested by EPEC, did not finally take place until August of 1983, some three years from the date of the City's order.

Like the two previous dockets (Nos. 2641 and 3254), Docket No. 3382 did not result in any finding as to what, at any given point in time, EPEC's level of participation in Palo Verde ought to have been. While the city issued orders in 1979 and 1980 directing that a certain percentage be sold, these orders were appealled, and, on appeal, nothing definite was established other than that, at least around the time of August of 1983, there would be no fault on the part of EPEC in failing to sell, because, according to the stipulation, there were no buyers.[14]

Although prior to 1981 EPEC did not try to sell any of its interest in Palo Verde, beginning in 1981 it did make efforts to find a buyer for up to 150 MW, or one-quarter, of its share and came close to effectuating two such sales. In 1981, EPEC came close to selling 150 MW of its interest in Palo Verde to M-S-R Power Agency (M-S-R), which is located in California and takes its name from the cities of Modesto, Santa Clara, and Redding. M-S-R put the proposed sale before the voters in the Modesto Irrigation District, but the voters rejected it by a 52 to 46 percent margin in December of 1981. In July of 1982, EPEC again came close to a sale of 150 MW, this time to the Sacramento Municipal Utility District (SMUD) in California, but this sale was rejected by SMUD's board of directors. During this priod of time, Palo Verde Unit 1 was still expected to be on line in mid to late-1983 with PV Unit 2 to follow in late 1984.

In this same late-1981/1982 timeframe, EPEC entered into certain long term, firm-capacity contracts to sell power to TNP (Texas-New Mexico Power Company) and IID (Imperial Irrigation District). The TNP contract was signed in December of 1981, and called for EPEC to supply varying amounts of power during the years that it was to be in effect. Although sales were to be made in years prior to 1986, the record does not reflect how much power was to be sold to TNP prior to 1986. At the time that the contract was signed in December of 1981, however, Palo Verde would have been expected to begin coming on line by mid-1983.

The contract with IID was signed in September of 1982. As with the TNP sale here again, the record does not reflect how much power was to be sold prior to 1986. At the present time, the contract with IID, which was renegotiated in 1986 in part to extend the term of the sale from the year 1992 to the year 2002, calls for a supply of 100 MW of firm capacity per year. (It also calls for some 50 MW of contingent capacity.)

For the period 1988 through 1996, these two contracts will dispose, on average, of about 169 MW of firm capacity per year. (Firm sales to TNP and IID will fluctuate from a low of 154 MW in 1988 to a high of 179 MW in 1993, leveling off to 175 MW per year in 1994 through 1996, so the yearly numbers do cluster around the average).

EPEC Manager of Resource Development and Contracts Frederic E. Mattson disputed the suggestion that these off-system sales dispose of surplus power. (Transcript at 6318). As the following exchange (Transcript at 6318-9) indicates, EPEC would not deem capacity dedicated to off-system sales as "surplus" so long as EPEC would have to add other capacity in the "near future" (not specified) to replace this capacity:

> Q. I assume that when you took on this obligation, that you felt that you were reserving sufficient power to adequately serve your other customers?
>
> A. No. That is the quandry. Because of our regulatory and financial considerations, we are selling power in the short-term, and we'll need to replace that power in the long-term.
>
> Q. Would you please explain what you mean by "short-term" and "long-term" in connection with this transaction?
>
> A. Well, if you look at our loads and resources document, you'll see that we'll need all three Palo Verde units in the near future. . . And so selling a piece of Palo Verde is actually causing us to add additional generating resources to replace Palo Verde in the near future.[15]

As this exchange illustrates, EPEC is not saying that this power is needed by the native system in the sense that its dedication to off-system sales is going to cause brown-outs, just that EPEC expects to have to make provision for additional power to meet native system requirements earlier than would otherwise be the case. This exchange also reflects that a concept like "surplus" has little meaning where capacity is not deemed surplus so long as its availability means that future capacity additions can be postponed to the distant future. Clearly, concepts like "regulatory considerations" and "financial considerations" have far more impact and immediacy in respect of utility planning. (This is not to suggest that management is somehow behaving badly; management is simply acting and reacting according to real-world incentives and constraints. Apart from real-world considerations like regulatory disallowance and rate shock, management would not have reason to worry about paring capacity additions to a minimum; insofar as the utility's rates are linked to the size of its investment in plant, its concern would be always to have on hand as much capacity as the utility's customers would profitably support through their rates, with no particular ceiling on quantity being dictated by the customers' immediate needs.)

The TNP sale took place in December of 1981, prior to the ultimately unsuccessful SMUD deal in 1982, and possibly prior to the M-S-R deal which fell through at approximately the same time as the consummation of the TNP sale. The IID sale took place in September of 1982, subsequent to both the M-S-R and SMUD proposals having fallen through. Interestingly, Mr. Mattson commented that there was no particular cause-and-effect relationship between the falling through of the participation sales and the consummation of the IID sale. (Tr. at 7092). Certainly, it would be reasonable that EPEC not posit a connection betwen the two insofar as the Examiner's Report in Docket No. 1981 indicated that off-system sales would be an acceptable way of disposing of Palo Verde capacity, and no less acceptable than a sale of participation. EPEC would, of course, not have been able to undo the contracts with TNP and IID in order to resell this same capacity in the form of participation in Palo Verde.

In June of 1983, EPEC increased to 33 percent the share of its interest that it was willing to sell. (This would equate to 200 MW.) Shortly thereafter in August of 1983, the settlement in Docket No. 3382 (to which reference has previously been made) was signed stipulating that there were, however, no buyers for Palo Verde participation at that time.

One last regulatory event taking place in 1983 was to have a significant impact on EPEC in rate cases to follow. That event was the amendment of section 41(a) of the PURA. Previously, this section has provided that a utility could include construction work in progress in rate base to the extent necessary to the utility's financial integrity. In 1983 this section was amended to add the following language:

> Construction work in progress shall not be included in rate base for major projects under construction to the extent that such projects have been inefficiently or imprudently planned or managed.

4. 1984-1985

Docket No. 3254 was the last of the rate case reports involving EPEC to be presented in ten pages or less. In April of 1984, EPEC filed its fourth application for a rate increase, assigned Docket No. 5700, and, in June of 1985, its fifth application, assigned Docket No. 6350. Given the brevity of the previous reports, it is perhaps noteworthy that each of these reports ran close to 150 pages.

Docket No. 5700 was one of the first rate cases involving major construction work in progress that was filed after the 1983 amendment of Section 41(a). The Commission held in Docket No. 5700 that the utility has the burden under Section 41(a) of proving that the construction work in progress (CWIP) that it seeks to include in rate base relates to a project that has been prudently and efficiently planned and managed. According to the report and order, there is no presumption of prudence and efficiency for purposes of including CWIP in rate base under Section 41(a). The Commission further found that EPEC had failed to meet its burden, and it held that, in the absence of a showing that the full extent of the utility's participation in the project is prudent, it is appropriate to include CWIP in rate base (where necessary to financial integrity) in the same proportion as the percentage of the capacity that is reasonably likely to be used and useful when the project comes on line.[16] Specifically, Finding of Fact No. 17 at page 3 of the Final Order states:

> EPEC failed its burden of proof of showing that the company's continued 15.8 percent participation in the Palo Verde project was a prudent decision. Therefore, using a prudence and efficiency standard, it would be reasonable to exclude from rate base up to 50 percent of EPEC's test year end PVNGS CWIP; representing the quantification of estimated excess capacity EPEC is expected to experience when the Palo Verde units come on line.

The Commission never quantified the share of Palo Verde in which it would, at any given point in time, have been prudent for EPEC to participate; it found only that a 15.8 percent share was too much for EPEC to have "continued" with. The choice of the word "continue" might suggest that the original decision to commit to 600 MW of Palo Verde was thought to be either unobjectionable or beyond reconsideration in light of the grant of certification in Docket No. 1981. A careful reading of the report would, however, show that this is not so. Even though the report in Docket No. 5700 states:

> . . .[T]he examiners note that the evidence in this case does not establish that EPEC was in fact imprudent in deciding to participate in PVNGS in the first place,

considering the holding in the docket with regard to burden of proof, the failure of the evidence to establish the imprudence of the original decision really signifies nothing as to whether the original decision was *prudent*. Thus, while the use of the word "continue" in Paragraph 17 of the Order might suggest that the original decision was considered unobjectionable, given the ruling on burden of proof, its use would simply be dictated by the absence of a finding that the original decision was imprudent.

Similarly, with regard to the significance of the certificate, the report indicates that the certificate's issuance would not dispose of any rate case issues relating to imprudent planning occurring before or after the certificate's issuance. Thus, the use of the word "continue" would not in any way signify a distinction being made between events taking place pre- and post-certification.

Moreover, although the Commission allowed fifty percent of Palo Verde CWIP in rate base, this was clearly not based on any finding that fifty percent of Palo Verde was prudently and efficiently planned and managed. Presumably, having made no finding on the extent to which the Palo Verde participation was prudently planned or managed, the Commission could have excluded all Palo Verde CWIP. Instead, the Commission granted an allowance of fifty percent of CWIP based on "the quantification of estimated excess capacity EPEC is expected to experience when the Palo Verde units come on line".

Arguably, to have been consistent with the approach taken in Docket No. 1981, the Commission would have had to have been projecting a peak for 1994 of roughly only 731 MW. (Subtracting 300 MW from the 1031 MW referred to in Docket No. 1981 leaves 731 MW.) In other words, if, in 1978, 600 MW of Palo Verde would have "fit in" to a peak of 1031 MW by 1988, by the same token, in 1984, 600 MW of Palo Verde, with lengthened construction schedules, should more or less have "fit in" to a peak of 1031 MW for 1994. In order for 300 MW of Palo Verde to represent excess capacity under the parameters set out in Docket No. 1981, it would seem that, all other things being equal,[17] the projected ten-year peak would have had to fall short of 1031 MW by at least 300 MW. Clearly, however, the Commission was not basing its decision on what the peak was likely to be at the end of a ten-year forecast, nor is a projected peak of 731 MW for future year 1994 really plausible for that period; rather the Commission was looking at the capacity that would be excess in the years immediately following the anticipated in-service dates of the units.

As the Commission adopted the City of El Paso's recommendation that fifty percent of Palo Verde CWIP be excluded, over the examiners' recommendation that only forty percent be excluded, it may be inferred that the Commission was persuaded by the City's witness Dr. Ben Johnson regarding the calculation of excess capacity. It appears that Dr. Johnson used EPEC's projections of total system peak demand, subtracted the off-system sales that would have been added into it, and then added a reserve margin based on twenty percent of that peak. (Report at p. 23).

This is a very different approach than that taken in Docket No. 1981, and it is certainly arguable that the Commission which decided Docket No. 5700 would have adopted the staff recommendation in Docket No. 1981 and certified only half of the project and, vice versa, that the Commission which decided Docket No. 1981 would have looked to total system peak for 1994 and made no disallowance if it been deciding Docket No. 5700. Because the actual forecasts of peak demand do not, except for the 1031 MW figure quoted in Docket No. 1981, appear in either of the reports, it is extremely difficult to make a clear and uncomplicated demonstration of this using such information as is available about these time periods. The easiest way to show how this could come about would be to apply the two "formulas" to the numbers that may be gleaned from the instant docket. For purposes of this demonstration, which is really to show the very different results that can be achieved using the two approaches, it is not necessary to be concerned at the outset with refining or modifying the formulas; indeed, this might only obscure the comparison. Moreover, it is easiest to profile the comparison using the company's own forecasts, again without any of the modifications or refinements that would require extensive discussion and qualification. The following calculations result.

If one looks at the years 1990, 1991, and 1992, when all three Palo Verde units are supposed to be in service, the company is projecting native system peaks of 918 MW, 952 MW, and 976 MW respectively. Adding a twenty percent reserve margin yields the following totals: 1102 MW, 1142 MW, and 1171 MW. Total system generating capacity for those years as shown in the company's own loads and resources forecast will be a constant 1503 MW, for an "excess" ranging from 401 MW to 332 MW. (Staff forecasts of peak are significantly lower than the company's, so the "excess" would be even greater if they were adopted and would offset some or all of the refinements in the formula for which the company would undoubtedly argue. Additionally, one might argue that EPEC's calculation of total system generating capacity is understated becasue it ignores the availability of purchased power and reflects the elimination of Rio Grande Units 3, 4, and 5 due to early retirement. Again, there would be countervailing arguments from the utility about the impropriety of including these resources.)

By comparison, using the Docket No. 1981 approach and looking to the company's total system peak for future year 1996, which is 1282 MW - this would include firm, off-system sales to TNP and IID, but these were the types of sales that the report that was adopted in Docket No. 1981 said were appropriate and would benefit ratepayers - the 600 MW of Palo Verde would, at that time, on the basis of these projections, constitute a mere 46 percent of peak. Thus, it may be shown, on the basis of the same forecast, that both *fifty percent* of EPEC's participation in Palo Verde is excess and *none* of EPEC's participation in Palo Verde is excess, at least in terms of what was asserted in Docket No. 1981 to be an appropriate relationship between Palo Verde and peak.

Moreover, even adding refinements to the Docket No. 1981 approach may not change the result. For example, one of the first refinements that might be made would be to look at the placement of the capacity addition in terms of the ten-year forecast. In Docket No. 1981, the last unit of Palo Verde was probably due on line around the sixth year of the ten-year period forecasted whereas, in the present docket, the last unit is not due to be in-service until December of 1989 which would be the end of the third, or about the fourth, year of the ten-year forecast. To equalize the number of years between the addition of the last unit and the end of the ten-year forecast, one could scale back by two years and look at the peak in 1994. On this basis, 600 MW would represent a slightly larger 49 percent of peak. This would still be less than the magic 58 percent from Docket No. 1981, however. (This is not to suggest, by the way, that EPEC is necessarily "safe", no matter what the forecast, under a Docket No. 1981 approach, but clearly the utility runs a lesser risk of regulatory disallowance under its aegis.)

Whether Docket No. 1981's aegis actually does provide EPEC with any protection is of course debatable. There is no magic significance to the relationship between Palo Verde and peak, in isolation, except insofar as Docket No. 1981 says there is. Thus, it is perfectly easy to dismiss the dictum about 600 MW of Palo Verde "fitting in" to a peak of 1031 MW as a formula for determining whether there is any surplus. Having said this, it is nonetheless still possible that the stated rationale for granting the certificate in Docket No. 1981 has some enduring significance for the issues that are before the Commission in this docket (No. 7460). That significance lies in the extent to which it is plausible that the dicta in the report had an influence on EPEC's subsequent behavior. Utility managers presumably behave as businesspeople and, insofar as the utility's rates are linked to the size of its investment in plant, would want to build as much capacity as ratepayers could be relied upon to support in a profitable manner through rates. Apart from fear of regulatory disallowance, there would be no economic incentive to pare capacity additions to a minimum; the relevant inquiry would tend to be what is the *maximum* that can be built. It is probably up to the regulatory body to focus attention on the *minimum* that can reasonably be built, and this the examiner in Docket No. 1981 effectively failed to do. The examiners in Docket No. 5700 took just the opposite approach and did focus on this issue; therein lies the incompatability of the two dockets and an explanation of how, on the basis of the same forecast, one can show both fifty percent excess capacity and zero excess capacity.

5. 1985-1986

In June of 1985, EPEC filed its fifth application for a rate increase, assigned Docket No. 6350. The Commission followed the precedent that had been established in Docket No. 5700 and disallowed Palo Verde CWIP in the same proportion as the percentage of EPEC's interest that was likely to represent excess capacity in the years following the in-service dates of the units. According to the examiner's report, which the Commission adopted, this was still fifty percent.

The method that the examiner used to determine the extent of the capacity deemed excess was basically the same as that used in Docket No. 5700. The examiner took Commission staff's forecast of native system peak demand, to which he added a twenty percent reserve margin. He rejected EPEC's chosen method of calculating reserve margin[18], and he intentionally did not add to native system peak either off-system sales to TNP and IID or contingent power held in reserve for Public Service of New Mexico (PNM). On the supply side, he followed the recommendation of Dr. Johnson in including the capacity of Rio Grande Units 3, 4, and 5, based on a finding that the record reflected insufficient justification for their early retirement. He did, however, reject the recommendation of Dr. Johnson that purchased power available from Southwestern Public Service (SPS) be included, noting that the purchased power available from SPS would more or less cover any request for power by PNM in the unlikely event that PNM demanded its entitlement.

The examiner did not include the specific forecast of the loads and resources on which his conclusion was based. In addition, although he reported Dr. Johnson's computations of excess capacity for the years 1986 through 1994, the examiner's recommended inputs would have been slightly different, and so the exact computation that would result from the use of the examiner's inputs are not reflected in the report. Dr. Johnson's computations of excess capacity as reflected in the report were as follows:

Year	Excess MW
1986	370
1987	334
1988	436
1989	402
1990	445
1991	415
1992	260
1993	305
1994	254

The examiner's computations, were they to be carried out, should differ from Dr. Johnson's for two reasons. First, on the demand side, Dr. Johnson used EPEC's forecast of native system demand which was slightly higher than the staff's and, secondly, on the supply side, Dr. Johnson presumably included some estimate of the amount of reasonably reliable purchased power available from SPS. By comparison, the examiner would have used the slightly lower projections of the staff forecast which would be partially offset by the exclusion of purchased power available from SPS.

6. 1986-Present

In March of 1986, EPEC filed a petition requesting that Palo Verde Unit 1 be declared in service, and, by order of November 14, 1986, the Commission established an in-service date of February 24, 1986 for that unit.

Similarly, in December of 1986, EPEC filed a petition requesting that Palo Verde Unit 2 be declared in service and, by order of October 21, 1987, the Commission established an in-service date of September 22, 1986, for this unit.

The anticipated in-service date for Palo Verde Unit 3 is December of 1989 which is actually the anticipated completion date for the Arizona Interconnection Project. (Tr. at 9005.) Although Palo Verde Unit 3 is expected to be complete by January or February of 1988 (Tr. at 9008), existing transmission facilities, or portions thereof, connecting El Paso with PVNGS, are already at full capacity, and so the completion of the Arizona Interconnection Project will be necessary in order to carry the additional 200 MW to the El Paso area.

C. Prudence of the Decision to Participate
in a 15.8 Percent Share of Palo Verde

1. The Initial Decision

In 1972, Arizona Public Service Company (APS) and Salt River Project Agricultural Improvement and Power District (SRP) formed the Arizona Nuclear Power Project (ANPP) and became its steering committee. They contacted every electric utility serving Arizona, western New Mexico, and west Texas, inviting them to participate as owners in the construction of Palo Verde Nuclear Generating Station (PVNGS or Palo Verde). As originally conceived, PVNGS was to be the largest nuclear power station in the United States. It was to consist of three identical 1200 MW units, with an option to add two more identical units later on. APS was to serve as the project manager during construction and as the operating agent subsequent to completion. A new Combustion Engineering System 80 Nuclear Steam Supply System (NSSS) was to be utilized in the reactor vessel, and Bechtel Power Corporation (Bechtel) was to be the engineer-constructor.

Sometime in 1972 or early 1973, the steering committee held a meeting for those interested in the project. EPEC attended the meeting. At the meeting, the steering committee distributed copies of a nuclear project planning study that had been prepared by NUS Corporation (NUS) for a nuclear project study group composed of APS, SRP, and TG&E (Tucson Gas & Electric Company). In addition to distributing the NUS study, the steering committee made a presentation that would have updated some of the cost information presented in the NUS study.

Sometime during or after this meeting EPEC submitted a request for a 19 percent share. This would have translated into 684 MW. Although EPEC subsequently ended up with a 15.8 percent, or 600 MW, share when, together with TG&E, PNM (Public Service Company of New Mexico), and the steering committee members, it signed the Participation Agreement in August of 1973, its original planning decisions were based on 684 MW. What happened is that, when all of the participants were asked to finalize their requests, the results showed that to accommodate them all the nominal rating of the units would have to be 1,550 MW, which was determined to be too great. The nominal rating design of the units was brought up to 1,270 MW, and there was a round of negotiations to close the gap between available and requested capacity. The participants ultimately decided on a pro-rata reduction in each participant's request, and this brought EPEC down to a 15.8 percent share of the three 1,270 MW units.

The following factors contributed to EPEC's decision to become involved in Palo Verde. First, EPEC had worked successfully with APS in the past. Specifically, EPEC had been a participant with APS in the Four Corners coal project, the last two units of which had been completed as recently as 1969 and 1970. (Tr. at 3836.) As was to be the case with PVNGS, APS had been the project manager at Four Corners. All indications are that EPEC had considerable faith, well-founded, in a project spearheaded by APS.

Second, EPEC was aware of problems created by its heavy dependence on natural gas and wanted to continue to diversify the Company's generation mix. At 110 MW, its Four Corners participation had been a step in this direction, but the remainder of its approximately 710 MW came from natural gas, the supplies of which were subject to curtailment anytime there was a shortage.

Third, EPEC was familiar with the environmental problems and costs associated with coal plants. It had been involved with coal at Four Corners and was in the process of studying a possible joint coal facility with PNM. (Tr. at 3926). Moreover, it had formed an unfavorable impression of the process of having to meet evolving regulatory requirements for coal plants, which served to increase its interest in a nuclear option.

Fourth, EPEC was looking for opportunities to participate in jointly-owned coal and nuclear projects. It was aware that there were, and are, substantial economies of scale associated with nuclear and coal facilities of a size that would outstrip anything that EPEC could finance and build on its own.

Fifth, EPEC was limited in respect of the utilities with which it could interconnect in order to participate in joint projects. Because EPEC is, and was, an interstate utility, Texas utilities to the East would not interconnect with it; they did not want to become subject to FERC (Federal Regulatory Energy Commission) jurisdiction by virtue of being connected to an interstate utility.

Sixth, such information as EPEC would have had on then-current cost comparisons of coal and nuclear plants would have showed nuclear plants to be the cheaper option. EPEC made no independent study of its own, and there is no evidence that it attempted a critical assessment of any particular study. Under these circumstances, it is likely that it would have placed considerable weight on the opinions and cost estimates of the ANPP steering committee members. According to retired ANPP Executive Vice President and Chief Operating Officer Thomas G. Woods, Jr., the studies that ANPP steering committee members would have had in 1972 were showing the cost per kWh (kilowatt-hour) of a new nuclear facility to be about half that of a new coal plant. (Tr. at 2694.) According to Mr. Woods, it was indeed the "generally accepted opinion in that time frame that nuclear was the way to go, the cheapest way." (Tr. at 2725.)

In reaching its decision to participate in Palo Verde at some level, it would have been reasonable for EPEC to have considered the factors enumerated and relied on information developed by the ANPP steering committee. Moreover, on the basis of this information, it would have been reasonable and prudent for EPEC to conclude that it should participate in some portion of the project. None of the above factors would, however, without more, have dictated the level at which EPEC should participate. It is with regard to this aspect of the decision - level of participation - that the prudence of EPEC's decision and its planning process becomes problematic.

To the best of the undersigned examiners' ability to reconstruct events based on the evidence, EPEC began the process of deciding how much of PVNGS to participate in by reviewing its 1972 forecast of loads and resources. According to the official 1972 forecast, EPEC was projecting peak loads of 1099 MW and 1,198 MW for future years 1980 and 1981 respectively, based on a 9.1 percent annual increase in system peak requirements. Including its Newman (478 MW)[19], Rio Grande (333 MW) and Four Corners (110 MW) units, EPEC would at that time have been capable of generating a total of 921 MW without Palo Verde. According to EPEC President and Chief Executive Officer Evern Wall, EPEC's 1972 loads and resources forecast showed EPEC needing an additional 660 MW in the 1980 to 1984 timeframe. (Tr. at 22.) Six hundred sixty megawatts plus 921 MW would equal 1,581 MW. Mr. Wall does not specify how it was determined that an additional 660 MW would be needed within this timeframe. Projections of peak load for 1983 and 1984 do not appear on the official 1972 forecast. Nonetheless, using the 9.1 percent growth rate and extrapolating from the 1982 projection would produce system peaks in 1983 and 1984 of 1,307 MW and 1,425 MW respectively. (As may be observed, system load in these outlying years would be growing by increments in excess of 100 MW per year as load growth accelerated up the side of an exponential curve). The Company would naturally have to add in a reserve margin. The formula for calculating reserve margin which the Company has used for many years is "largest single hazard plus five percent." This means that the Company takes the rating of its largest single unit (which, in the case of a 19 percent share of a 1,200 MW unit, would be 228 MW) plus five percent of system peak. Thus, in 1980 the Company would need a total of 1,327 MW (1099 MW + 283 MW), increasing to 1,724 MW (1,425 MW + 299 MW) by 1984. Under these assumptions, it is easy to see how the Company might be projecting a need to add 684 MW of new capacity to existing capacity of 921 MW, for a total capacity of 1,605 MW by 1981. Other additions, like Copper Station, may have been on the drawing board as well.

It is known that at some point in 1972 EPEC had Stone & Webster, its consultants (and former owners), make a financial analysis of a plan involving an investment in a large nuclear construction program. According to the testimony of staff financial analyst Raymond Orozco, this 27-page analysis involved a $390 million construction program involving two nuclear units plus an associated 345 kV transmission line. It assumed eight percent load growth compounded annually over a ten-year period.

The record does not reflect how the $390 million estimate used in the financial study related to the specific decision to request 684 MW of PVNGS; neither is there mentioned how many megawatts these two hypothetical nuclear units were supposed to produce. The study was based on a Stone & Webster computer model. While it is apparently relatively simple to change the inputs to the model to reflect differing assumptions, there is no evidence that EPEC ever had a study done, prior to making its preliminary bid for 684 MW, or prior to signing the Participation Agreement for 600 MW, that related to a plan to commit to that specific number of megawatts of PVNGS.

EPEC's position seems to be that, if it is important that Stone & Webster have done such a study, it probably did one, but the study did not survive. Moreover, EPEC was not regulated by the state at this time so, according to EPEC, there was no reason for it to be documenting its decision-making processes. Staff witness Orozco criticized the Company extensively for not having made sensitivity analyses. These would be analyses to show, not just whether a particular option, under a particular set of circumstances, is feasible, but whether and at what point a particular option becomes infeasible due to changes in circumstances like variation in cost or load growth. Again, EPEC's position seems to be that, if it is important that Stone & Webster have done sensitivity analyses, it did them, but nothing survives. This is illustrated by the following exchange between the Company and EPEC rebuttal witness Daniel T. Harning:

> Q. Mr. Harning, you said "The most feasible and reasonable forecast or alternative is selected and it is that plan which is printed or published." Can you explain what happens to the alternatives or plans that were not selected?
>
> A. Obviously, some of these alternatives are not feasible and may be saved only for a very short period of time or discarded after the most feasible plan is selected. Many times a hard copy of an alternative is not made as the STAFF program has the capability of viewing selected lines, sections, or whole reports on the screen. In that case, such an alternative cannot be saved.
>
> Q. With respect to the two Stone & Webster studies that are referred to by Mr. Orozco, were sensitivity analyses run?
>
> A. Of course. It takes less than two minutes of running time to produce all the output referred to by Mr. Orozco. . . .

(EPEC Ex. No. 108, Vol. 5, Tab 35 at 4.)

There are some problems with this argument. Part of EPEC's rationale for having only the single financial study from 1972 in hard copy is that the financial study, like the Company's load forecast, represents the "most likely scenario". (EPEC Ex. No. 108, Vol. 5, Tab 35 at 3-4.) Surely, in order to represent the "most likely" scenario, the financial study would have required relatively "hard" cost data on PVNGS. Yet, ANPP did not issue its baseline cost estimate for the project until 1974. There was no "hard" cost data on PVNGS at this time. Moreover, the picture that emerges most clearly in respect of nuclear (and coal) cost estimates in this period is that they were uncertain, but everyone thought they were going to go up as unpredictable new safety and environmental requirements were established, and as the utility industry gained experience with plants that were not built under turnkey contracts with reactor vendors as they had been in the 1960's.

Under these circumstances it would seem far more useful to have produced a "worst case" scenario for a project as much like financing a 684 MW share in PVNGS as possible as opposed to a "most likely" scenario involving a hypothetical project bearing only a general relation to the specific investment that was being contemplated. The most critical factor would have been load growth. Even if the costs of nuclear energy escalated dramatically over the planning horizon, so long as the only alternative were coal and coal were also expected to bear a comparable price, the price would have to be paid one way or another in order for the energy to be available. If, however, anticipated load deteriorated (possibly in response to high energy prices) there would be fewer kilowatt hour sales over which to spread the cost of the expensive new capacity additions, particularly insofar as with high fixed costs they would only be economical to run as baseload units. Under these circumstances, load could further deteriorate due to rate shock.

As well as the undersigned examiners can reconstruct the way in which the STAFF (Stone and Webster Automated Financial Forecast) computer model would have been utilized by EPEC, it would basically have been asked whether a large nuclear construction project could be financed under a "most likely" load growth scenario. There is no indication in the record that it was ever utilized in any study to determine the Company's alternatives to a 684 MW participation in PVNGS. It would seem that the decision had already been made to have PVNGS provide the lion's share of new generating capacity, and that the STAFF Model, to the extent that it was utilized to make any alternative runs, would simply have been asked whether, under a "most likely" load forecast, the project could be financed. As long as the answer was yes, it would be plausible that this type of computer run would not be reduced to hard copy and preserved. It is doubtful, however, that if EPEC had wanted information to use to determine the levels at which, under various cost assumptions, load growth deterioration could lead to problems of rate shock, it would not have required a hard copy of some alternative runs and some additional work to evaluate whether there were any alternatives or contingency plans that would help EPEC to address problems of load growth deterioration if they developed. This kind of question would seem to be sufficiently complex that a STAFF model computer run could not answer it "yes" or "no" in two minutes and be discarded. Moreover, one doubts that the STAFF Model would be designed to answer this kind of question per se. More plausible than that Stone & Webster made the specific kind of sensitivity studies that Mr. Orozco contends would have been prudent is that alternative runs involving possible load growth deterioration would have been considered unnecessary or would have been ignored on the ground that the utility has to plan to meet the "most likely", or even a slightly optimistic, load forecast.

Thus the decision would essentially have been made on the basis of a set of "most likely" exponential trendline projections of very substantial peak load growth sustained over ten years and more, plus a reasonable conclusion that PVNGS was a good project to be involved in at some level, plus a basically untested assumption that EPEC did not want to be involved with a coal project - whose regulatory hurdles EPEC had first-hand experience with - if, for the same money or less, it could be involved in a nuclear project whose regulatory requirements it had yet to experience. Lastly, EPEC had in hand the 1972 Stone & Webster study showing that a large construction project was feasible for the Company; it may or may not have had some alternate runs made of the program to test whether a more or less PVNGS-specific project at 684 MW was feasible; if it did, it got back "yes" answers under its "most likely" scenario.

This is exactly the kind of analysis and weighing of the studies and factors alluded to by the Company that would require no formal PVNGS participation study, no formal evaluation of the investment's "downside risk," and very little paperwork. One thing that can be said for sure about the initial decision to participate in 684 MW of PVNGS is that there is no paper trail showing how EPEC management put the decision together. How EPEC could have evaluated the risk of load growth deterioration and its interaction with project costs without generating some kind of paper tail is hard to imagine. On this basis, one may conclude that it did not attempt this kind of study. It may be that the Company thought it safe to dismiss the load deterioration problem altogether, much as the examiner in Docket No. 1981 did, on the basis that, with off-system sales or sales of participation some course of action could always be improvised later on.

This scenario may not be accurate in every detail, but it is more plausible than that, prior to committing to an interest in PVNGS, the Company had thoroughly researched alternative expansion programs and had a master plan for dealing with contingencies like load growth deterioration, but did not have these things written down anywhere. Further support for this view comes from the Company's own example from Docket No. 6350 of the kind of study on which it relied in making its decision to participate in 600 MW of PVNGS. This was a several page document prepared in 1975 whose ultimate conclusion was no more definitive than that "nuclear generation of the size of PVNGS is. . . in no way inferior to other sources." Here again, this is the type of information that would support a decision to participate in PVNGS at some level, but not the type that would provide assistance in reaching a decision as to how much of PVNGS it would be prudent to invest in.

Lastly, in support of the contention that EPEC had no master plan for how it would deal with load growth deterioration, it may be observed (See Attachment A) that, of the five original participants, EPEC and PNM are the only ones that have not changed their level of participation at some point in time. PNM's interest, at 10.2 percent, is, however, two-thirds of EPEC's. APS began, and has ended, with a 29.1 percent interest to be sure, but APS is a much larger utility than EPEC. TG&E, which along with EPEC signed up for a 15.8 share in 1973, was totally out of the project by 1975. SRP entered an agreement in 1977 that basically disposed of 5.7 percent of its interest contingent upon commercial operation of Palo Verde Unit 1, with an option to repurchase this share in future year 2001. SRP had previously sold a tiny portion of its interest to Arizona Electric Power Corporation, but apparently was willing to take this interest back when this utility dropped out of the project in 1976. The activities of GT&E and SRP would tend to indicate that, in the pre-1978 period, these utilities were thinking about ways to readjust or fine-tune their expansion programs. By comparison, there is no evidence, despite dramatically deteriorated load growth after the Arab oil embargo of 1973, that EPEC on its own initiative ever thought that it was necessary to readjust or fine-tune its Palo Verde commitment. Moreover, in 1981, when it first offered some of its Palo Verde interest for sale, EPEC was responding to the pressures of regulators and short-term financing considerations rather than doing what it thought was "best" for the Company and its ratepayers. From this it may even be inferred that EPEC's idea of a "best plan" is, and perhaps has always been, one that can ignore the contingencies and downside risks standing between it and its perfectly legitimate long-term goals like having enough power on hand when it is needed by the customer. Indeed, certain of the criticisms of the Company contained in the 1985 Touche Ross Audit cited by staff witness Orozco would bear this out. One of Touche Ross's findings was that EPEC's financial planning process was "more event driven than would be appropriate." Another was that there "appears to be relatively limited sensitivity analysis and contingency planning to anticipate the impact of alternative series of events." In this connection, the audit states:

> "The range of scenarios analyzed relative to issues that have significant impact on the financial position of EPEC is usually geared toward most likely and optimistic situations. The worst case scenarios analyzed are what would normally be considered neutral or stay-even sets of circumstances. For example, generally favorable rate case treatment and Palo Verde operability are assumed in the analyses conducted with little consideration of other possible or even likely scenarios."

(Staff Ex. No. 18 at 20-21). Considering that EPEC had no financial planning department as such at the time that the decision to participate in PVNGS was made, and that the financial department that Touche Ross studied in the mid-1980's was the financial department that had been "strengthened" in response to the Theodore Barry and Associates (TBA) management audit of 1976, it would seem that, Mr. Harning's testimony to the contrary notwithstanding, Mr. Orozco's criticisms of the Company for not analyzing sensitivities and exploring plans to deal with worst case scenarios touch on areas where EPEC has been weak for some time and was weak at the time it made its initial decision with regard to Palo Verde.

2. Discussion of Staff Witnesses' Conclusions

Staff witnesses Orozco and Rosenblum both concluded that EPEC's planning process with regard to PVNGS was deficient. Mr. Orozco focused on the lack of sensitivity studies showing the conditions under which the project might not be feasible. According to Mr. Orozco, the Company might still have gone ahead with the plan to take the share in Palo Verde that it did, but the knowledge gained regarding the parameters beyond which the project might be in trouble would at least have contributed to the Company's ability to make mid-term corrections. Commenting about the limitations inherent in looking at "most likely" scenarios, Mr. Orozco states at page 16 of his prefiled testimony:

> The lack of a sensitivity analysis which integrated financial feasibility with other strategic concerns which EPEC was facing makes these two studies [referring to the 1972 and 1974 Stone & Webster studies] deficient for purposes of determining the financial feasibility of their participation in ANPP at any level. This lack of integrated planning may have obscured key interrelationships and made it difficult for EPEC management to understand the overall risks involved in pursuing the strategy they selected. The studies I evaluated were based on "most likely" and perhaps even optimistic estimates. While management could have perceived some degree of risk based on their perceptions and knowledge of the environment, it would be presumptuous to assume they held "perfect knowledge" of the consequences of possible, if unlikely, events.

In other words, the Company should have found useful studies analyzing the parameters beyond which the project could be in trouble. If load growth deteriorated and project costs increased, the Company would have been able to use such studies to see where it was headed along a continuum from a plan that would require modest rate relief to one that would send the customer base into rate shock.

EPEC attempted to rebut Mr. Orozco's testimony in several ways. One was to provide the testimony of Mr. Harning, some of which was quoted in the previous section, to the effect that all of the sensitivity analyses that Mr. Orozco found wanting might have been generated by Stone & Webster in a matter of minutes but never saved. According to this argument, if it is important that EPEC have had certain information, it probably did, but the information would not need to have been preserved in hard copy.

The problem with this argument is that it is not the ease with which Stone & Webster can change the variables in its STAFF model to produce a "most likely" scenario that is important, but rather EPEC's apparent lack of interest in any study other than a "most likely" or somewhat optimistic scenario as this would determine how the model was being used. Moreover, as the first sentence of the above quote would indicate, Mr. Orozco's concerns went further than just that the Company have made sensitivity studies; he was looking for an analysis that "integrated financial feasibility with other strategic concerns." This might be a study, for example, of strategies for dealing with the risk that continued high load growth would not materialize. Such a study does not sound like the sort of thing that would be produced on an alternate run of the STAFF model.

The second way in which EPEC rebutted the testimony of Mr. Orozco concerns Mr. Orozco's admission that the Company might have made the same decision that it did even if it had made further studies showing that it was properly aware of, and averse to, the risks involved in what it was undertaking. According to the argument advanced by EPEC witness Hieronymous, a decision can be prudent, and should be judged on its own terms, regardless of how it was reached. The problem here is that it is improper to use hindsight. One can not judge a prudent decision to be only that which, in fact, steers the safe course; one has to allow for shipwrecks, sometimes, even among the prudent. This being the case, in order to find out whether a decision was "prudent", one would have to know, not only whether the manner of reaching the decision was appropriate, but, if it was not, whether a hypothetical process that was appropriate might nonetheless have resulted in the same decision being reached.

Really, it is too much to ask that one reconstruct the appropriate process fifteen years after the fact in order find whether a decision made on an inappropriate basis might still have been made on an appropriate one. Moreover, there would be no point in encouraging inappropriate decision-making practices by placing the burden on this Commission to reconstruct the range of prudent action that an appropriate decision-making process should have revealed back in the relevent time period. If this was more than the Company was willing to undertake prior to making a decision of this magnitude back in 1973, it would be inappropriate to enlist this Commission in such a project in the context of the Company's 1987 rate case, whatever abstract merits such an approach might have.

Staff witness Rosenblum focused on the lack of an EPEC-specific study comparing coal and nuclear costs. EPEC possessed plenty of generic studies from various time periods discussing the relative economics of nuclear energy versus coal, which it cited as support for its decision, but in each case Mr. Rosenblum was able to show that the studies taken alone or in conjunction should have led to at least one very high caliber study of the alternatives specifically available to El Paso Electric Company. EPEC had, for example, a 1968 Stone & Webster study the cover letter of which states:

> Nuclear generating technology has not advanced to the stage where atomic plants can produce electricity at prices competitive with gas-fired or coal-fired plants in the Texas-New Mexico area under existing fuel costs. . . .

(Staff Ex. 19, p. 6). While the letter went on to state that nuclear generation was likely to become competitive at some point in the future, one clearly would not base a decision to invest in a nuclear plant on this particular study.

The study itself states:

> No nuclear units were considered for El Paso during the 1973-1985

study period due to the comparative investment requirements for such capacity under the present state of the art.

(Staff Ex. 19, p. 7).

Another example of a study cited by EPEC as supporting its decision was the EPE-PNM Joint Planning Study - Phase I. Although there is no evidence in the record that there was any particular follow-up to this report prior to EPEC's entering into the PVNGS commitment, this study points to the need for further study and to the kinds of questions that should be asked. It states:

> Economics, very preliminary economics, indicate a mix of coal and nuclear units can be optimized to supply the quantities of power that will be required. . . Detailed knowledge and understanding of the coal and uranium availability in the 1980's are required for realistic planning.

(Staff Ex. 19, p. 8). Despite the report's statement that its findings were preliminary and that certain detailed knowledge would be "required" for "realistic planning," there is no evidence that EPEC undertook further studies or possessed such detailed knowledge prior to August of 1973 when it signed the Participation Agreement.

Yet another study cited by EPEC in support of its decision was the 1971 Steering Committee and Task Force Report of the Arizona Nuclear Resource Study Group consisting of APS, SRP, and TG&E. This report specifically warned:

> . . . It is essential for each participating entity to do further in-house review and make comparisons with alternate resources.

(Staff Ex. 19, p. 10). Here again, there is no evidence that EPEC followed up with the kind of study recommended.

One of the Company's witnesses Lee Dittmar stated in his prefiled testimony that EPEC "prepared in-depth studies over more than a decade in support of its decision [to participate in PVNGS]." As noted by Mr. Rosenblum, the only study included on Mr. Dittmar's list dating from a period later than 1968 (which was the year in which Stone & Webster issued the study to which reference has previously been made concluding that nuclear generation was not yet a feasible option for EPEC), was a Stanford Research Institute report entitled "Meeting California's Energy Requirements, 1975-2000". According to Mr. Rosenblum, only a few of the more than 400 pages in this report even address the future prospects of coal versus nuclear power. Thus, however "in depth" this study may have been with regard to the topic that it was addressing, it would hardly, on the basis of a few pages, have possessed depth with regard to the questions facing El Paso Electric Company. Moreover, as it was prepared by Stanford Research Institute, it would not constitute an in-depth study *prepared* by the Company.

What one has is not ten year's of in-depth studies preparatory to a specific and very substantial investment, but rather a collection of coal studies going back ten years plus a collection of generic coal and nuclear studies which, taken alone or in conjunction with one another, would have indicated the need for further study--without which it clearly would have been more risky to proceed. As summarized by Mr. Rosenblum after his detailed study:

> The critical point is that the issue is not generic and should not be treated as such. A sound decision for one utility may be a poor one for another. It was incumbent upon EPEC to perform its own independent, in-depth cost comparsion for all of its recognized alternatives. This the Company failed to do.

(Staff Ex. 19, p. 10). On this rests Mr. Rosenblum's conclusion that EPEC's actions with respect to reaching its decision were unreasonable and that the decision was made on an imprudent basis. Like Mr. Orozco, Mr. Rosenblum was nonetheless unable to say that an appropriate decision-making process would have ruled out the decision that EPEC in fact made. Both Mr. Orozco and Mr. Rosenblum also noted that they were unaware of any theory that would enable them to recommend any specific disallowance of projects costs or capacity based on their conclusions.

3. Decisional Prudence as it Relates to the Used and Useful Test

Except as decisional prudence may relate to the sensible application of a used and useful standard there is no statutory basis in Texas for excluding plant-in-service based solely on a determination that there was either imprudence on the part of the utility in its planning to meet future capacity needs or insufficient proof of prudence in that regard. Section 39(a) of the PURA provides:

> In fixing the rates of a public utility, the regulatory authority shall fix its overall revenues at a level which will permit such utility a reasonable opportunity to earn a reasonable return on its

> invested capital *used and useful* in rendering service to the public over and above its reasonable and necessary operating expenses.

(Emphasis added.) While inefficiency or imprudence in the planning or management of a project under construction is a statutory basis for excluding construction-work-in- progress from rate base, construction-work-in-progress is not plant-in-service and would be excluded from rate base altogether as not being presently used and useful without special statutory authority for including it. Decisional prudence becomes an issue in respect of plant-in-service, however, where a problem of excess capacity is perceived to exist.

EPEC takes the position that its entire investment in Palo Verde was prudent and that any plant-in-service representing a prudent investment decision should be deemed to meet the used and useful test regardless of whether there is excess capacity when the plant first comes on line. Moreover, by virtue of off-system sales and other mechanisms that tend to match loads with resources more closely than would be the case under the City's reckoning, EPEC takes the position that there is no significant excess capacity. EPEC would handle any problem of rate shock through the mechanism of the specific rate moderation plan adopted under the stipulation which it and certain of the parties including the Commission's general counsel have signed.

The City of El Paso appears to take the position that decisional prudence is an independent standard for excluding plant-in-service. It so happens that, in this docket (No. 7460), the City has concluded that less of the investment is used and useful than the portion which meets the prudent investment test. Thus, there would be no direct conflict with statute in this docket (No. 7460) if the entire percentage representing, by the City's reckoning, an imprudent investment were excluded because this portion (50 percent) would already be subsumed under the portion (60 percent) excluded under the used-and-useful test. If, however, the percentages were someday reversed, meaning that more of the plant were used and useful to serve ratepayers than the portion determined in this docket to represent a prudent investment, there would be a problem. Under the City's approach, the Commission would presumably at that time be obligated to exclude used and useful plant under a prudence standard based on the findings in this docket (No. 7460). Indeed, City witness Ben Johnson had a suggestion for dealing with the contingency that in a subsequent rate case more of the plant turn out to be used and useful than the portion representing a prudent investment. His suggestion was that the capacity representing the imprudent investment be valued in rates at a fair market value as opposed to receiving traditional rate base treatment. There would be, however, no statutory basis for proceeding in this manner.

Of course, as a practical matter this outcome would be unlikely to occur because the utility would probably make every effort to divest itself of any portion of the investment excluded from rate base. The portion of the plant excluded from rate base would, arguably, become the utility's to dispose of and thus would not remain dedicated to jurisdictional ratepayers unless such dedication were the only option or the most profitable option available to the Company.

A somewhat different course would be to view decisional prudence as an aspect of the used and useful test such that, in order to decide which capacity is used and useful and which capacity is excess, one would simply count last any capacity resulting from an imprudent investment decision. This course would be compatible in some respects with City of El Paso's approach to determining excess capacity. For purposes of determining excess capacity, City of El Paso would for example bring back into the calculation of available capacity the Rio Grande units which the Company had placed in retirement. This would be entirely compatible with the approach of making decisional prudence an aspect of the used and useful test. If, for example, the Palo Verde decision and all subsequent actions were found to be entirely reasonable and prudent, the utility could at its option remove any capacity of its choosing from rate base in order to balance resources with loads in the event of surplus. If, on the other hand, the Palo Verde decision were found to be imprudent, it would be unfair to ratepayers to allow the utility to juggle loads and resources so as to make more of an imprudent investment appear used and useful. Thus, it would be appropriate for the Commission to decide which resources should be counted in available capacity for purposes of determining how much, if any, of Palo Verde is excess under the used and useful test.

One respect in which this latter approach differs from EPEC's is that it admits the possibility of a utility making an imprudent investment and experiencing excess capacity as a result. Obviously, if, as EPEC would show, there is no imprudence and no excess capacity, there is no problem. It would also differ in that it would impose a used and useful test even on investments that were prudently made for purposes of charging current ratepayers with a return on plant that was not used or useful to serve them. This would be consistent with what has been done in the past in this and other jurisdictions in respect of the prudent portion of cancelled projects. Although the utilities involved have been permitted to recover the expenditures on such projects, they have not been allowed to include those expenditures in rate base for purposes of earning a return on them. Public Utility Commission v. Houston Lighting and Power Company, 715 S.W.2d 99 Tex. Civ. App.--Austin 1986, rev'd on other grounds in part and affirmed in part, slip opinion, Dec. 17, 1987); Jersey Central Power and Light Company v. FERC, 730 F.2d 816 (D.C. Cir. 1984); Nepco Municipal Rate Committee v. FERC, 668 F.2d 1327 (D.C. Cir. 1981).

D. Applying the Used and Useful Test

1. EPEC's Loads and Resources Forecast

As adapted from EPEC's 1987 loads and resources forecast to exclude the 200 megawatts associated with Palo Verde Unit 3, and with one minor change in format[20] to make it easier to compare with Commission staff's forecast, EPEC's ten-year forecast of loads and resources is as follows. (To facilitate their presentation on the page, they have been broken up into two five-year projections. The first set runs from 1987 through 1991; the second runs from 1992 to 1996):

I. EPEC's Loads and Resources Forecast 1987-1991

(MW)

1.0	Peak Projection	1987 (Hist.)	1988	1989	1990	1991
1.1	Native System Peak	818	840	885	918	952
1.2	Firm Sales to Others	143	154	159	163	168
1.3	Losses to Others & ANPP Start-up	25	25	11	9	9
	TOTAL	987	1,019	1,055	1,090	1,129
2.0	Generation Sources					
2.1	Newman, Gas/Oil	478	478	478	478	478
2.2	Rio Grande, Gas/Oil	246	246	246	246	246
2.3	Copper, Gas/Oil	69	69	69	69	69
2.4	Four Corners, Coal	110	110	110	110	110
2.5	Palo Verde, Nuclear	400	400	400	400	400
	TOTAL	1,303	1,303	1,303	1,303	1,303
3.0	Sched. Maint.	0	103	69	106	0
4.0	Contingent Power-PNM	43	43	43	43	43
5.0	Avail. Generation	1,260	1,157	1,191	1,154	1,260
6.0	Reserve Req.	262	264	266	268	269
7.0	Net Resources	998	893	925	886	991
8.0	Net Resource Margin	11	(126)	(130)	(204)	(138)

II. EPEC's Loads and Resources Forecast 1992-1996

		(MW)				
1.0	Peak Projection	1992	1993	1994	1995	1996
1.1	Native System Peak	976	1,009	1,039	1,068	1,099
1.2	Firm Sales to Others	174	179	175	175	175
1.3	Losses to Others &					
	ANPP Start-up	8	8	8	8	8
	TOTAL	1,158	1,196	1,222	1,251	1,282
2.0	Generation Sources					
2.1	Newman, Gas/Oil	478	478	478	478	478
2.2	Rio Grande, Gas/Oil	246	246	246	246	246
2.3	Copper, Gas/Oil	69	69	69	69	69
2.4	Four Corners, Coal	110	110	110	110	110
2.5	Palo Verde, Nuclear	400	400	400	400	400
	TOTAL	1,303	1,303	1,303	1,303	1,303
3.0	Sched. Maint.	0	0	0	0	0
4.0	Contingent Power-PNM	43	43	43	43	43
5.0	Avail. Generation	1,260	1,260	1,260	1,260	1,260
6.0	Reserve Req.	271	273	274	276	277
7.0	Net Resources	989	987	986	984	983
8.0	Net Resources Margin	(169)	(209)	(236)	(267)	(299)

As one may observe from the tables, there is a negative net resources margin for every year of the forecast beginning with 1988. By EPEC's calculations, even after including Palo Verde Unit 3 beginning (according to the latest projected in-service date) in 1990, there would still be a negative net resources margin for every year of the forecast except 1991 and 1992 when there would be a positive resources margin of 62 MW and 31 MW respectively. Clearly, by EPEC's reckoning, it will need without delay all 400 MW of Palo Verde Units 1 and 2 to meet its various commitments. Virtually every line of the forecast is, however, subject to controversy.

2. Commission Staff's Forecast

Commission staff was the only entity involved in the rate case aside from EPEC that produced its own forecast of native system peak. There were actually two staff forecasts--one sponsored by staff witness Jay Zarnikau reflecting the staff's 1986 forecast, and one sponsored by Paul S. Ramgopal using updated information but incorporating assumptions, not necessarily endorsed by the staff, that would be similar to EPEC's for the purpose of critiquing EPEC's forecast.

The 1986 staff forecast of native system peak was about 100 MW lower than EPEC's by future year 1989 as the following table reflects:

Year	EPEC Forecast (MW)	1986 Staff Forecast (MW)
1987	818 (Hist.)	783
1988	840	777
1989	885	786
1990	918	802
1991	952	825
1992	976	852
1993	1,009	880
1994	1,039	910
1995	1,068	940

Part of the difference in the forecasts is attributable to assumptions about the timing of EPEC's first rate case following the nuclear capacity coming on line. Staff had anticipated that rates would increase dramatically as of 1987 with the result that consumption would be depressed. (Tr. at 6641). For years beyond 1987, the 1986 staff forecast continues to reflect the depressive effects of a large rate increase whereas EPEC's forecast reflects a decline in the real price of electricity over the same period. (Tr. at 6796). This decline in the real price of electricity is, incidentally, not representative of what would occur if EPEC were granted the rate increase that it is requesting in the event that the stipulation is not approved; if it were granted the increase that it requested in its original application, there would be a real price increase. Other differences between EPEC's 1987 forecast and staff's 1986 forecast would be attributable to differences in the models.

Staff forecasts of peak demand were more accurate than EPEC's in Docket Nos. 1642 and 1981. It is not clear whether the staff's 1984 forecast was more accurate than EPEC's 1984 forecast because EPEC's 1984 forecast of native system peak is not in evidence. The staff's 1984 forecast of native system peak was nonetheless quite accurate. (Staff Ex. No. 21 at 48.) One may have confidence in the staff's forecasting efforts based on these results and on the generally better track record of the staff in comparison with most of the state's utilities. (Staff Ex. No. 21 at 48.) In addition, the 1986 staff forecast was virtually identical to the 1986 forecast produced independently by the New Mexico Public Service Commission. This would tend to corroborate the staff's work as there was no communication or collusion between the two regulatory bodies in respect of either information-gathering or forecasting (Staff Ex. No. 21 at 59.) Staff's 1986 forecast is obviously off-the-mark for 1987 because there was no steep rate increase in 1987 as projected. Staff's 1986 forecast would nonetheless have validity in later years assuming a steep increase in EPEC's rates.

Assuming a steep rate increase, EPEC's 1987 forecast would not have as much validity for 1988 and beyond as the staff's 1986 forecast. Assuming rate moderation, EPEC's 1987 forecast would still probably be less accurate than staff witness Ramgopal's. Mr. Ramgopal's forecast of native system compares with EPEC's as follows:

Year	EPEC 1987 Forecast (MW)	Paul Ramgopal's Forecast (MW)
1988	840	837
1989	885	860
1990	918	881
1991	952	901
1992	976	924
1993	1,009	949
1994	1,039	972
1995	1,068	998
1996	1,099	1,022

Mr. Ramgopal's forecast of native system peak is obviously much closer to EPEC's than is the staff's 1986 forecast. It is nonetheless about 50 MW lower than EPEC's by 1991. Considering that Mr. Ramgopal's forecast is more optimistic than the staff's 1986 forecast, and probably more accurate than EPEC's under ostensibly similar assumptions, the first modification that might be made in EPEC's 1987 loads and resource forecast would be to substitute Mr. Ramgopal's forecast of native system peak.

3. Effects of Cogeneration and Conservation and Load Management

Included with Mr. Ramgopal's testimony was the staff calculation of the savings from cogeneration and conservation and load management (CLM) that could be netted against peak demand. That calculation is as follows:

Year	Cogen & C/LM (MW)
1988	11
1989	26
1990	39
1991	53
1992	67
1993	81
1994	94
1995	108
1996	108

There was no comparable line item included in EPEC's 1987 loads and resources forecast. Mr. Ramgopal's source for the savings attributable to cogeneration was Appendix 1 of EPEC witness Jim Griffith's testimony. The source for the savings attributable to conservation and load management was the testimony of staff witness Nat Treadway.

Mr. Treadway projects the following savings based on the Commission's Long-term Electric Peak Demand and Capacity Resource Forecast for Texas:

Year	(CLM (MW)
1988	0
1989	14
1990	27
1991	41
1992	55
1993	69
1994	82
1995	96

A part of this forecast is devoted to estimating potential savings from conservation and load management for various areas within the state. When a utility lacks what the staff considers to be a reasonable program-by-program estimate of the impact on peak load of possible conservation and load management techniques, it turns to its most recent forecast - in this case, a 1986 forecast.

In support of its position that little can be achieved in its service area in the way of conservation, EPEC observes that certain conservation techniques that have proven very successful in areas with high levels of refrigerated air conditioning would achieve little in El Paso. Because of El Paso's dry climate, residents are generally able to take advantage of evaporative cooling techniques that utilize little electricity. Even so, according to Mr. Treadway, EPEC has not demonstrated that it has fully explored the constituent parts of its summer peak to determine the savings that are possible. While residential air conditioning represents only four to five percent of EPEC's summer peak,

> "[t]he remaining 96 percent of EPEC's summer peak is composed of *something*; and until EPEC has studied its end uses of electricity and all conservation and load management alternatives, it does not know whether its alternatives are limited."

(Emphasis in original.) (Testimony of Treadway at 4-5.)

Given EPEC's apparent weakness in the area of conservation and load management - despite criticism in this regard in Docket No. 6350, and considering that such techniques are generally cost effective as compared with building new generating capacity, it is appropriate to adopt the staff's estimates and net them against the native system peak. Similarly, there appears to be no reason why the modest savings attributable to cogeneration should not be netted against native system peak. This would constitute yet a further modification to EPEC's 1987 loads and resources forecast.

4. Firm Sales to Others

Although the evidence shows the megawatts dedicated to TNP and IID through the year 1996 and reflects the expiration date of the IID contract in the year 2002, it does not reflect the expiration date of the TNP contract. All of this information is potentially significant because, to some extent, the capacity tied up in off-system sales determines the timing of EPEC's next capacity addition. Indeed, Company witness Frederic Mattson acknowledged that EPEC is planning to add new capacity sooner than it would otherwise have to because of the off-system sales (Tr. at 6318-9.)

The capacity tied up in off-system sales will, of course, "revert" to EPEC at some point in the future. At least some of the capacity built to service load during the pendancy of the TNP and IID contracts could then be redundant; it would not have been necessary to build to service native system requirements alone and, absent the off-system sales, it might simply become a surplus. In that event, the events of the late 1970's might repeat themselves in that EPEC would engage in a new round of off-system sales. To the extent that regulators recognized the off-system sales in total system peak for all purposes including planning new capacity additions, the off-system sales would both justify the need for the existing capacity and precipitate a new round of building.

Regulators who, in the ratepayers' interest, would have preferred that the utility plan and build a system to meet native system requirements alone would probably find it difficult to break this cycle. The utility would have proved that its building plans were reasonable and prudent to meet the total system peak that included the off-system sales; it would then not be the utility's "fault" if it was left with a surplus at the expiration of the contracts. In this way, the utility would have the opportunity to justify entering into a new round of off-system sales.

Used strategically, off-system sales could result in a utility's being able to earn a return on a larger rate base than it would otherwise be able to justify based on native system requirements, with ratepayers making up the difference between the revenues from off-system sales and the expenses associated with the new capacity that was not necessary to serve them. Used strategically, off-system sales could be the key to higher profits, with the utility resorting to rate moderation plans to avert any problems that might be created by rate shock when large new capacity additions first came on line.

If off-system sales to TNP and IID are included in this docket (No. 7460) for purposes of determining how much of EPEC's investment in Palo Verde is used and useful to ratepayers, the Commission will be starting down this path. The present docket (No. 7460) nonetheless gives the Commission the opportunity to set a course that will involve reasonable and prudent planning to meet native system requirements, and native system requirements alone. Based on EPEC's initial lack of prudence in planning to meet its capacity requirements in the 1980s, it is not incumbent on this Commission to include those off-system sales in total system peak for purposes of determining used-and-useful capacity; moreover, to include them would represent the single most detrimental action that could be taken with regard to protecting the ratepayers' interests now and in the future.

The Commission excluded off-system sales in Docket No. 5700 and 6350 for purposes of determining how much of the Palo Verde investment was likely to be used and useful when the units came on line. If this Commission nonetheless feels obliged to include off-system sales based on certain dicta appearing in the report in Docket No. 1981, it might wish to note that EPEC renegotiated the IID contract in 1986, extending it from the year 1992 to the year 2002. This ties up 100 MW of firm capacity through that year which is still fourteen years distant. Considering that the contract was renegotiated subsequent to the final order in Docket No. 5700, and probably subsequent to the issuance of the report in Docket No. 6350 - the report was issued January 9, 1986 - if not subsequent to the final order in that docket as well, the Commission would not be obliged to include these off-system sales in total system peak even if it included others. Unlike the original round of sales which arguably were negotiated under the aegis of Docket No. 1981, these sales were negotiated in the light of the Commission's opposition to giving rate base treatment to the capacity that EPEC was dedicating off-system.

5. Losses to Others and ANPP Start-up

EPEC's calculation of "losses to others and ANPP start-up" are reprinted below for ease of comparison with what appear to be the comparable staff calculations. The staff calculations were not set out as such in the staff testimony. Rather, Mr. Ramgopal had a set of calculations for "miscellaneous peak" which he added to native system peak. This miscellaneous peak consisted of TNP and IID sales plus items labelled "total pump demand," "losses from expanded system," and "ANPP start-up-NMSU Cool Storage." The examiners assume that these items are the same as what EPEC labels "losses to others and ANPP start-up" except for the TNP and IID sales, which thus can be subtracted out to yield a comparable set of numbers as follows:

Year	EPEC	Staff
1988	25	39
1989	11	39
1990	9	40
1991	9	45
1992	8	43
1993	8	43
1994	8	43
1995	8	43
1996	8	43

The staff numbers are obviously quite a bit higher than EPEC's, which means that it would be to EPEC's advantage to adopt the staff's numbers. In this case, it would be appropriate to do so, assuming they are indeed comparable, in the event that Mr. Ramgopal's calculations of native system peak are adopted.

6. Generation Sources

The controversy with regard to generation sources concerns the retirement of Rio Grande Units 3, 4, and 5 and the availability of purchased power from SPS (Southwestern Public Service). Prior to their retirement, Rio Grande Units 3, 4, and 5 together generated a total of 87 MW. City witness Ben Johnson estimates that approximately 100 MW is also available from SPS.

EPEC retired Rio Grande Units 3, 4, and 5 in December of 1985. According to the report in Docket No. 6350, which was issued in early January of 1986, EPEC was not due to retire these units until late 1987. (Report at 37.) Thus, they would have been included in rate base for purposes of Docket No. 6350. The late 1987 retirement date for the units represented a significant change from the units' scheduled retirement dates as of 1983. As of 1983, Unit 3 was scheduled for retirement at the very end of 1988, Unit 4 was scheduled for retirement at the very end of 1991, and Unit 5 was scheduled for retirement in 1992 or thereafter. EPEC presented no explanation in Docket No. 6350 of why these retirement dates had been moved up to 1987.[21] For this reason, the examiner in Docket No. 6350 included these 87 MW for purposes of estimating whether there would be excess capacity when Palo Verde came on line.

In this docket (No. 7460), EPEC provided an explanation of why it retired the units in late 1985 instead of in 1987 as represented in the 1985 rate case. (It was never explained what caused the retirement dates to be moved up to 1987, however.) The explanation for moving the dates from 1987 to 1985 is that this retirement enabled EPEC to save $658,000 consisting of $480,000 for major overhaul work needed to keep the units insurable, $127,000 for insurance, $50,000 for property taxes, and $1,000 for operating expenses. The evidence does not reflect to what extent these expenses would already have been factored into EPEC's rates from Docket No. 6350 nor does it reflect what effect, if any, the $480,000 overhaul would have had on prolonging the units' life.

According to EPEC witness Joseph E. Wasiak, the units are being held for future use because they can be refurbished and reactivated. Elsewhere in his testimony in connection with Rio Grande Unit 8, Mr. Wasiak discusses plant-life extension techniques, which would involve modifying an existing unit in such a way that its useful life would be extended five or ten years and it would even be capable of producing more megawatts. For example, Rio Grande Unit 8, which is rated at 150 MW, might be capable, after modification, of being rated at 170 MW. (Wasiak at 537.)

Although there is nothing in this docket (No. 7460) to indicate exactly what EPEC would obtain in the way of extended plant-life for Rio Grande Units 3, 4, and 5 from any specific overhaul program, these units could be put back in service for some period of time if EPEC did not have enough capacity to meet its peak requirements without them.

City witness Ben Johnson provides a set of calculations in his testimony based on the $480,000 overhaul showing that, from the ratepayers' perspective on a cost per kilowatt basis, it would be better to obtain these megawatts from an overhaul of Rio Grande Units 3, 4, and 5 than to obtain them from Palo Verde.

So long as EPEC retains all 600 MW of Palo Verde, it has no reason for the time being to spend any money to obtain the additional 87 MW. The 87 MW that are potentially available could nonetheless displace Palo Verde capacity, and the evidence is insufficient to show that it would not be cost effective from the ratepayer's standpoint to do this. The utility could, for example, attempt to sell or make other disposition of Palo Verde capacity in order to achieve savings for its ratepayers by utilizing the Rio Grande capacity.

Had EPEC's initial decision to participate in 600 MW of Palo Verde been based on prudent planning and EPEC absolutely could not make any reasonable disposition of Palo Verde capacity, it would be reasonable and appropriate to exclude the capacity available from Rio Grande Units 3, 4, and 5. To the extent that EPEC's showing as to prudence is less than convincing, however, it is reasonable and appropriate to include Rio Grande Units 3, 4, and 5. A utility should be encouraged to look for ways to fine-tune its generation mix to achieve savings for its ratepayers as opposed to simply being allowed to retain whatever capacity most enlarges its rate base. Given the equities in a situation where the utility cannot show that an investment represents prudent planning and continuing efforts to fine-tune its generation mix, it would be inappropriate to allow the capacity which that investment represents to displace other, cheaper capacity.

Similarly, with regard to the purchased power available from SPS, one can make a case that it is inappropriate to allow Palo Verde capacity to displace this less expensive source of power. EPEC has had an arrangement with SPS for interruptible purchased power since 1981. Prior to January 1, 1987, this arrangement allowed EPEC to request up to 100 MW; then for the twelve months prior to January 1, 1988, this arrangement allowed EPEC to request up to 75 MW. Looking forward, the arrangement allows EPEC to request as much as 50 MW through May of 1989, dropping down to 30 MW thereafter. That purchased power from SPS has been a reliable source of power for EPEC is reflected in the purchases that EPEC has made in years prior to Palo Verde coming on line. Even though the power was interruptible, in 24 out of 32 months of purchases between 1984 and 1987, the average availability of power from SPS was between 99 and 100 percent. The lowest availability in any month was 92.7 percent, which occurred in October of 1985 (*i.e.*, off-peak). According to City witness Ben Johnson, the performance record of interruptible purchased power from SPS places this capacity in the same category as a typical base-loaded unit[22], meaning presumably that it provides power consistently throughout the year including both on-and off-peak periods.

By the City's reckoning, EPEC could have continued taking 100 MW of purchased power from SPS had it desired to do. According to SPS's 1986 Annual Report, SPS's generating capacity in that year exceeded its system peak by 39 percent and it did not anticipate needing additional base-load capacity until the mid-1990s. (City Ex. No. 46 at 51.)

Obviously with Palo Verde coming on line, EPEC has not pursued purchased power to the extent of 100 MW, from SPS or anyone, and, as the world does not stand still, it is debatable to what extent purchased power that the Company has not put under contract should be counted in available generating capacity. If 100 MW of hypothetical purchased power were included in generating capacity for purposes of determining how much of Palo Verde is used and useful, it is conceivable that 100 MW of Palo Verde might be displaced from rate base as a result. If EPEC then took that 100 MW of Palo Verde and disposed of it off-system, but 100 MW of *something* was needed to service native system requirements, there could be a shortfall. There is no real assurance that EPEC would pursue the additional megawatts from SPS and find them available when they were needed. Unlike the 87 MW of Rio Grande Units 3, 4, and 5 which one knows the utility can bring back on line if it disposes of an equivalent share of Palo Verde, the megawatts of hypothetical purchased power are riskier to count in the same manner as plant that has been temporarily mothballed.

The approach of the examiner in Docket No. 6350 was to net SPS purchased power against contingent PNM sales. The examiner did not state the number of megawatts involved in either case, but, whatever whey were, they cancelled each other out, which made this a relatively cautious approach. In this docket (No. 7460), netting contingent PNM sales of 43 MW against 100 MW of hypothetical SPS purchases as requested by the City would add an extra 57 MW net to the supply side of the loads and resources equation. This might be an unduly risky course. The utility might treat as "deregulated" the portion of Palo Verde that was displaced by hypothetical purchased power. It might sell this portion or dispose of it in some other way that would make it unavailable to jurisdictional ratepayers. The hypothetical purchased power might then never materialize to make up any shortfall, and the ratepayers would be at risk of not having sufficient power.

A safer course would be to continue to treat purchased power and contingent power held for PNM as simply cancelling each other out. (See also discussion of PNM-contingent power in this section of the report.) Thus 43 MW would be included on both the demand and the supply side of the loads and resources forecast. Considering that at least 30 MW of purchased power would already be subject to contract, even though interruptible, and that the likelihood of PNM demanding its 43 MW is fairly remote, there would be little if any risk to the ratepayers. At the same time, the message would presumably be conveyed that the Commission wants utilities to look at ways to fine-tune their resource mix to save ratepayers money.

7. Scheduled Maintenance

Beginning in 1988 and continuing up through 1990, scheduled maintenance appears on EPEC's 1987 Loads and Resources Forecast as a very large item on the demand side of the forecast. It represents 103 MW in 1988, 69 MW in 1989, and 106 MW in 1990, dropping to zero in 1991. Normally, all maintenance involving the outage of units is scheduled off-peak. EPEC's justification for scheduling certain maintenance on-peak is that, in years 1988 through 1990, it is impossible for it to do all maintenance off-peak. This is because there would be insufficient capacity to serve load plus, as stated in EPEC's Phase II Brief at page 307, maintain "required" reserves.

Leaving aside for the moment any objections to the use of the word "required" in connection with EPEC's chosen method of calculating reserve margin,[23] it may be noted that EPEC uses for off-peak purposes the same calculation of reserve margin that it uses on-peak. Thus, to the extent that the largest-single-hazard-plus-five-percent method is generous at the peak compared with what the Commission in Docket Nos. 5700 and 6350 considered adequate, this method would seem even more generous for purposes of assuring reliability off-peak. Substituting in a 20-percent-of-peak reserve margin based on EPEC's own calculations of total system peak would lower reserve margins in 1988, 1989, and 1990 from 264, 266, and 268 MW respectively to 204, 211, and 218 MW. Whether these 50 to 60 MW would have made a megawatt-for-megawatt difference in terms of scheduling more maintenance off-peak is not capable of determination from the record. If the lesser reserve margins did make a megawatt-for-megawatt difference, however, on-peak scheduled maintenance would be more or less cut in half. Among the reasons why reductions in reserve margins might not make a megawatt-for-megawatt difference would be that, even in situations where more maintenance could theoretically be scheduled off-peak, there might not be the work crews available to perform the work because they might be busy elsewhere. Still, in spite of the contraints on scheduling maintenance, EPEC was in control of the method it used for calculating reserve margin. It chose to ignore the method adopted by the Commission in two previous dockets, and, in this context, that method could only have contributed to a lesser figure for scheduled maintenance on peak.

The City of El Paso, in its brief at page 46, points out a further impediment to finding that EPEC's need for maintenance on-peak is as set forth on the Company's 1987 loads and resources forecast. In its 1987 loads and resources forecast, EPEC assumed a 12-month refueling and maintenance schedule for Palo Verde whereas EPEC actually plans to use an 18-month cycle. It is reasonable to suppose that the use of an 18-month cycle would have an impact on the schedule. One might even speculate that it would tend to reduce the amount of maintenance needing to be scheduled on-peak. In any event, it would seem incumbent on EPEC to have supplied the Commission with numbers based on the refueling and maintenance schedule that is actually planned. Certainly, EPEC had no trouble factoring the 18-month cycle into its calculations of higher capacity factors for Palo Verde. In a context in which the use of an 18-month cycle was clearly to EPEC's advantage, EPEC witness George Fitzpatrick was able to testify that it would improve the capacity factor of Palo Verde over its life cycle by 4.6 percent (Fitzpatrick at 7828.) In the context of matching loads with resources, however, one must believe that EPEC either made no redetermination, or made one, but found it was not to its advantage. In any event, the Commission does not have the numbers it should have to determine the need for scheduling maintenance on-peak. To the extent that EPEC has the burden of proof in this matter, it has failed to carry it because it did not factor in any changes attributable to an 18-month refueling and maintenance cycle for Palo Verde. Moreover, even on the basis of the cycle that was assumed, the numbers may be overstated because of EPEC's insistence on using largest-single-hazard-plus-five-percent instead of the method adopted by the Commission in the Company's last two rate cases. The City of El Paso recommends including zero for on-peak maintenance and in this the examiners concur.

8. Contingent Power-PNM

Pursuant to an agreement dated July 19, 1966, PNM (Public Service of New Mexico) provides EPEC with firm transmission service for EPEC's Four Corners entitlement from the Four Corners area in New Mexico to EPEC's West Mesa substation outside Albuquerque. In exchange, EPEC makes available to PNM contingent capacity from Rio Grande Units 7 and 8. The agreement is unit-specific. If Rio Grande Units 7 and 8 are out of service for any reason, EPEC has no obligation to supply PNM with power.

PNM has not requested any power under this arrangement since 1980. It appears that PNM has ample capacity of its own without this contingent capacity. Although EPEC's 1987 loads and resources forecast sets 43 MW aside every year for this contingent demand, PNM does not include this capacity in its own loads and resources forecast which it submits to its regulators.

The City of El Paso argues, as it has in previous dockets, that this contingent obligation should be excluded from the demand side of the loads and resources equation. The City's argument is that to include it would in effect be to justify a portion of Palo Verde even though it would be inappropriate to retain 43 MW of a nuclear base loaded plant in order to stand ready with 43 MW from whatever source to service this particular load. According to the City, EPEC could, for example, more appropriately handle this contingency through purchased power. Thus, there is a certain logic to balancing hypothetical purchased power on the supply side against the relatively remote contingency that PNM will demand power from Rio Grande Units 7 and 8. As discussed in the previous subpart of this section of the report on purchased power, the examiners would handle PNM-contingent power in more or less the same manner as did the examiner in Docket No. 6350. Thus, 43 MW would appear dedicated to PNM-contingent power, but only because of the off-setting allowance for hypothetical purchased power.

9. Reserve Requirements

Unless the Commission wishes to depart from the position that it has taken in the last two rate cases involving EPEC, it should continue to use a reserve margin of twenty percent of peak. It is a rule-of-thumb which Commission staff considers reasonable and adequate. The Company's chosen method which is largest-single-hazard-plus-five-percent of peak would result in a larger reserve margin. This would have the effect of making more of its generating capacity appear used and useful. The calculation of reserve margin also affects scheduled maintenance as is pointed out in the subpart of this section of the report dealing with that topic. Further justification for departing from the Company's chosen method of calculating reserve margin is discussed in City of El Paso's brief at pages 44-45.

According to the City, calculations show that, if EPEC had reduced its commitment to Palo Verde to 150 MW per unit, its reserve requirement would fall by 63 MW under the largest-single-hazard-plus-five-percent method just by virtue of this change. Thus, for the additional 150 MW of Palo Verde in which it invested, it "netted" only 87 MW under the largest-single-hazard-plus-five-percent method of calculating reserve margin. This is because of the way in which the size of the largest units contributes to the "required" reserve margin. If, for example, EPEC had wanted 600 MW total, but had invested in *four* 150 MW units as opposed to *three* 200 MW units, it would not have needed to set these extra 63 MW aside strictly for reserve margin purposes. (There is, incidentally, no evidence that EPEC ever considered these effects when it determined to take as much as 684 MW of future power requirements from Palo Verde Units 1, 2, and 3.) By comparison, the size of the largest single unit does not affect the calculation of the reserve requirement under the 20-percent-of-peak method.

10. The Loads and Resources Forecast as Modified by the Examiners' Recommendations

The following tables show the loads and resources forecasts for 1988-1991 and for 1992-1996 with the examiners' recommendations incorporated.

I. Examiners' Loads and Resources Forecast 1988-1991

		1988	1989	1990	1991
1.0	Peak Projection				
1.1	Native System Peak	837	860	881	901
1.2	Cogen & C/LM	(11)	(26)	(39)	(53)
1.3	Losses to Others &				
	ANPP Start-up	39	39	40	45
	TOTAL	865	873	882	893
2.0	Generation Sources				
2.1	Newman, Gas/Oil	478	478	478	478
2.2	Rio Grande, Gas/Oil	333	333	333	333
2.3	Copper, Gas/Oil	69	69	69	69
2.4	Four Corners, Coal	110	110	110	110
2.5	Palo Verde, Nuclear	400	400	400	400
2.6	Purchased Power	43	43	43	43
	TOTAL	1,433	1,433	1,433	1,433
3.0	Sched. Maint.	0	0	0	0
4.0	Contingent Power-PNM	43	43	43	43
5.0	Avail. Generation	1,390	1,390	1,390	1,390
6.0	Reserve Req.	173	175	176	179
7.0	Net Resources	1,217	1,215	1,214	1,211
8.0	Net Resources Margin	352	342	332	318

II. Examiners' Loads and Resources Forecast 1992-1996

		1992	1993	1994	1995	1996
1.0	Peak Projection					
1.1	Native System Peak	924	949	972	998	1,022
1.2	Cogen & C/LM	(67)	(81)	(94)	(108)	(108)
1.3	Losses to Others &					
	ANPP Start-up	43	43	43	43	43
	TOTAL	900	911	921	933	957
2.0	Generation Sources					
2.1	Newman, Gas/Oil	478	478	478	478	478
2.2	Rio Grande, Gas/Oil	333	333	333	333	333
2.3	Copper, Gas/Oil	69	69	69	69	69
2.4	Four Corners, Coal	110	110	110	110	110
2.5	Palo Verde, Nuclear	400	400	400	400	400
2.6	Purchased Power	43	43	43	43	43
	TOTAL	1,433	1,433	1,433	1,433	1,433
3.0	Sched. Maint.	0	0	0	0	0
4.0	Contingent Power-PNM	43	43	43	43	43
5.0	Avail. Generation	1,390	1,390	1,390	1,390	1,390
6.0	Reserve Req.	180	182	184	187	191
7.0	Net Resources	1,210	1,208	1,206	1,203	1,199
8.0	Net Resources Margin	310	297	285	270	242

On the basis of this loads and resources forecast, the examiners would recommend that 300 MW, or 75 percent, of the Palo Verde capacity under consideration in this docket be considered used and useful. If 100 megawatts were subtracted from the line item designated "net resource margin", which represents the capacity that is left over after all of the system requirements including reserve requirements have been met, the utility would still have the following net resource margin between now and 1996:

Year	Net Resource Margin 25 Percent Exclusion (MW)
1988	252
1989	242
1990	232
1991	218
1992	210
1993	197
1994	185
1995	170
1996	142

Admitedly part of the appeal of a 25 percent exclusion would be consistency with what was done in Docket Nos. 5700 and 6350. If Palo Verde Unit 3 came on line and all 200 MW of it were excluded from rate base, the total exclusion would equal 300 MW, or 50 percent of the Palo Verde commitment.

The ample cushion against unforeseen contingencies in the form of the net resources margin would arguably be of benefit of ratepayers. If load growth were higher than anticipated or construction time for EPEC's next capacity addition were longer than anticipated or savings from conversation/load management did not materialize on schedule, this capacity could become used and useful to ratepayers in the more immediate sense of serving to meet one of the specific line items in the forecast. It is not necessarily critical to the used-and-useful test that this capacity be assigned to a particular line item at this time. Contingent capacity serves a purpose just because it is not assigned to any particular item. Obviously, there has to be a limit to it somewhere based on what is reasonable. Given that, since 1984, the Commission has been projecting a 50 percent exclusion of the 600 MW involved in EPEC's share of Palo Verde Units 1, 2, and 3, it would be reasonable to take that regulatory history into consideration in establishing a net resources margin that would be includable in rate base under a "used and useful" standard.

The cushion provided to EPEC would help it in a number of ways. Even without utilizing any of the megawatts coming on line by 1990 from Palo Verde Unit 3, EPEC could leave Río Grande Units 3, 4, and 5 in mothballs if it chose not to spend the money to refurbish them; it could perform a substantial amount of maintenance on-peak if that is really still in its plans; and it would have added flexibility in terms of meeting its off-system commitments to TNP and IID.

One last feature of this arrangement is that, while the Company would receive something of benefit to help it deal with items that were included or excluded contrary to its request, the arrangement would entail none of the pitfalls of making specific line item adjustments in order to "help out the Company" or satisfy a general desire to "err on the safe side." In this instance, the place to satisfy a general desire to err on the safe side would be in the net resources margin. Like the grandfather factor which arguably was an unspoken consideration in Docket No. 1981, a factor left as unacknowledged element in a finding or conclusion where it does not belong can have far-reaching consequences that may be unfortunate. A desire to err on the safe side is a valid consideration. A general desire to err on the safe side is appropriately accommodated by including a substantial net resources margin in this case; it would be inappropriate cropping up as an inclusion of off-system sales. Similarly, interest in how the decision in this case will affect the utility going forward, regardless of what has transpired in the past, is unavoidable. Here again, the place to accommodate that consideration is in the net resources margin and not through off-system sales, or scheduled maintenance, or any other place where it may have unintended and undesirable consequences.

The Commission might, of course, wish to consider excluding as much as 200 MW, or 50 percent, of Palo Verde Units 1 and 2. The "cushion" would then fall to the more modest levels set forth below:

Year	Net Resources Margin 50 Percent Exclusion (MW)
1988	152
1989	142
1990	132
1991	118
1992	110
1993	97
1994	85
1995	70
1996	42

It would be a not insubstantial cushion at the outset, slowly diminishing over a nine-year horizon over which new capacity additions could be planned and built. The examiners are nonetheless not recommending this particular option. Among other reasons, it reduces the margin for error in load forecasting or construction schedules or conservation and load management to a point that might be troublesome if EPEC totally divested itself of Palo Verde Unit 3 through a participation sale or dedicated the entire capacity off-system. In addition, if Palo Verde Unit 3 were requested in rate base and excluded, the total exclusion would equal 400 MW or two-thirds of the investment, contrary to expectations that may have been building up over the years. It arguably would be incautious and damaging to the utility's ability to serve customers going forward to depart too radically from the course that has been steered since Docket No. 5700.

The City of El Paso argues for a 240 MW, or 60 percent, exclusion. Under the loads and resources forecast developed in this section of the report, which does not incorporate all of the recommendations of the City, the net resources margin would then be as follows:

Year	Net Resources Margin 60 Percent Exclusion (MW)
1988	112
1989	102
1990	92
1991	78
1992	70
1993	57
1994	45
1995	30
1996	2

For the reasons set forth in the previous discussion of the 50 percent option - only more so - the examiners are not recommending this third option.

11. Adjustments to Capital Costs of Palo Verde Unit 1 and Common Facilities and Adjustments to Sale/Leaseback Payments

Without the 25 percent exclusion, the capital cost of Palo Verde Unit 1 is as follows:

Cash	$345,195,082
Gross AFUDC	255,959,831
TOTAL	$601,154,913

Applying the 25 percent exclusion to $601,154,913 yields used and useful plant in service of $450,866,185, from which one would deduct the applicable credits shown on EPEC schedule A-7, Adjustment No. 31, plus the credits associated with Unit 2 that EPEC assigned to Unit 3 as a result of the sale/leaseback of Unit 2. The total annual "book break-even" lease payment on Palo Verde Unit 2 is $54,684,000. Seventy-five percent of this amount equals $41,013,000. One hundred percent of deferred book breakeven lease payments on Palo Verde Unit 2 equals $6,307,110. Seventy-five percent of this amount equals $4,730,333.

EPEC owns 15.8 percent of Palo Verde Units 1, 2 and 3. It therefore owns an undivided 15.8 percent of all common facilities. If EPEC were to sell participation in *all* of Palo Verde Unit 3 (200 MW) plus participation in 25 percent of Units 1 and 2 (100 MW out of 400 MW), EPEC would be reducing its investment in plant, including common facilities, by half. Because EPEC is requesting in this docket (No. 7460) recognition of all common facilities associated with its entire 15.8 percent interest including its interest in Unit 3, it would seem appropriate to exclude 50 percent of the capital cost of these facilities, as this is the share of common facilities that would accompany the sale of participation in excess Palo Verde capacity including the capacity associated with Unit 3.

FERC accounting rules nonetheless dictate that 100 percent of common facilities be allocated to Unit 1. It is the examiners' understanding that, on the basis of these rules, only 25 percent of common facilities may be excluded in accordance with the examiner's recommended finding on excess capacity even though, in logic, this finding would seem to dictate a 50 percent exclusion. The total common facilities associated with EPEC's 15.8 percent share in all three units is $121,746,035. Seventy-five percent of this amount equals $91,309,526 from which one would deduct the applicable credits shown on Schedule A-7, Adjustment No. 31.

Schedule A-7, Adjustment No. 31 also sets out plant balances for Palo Verde Transmission and Palo Verde General. Although none of the parties discussed or briefed the issue, it is the examiner's general understanding that these items would not be handled in the same manner as Palo Verde Unit 1 and Common Facilities, and that nothing would be deducted from these plant balances based on the recommended rate base exclusion for Palo Verde capacity.

E. Expenses Associated with Plant in Service that is Deemed Only Partially Used and Useful

1. General Discussion

Expenses associated with Palo Verde Units 1 and 2 would include the following: fuel costs, operations and maintenance (O&M) expense, deferred O&M expense, depreciation expense, carrying charges on deferred expenses, and decommissioning expense. There would also be various tax effects associated with the impact of these expenses on revenue requirement, and taxes are, of course, also an expense.

City of El Paso's approach to handling the Palo Verde expense issue would be to disallow all Palo Verde expenses in the same proportion (50 percent) as the percentage of the Palo Verde investment that it deemed imprudent. (Testimony of Ben Johnson at 10). Although the City is recommending that only 40 percent of Units 1 and 2 be found used and useful, it is not recommending that only that percentage of Palo Verde expenses be allowed; rather it would give the Company the benefit of expenses on the "prudent" portion. Although the examiners were not able to conclude along with City of El Paso that any specific percentage of Palo Verde was imprudently invested in, the fact that City of El Paso made the distinction between expenses associated with non-used and useful plant and expenses associated with plant representing an imprudent investment raises an important issue.

It is quite compatible with precedent to allow expenses associated with non-used and useful plant. In the case of cancelled projects, for example, utilities have been permitted through amortization to recover expenses associated with plant that will never come on line. In such a case, the prudence of the investment is obviously part of the basis for finding that the amortization expense is reasonable and necessary. In addition, in such a case one knows that the utility has incurred the expense and that to disallow it would adversely affect the utility's financial integrity. Thus, the factors bearing on whether an expense is reasonable and necessary need have nothing to do with whether the plant to which the expense relates is used and useful.

Conversely, however, nothing in the PURA specifically requires that one look only at whether an investment is prudent as opposed to whether it is also used and useful. Neither the examiner nor Commission staff was able to find a basis for quantifying the portion of Palo Verde that EPEC "should" in some ultimate sense have invested in. This was not for lack of giving the matter thought. To require that a specific portion of an investment be deemed "imprudent" before it would be fair to the utility to disallow any of the otherwise reasonable and necessary expenses associated with it might, in effect, be to require that they be allowed. (Arguably, in the case of Palo Verde, to quantify the imprudent portion of the investment would require a little magic and a very strong belief that such quantification is possible. These may be a poor foundation to build upon in terms of constituting substantial evidence for a finding of fact.)

One could, of course, take the position that expenses associated with plant that is not used and useful and has not been affirmatively shown to represent an entirely prudent investment should generally be disallowed in the same proportion as the percentage of the plant's capacity which is not used and useful. One would still face a number of practical problems in terms of implementing this approach. For example, it would appear that the utility in all fairness ought to be allowed certain off-setting expenses to the extent that some retired unit or conservation program for which the utility was not recovering expenses was figured into loads and resources for purposes of determing whether there was excess capacity on the system. Fuel expense, which is discussed in the next section, very nicely illustrates the proposition that the practical problems one encounters when one tries to estimate hypothetical expenses are substantial enough that this method is no easy solution either.

Lastly, there is the financial integrity issue, particularly when one is considering excluding out-of-pocket expenses that one knows the utility will actually incur.

Considering all these issues, the examiners' recommended approach generally would be to give weight to the financial integrity issue in connection with expenses that one knows the utility will be out-of-pocket even if there was imprudence in connection with the investment to which those expenses relate. Financial integrity is not an inappropriate issue to consider, particularly where actual, on-going, out-of-pocket expenses are concerned. There is a benefit to ratepayers in ensuring that a utility is able to pay its bills going forward no matter what has transpired in the past. The examiners are nonetheless recommending that otherwise reasonable and necessary depreciation expense be disallowed in the same proportion as the investment is found not to be used and useful. This is a reasonable approach which is simple to execute and even allows the utility room to argue to the Commission that its financial integrity is being unduly impaired which, in a sense, is the real issue here. There was, incidentally, rebuttal testimony filed by Company witness Gaeckle on the issue of EPEC's financial impairment in the event that the Commission adopts City of El Paso's recommendations in this docket (No. 7460). These recommendations would obviously cut far more from EPEC's rate request than would the examiners'.

2. Fuel Expense

In the case of fuel expense, which is subject to reconciliation, it would ultimately make little sense to take the position that it has to be calculated as though baseloaded plant which is actually available and has the lowest fuel cost on the system did not exist. This is what would happen if fuel costs associated with the Palo Verde capacity deemed excess were excluded from the fuel mix. Because Palo Verde is baseload capacity with the lowest fuel costs on the system, it would probably be dispatched first to meet projected load. Analyzing the most economical way to meet projected loads hour-by-hour on a simulated basis according to what capacity is available is the way that fuel factors are calculated. Under the Commission's rule, fuel factors are supposed to be based on known and reasonably predictable fuel and purchased power expense. Because Palo Verde capacity would tend to be dispatched first, excluding fuel costs associated with it would mean substituting fuel costs for some other unit. These fuel costs would necessarily be higher. Thus, the end result would be to allow the Company to recover fuel expense subject to reconciliation that would be higher as a result of playing a make-believe game of dispatching the system with something other than Palo Verde capacity.

These fuel expenses are ultimately subject to reconciliation. The point of reconciliation is to determine what fuel costs actually were and whether the system was dispatched in an economical manner. It would make little sense to invest the time and effort playing complex pretend games with generation mix initially if the end result were only that fuel expense is "trued up" to limit the utility to recovering what it actually spent. The examiners' recommendation in this case would simply be to set fuel factors based on all known and reasonably predictable fuel and purchased power expense including fuel expense associated with all 400 MW of Palo Verde Units 1 and 2. While ratepayers would be getting the benefit of lower fuel costs associated with nuclear power, the utility would ultimately bear no loss insofar as fuel expense would be "trued up" at some point anyway. Moreover, if it were not trued-up, so as to allow the utility to keep the difference between actual expense and make-believe expense to help it defray other costs, this would conflict with the rules on reconciling fuel expense.

City of El Paso provided the testimony and calculations of fuel expense of Dr. Don Reading, a Ph.D. in economics, based on excluding fuel costs associated with the portion of Palo Verde Units 1 and 2 that the City is recommending be excluded from rate base. Dr. Reading included the costs associated with the capacity that his analysis indicated would be dispatched in the absence of the excluded Palo Verde capacity. His analysis was based on excluding 60 percent of Palo Verde Units 1 and 2, or, in the alternative, 50 percent of these units. Although his general approach would have validity insofar as it was found necessary to calculate fuel expense as though some portion of Palo Verde Units 1 and 2 were not available, his actual analysis would have to be redone for virtually any scenario other than those he considered. Many of the factors affecting system dispatch are interdependent. If one changes available capacity, this may entail changes in scheduled maintenance, which in turn may affect available capacity, and so on. For the analysis to have validity, one would have to know in advance the exclusion that was contemplated. The analysis is not simple and appears to require the exercise of both judgment and highly developed technical skill. Considering that fuel expense will ultimately be trued up, it is not worth traveling down this road, and nothing in the PURA requires it. Fuel factors should be calculated on the basis of 400 MW of Palo Verde being available. This will actually result in ratepayers paying less for fuel expense than they would under the City's alternative.

3. Palo Verde O&M Expense

One hundred percent of the annual O&M expense requested for Palo Verde in this docket equals $30,061,000. Apart from the plant exclusion issue, this is the level of expense that would be reasonable and necessary. Twenty-five percent of this amount equals $7,515,250. Considering that this is the amount associated with some 100 MW of Palo Verde, this is sizeable as compared, for example, with the annual O&M expense of $4,014 previously associated with the 87 MW of Rio Grande Units 3, 4, and 6.

If one were to exclude 25 percent of Palo Verde O&M expense, costs associated with Rio Grande Units 3, 4, and 5 ought, in fairness to the utility, to be included as an off-set. There would be a number of expenses in addition to the $4,014 annual O&M expense. It would cost at least $658,000 to refurbish them, keep them insured, and pay property taxes on them. (City Ex. No. 46 at 59). There would be some return and depreciation expense associated with them, although these would be relatively modest. There would also be fuel costs associated with the units, in respect of which one would encounter the same kind of difficulties of analysis encountered generally with regard to calculating hypothetical or imaginary fuel expense.

In addition, if one were going to exclude 25 percent of Palo Verde O&M, one would want to include as an off-set an estimate of what the conservation/load management programs would cost that would enable it to achieve the savings of peak load that staff witness Treadway estimates are reasonable - minus, of course, any for which the utility is already recovering expenses. There is no number in evidence for what the cost of any additional programs might be.

In addition, one would want to consider as an off-set the purchased power expense associated with 43 MW of SPS purchased power. In point of fact, however, the utility is already recovering substantial SPS purchased power expense calculated on the basis of 50 MW of demand, so that nothing additional would need to be considered as an off-set to Palo Verde O&M for this item.

Even if all the calculations pertaining to off-sets could be made on the basis of the evidence in this docket and they showed that it was cheaper from the ratepayer's standpoint to pay the off-sets as opposed to the Palo Verde expenses, the examiner would still recommend that all $30,061,000 be included in revenue requirement. Palo Verde is baseload capacity in which EPEC has a 15.8 percent interest. EPEC will be incurring its full pro-rata share of O&M expense unless and until it sells participation in the project. That some of the capacity is excess in terms of EPEC's needs will not enable it to save any O&M expenses by, for example, shutting down the plant or operating it less.

The examiners' recommendation is primarily based on preserving the utility's financial integrity as this an out-of-pocket expense. The sheer difficulty, as a practical matter, of calculating the appropriate off-sets if a 25 percent exclusion were to be made is also admittedly a factor, as is the fact that ratepayers are getting some off-setting benefit due to lower fuel costs for nuclear power under the recommendation on fuel expense.

4. Deferred Palo Verde O&M Expense

As shown on EPEC's Schedule A-7, Adjustment No. 12, EPEC is requesting deferred Palo Verde O&M expense of $12,797,731 to be amortized over three years, for annual amortization expense of $4,265,907. Consistent with the recommendation in the preceding section, the examiners are not recommending any change in this amount due to the recommended rate base exclusion of Palo Verde capacity.

5. Depreciation Expense Associated with Palo Verde Unit 1, Common Facilities, Palo Verde Transmission, and Palo Verde General

According to EPEC Schedule A-7, Adjustment No. 17, Work Paper p. 2, the plant balance and depreciation expense associated with Palo Verde Unit 1, Common Facilities, Palo Verde Transmission, and Palo Verde General are as follows:

Palo Verde Unit No. 1	Adjusted Plant Balance	Depreciation Rate	Adjusted Depreciation Expense
Cash	$ 345,195,082	0.026087	$ 9,005,104
Gross AFUDC	255,959,831	0.026087	6,677,224
Texas Credit	(111,141,369)	0.026087	(2,899,345)
New Mexico Credit	(12,211,194)	0.026087	(318,553)
FERC Credit	(158,716)	0.026087	(4,140)
Texas Displacement	(8,201,058)	0.026087	(213,941)
New Mexico Displacement	(1,516,120)	0.026087	(39,551)
FERC Displacement	(1,100,634)	0.026087	(28,712)
Net Palo Verde Unit No. 1	$ 466,825,822		$12,178,086
Common Facilities			
Cash	69,488,765	0.026087	1,812,753
Gross AFUDC	52,257,270	0.026087	1,363,235
Texas Credit	(22,528,949)	0.026087	(587,713)
New Mexico Credit	(3,462,453)	0.026087	(90,325)
FERC Credit	(22,928)	0.026087	(598)
Net Common Facilities	95,731,705		2,497,352
Palo Verde Transmission			
Gross	20,851,098	.0444	925,789
Texas Credit	(2,443,836)	.0444	(108,506)
New Mexico Credit	(247,062)	.0444	(10,970)
Net Palo Verde Transmission	18,160,200		806,313
Palo Verde General			
Total	223,062	.0307	6,848

Based on the exclusion of 25 percent of Palo Verde Unit 1 and Common Facilities from rate base, the examiners would recommend reducing the "cash" and "gross AFUDC" plant balances for these items by 25 percent and recalculating depreciation expense on that basis after deducting the AFUDC credits associated with Unit 2 that were assigned by the Company to Unit 3, plus other applicable credits.

There were essentially three staff adjustments to depreciation expense, only one of which should be adopted. The other two would not be compatible with the examiner's recommendations in this docket (No. 7460).

The one that should be adopted has to do with the way in which the Company had handled deferred depreciation expense on Palo Verde Unit 1. The final order in Docket No. 6350 permits EPEC to book deferred depreciation expense for Palo Verde Unit 1 to FERC Account 186 for the period between the unit's in-service date and the date that the unit goes into rate base. Instead of booking the deferred depreciation expense to FERC Account 186, however, EPEC used a method that would tend to achieve the same result. It estimated that 20 months would elapse between the March 1986 in-service date and the date that the unit would go into rate base. On this basis, it recalculated depreciation expense based on a plant life of 38.3 years as opposed to 40 years.

The Company's 20-month deferral period would have ended in October of 1987. Using the same method, staff witness Mark Young recalculated depreciation expense using a 22-month deferral period ending in January of 1988. This translates to a plant life of 38.17 years. The staff adjustment essentially serves as an "update" to the Company's request. The rates to be set in this docket (No. 7460) obviously did not go into effect in October of 1987. The examiners are recommending that depreciation should be calculated using a 24-month deferral period (March 1986-March 1988) since rates set in this docket will go into effect sometime in March 1988.

Although none of the parties specifically discussed or briefed the issue, it is the examiners' general understanding that Palo Verde transmission and Palo Verde general would not be handled in the same manner as Palo Verde Unit 1 and common facilities, and that nothing would be deducted from these plant balances based on the recommended rate base exclusion for Palo Verde capacity.

6. Carrying Charges Associated with Deferred Expenses

EPEC incurred carrying costs in connection with Palo Verde during the deferral periods for Units 1 and 2. It is proposing to amortize AFUDC on Units 1 and 2 for the deferral periods over 38.3 years. It also incurred carrying costs on deferred O&M expenses. It is proposing to amortize these costs over a three-year period. This is reflected on EPEC Schedule A-7, Adjustment 17.1 and results in annual amortization expense of $1,455,795. The examiners are not recommending any change in this amount as a result of the recommended rate base exclusion of Palo Verde capacity.

7. Decommissioning Expense

EPEC has requested annual decommissioning expense of $1,700,000 to be placed in a sinking fund to cover EPEC's share of the cost of decommissioning Palo Verde Units 1 and 2 when they reach the end of their useful lives. The examiners are not recommending any change in this amount due to the recommended rate base exclusion of Palo Verde capacity.

In the event that EPEC eventually sells participation in some portion of Palo Verde, however, ratepayers will have paid in a disproportionately large share of decommissioning funds as of that point in time. In other words, the sinking fund will be larger than it would need to be at that point in time to cover the share in Palo Verde that EPEC would still own. One way of handling this situation would be to require EPEC to keep records of ratepayers' contributions to the sinking fund and make refunds of monies contributed in excess of sinking fund needs as of the time of sale based on the lower level of participation.

It is nonetheless the examiners' understanding that there are benefits to ensuring that no withdrawals may be made to the sinking fund so as to prevent the Company from using the fund to obtain working capital. There would also be transaction costs associated with calculating ratepayer contributions, determining an appropriate refund methodology, and ultimately making the refund. An alternative to requiring refunds would simply be to reduce the level of funding going forward to reflect both the lower level of participation in the project and the higher contribution levels in the earlier period.

F. Construction Prudence and Efficiendy

1. Legal Analysis of "Construction Prudence"

Section 39(a) of the PURA provides that in fixing the rates of a public utility the regulatory authority shall fix its overall revenues at a level which will permit such utility a reasonable opportunity to earn a reasonable return on its *invested capital used and useful in rendering service to the public* over and above its reasonable and necessary operating expenses. Although there is no specific language within the PURA outside the context of construction work in progess (CWIP) providing for the exclusion of construction costs on the basis of imprudence or inefficiency of management,[24] it is fair to read such a standard into the PURA based upon the "used and useful" language in Section 39(a), and based upon the mandate of Section 38 which requires that the Commission set "just and reasonable" rates. The language of Section 35(a), which in pertinent part provides that utilities shall furnish such facilities as shall be "safe, adequate, efficient, and reasonable," constitutes further support for this view.

Arguably, to the extent that a utility or its agent was demonstrably at fault in causing certain expenditures for materials and labor to be incurred on a project which, but for the act of mismanagement, would not have been incurred, that portion of the investment is not "used and useful," or, in any event, would result in unjust and unreasonable rates if required to be recognized in rate base. Thus one would determine the expenditures caused by the act of mismanagement and excise them.

In connection with this case, City of El Paso puts forward a theory that, even in the absence of proof of cost causation or fault on the part of the utility or its agent, costs are not "used and useful" if they are incurred as a result of encountering problems and correcting them. The examiners reject this theory. Costs are no less necessary to be incurred because they are incurred to correct problems. Unless there is fault on the part of the utility or its agent, there is no basis to distinguish costs incurred as a result of "problems" from any other costs.

Where overall costs of a project appear "reasonable" under the circumstances, it is fair and appropriate to require proof of fault on the part of the utility or its agent as a predicate to any exclusion of construction costs incurred as a result of specific problems at a construction project. This proposition itself begs the question of the proper approach to take where, considering all the circumstances, project costs appear to be unreasonably high and the utility submits insufficient proof of prudence and efficiency. In such case the Commission, consistent with the mandate of Section 38 and the requirements of Section 35(a), could exclude construction costs to the extent that the utility overall had provided a facility that, under all the circumstances, was unreasonably expensive, without adequate proof of proper management and control of the project.

Determining whether a utility has been prudent and efficient in its management of a project is obviously not an exact science; neither is determining what "reasonable" costs are for a project that may have run into difficulty for a variety of reasons. The above analysis of theories upon which, consistent with statute, construction costs may be excluded nonetheless provides a framework for determining whether, based on sufficient evidence of "fault," costs incurred as a result of specific problems may be excluded or whether, based on insufficient evidence of prudence and efficiency in the record in the face of what appear to be unreasonably high construction costs under the circumstances, the excessive portion of costs for the project as a whole may be excluded.

2. Quality of Management and History of the Palo Verde Project

a. The Pre-Construction Phase. In August 1970, APS, Salt River Project, and Tucson Gas & Electric formed the Arizona Nuclear Resource Study Group to investigate the feasibility of constructing and operating a nuclear power station in Arizona. After extensive investigation, the group concluded that such a station could be built in the area west of Phoenix. After additional study and consideration of the merits of the project in terms of their own company-specific needs, APS and Salt River Project decided to jointly construct a 600 to 1200 MW nuclear power plant. By Memorandum of Understanding dated May 22, 1972, they formed the Arizona Nuclear Power Project (ANPP) to develop plans to engineer, design, construct, operate, and maintain a jointly-owned nuclear power station. APS was designated Project Manager and Operating Agent and put together a project team to manage planning and construction. (EPEC Ex. No. 44, Vol 1, Tab 3, at 25-28, 30-36.)

At or about this time, APS and Salt River Project invited other utilities to participate in the project. Of those who were contacted, EPEC, PNM, and Tucson Gas and Electric Company joined the project. Based on the capacity needs indicated by the various participants, the project settled on a plan to construct three identical 1270 MW units at the Arizona site. While the 1270 MW unit size was slightly larger than had originally been contemplated by APS and Salt River Project, it was considerably smaller than the unit size that would have been dictated by the capacity requests being made by the participants. To accommodate all of these capacity requests, the units would have needed to be rated at 1550 MW each. Regulatory and engineering considerations appear to have restrained unit size at the 1270 MW level. Among other considerations, the NRC limits thermal core power in such a way that a 1300 MW unit is approximately the maximum that could be licensed. (Tr. at 7449.)

An extensive effort was made to find a Project Director with the proper experience to head up the project. In March 1972, APS hired Mr. Edwin E. Van Brunt, Jr. Mr. Van Brunt has extensive nuclear engineering and project management experience. He had worked at Ebasco Services for 11 years prior to being hired by ANPP. The last position that he held for Ebasco was Project Manager on the St. Lucie nuclear plant built for Florida Power and Light Company. Previously, he had served as Project Engineer and Assistant Project Manager on Millstone Unit 1 for Northeast Utilities. Before that he had served as Project Manager on the Power Burst Facility for the Atomic Energy Commission, and before that as a nuclear engineer on the Advanced Test Reactor for the Atomic Energy Commission. (EPEC Ex. No. 44, Vol. 1, Tab 3 at 36-38).

The project selected an organizational structure that included a single engineer-constructor. After studying the matter, the project concluded that combining functions in a single entity would avoid communication problems, improve accountability, and generally reduce "interfaces." (EPEC Ex. No. 44, Vol 2, Tab 3 at 40-42.) It invited approximately 16 potential engineer-constructors to discuss their interest, experience, and qualifications. ANPP limited this invitation to firms having experience with power production units of 500 megawatts or more plus some experience with nuclear power. The initial screening left eight candidates from whom the project requested more detailed information. (EPEC Ex. No. 44, Vol 2, Tab 4 at 42-44.)

ANPP's Project Director, Assistant Project Director, and the nuclear consultant worked independently of one another to evaluate each of the candidates. They used a point system to rate the firms. The areas they looked at included the following: overall company experience, budget and schedule performance, experience of key personnel, internal organizational processes and procedures, technical competence, quality assurance procedures and personnel, history of labor relations, logistical support, and contractual terms. Based on the evaluations, ANPP narrowed the field to Bechtel and Ebasco. (EPEC Ex. No. 44, Vol. 2, Tab 4 at 42-46.) The three evaluators made further investigations of Bechtel and Ebasco, visiting construction sites and firm headquarters. They looked again at contract terms.

The project ultimately judged Bechtel superior to Ebasco. (EPEC Ex. No. 44, Vol. 2, Tab 4 at 42-50.) Bechtel was one of the most experienced in the field, was capable in the area of labor relations, and had the best safety record in the industry. (EPEC Ex. No. 44, Vol. 2, Tab 4 at 46.) It would perform the work for a fixed fee plus expenses, meaning that its profit would not go up if there were cost increases. Its contract terms also guaranteed the continuity of key Bechtel employees over the life of the project. (EPEC Ex. No. 44, Vol. 3, Tab 7 at 33.)

Although the project went through a similar process to determine who the NSSS (Nuclear Steam Supply System) vendor should be, the size of the units at PVNGS may to a large extent have dictated the choice of Combustion Engineering

(CE). At 1270 MW each, the Palo Verde units were and are the largest in the United States. (The next largest, according to ANPP witness Thomas G. Woods, Jr., would be on the order of 1,100 MW). (Tr. at 2554). The size of the units at Palo Verde would have required a larger NSSS than had ever before been placed in operation. CE may have been the only firm that could reasonably have supplied an NSSS of the required size. According to Mr. Van Brunt, the CE System 80, which is what ANPP ordered, was the largest being designed for use in the United States at that time. (EPEC Ex. No. 44, Vol 6, Tab 17 at 51.) The System 80 was a larger, somewhat modified version of a proven design. Size alone would nonetheless have made it, if not "experimental", at least a first-of-kind design.

At the time that ANPP ordered the System 80, there were three other utilities before it who had also ordered it. If those utilities had moved ahead with their projects on schedule,[25] ANPP would not have been the first to install and test the System 80 in an actual nuclear plant. ANPP could reasonably have expected that there would be extensive design reviews and testing over the years at ANPP and other projects to work out minor defects and "bugs." Unless there was reason to believe that the design would turn out to be fundamentally defective in the scale that was required, it would have been reasonable to have proceeded with the CE System 80.

Because of the kinds of problems that have been encountered at Palo Verde with the CE System 80, and that may still be occurring, it may be the case that the basic design will not work in the scale that is required. The sheer volume of water that has to flow through the system appears to have caused stress damage to the parts in the past and may still be causing stress damage even though among other modifications the openings through which the water flows have been enlarged to relieve some of the stress. It has not, however, been suggested either that an NSSS on the scale of the System 80 will not work or that it was unreasonably risky to have gone ahead with the System 80 based on anything that may have been known at the time about the physical limits of sizing an NSSS. The evidence would rather tend to indicate that an NSSS on the scale of the System 80 is generally thought to be a reasonable proposition from an engineering standpoint.

In terms of its qualifications and level of professionalism, CE would also have seemed equal to the task of supplying an NSSS on the scale of the System 80. Conceivably, however, there could be physical limitations to the scale of an NSSS that the System 80 exceeds - in which case the project is obviously in trouble. It is also possible that there is something about the design on which the System 80 is based that poses no problem in the smaller version but is incapable of withstanding the higher pressures exerted in the System 80 itself without sustaining damage to the pump shafts. Again, if this is so, the project will be in continuing difficulty as it means that the modifications that have been made in response to the design problems will not represent a lasting solution. A third possibility is that the modifications that have already been made have largely solved the problem, although there may have been some cracking in three of the four reactor coolant pump shafts on Unit 1 since the modifications. This particular problem has been taken care of temporarily at least by replacing all four of the stafts with new shafts. (Tr. at 7428.) Thus, further modification may be necessary, or it may be necessary to replace pump shafts every time the unit is refueled - which is not an operating and maintenance chore that the project apparently was contemplating when it built the units.

On the basis of the evidence, including the conclusion of staff witness Burns that ANPP's selection of CE was reasonable (Staff Ex. No. 23 at III-1), the examiners can find no basis to fault ANPP in its choice of NSSS supplier. The only colorable question as to the prudence of management decisions in this early phase is as to the wisdom of building units on the order of 1270 MW for which there was no proven design for an NSSS on the scale of the System 80. Conceivably, ANPP could have decided to construct smaller units to avoid any risk of encountering problems on a first-of-kind NSSS that was larger than any previously operating in the United States. In retrospect, considering the excess capacity faced by EPEC alone, it seems regretable that the project could not have proceeded on the basis of smaller units that could have incorporated an NSSS of proven design, especially as the design problems encountered on the project could be size-related. In retrospect, it would have been desirable for the management personnel with the nuclear engineering background to have attached more of a risk to a first-of-kind system as large as the System 80 and to have restrained the capacity planners more than they did. As there is no evidence that the size of the System 80 exceeds the physical limits of on NSSS, or should have been thought to do so, the examiners would nonetheless find that the project was reasonable in going ahead with the System 80.

With regard to the choice of steam turbine generation, the project again went through a careful selection process to choose General Electric Company (GE) as the supplier. GE turbine generators have the highest reliability in the industry. Moreover, GE is an established company and a leader in its field. (EPEC Ex. No. 44, Vol. 2, Tab 4 at 64-66.)

With regard to the procurement of materials and supplies, Bechtel handled all aspects of the process from the prequalification of vendors to the negotiation and administration of contracts. This was appropriate in that it enabled the project to benefit from Bechtel's extensive experience with and knowledge about the various suppliers. ANPP did exercise certain kinds of control. In the bid evaluation and contract negotiation phase, it reviewed the evaluations and recommendations of Bechtel and retained final authority to approve or disapprove contracts and subcontracts. It also provided Bechtel with standard contract provisions to be included in those contracts. In the procurement and construction phase, ANPP audited procurement and made sure that it proceeded according to written policies and procedures. (EPEC Ex. No. 44, Vol. 3, Tab 8 at 4-17.) In addition, ANPP Quality Assurance monitored the quality assurance programs of all vendors of safety-related materials and supplies. (EPEC Ex. No. 44, Vol 3, Tab 8 at 70-82; EPEC Ex. No. 44, Vol. 5, Tab 12 at 31-37.)

Although Bechtel was the architect of the plant, ANPP exerted appropriate control over the design. It used a detailed design criteria manual to establish the requirements that Bechtel's design had to satisfy. These included special requirements aimed at making operation and maintenance at the plant more efficient. ANPP verified compliance with the manual through detailed technical reviews of Bechtel's designs. (EPEC Ex. No. 44, Vol. 3, Tab 7 at 109; EPEC Ex. No. 44, Vol. 2, Tab 4 at 79-83.)

b. The Construction Phase. With regard to construction on the project, Bechtel was responsible on a day-to-day basis for quality assurance subject to requirements set by ANPP. During the course of construction, ANPP conducted quality assurance audits to determine that its requirements were being met. (EPEC Ex. No. 44, Vol. 5, Tab 12.) ANPP also monitored cost and schedule controls at the project and attempted to implement programs and policies that would enhance productivity, boost morale, and encourage good communication between managers and construction supervisors. ANPP's tools for monitoring and controlling project costs and schedules included the following: the Milestone Summary Schedule, the Intermediate Schedule, Weekly Schedules, the Activity Package System, Control of Engineering Budget and Schedule, PREMIS, Material Tracking System, Manpower and Bulk Commodity Planning, Schedule Change Notices, and Heckle & Bucksheets. These are basically systems and computer programs that help management keep track of what is going on and determine which tasks lie along the critical path in terms of the order in which they need to be accomplished so as not to hold up some other aspect of construction on the project. (EPEC Ex. No. 44, Vol. 5, Tab 13 at 39-66.) ANPP also had a system for making sure that it was forecasting, recruiting, and maintaining the appropriate levels of craft manpower with the appropriate specialties at the appropriate times. (EPEC Ex. No. 44, Vol. 3, Tab 9 at 111-133.) ANPP took a variety of steps to ensure good labor relations and worker morale at the project, ranging from a labor stabilization agreement designed to minimize delays in the event of a labor dispute to worker safety and training programs to the creation of housing at the project, as well as provision for bus service to the site and social gatherings for those working there.

Construction began at Palo Verde in November of 1976. The NRC had issued the construction permit for Palo Verde in May of 1976 and Bechtel had begun mobilizing construction personnel to work with engineering personnel on preconstruction planning some eighteen months before that. During the first phase of construction, site preparation, excavation, and backfilling took place. Then rebar, structural steel, embedded piping, and conduit were installed, and concrete was poured. There were some special challenges such as making sure that the wet concrete to be poured was maintained at a temperature of 50°F during one of the hottest summers in Arizona's history. (Tr. at 3702.) The project's solution to this particular problem was to build an on-site ice plant and a 30-thousand-foot sunscreen.

The project made an effort to use the knowledge gained each time that a task or a procedure was performed to increase productivity, and it had measurable success with this. For example, Unit 1 required a double concrete pour (of unspecified length) which is the usual technique that is employed. Because of the knowledge gained from the Unit 1 pour, however, Unit 2 required only a single pour of 50 hours, and Unit 3 required only a single pour of 38 hours. Another example is that, while the project performed a certain amount of welding on the Unit 1 dome prior to lifting it into place, it recognized additional ways to achieve cost savings on Units 2 and 3 as a result of the Unit 1 experience. Specifically, on Units 2 and 3 it recognized that it could also install the containment spray pipe in the dome prior to lift for additional cost savings. (EPEC Ex. No. 44, Vol. 3, Tab 9 at 36-42.)

The three Palo Verde Units were designed and built in a "cookie-cutter" mode. The design of the units evolved over the course of construction, to some extent as the result of changing regulatory requirements. Even so, whenever a change was made for any reason in one unit, it was also incorporated in the other two so that there would be no design or "as-built" differences among the three units. This ultimately made it easier to license the units and, among other benefits, continues to facilitate operating and maintaining the units.

A noteworthy feature that was built into the design of the project from the very beginning is what is referred to as "high availability." At Palo Verde this means for example that there is at least 10 inches of clearance under and around each piece of equipment so that nothing is inaccessible. In addition, every piece of equipment is accessible from above by some form of lift device, chain hoist, or crane so that it can be easily removed if necessary. (Tr. at 3695.)

The project also utilized a scale model of the plant from an early stage in construction. This helped the engineers to visualize space requirements and prepare detailed design drawings; it also helped the construction personnel and vendors to understand the design drawings and how what they were working on fit together with other aspects of the design and construction of the project. (EPEC Ex. No. 44, Vol. 3, Tab 7 at 87-92.)

Studies indicate that these measures on the whole resulted in high levels of productivity at the project. Indeed, aside from problems and delays occurring as a result of the design defects in the NSSS, PVNGS, by comparison with progress and productivity at other nuclear projects, represents a good to excellent example of how to build a nuclear plant.

The project enjoyed good relations with the NRC (Nuclear Regulatory Commission) and worked throughout to meet or exceed the relevant safety requirements. One reflection of how a positive attitude towards safety benefitted the project is that when the NRC made a control room simulator mandatory as a result of the Three Mile Island accident, ANPP did not have to redesign or backfit its plant - it already had a control room simulator. (EPEC Ex. No. 44, Vol. 3, Tab 7 at 73.) A further example of the project's "proactive" as opposed to reactive approach to nuclear safety is that, immediately following the Three Mile Island accident, APS created the PVNGS Safety Evaluation Task force to review the implications of the accident and provide input into the design of the plant. Palo Verde has the distinction of being the first post-Three Mile Island nuclear plant to be granted an operating license by the NRC. The project was able to satisfy regulators' safety concerns at a time of heightened awareness and increased stringency with regard to safety and quality assurance issues. As expressed by Mr. Van Brunt, the project was interested in "building in quality" as opposed to merely "inspecting" it in, and it appears that this attitude served the project well in terms of safety and licensability.

The findings of the Ford Amendment Study Group, which was a team of specialists assembled by the NRS to study quality assurance at nuclear power plants in response to a 1982 directive from Congress, is noteworthy. This group made an on-site assessment of Palo Verde primarily in August of 1983. Although noting that deficiencies needing corrective action had been identified by the NRC in the 1983 CAT (Construction Appraisal Team) report, the group nonetheless cited Palo Verde as a model project illustrating the positive role of management in "contributing to the absence of major quality failures in construction." (EPEC Ex. No. 44, Vol. 4, Tab 11 at 181.) Furthermore, at the time of licensing, NRC Commissioner Roberts stated that he "was never involved in a project where both the owner and the architect/engineer were more concerned about getting a quality job, and it showed from the very beginning. I have never been involved with a better-managed project." (EPEC Ex. No. 44, Vol. 4, Tab 11 at 182.) Although City of El Paso witness Hubbard cited the number of corrective action reports (CAR) filed by ANPP with the NRC over the years as evidence of "serious management failure" at the project (City Ex. No. 48, Attachment B, Vol. 1 at 93), staff witness Terence Burns testified that this conclusion was incorrect and that, on the contrary, it would have been the absence of the project's detecting and reporting deficiencies requiring corrective action that would have signalled the serious management failure. (Staff Ex. No. 23 at III-2.)

c. The Start-up Phase. As construction and installation of some systems and components began coming to a close at Palo Verde, the project entered the "start-up" phase. Although at some projects "prerequisite" testing is left to the builder, at Palo Verde the start-up department within ANPP was made responsible for both prerequisite and preoperational testing leading up to fuel load. The purpose of testing is to determine that equipment turned over by the builder meets acceptance standards and is working properly. At Palo Verde it was the responsibility of the start-up department to devise test procedures satisfying the NRC and carry them out. It also had to provide the documentation required by the NRC to demonstrate that the tests had been properly performed. Obviously, it had to be prepared to take appropriate action in the event that equipment turned over by construction was not in an acceptable condition or failed during testing. Lastly, at Palo Verde the start up department was made responsible for developing the programs and procedures that would be put into effect to operate the plant after it went into commercial operation.

ANPP began working on plans for the organization of start-up as early as 1973. By 1977, an actual start-up department was being staffed. Because of the need to devise programs and procedures for start-up, a great deal of the work had to take place before any system or component could be transferred to start- up. The first transfer took place in May of 1981.

The start-up department encountered a number of difficulties along the way. The period in which start-up was active was one in which there were many regulatory changes affecting nuclear construction projects. Start-up obviously had to keep up with the changes and make sure that its procedures kept up with the changes. The NRC also became increasingly demanding in the area of documentation. Test procedures ultimately had to be written in such a way that the project could document that each step in a procedure had been performed in the precise manner specified. This required a much greater level of detail than had originally been anticipated. (Tr. at 7601.) The start-up department also learned as of 1981 that the CE System 80 at the project would be the first of its kind to be tested at a nuclear project. It had not expected to be pioneering these tests, but rather had anticipated that this undertaking would fall to the lot of Duke Power Company. (Tr. at 3713.)

By 1981, it was clear that schedules that had been established for the orderly turnover of systems to start-up testing were unrealistic and would have to be revised. Because of the changes and delays involved, senior management at this time commissioned Sargent & Lundy to conduct a study of the start-up program at Palo Verde and make recommendations for changes. The start-up program subsequently went through a reorganization as a result of the Sargent & Lundy recommendations. Although city witness Hubbard cited the need for reorganization as evidence of inadequate management at the project (City Ex. No. 48, Attachment B, Vol. 1 at 92), the circumstances of the reorganization indicate to the contrary that start-up was encountering difficulties - like finding itself testing a first-of-kind NSSS - that could not reasonably have been anticipated, and that management responded appropriately when it appeared that the department needed help. The fact of delays and the need for changes in organizational structure could be due to causes other than management imprudence or inefficiency. In light of the way management responded when it thought there was a problem, one could even tend to rule those causes out.

Staff witness Burns found only that ANPP had not presented sufficient evidence about the early phases of start-up for him to reach a conclusion about whether it was organized and administered in an appropriate fashion. By comparsion, he was able to reach the conclusion that it was organized and administered in an appropriate fashion by 1984.

Although the examiners would find that the start-up department as it existed prior to reorganization might have proved inadequate had it not been reorganized, there is evidence to suggest that the need for improvement in the original start-up organization came about in part as a result of changes and conditions that could not reasonably have been anticipated. Although there is some lack of direct evidence showing that management of start-up was appropriate prior to reorganization, there is at least evidence showing good faith on the part of management and appropriate action in response to difficulties and problems needing correction - which overall reflects well on management. It is not as though management had a problem with start-up, but did nothing other than attempt to prove after the fact that its start-up organization was perfectly adequate. Considering that the project was able to obtain a finding from Sargent & Lundy that, although start-up could benefit from changes, it was still "adequate" the way it was, it is obvious that management could have taken this position to the detriment of the project itself.

d. <u>RCS and LPSI Failures</u>. At the time that ANPP selected Combustion Engineering as the NSSS vendor, CE did not manufacture reactor coolant pumps. CE therefore conducted a bid selection process and prepared a list of potential vendors for review by ANPP and Bechtel. (EPEC Ex. No. 44, Vol. 6, Tab 17 at 15-16.) This list included Klein, Schanzlin, and Becker (KSB) of West Germany, Bingham-Willamette Pump Company of Oregon, Byron-Jackson Pump Division of California, and Westinghouse Pump Division of Pennsylvania. Of the four, KSB was ultimately judged to be the best. CE and KSB subsequently formed a joint venture to manufacture reactor coolant pumps for the CE System 80 NSSS. (Staff Ex. No. 23 at VI-10).

CE also did not manufacture low pressure safety injection (LPSI) pumps. It conducted a similar bid selection process, and the project ultimately decided upon a pump/motor combination utilizing an Ingersoll Rand pump and a Westinghouse motor. (Tr. at 3741.)

Although the KSB pump design for the RCS required very little modification for the CE System 80, it did require some, and was therefore a first-of-kind pump. In 1978, before it was installed at Palo Verde, it was put through a 500-hour demonstration test under plant operating conditions with 30 stop-start cycles and special tests to demonstrate the capability of the pump seals (Staff Ex. No. 23 at VI-13.) When the pumps were subsequently taken apart and examined, stress corrosion was found in the diffuser cap screws. After metallurgical evaluation, CE/KSB concluded that this problem would be solved by utilizing cap screws with somewhat different physical properties. Cap screws were accordingly manufactured using materials with these physical properties. (EPEC Ex. No. 44, Vol. 6, Tab 17 at 54-55.)

Following the changeout of the capscrews, one of the Palo Verde reactor coolant pumps was tested at approximately 150 percent of design flow for 50 hours. The pump was disassembled after testing and the integrity of its components was confirmed. (EPEC Ex. No. 44, Vol 6, Tab 17 at 58.) The next indication that there were any problems with the RCS came at the time of the hot functional test prior to fuel load at Palo Verde Unit 1 in July of 1983. Again, the pumps were taken apart after testing and examined. Again, the diffuser cap screws showed stress damage. Four of the cap screws were broken and three of these had come free of their locking devices. Two other cap screws had come loose. There were other parts showing stress damage as well, such as the leading edges of diffuser vanes. (EPEC Ex. No. 44, Vol. 6, Tab 17 at 57.)

Also during this time period problems surfaced with the LPSI pumps. These problems were also stress-related. It appears that when the pump motor was started there were electromagnetic forces created in the motor that would exert force on the side of the motor shaft. The shaft was locked in place at the top and at the bottom, so in reaction to the force it would bend slightly in the middle. This bending would in turn cause the impeller to hit the wear rings, which would ultimately cause the motor to shut off because of the increased resistance. (Tr. at 3743-4.) This was a difficult problem to diagnose and took up six to eight months, because, without being able to look inside the pump while it is switched on (which is physicaly impossible), about all that anyone could observe was that, for no apparent reason, the motor was suddenly shutting itself off.

With regard to both the RCS and LPSI failures, the project took immediate and appropriate action to get the problems resolved, but the resolution still consumed a substantial amount of time. Although the RCS and LPSI failures undoubtedly held up some aspects of the project, activity did not cease, and, to the extent possible, the project would have "worked around" the RCS and LPSI problems. Start-up was going through reorganization at this time and there is some indication that there would have been schedule delays due to that even if it had not been for the RCS and LPSI problems.

In connection with the RCS and LPSI failures, City witness Hubbard provided testimony that in his opinion the RCS and LPSI failures were the result of ANPP's mismanaging the project. This opinion evidence was struck at the request of EPEC on the ground that opinion evidence based on speculation or conjecture lacks probative value. Although Mr. Hubbard accused management of failing to take "requisite" action to ensure that problems on the RCS and LPSI pumps did not occur (City Ex. No. 48 at 22), he never indicated what action was requisite or otherwise appropriate to take. There is no opinion evidence in the record to indicate that, in regard to the CE System 80, ANPP did something it should have known not to do or failed to do something it should have known to do.

By comparison, the conclusion of staff witness Burns was that, while ANPP had the qualified personnel to monitor the technical aspects of the CE System 80 design, it did not provide him with sufficient information to determine that the project had in fact conducted adequate technical design reviews on issues other than "operability and maintainability." (Staff Ex. No. 23 at VI-27.) On rebuttal, EPEC submitted additional testimony from Mr. Van Brunt to the effect that both ANPP and Bechtel had engaged in numerous detailed technical reviews of the CE design both from the point of view of how the System 80 would interface with other systems and components and how it would perform its intended function. (EPEC Ex. No. 108, Vol 1, Tab 4.) Because of the technical complexity of this area, it is difficult to determine, without a response from Mr. Burns, whether the kinds of reviews detailed in Mr. Van Brunt's rebuttal testimony would satisfy his concern that they have gone beyond "operability and maintainability." Here is an area in which, while there is no evidence on which to base an affirmative finding of management imprudence, the evidence of management "prudence" is somewhat inconclusive because of its being largely presented on rebuttal and being inherently difficult for a layman to evaluate.

After sifting through the facts and having the benefit of hindsight, it would appear to the examiners that the one stone left unturned that might have revealed the problems prior to installation of the RCS equipment at Palo Verde would have been to rerun the same grueling 500-hour demonstration test after changeout of the capscrews. It appears that, instead of this, there was a 50-hour test. The absence of a second 500-hour test was, however, not a concern expressed by Mr. Burns and, as previously indicated, Mr. Hubbard was never specific about what should have been done to detect the equipment failures. The examiners are therefore not in a position to say that failure to require that CE perform more than a 50-hour test on the equipment was imprudent.

Although the RCS and LPSI problems appeared to have been solved, and the units have since been licensed, there may be some continuing problems relating to the reactor coolant system. These do appear to be stress related in that there may be cracking in the pump shafts. (Tr. at 7427-8.) Although it would be small consolation if there really are insoluble problems with regard to the pump shafts, Mr. Van Brunt indicated that these kinds of stress problems may be generic to the nuclear industry rather than just peculiar to the equipment at Palo Verde. (Tr. at 7430.) If some of the problems were peculiar to the equipment at Palo Verde, this might indicate that the scale of the System 80 is a factor insofar as the design worked successfully in smaller versions. In any event, the problems appear to be ones that tend to slip through the technical review design process even where there are highly qualified people in charge, only to show up when the equipment is placed under actual operating conditions for an extended period of time.

ANPP currently has litigation pending against CE as a result of these equipment failures. Although CE directly absorbed some of the costs relating to the failures, other direct and indirect costs resulting from the failures have been incurred by ANPP and thus by the participants.

e. <u>Effluent Pipeline</u>. When ANPP started planning the Palo Verde project, one of the key considerations was water because every power plant requires large amounts of water for cooling purposes. It not only had to secure the rights to an adequate supply, but, because the Palo Verde site is in the desert far from any large supply of water, it had to build facilities to pipe it in. In an arrangement that is unique within the nuclear industry, it went into partnership with City of Phoenix to build the 91st Avenue Sewage Treatment Plant and thereby obtain the right to use a certain number of acre/feet per year of municipal sewage effluent to meet its needs at Palo Verde. (Tr. at 7448-7449.)

The project secured the water supply before it knew the ultimate size and number of the units at the site. To be on the safe side, it contracted for enough water for four 1300 MW units. This equaled 140,000 acre/feet per year, or 35,000 acre/feet per year per unit. (Tr. at 7449.) Insofar as securing an adequate water supply for a project that was being put together would present a kind of chicken-and-egg problem, it appears reasonable that the project went ahead with negotiations for water rights even though there was uncertainty about the number and size of the units.

The decisions regarding the sizing of the pipeline were not made until approximately 1975. (Tr. at 7450-7451.) At this time the project knew for certain that it was building three 1270 MW units at the site. It also had options with its vendors to purchase equipment for two more identical units at some point in the future, so there was some possibility of ultimately having five units located at the site.

The project determined to build the pipeline in three major sections. The first would run seven miles from the 91st Avenue sewage plant to the Buckeye Station and would be capable of handling 170,000 acre/feet per year. This would enable it to carry the full 140,000 acre/foot entitlement for Palo Verde plus an additional 30,000 acre/feet for the Buckeye Irrigation Company (Buckeye). ANPP had agreed to carry 30,000 acre-feet for Buckeye in exchange for the right-of-way for the pipeline all the way to the Hassayampa River. (Tr. at 7455.) According to Mr. Van Brunt, the incremental cost of sizing the pipeline to handle 30,000 acre/feet for Buckeye saved the project millions in right-of-way costs. (Tr. at 7451.) The second section would run 23.5 miles from the Buckeye Station to the Hassayampa River Pumping Station and would still be capable of handling the full 140,000 acre/foot entitlement for Palo Verde. The last section would run about 8.5 miles from the Hassayampa River Pumping Station to Palo Verde itself and would be capable of handling only 105,000 acre/feet per year.

The project considered a number of factors when it determined the sizing on the different sections of pipeline. The pipeline had to be able to handle uneven flows of effluent. It was also desirable that it serve to some extent as a reservoir or storage facility for extra quantities of water in the event of a shutdown at the sewage plant or an emergency at Palo Verde. Although Palo Verde would normally use only 63,600 acre/feet of water in a year, the pipeline at a minimum would need to be able to carry 94,800 feet just to allow for the diurnal manner in which the volume of effluent fluctuates. (Tr. at 7488.) There would be an advantage to sizing the pipeline larger than that to allow for storage of additional quantities of water as insurance against a shutdown at the sewage plant or an emergency at Palo Verde. (Tr. at 7488.)

The project also considered incremental cost. The difference between the cost of 31 miles of pipeline sized for 105,000 acre/feet (which was the minimum the project considered and would not have handled the 30,000 acre/feet need for Buckeye) and pipeline sized for 170,000 acre/feet (which was the maximum) was the difference between $21,975,000 and $20,100,000, or $1,875,000. (Tr. at 7469.) Considering that the pipeline that was built was a combination of different sizes, the actual incremental cost between the absolute munimum, (94,800 acre/feet) that could have been built and the actual pipeline that was built probably would have been less than this difference. The exact figures are not in evidence.

There is controversy between ANPP's witness and City of El Paso over whether the pipeline was sized for five 1270 MW units rather than three 1270 MW units. In the face of the record on incremental cost, the City maintains that the pipeline was sized to accommodate five 1270 MW units and, therefore, after assigning one-fifth of the cost to Unit 3, three-fifths of the cost of the pipeline ought to be excluded from construction costs as not being used and useful, or as representing excess capacity.

This proposition presents in microcosm enough issues for a good law school exam question. For the sake of avoiding some interesting theoretical discourses, let us start by assuming that the City's theory of excluding the excessive portion of costs for pipelines exceeding the absolute minimum requirements is correct. The discussion could then be limited to the evidence on incremental costs and the decision to assign 100 percent of common costs to Unit 1. Even assuming that the pipeline was sized for five units, the cost of what was actually built is not two-fifths, or 40 percent, greater than the minimum that could have been built to service three units. The $1,875,000 difference between the 170,000 acre/feet pipeline and the 105,000 pipeline is only about nine percent. (EPEC's 15.8 percent share would translate to $296,250.) Although the exact figures are not in evidence, the difference between what was built and the minimum that could have been built is probably even less than $1,875,000, although $1,875,000 would be a reasonable proxy under the circumstances.

Let us then modify things slightly. Obviously, there is no law which in effect says that a utility has to size a pipeline to meet minimum requirements regardless of safety and reliability concerns. The requirement of Section 35(a) of the PURA is that facilities be "safe, adequate, efficient, and reasonable." There is sufficient evidence in the record to find that there were advantages to sizing the pipelines more or less the way ANPP did, quite apart from whether the pipeline is physically capable of servicing more than three units or was built to have considerable versatility in that regard. On this basis, some or all of even the $1,875,000 difference disappears.

Lastly, it is just not self-evident that building versatility into a pipeline where there is (or was) interest in building additional units at the site and incremental costs are small is either unreasonable or inefficient. (Although this could be glorious launching pad for a stimulating discussion of the used and useful principle as it relates to the dictates of reason and efficiency with regard to incremental cost issues in the sizing of pipelines, these issues will not be discussed as this would be a *de minimus* exclusion in any event.)

With regard to assignment of costs to Unit 1, the examiners have made the decision to assign 100 percent of the cost of common facilities to Unit 1 based on FERC accounting rules. Thus, even if the Commission decided that some portion of pipeline costs should be excluded, there would still be no extra bite taken out for common costs assigned to Unit 3 unless the Commission also decided to depart from the FERC convention.

3. Palo Verde Costs

The following table represents Palo Verde construction costs without AFUDC as of February 28, 1987:

($ millions)

CATEGORY	UNIT 1	UNIT 2
Base Construction	1550.2	1261.9
Preop & Start-up	524.5	384.6
Common	197.6	197.6
Totals	2272.3	1844.1

The total cash cost of Palo Verde Unit 1 as of February 28, 1987, was $2.2723 billion. The total cash cost of Palo Verde Unit 2 as of that date was $1.8441 billion. This cash cost would not include any AFUDC (Allowance for Funds Used During Construction) or any of the in-house, or home office, expenses that the participants would have accrued or incurred as result of being involved in the project.

The following table represents EPEC's costs (after rounding) as reported in this application (See EPEC Schedule A-7, Adjustment No. 31).

($ millions)

CAPITAL ITEMS		LEASE ITEMS	
Palo Verde, Unit 1		Palo Verde, Unit 2	
Cash	= $345	Cash	= $265
AFUDC	= 256	AFUDC	= 202
Total	= $601	Total	= $467
Common Facilities (2/3)		Common Facilities (1/3)	
Cash	= $ 69	Cash	= $ 27
AFUDC	= 52	AFUDC	= 20
Total	= $121	Total	= $ 47
TOTAL CAPITAL	= $722	TOTAL LEASE	= $514

MHB Technical Associates, in behalf of City of El Paso, filed testimony supporting a $172.24 million exclusion of construction costs (including AFUDC) associated with EPEC's 15.8 percent interest in Palo Verde Units 1 and 2. (City Ex. No. 61 at 24.) To arrive at this figure, Mr. Hubbard of HMB added "delay costs" of $169.66 million to "direct costs" of $2.54 million. The $169.66 million in delay costs have strictly to do with time-sensitive costs such as price escalation and finance charges on the project as a whole as a result of coming on line later than it probably would have if it had not been for the RCS and LPSI failures. (Although the Hubbard testimony recognizes that the project would have been delayed to some extent during this same period as a result of the start-up reorganization, this would not affect his analysis). He estimated that the project was delayed 16 months on Unit 1 and 15 months on Unit 2 as a result of the RCS and LPSI failures. He multiplied "delay costs" of $5.473 million per month times 31 months to arrive at the $169.66 million figure. The $5.473 figure was drawn from a study of construction cost escalation and finance costs prepared by APS in 1982, possibly to estimate the cost of delaying Palo Verde Unit 3. (Tr. at 6527-6528; Staff Ex. No. 24 at 7.) The $169.66 million figure is not a measure of the expense associated with any additional materials or labor that went into Palo Verde Units 1 and 2 as a result of the RCS and LPSI failures.

The "direct costs" of $2.54 million (which does not include AFUDC) represent EPEC's share of the only costs that ANPP has quantified thus far as having been incurred by the project as a result of the RCS and LPSI failures and certain other miscellaneous claims against CE for which it has filed suit. Although ANPP has not been able to quantify all of the direct and indirect costs that it may have incurred as a result of the RCS and LPSI failures, ANPP believes these costs to be substantially in excess of these "direct costs" and is seeking to have all of them reimbursed by CE.

Mr. Hubbard's original theory for why the $172.24 million should be excluded from EPEC's share of construction costs was that, but for the mismanagement of the project, Units 1 and 2 would have come on line 16 and 15 months earlier respectively, and the project would not have incurred either the time-sensitive costs or the costs of additional labor and materials attributable to the RCS and LPSI failures. Mr. Hubbard presented no evidence of mismanagement by ANPP; the only factual evidence presented by Mr. Hubbard was evidence showing that there were problems with the RCS and the LPSI pumps, which is a proposition that no one disputes. Mr. Hubbard also gave his opinion that because there were problems with the RCS and LPSI pumps, this was evidence that ANPP had mismanaged the project. This opinion evidence was struck because it was based on speculation about the causes of the RCS and LPSI failures - which need not have been the fault of ANPP. Indeed, it has not yet been established that they had to be the result of *anyone's* negligence or mismanagement.

Mr. Hubbard was thereafter permitted to supplement his testimony for reasons which were unrelated to his theory of damages. In his supplemental testimony (City Ex. No. 61), Mr. Hubbard took the position that the costs associated with the RCS and LPSI problems should be excluded on grounds that they are not "used and useful" regardless of "fault" issues. This position was echoed in City of El Paso's Phase II brief which notes that, of all those concerned, ratepayers are clearly not at fault.

Commission staff filed the testimony of Mr. Morris Jacobs, a consultant with Arthur Young & Co., critiquing Mr. Hubbard's method of calculating delay costs and demonstrating how Mr. Hubbard's $169.66 million in delay costs could be reduced to $28 million by using escalation and finance cost data current with the actual period of the delays--1984 to 1986 as opposed to 1982 when inflation was very high--and by recognizing as an offset the time-value of money.

The basic concept of the time-value of money is simple and straight-forward. If, for example, a project costing $3 billion is put on hold for one year, and, at the end of that year, goes into rate base costing $3.3 billion because of the accrual of AFUDC at the rate of 10 percent, ratepayers are no worse off because they have had the use of their money at 10 percent for an additional year. To give another example, a promise to pay $1,000 today is worth more than a promise to pay $1,000 one year from now. How much more depends on what the $1,000 can earn in a year. Mr. Jacobs' actual calculations are anything but simple. Mr. Jacobs also included as an offset to the time-value of money certain items such as savings on fuel expense that would also be delayed.

Although it submitted Mr. Jacobs' testimony as a response to Mr. Hubbard, Commission staff never indicated what its "theory of damages" was for making the $28 million exclusion. Staff witness Burns made no finding that mismanagement by ANPP was the cause of RCS and LPSI failures or that some kind of technical review that ANPP was at fault in not making would have detected the problems. Thus, unless one believes that a cost is categorically not "used and useful" if it was incurred in connection with correcting a problem, regardless of whether there was fault on the part of the utility in causing the problem, there is no basis in the record or in logic for this Commission to adopt either the exclusion of Mr. Hubbard or that of Mr. Jacobs.

One way in which the kind of findings made by Mr. Burns could result in an exclusion of construction costs would be if overall projects costs appeared to be unreasonably high and the evidence of prudence and efficiency as to some aspect of the project was inconclusive. Clearly there were doubts expressed in Mr. Burns's testimony about the efficiency of start-up management at least prior to 1984. His conclusions were that he did not have enough evidence and enough of a breakdown on costs to determine that start-up was managed prudently and efficiently in the early phases.

Even if the evidence of prudent and efficient management is inconclusive in the respects noted by Mr. Burns, the examiners would still recommend no disallowance of construction costs based on that testimony. If overall projects costs appeared to be unreasonably high and the evidence of prudence and efficiency as to some aspect of the project was inconclusive, this could serve as a basis, under the mandate to set "reasonable" rates, to limit *overall* construction costs to an amount that was reasonable under the circumstances. (To do otherwise would be to give the utility the entire advantage whenever there was insufficient evidence).

In this case, however, the argument for excluding construction costs where there is insufficient evidence at least fails the first prong of the test. Even with the increase in costs that undoubtedly resulted from the RCS and LPSI failures, there is substantial evidence in this docket (No. 7460) that overall project costs are reasonable. A prime example of this is that the same MHB Technical Associates which is supporting the $172.24 million disallowance in construction costs on behalf of the City of El Paso was recommending Palo Verde participation to one of its clients in 1981 on the basis of costs per kilowatt that were higher than EPEC's have in fact turned out to be. (Tr. at 5648.) Staff witness Burns also conceded that Palo Verde is generally thought to compare favorably with most nuclear plants on a cost-per-kilowatt basis. (Tr. at 7350.)

Mr. Woods and Dr. Lewis Perl both testified for the Company that Palo Verde does compare favorably with other nuclear plants on a cost per kilowatt basis. How favorably depends on the plants with which one compares Palo Verde. Dr. Perl used a sample of 48 units, or 34 projects. (Tr. at 6978.) Dr. Reading who testified for the City of El Paso attempted to rebut Dr. Perl's testimony. He did this by whittling Dr. Perl's sample of 34 projects down to nine consisting of Bellefonte, Watts Bar, Comanche Peak, Catawba, Vogtle, Byron, Braidwood, San Onofre, and South Texas on the grounds that the other projects in the 34 project sample were not comparable to Palo Verde. He then kicked out another three plants from his own sample because they had been the subject of cost disallowances. This left six projects on the basis of which Dr. Reading was able to show that Palo Verde ranked third behind Comanche Peak and South Texas in terms of having the highest costs per kilowatt in the sample.

One reaction to Dr. Reading's testimony is that the sample size of the projects considered to be comparable appears rather small. The examiners are already inclined to approach cost comparisons among unique projects with some trepidation. They are not convinced that ranking third behind Comanche Peak and South Texas in a carefully selected sample of six or seven projects is necessarily evidence of having unreasonable construction costs. Dr. Perl's regression analyses are surely not without their flaws, but positive evidence of unreasonably high project costs at Palo Verde is simply not present in this docket.

G. Claims Against Combustion Engineering

Except for the direct costs of $2.54 million, not including AFUDC, which ANPP has so far been able to estimate were incurred as a result of the RCS and LPSI failures and other miscellaneous claims, ANPP has not been able to quantify the damages that APS (Arizona Public Service) as project manager and operating agent is presently seeking from Combustion Engineering in behalf of the participants under a contractual theory of breach of warranty. There was intense interest in this docket (No. 7460) in why APS, which has known since 1983 that it had a problem on its hands, has not been able to quantify the costs for which it is seeking reimbursement. There was also intense interest in why APS did not institute a special tracking system for these costs. APS's response has been that to quantify all of the damages that the RCS and LPSI failures caused would require it to sift through a veritable mountain of data. Moreover, it steadfastly maintains that to have instituted a tracking system for all the ways in which the RCS and LPSI failures would have an impact on costs at the project would either have been an impossibility, or at the very least a proposition so expensive and time-consuming that, under a cost/benefit analysis, it would not have been worth doing. (Tr. at 7685-768; 7691-7694.)

Whatever the difficulties of estimating or tracking additional costs on the project attributable to the RCS and LPSI failures, it seems extremely odd in one sense that the project has not been able to put forward either any estimate of overall damages or even just a theory of how, short of an undertaking similar to emptying the Atlantic Ocean with a spoon, it is going to be able to quantify its damages sufficiently to be able to collect them from Combustion Engineering. To be specific, this is odd in the sense that the project would have to be able to estimate or quantify costs in some way at some point in time in order to be able to collect anything from CE. In another sense, this is not odd at all. Insofar as ratepayers may be counted on to make the participants whole regardless of the outcome of the lawsuit, there arguably would be no great incentive to pursue the CE litigation in the same manner as if the ratepayers were not going to make them whole. It is conceivable that the regulated participants are waiting to try to settle the case after they know the outcome of the various rate cases involving Palo Verde. At that point, even if APS is at sea about how to quantify costs directly, the participants will know, based on the regulatory disallowances, if any, what it would take from their point of view to make them whole for what they spent on the project. This might be the basis of settlement or compromise.

In light of this, one way to save ratepayers money would be to estimate what the CE damages ought to be and simply exclude this amount from construction costs on the theory that, unless these costs are excluded up front they may never be recovered from Combustion Engineering.

Considering that the only specific kinds of costs that the project was able to identify as being affected by the RCS and LPSI failures were costs that are apparently already included in the $2.54 million figure which represents EPEC's share of those costs (Tr. at 7695), it is possible that the remainder of the costs would be time-sensitive costs, such as AFUDC on the direct costs and other time-sensitive delay costs like those which Mr. Hubbard and Mr. Jacobs attempted to calculate. Considering that Mr. Jacobs analyzed delay costs in terms of the impact of project delay on *ratepayers*, the examiners are not certain to what extent, if any, Mr. Jacob's critique of Mr. Hubbard's testimony would have validity in the context of estimating ANPP's contractual damages against CE. To the extent that it has validity in this context, it would seem that, at a minimum, EPEC's ratepayers would be interested in an exclusion of $30.54 million ($28 million + $2.54 million). This exclusion would essentially be based on a theory that this sum of money represents a substantial claim that EPEC has outstanding against a supplier, which, if it is not excluded, will enable EPEC to recover twice for the same expenditure.

The examiners are nonetheless not recommending that such an exclusion be made at this time. This docket (No. 7460) was not litigated on the basis of trying to estimate what ANPP's damages against CE should theoretically be under a breach of contract theory. Although there is some evidence in this docket bearing on this issue, it is incomplete at best. ANPP's damages against CE under a contract theory, as opposed to ratepayers' "damages" against EPEC under a quasi-tort theory, could be much more or much less than what witness Hubbard estimated. It would be better to start over in a new docket constituted as an inquiry or a Section 42 proceeding, and build on the knowledge that has been gained in this proceeding, rather than try to retrofit the testimony of witnesses Hubbard and Jacobs to the new legal theory.

The examiners would urge the Commission's General Counsel and the intervenors to determine whether they wish to pursue these issues in a separate proceeding. The examiners are recommending, in light of the "moral hazard" that the Palo Verde participants will want to settle with Combustion Engineering for what is in *their* interests' which may not be the same as what is in the *public* interest, that some action be taken by regulators to review any settlement or compromise that APS may reach with Combustion Engineering to determine that it is in the public interest. EPEC, through APS, has the duty of a person occupying a position of trust to recover valid claims against suppliers on behalf of ratepayers. If it breaches that duty by entering into a settlement or compromise that is contrary to the public interest, or fails to pursue the claim, that could serve as a basis to adjust EPEC's basis in the plant to exclude the amounts that should have been recovered from CE. The examiners are, of course, recommending that an appropriate percentage, given the decisional prudence exclusion, of whatever damages are actually recovered from CE be accounted for as an offset to rate base.

Examiner Adams posed the following question to the parties to be addressed in briefs:

> Does the utility have an adequate incentive to pursue third parties for damages, particularly damages that may be difficult or expensive to calculate, if ratepayers may be counted upon to make the utility whole regardless of the outcome of such suit?

EPEC replied on the affirmative, giving as one of its reasons the Company's awareness of the Commission's authority "to audit the Company's actions in any claim pursuit." (Applicant's Phase II Brief, Vol 1, p. 116.) The examiners are simply recommending that this authority be exercised in an effective manner.

VIII. Sale/Leaseback of Palo Verde Nuclear Generating Station Unit 2

A. Introduction

On October 31, 1986, EPEC filed at this Commission an application reporting the sale and leaseback in August 1986 of 73.5 percent of EPEC's ownership of Unit 2 of the Palo Verde Nuclear Generating Station (PVNGS) and of the common facilities. The filing was assigned Docket No. 7172. The application stated that the service area and quality of service would not be affected by this transaction, since EPEC would continue to operate the plant; that there would be no effect on neighboring utilities, cities, or political subdivisions; and that notice had been given as required. A prehearing conference was convened on December 3, 1986, at which time motions to intervene by the City of El Paso (City), the Office of Public Utility Counsel (OPC), and ASARCO, Incorporated were granted and a briefing schedule established. (A later motion to intervene by the Texas State Agencies was granted on January 8, 1987.) In briefs filed December 17, 1986, the parties addressed the appropriateness of deferring the review of this sale and leaseback transaction until EPEC's next rate case. The parties agreed generally that since PURA §63 directs the Commission to take the effect of the sale and leaseback into consideration in ratemaking proceedings if it finds that the transaction is not in the public interest, postponement of the investigation until the filing of the rate case was desirable; would not adversely affect any party; and was an efficient allocation of the Commission's resources. Accordingly, the proceedings in Docket No. 7172 were stayed.

On August 13, 1987, EPEC filed an amendment to the application in Docket No. 7172 reporting the sale and leaseback in December 1986 of the remaining 26.5 percent of EPEC's ownership interest in PVNGS Unit 2. Upon the unopposed motion of EPEC in Docket No. 7460, Docket No. 7172 was consolidated with the rate case on October 27, 1987. (All of the parties to Docket No. 7172 were also already parties to Docket No. 7460.) The text below will discuss the August 1986 and December 1986 transactions as the two steps taken to effectuate the sale and leasing back of EPEC's 15.8 percent ownership interest in PVNGS Unit 2 and of a portion of its share of the common facilities.

Direct testimony on the sale/leaseback transaction was given by EPEC witnesses William J. Johnson, Vice President/Treasurer - Chief Financial Officer of EPEC (EPEC Ex. No. 1, Vol. 4, Tabs 21 and 22; EPEC Ex. No. 1A Errata at WJJ-10 and WJJ-11; Tr. at 5156-5248) and Alfred B. Calsetta, Vice President and General Manager of Ebasco Business Consulting Company (EPEC Ex. No. 1, Vol. 2, Tabs 12 and 13; Tr. at 4564-4637 and 5085-5154). City of El Paso witnesses addressing the sale/leaseback were Thomas C. DeWard, CPA, Senior Regulatory

Analyst with the accounting firm Larkin & Associates, Livonia, Michigan (City Ex. Nos. 6 and 6A; Tr. at 1137-1196 and 1283-1357); Dr. Ben Johnson, consulting economist and President of Ben Johnson Associates, Inc., a Tallahassee, Flórida firm of economic and analytic consultants specializing in the area of public utility regulation (City Ex. No. 46; Tr. at 6122-6180 and 6230-6260); and Kimberly Herbig, Senior Research Consultant and Vice President of Ben Johnson Associates, Inc. (City Ex. No. 45; Tr. at 5698-57510.

Financial Analyst Robert Reilley testified on the sale/leaseback for the Commission staff (Staff Ex. Nos. 10 and 10A; Tr. at 1679-1725). Rebuttal testimony for the Company was given by Mr. Johnson (EPEC Ex. No. 41, Tab 8; Tr. at 2445-2484) and Vincent Cannaliato, Jr., Senior Vice President, Managing Director and Manager of the Leasing and Project Finance Department at Smith Barney, Harris Upham & Co. Incorporated (EPEC Ex. No. 84, Vol. 3, Tab 5; Tr. at 6692-6742).

EPEC and the City of El Paso addressed the sale/leaseback issues in initial and reply briefs, general counsel in its reply brief.

B. Description of the Sale/Leaseback Transaction

EPEC witness Johnson and staff witness Reilley discussed the mechanics of the sale/leaseback transactions. Mr. Reilley characterized a sale/leaseback as a complex financing arrangement which is typically leveraged, indicating that the lessor has a relatively small equity investment. He pointed out that because the tax and accounting rules regarding leases are especially complicated, they shape the final form of a sale/leaseback to some degree. Such a lease generally only includes the fixed capital costs associated with the underlying asset, which in the case of an electric generating plant means that the lessee is responsible for fuel, operations and maintenance, property tax, and decommissioning expenses in addition to the periodic rental payments.

Mr. Johnson described the structure of the August 1986 sale/leaseback, involving 73.5 percent of EPEC's investment in PVNGS Unit 2, as essentially a traditional, tax-motivated lease transaction. The lessors wanted to own the unit for tax purposes but did not want to be encumbered by any business or operational risks of ownership. EPEC needed the lease to be a "true lease" for tax and book purposes. A complex series of agreements between EPEC, the lessors, and several other parties was required to achieve the goals of EPEC and the lessors.

The equity participants in the August transaction are Chrysler Financial Corporation, Palatine Hills Leasing, Inc., Energy Investments, Inc., Commercial Federal Investment Corporation, Burnham Leasing Corporation, and Alexander Hamilton Life Insurance Company. To secure an interest in the unit, the equity participants entered into a trust agreement with the First National Bank of Boston (FNB-B) providing for it to act on behalf of the various owners as Owner-Trustee. EPEC was not a party to this agreement. FNB-B acquired the unit and an interest in the real property from EPEC pursuant to the Conveyance of Interest in Real Property, and simultaneously leased it back to EPEC under the Facility Lease.

The Owner-Trustee secured the funds necessary to acquire the interest from EPEC through contributions from the lessors as equity participants (about 20 percent of the total sale price) and through the issuance of Initial Series Notes (Lessor Notes). This debt issuance was accomplished through appointment of First City National Bank-Houston (FCNB-H) as Indenture-Trustee. The Trust Indenture provided for the creation and issuance of the Lessor Notes. The Indenture-Trustee received security interest in the rent payments, payable pursuant to the Facility Lease, as collateral for the debt. The notes are non-recourse to the Lessors, but are guaranteed by EPEC as to payment of principal and interest through an Assumption Agreement attached to the Trust Indenture.

To finance the purchase of the Lessor Notes through the issuance of public debt, El Paso Funding Corporation (EPFC) was created. EPFC entered into a trust agreement with FCNB-H called the Collateral Trust Indenture. EPEC is a party to this agreement, which provided for EPFC to issue the debentures pursuant to the succeeding supplemental indentures. EPEC, EPFC, and FCNB-H were parties to a Term Note Supplemental Indenture which provided for the creation and issuance of Term Lease Obligation Bonds. These Lease Obligation Bonds were then sold to a consortium of banks through a "Bridge Loan" for later sale to the public through a competitive bidding process.

EPEC is obligated to make rent payments to the Owner-Trustee over the lease term of 26 1/2 years. (The 26 1/2 term is based on an IRS requirement that the term of a true lease should be no more than 80 percent of the useful life of the asset. [Tr. at 6735.]) These payments have been assigned to the Indenture- Trustee who will then make the necessary principal and interest payments on the Lessor Notes to EPFC. These payments will then be used to service the principal and interest payments on the Term Lease Obligation Bonds.

The December 1986 transaction was similar in result to the one described above, but it was not as complicated because there were only two equity participants, Commercial Federal Investment Corporation and Chrysler Financial Corporation. The main difference between the two transactions is that the portion of the later lease agreement related to Commercial Federal is a capital lease.

The total sale price of EPEC's investment in PVNGS Unit 2 was $684,685,500, which resulted in a gain for book purposes of $170,676,932. Because of differing treatment of AFUDC and certain capitalized overheads, the tax basis was lower than the book basis and resulted in a larger gain for tax purposes, of $402,634,206. The transaction had no impact on test year operating income, and it had no impact on 1986 earnings because EPEC intends to recognize the book gain over the 26 1/2 year lease period. The lease calls for EPEC to make two lease payments per year totaling $65,871,531. At the end of the lease period, EPEC has the option of purchasing the plant at its then-current market value or continuing the lease at one-half the annual rental payment. (EPEC Ex. No. 1, Vol. 4, Tab 21, pp. 12-15 and 40-41; Staff Ex. No. 10, pp. 11-13.) Mr. Johnson summarized the journal entries for the August sale/leaseback which reflected the cash received from the sale, the book value of the assets sold, the deferral of gain on the sale (cash proceeds less book value) and related deferred taxes, reversal of deferred taxes related to the assets sold, and taxes resulting from the gain on the sale at EPEC Ex. No. 1, Vol. 4, Tab 21, p. 15 and Tab 22, Exhibit WJJ-8, p. 1 of 2.

C. Discussion of the Evidence

In cross-examination, Mr. Johnson denied that the purchase price included tax benefits to the lessors. He testified that it was based on the appraisal on the future value of the asset. In defending the price as more than just an agreement between seller and purchaser, Mr. Johnson noted that in a sale/leaseback, there are Internal Revenue Code provisions defining specific criteria which must be met before the tax benefits can be claimed. One of these requirements is that the purchase price must be equal to and not greater than the fair market value of the asset as determined by an appraisal procedure. Compliance with the Internal Revenue Code is an integral part of the sale/leaseback transaction. (Tr. at 5187-5190.)

Mr. Johnson testified that sale/leaseback transactions such as these provide both lessors and lessees structural flexibility of capital resources, income streams, and tax benefits. The principal benefits to EPEC include: 1) enhanced liquidity (the sale provided EPEC with increased cash reserves); 2) lower capital costs (leasing is a low cost alternative to financing an asset at EPEC's weighted average cost of capital); and 3) realization of gain related to tax benefits (the lessors will be able to use these benefits sooner than EPEC, thus increasing the unit's market value).

EPEC chose an operating lease for the August transaction because treatment as an operating or "true" lease provided advantageous treatment under EPEC's current rate perspective. According to Mr. Johnson, a capital lease is nothing more than a financing, thus it must be capitalized on a company's books. The asset is retained, and the company records the liability and depreciation, etc. An operating lease is considered a true lease and, in this case, the cost would be part of EPEC's operating expenses.

The paramount concern in making this decision was the alleviation of rate shock, according to Mr. Johnson. The sale/leaseback, as an operating lease, will function as rate moderation for EPEC's ratepayers, because the effect of levelizing the capital costs through a lease payment achieves the rate moderation goal of shifting current costs to future periods. Certain constraints led to treatment of a portion of the December transaction as a capital lease; however, the same favorable ratemaking effects can be realized if the Commission agrees to treat the lease payments as an operating lease for cost of service purposes.

Mr. Johnson believes that the principal beneficiary in these transactions is the ratepayer. The normal rate of return on utility plant exceeds the implicit interest rate of the lease for a variety of reasons largely associated with the attractiveness of the lessor position from a tax viewpoint. The revenue requirements resulting from the need to depreciate utility plant is another cost avoided by the sale and leasing back of the asset.

The sale/leaseback transactions brought about a large cash influx. On cross-examination, Mr. Johnson described some of the uses to which EPEC put this cash. EPEC was able to redefine its capital structure by retiring $60 million in short-term debt, a $75 million floating rate note, and a $40 million long-term bond issue with a 16.35 percent coupon. The Company also hoped to retire a $60 million issue with a 16.20 percent coupon in the fall of 1987.

Out of the sale proceeds, the first and second lease payments under the sale/leaseback were made: $24 million on April 1, 1987, and $9 million on July 1, 1987. Part of the cash from the sale was used for the normal cash requirements of the business, and some for construction expenditures. Salary increases were reinstituted, and development of some new systems, such as installing a computer in the Engineering Department to help them monitor work orders and construction requirements, was begun. EPEC doubled up on sinking funds and preferred stocks in 1986, and will do so again in 1987. The Company also paid its back dues to Edison Electric Institute in December 1986, and made a payment to the Three Mile Island cleanup fund after the close of the sale and leaseback, although Mr. Johnson could not state with certainty that these payments had been made with cash from the sale/leaseback transactions.

The gain portion of the proceeds is being used and will be used to finance diversification activities through PasoTex, a subsidiary of EPEC. The goals for this diversification are to find small- to medium-sized companies which can be moved to the City of El Paso in order to create employment. The additional consumption of electricity would also have a favorable impact on the economy of the City of El Paso, in Mr. Johnson's view.

PasoTex had, at the time Mr. Johnson testified, acquired a Houston oil service supply company, Interserve, which could not be moved and will stay there. Westwood Lighting Company, a light fixture manufacturing company from New Jersey, had also been acquired and was being moved to El Paso. It employs about 350 people; Mr. Johnson did not know how many of them were moving from New Jersey to El Paso, but confirmed that all the senior officers and key management personnel were coming with this company.

Within the week prior to Mr. Johnson's testimony, PasoTex had acquired Border Steel, an El Paso company. This acquisition did not create any new jobs, but was made for the purpose of retaining the customer on EPEC's system and in the City of El Paso. PasoTex had also made a $60 million investment in the preferred stock of Commercial Federal Savings & Loan Association, a Nebraska concern, and had made other investments for which Mr. Johnson could not provide details.

Finally, Mr. Johnson testified that he hoped to reserve part of the cash for 1989 to cover three bond issues which expire then. These bonds, which have interest rates from 12 3/4 percent to 14 1/2 percent, were private placements and have no call provisions in them. Repurchase at the present time would entail payment of a premium. (Tr. at 161-173.)

Mr. Johnson testified that the replacement of a significant portion of the nuclear generating facility subject to return on rate base with an operating interest having known carrying costs strengthened EPEC financially; he views this as another benefit of the sale/leaseback. The sale/leaseback can be seen as the ultimate step in accomodating the necessary construction through successively cheaper financing.

The Company's proposed cost of service treatment of the sale/leaseback is termed "book break-even." Under this formula, the ratemaking treatment does not parallel the accounting treatment. Traditional ratemaking methodology for a recently completed plant being placed in service would be to include the plant and related investment in the utility's rate base and to include the related expenses for the new plant as a part of the cost of service. This methodology typically produces the highest revenue requirements in the early years with lower revenue requirements in later years, because the accumulated depreciation and accumulated deferred taxes reduce the gross plant investment.

The rate base continues to shrink each year, thereby reducing the return element of the total revenue requirements. In years past (and with respect to non-nuclear generating plant), these higher revenue requirements in the early years were offset with economies of scale and lower unit costs of production for new generating plants.

Over the past few years, utilities and regulators have developed several means by which to offset the high revenue requirements in early years. These "phase-in" plans defer collection of a portion of the traditional revenue requirements until later years when the revenue requirements, under traditional ratemaking methodology, would be lower. The result is to shift the necessary revenue requirements over a phase-in period and to smooth total revenue requirements over the life of the plant. Since a sale/leaseback defines a lease cost for the unit over the life of the lease, the cost remains constant over the lease period, in this case 26 1/2 years. Consequently, the revenue requirements are, for ratemaking purposes, constant or levelized over the lease period. Thus, in Mr. Johnson's view, the sale/leaseback transactions accomplish generally the same smoothing goals as a phase-in plan. A graphic comparison of lease payments versus traditional ratemaking revenue requirement methodology over a 26-year period shows that from 1986 through 1999, the lease payment is less than the revenue requirements developed under traditional ratemaking methodology. After 1999, the lease payments are higher than the traditionally calculated revenue requirements. (See, EPEC Ex. No. 1, Vol. 4, Tab 22, Exhibit WJJ-9.) The lease payments in a way "defer" revenue requirements from 1986 through 1999 and recover the "deferred" revenues over the remaining lease years, similar to a phase-in plan.

One of the benefits of smoothing the revenue requirements is that it insures equal benefits and costs of this unit over the lease term so that future and current ratepayers pay the same cost of the plant. However, the comparison in Mr. Johnson's graph did not include the entire lease payment which EPEC is obligated to make; the graph only shows the estimated lease payment based on the Company's proposed "book break-even" methodology. The complete derivation of this "book break-even" lease payment is shown in EPEC Ex. No. 1A Errata at WJJ-10 and was explored in cross-examination at Tr. at 5182-5184. The theory is that EPEC will charge ratepayers (that is, will include in cost of service) a lease cost calculated upon the actual book cost of the equipment sold plus the associated capital gains and ordinary income taxes related to the transaction. The ratepayer is to be charged only the lease payment related to the book cost and not the lease payment and associated taxes related to the higher sales price.

The actual capitalized cost of PVNGS Unit 2 was $514,010,000 with a corresponding accumulated deferred income tax associated with the borrowed funds portion of AFUDC of ($49,086,000), for a net investment of $464,924,000. The then-effective tax law required that a certain portion of this net investment would be recognized for tax purposes as taxable income. The Exhibit WJJ-10 shows that there are six separate taxes: federal ordinary income tax, federal capital gains tax, federal minimum income tax, Arizona ordinary income tax, Arizona capital gains tax, and New Mexico ordinary income tax. Only the portion (capitalized items) of the book cost in excess of the cash expenditures of $282,935,000 would be subject to these six taxes. As shown in the exhibit, the effective tax cost of this transaction, based upon the actual book investment, is $101,231,000, resulting in a "book break-even" sales price (including recovery of these tax costs) of $566,155,000. This "book break-even" sales price times the estimated weighted lease payment rate of 9.66 percent results in a "book break-even" lease payment of $54,684,000 annually, compared to the actual annual lease payment of approximately $66,000,000. In short, had EPEC sold PVNGS Unit 2 for the net capitalized cost plus associated taxes, the estimated lease payment would be $54,684,000, the amount included in this rate filing.

In EPEC Ex. No. 1A Errata at WJJ-11, Mr. Johnson demonstrated that on both a present value and an absolute dollar basis, the ratepayer will pay less by using "book break-even" lease payments for ratemaking purposes. The net savings is $29,824,000 on an absolute dollar basis, and $111,426,000 on a present value basis. This calculation is based on a revenue requirement determination of the capital cost items (gross investment, deferred taxes, and depreciation expense based on a 25-year straight line methodology) related to PVNGS Unit 2, excluding operating costs such as fuel, other O&M, decommissioning, etc., which will be incurred by EPEC under either the lease or rate base treatment. The overall rate of return requested in this application is utilized for the entire period. The income tax rates were modified to reflect a 40 percent rate for 1987 and a 34 percent rate for all subsequent years. In 1987, EPEC would need revenues to recover capital cost items of PVNGS Unit 2 of $81,312,000 versus a levelized lease payment, calculated using the "book break-even" methodology, of $54,684,000.

Mr. Johnson testified on cross-examination that the rate of earnings required on the unregulated assets in order for EPEC to make up the difference between the "book break-even" price and the lease payment EPEC must make to the lessors would be the composite lease rate of 9.66 percent. If earnings exceed that rate, the additional earnings will not be used to reduce revenue requirements. On the other hand, if earnings are less than 9.66 percent, ratepayers would be insulated from paying for the shortfall. (Tr. at 5198-5199; 5204.) However, his proposal for insulating the ratepayers in future years from being asked to fund the shortfall was to state that if EPEC were to request reimbursement from ratepayers, it would be included in the cost of service filing which would be subject to review by the Commission and intervening parties, who would then be able to see for themselves if anything had been included in the cost of service to reflect a request for ratepayer reimbursement of a subsidiary's earnings shortfall. (Tr. at 5199.)

The lease payment calculation does not include recovery of the expenses incurred in the sale/leaseback transactions; those are requested as a separate adjustment. As of December 1986, EPEC had booked $2,907,000 of transaction expenses; with the December transaction costs still pending, Mr. Johnson estimated total transactions costs to be approximately $3,500,000. EPEC proposes that these costs be deferred and recovered over the 26 1/2 year life of the lease. EPEC also allocated the AFUDC credits associated with PVNGS Unit 2 equally between PVNGS Units 1 and 3.

Mr. Calsetta testified about the valuation study conducted by Ebasco Business Consulting Company for rendering an opinion on the present fair market value of EPEC's undivided interest in PVNGS Unit 2. Other results of the study included opinions on the economic useful life of the unit, its residual value at the end of a lease and lease renewal term, and the nonlimited use nature of the property in the future to someone other than the lessor or the lessee.

Ebasco conducted three studies simultaneously. Similar opinions were also developed covering the undivided interests in the unit held by Arizona Public Service Company and Public Service Company of New Mexico. A number of investment firms simultaneously commissioned Ebasco to conduct the studies. Ebasco submitted valuation reports to 13 investment firms, five of which related specifically to the undivided interest held by EPEC. The investment firms represented equity investors who proposed to acquire varying proportions of EPEC's undivided interest and to enter into a sale/leaseback transaction with EPEC which closed in August 1986.

The study did not cover all property comprising EPEC's undivided interest; EPEC proposed to retain its interest in certain common facilities and the nuclear fuel associated with PVNGS Unit 2. Examples of the transferred common facilities include surveillance systems, water treatment facilities, storage facilities, and real property. Examples of retained common facilities include electrical power facilities, warehouses, parking lot improvements, and the administration building. Ebasco's report set forth a complete list of transferred and retained facilities.

The valuation of the real property was performed by Real Estate Science Corporation of Phoenix, Arizona.

Ebasco's opinion was that the present fair market value of EPEC's undivided interest in PVNGS Unit 2 and the transferred common facilities, excluding real property, was $682,000,000. Mr. Calsetta defined fair market value as the amount at which the assets would exchange between a willing buyer and a willing seller, neither being under compulsion, each having reasonable knowledge of all relevant facts, and with equity to both.

Mr. Calsetta opined that the useful life of PVNGS Unit 2 will be 40 years or more, the "or more" having been added in recognition of the current practice of the Nuclear Regulatory Commission in issuing 40-year operating licenses for nuclear units, which he considers somewhat conservative considering current technology and plant design. Based on an inspection of PVNGS Unit 2, a review of construction records, and a review of maintenance and operating plans, Ebasco's report concluded that design and construction of PVNGS and all common facilities incorporate all current state of the art technology. Expiration of the operating license after 40 years may be the administrative limit to the useful life of the unit, but design and construction in accordance with accepted industry standards should make a longer useful life possible from a technological standpoint, according to Mr. Calsetta.

The determination of fair market value was based on three methodologies: a cost approach, Reproduction Cost New Less Depreciation (RCNLD); a market approach involving a comparable sales analysis; and an income approach, using a revenue and expense analysis. Mr. Calsetta testified that no single method was numerically definitive in producing the estimate of fair market value. The combination of results formed the basis of Ebasco's opinion of fair market value.

Mr. Calsetta also explained that each of the three utility companies (EPEC, Arizona Public Service Company and Public Service Company of New Mexico) were simultaneously interested in entering into separate sale/leaseback transactions. Ebasco had the opportunity to assemble a combined unit valuation, thus it was possible to gather data from the three utility companies and combine it to represent a 55.1 percent interest in the unit, the sum of the individual undivided interests held by these three utilities. This provided a broader data base than would have been available had data from only one utility been used, allowing Ebasco to incorporate a type of weighted value of utility-specific costs, rather than having to use the specific costs for a single utility. Ebasco also performed the basis analysis with all common facilities included but excluding nuclear fuel, permitting comparisons among the three methods. After the opinion regarding value had been formed, the retained property was "backed out" by reducing the total value by an amount calculated from the proportional costs of retained common facilities to total common facilities.

Mr. Calsetta testified in some detail regarding the RCNLD methodology, which produced a value of $2,251,784,000 for 55.1 percent of PVNGS Unit 2 and its allocated common facilities as of the August sale/leaseback transaction date. (EPEC Ex. No. 1, Vol. 2, Tab 13, at Exhibit AC-3.) This value was used mathematically as a starting point for the revenue and expense analysis and as a reference value for later consideration of overall fair market value.

The RCNLD method is a widely accepted method for determining the cost to reproduce all items of property in their current condition. It involves representing all construction and associated costs at their inflated or deflated value at the assumed time of the transaction, and then reducing the new facility cost to reflect the observed depreciation as a measure of the actual condition of the property in relation to a new unit of property. Ebasco determined that PVNGS Unit 2 and all associated facilities were in a new condition, and there was no reduction for depreciation.

Ebasco evaluated four basic cost components, shown on EPEC Ex. No. 1, Vol. 2, Tab 13, at Exhibit AC-3. One-third of the total cost of the common facilities was allocated to each PVNGS unit in recognition that there are three units at the site. The first component, capital cost, was derived from actual booked costs as provided from Arizona Nuclear Power Project (ANPP) records. Original costs were assembled by year incurred and by subdivision according to the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. Handy-Whitman Utility Company index values for the geographical area (the Plateau Region) were used by year and FERC account to adjust the costs to current values.

The second component, individual utility cost, represents costs directly incurred by the separate utilities as shown in their records and indexed similarly to the capital cost component to adjust the costs to current values. The third component, AFUDC, is a calculated value. Ebasco used each utility's current (June 1986) interest rate applied to its proportion of plant costs to calculate AFUDC as interest on all construction expenditures through June 30, 1986. Finally, the fourth component, current dollar additions, represents the estimated cost to complete construction of PVNGS Unit 2 and one-third of the common facilities. This value was derived from construction cost forecasts provided by ANPP staff and the utilities after some adjustment to reflect costs that were booked between the time of the forecasts and the current time.

During cross-examination, Mr. Calsetta disagreed that adding AFUDC into capital costs and individual utility costs after making an adjustment for inflation introduced a "double-dipping" effect; however, he could not provide a theoretical justification for including interest again after calculating "cost today" which includes inflation and interest. (Tr. at 4594.) It was his belief that reproduction cost new is a methodology which recognizes that even though the cost of the unit is projected as of a point in time, it cannot be built at one point in time (Tr. at 4593), thus including AFUDC in the costs indexed is not improper.

In describing the comparable sales analysis, Mr. Calsetta acknowledged that it is definitive only when a large number of identical (or nearly comparable) sales have taken place, normally not the case for utility property in general and certainly not for nuclear power plant property. It was used in Ebasco's study to indicate a range of market values among a small number of sales which could be identified and adjusted sufficiently to reflect comparability. (EPEC Ex. No. 1, Vol. 2, Tab 13, at Exhibit AC-4.)

The revenue and expense analysis was an after-tax income analysis performed to determine the present value of future earnings attributable to the overall (55.1 percent) undivided interest in PVNGS Unit 2. Mr. Calsetta specified the assumptions which were used in this analysis, which was performed using two alternate assumptions regarding the capital structure of the investment. The results of the analysis using a capital structure of 100 percent equity and a range of returns on equity from 9 percent to 13 percent are shown in EPEC Ex. No.1, Vol. 2, Tab 13, at Exhibit AC-5. A similar analysis for the 50 percent equity case is shown in EPEC Ex. No. 1, Vol. 2, Tab 13, at Exhibit AC-6.

The conclusion drawn by Mr. Calsetta and Ebasco from these analyses was that a purchase price near the RCNLD could vary significantly without resulting in a return on equity outside the acceptable range. Mr. Calsetta's general opinion (subject to the results of the other two methodologies) was that a fair market value purchase price would correspond to the midpoint of the range of acceptable returns on equity, but he pointed out that in this case there was a fairly wide range of indicated possible purchase prices, from $2,992,244,000 to $2,107,710,000, corresponding to the returns on equity from 9 percent to 13 percent, respectively. If that range had been narrower, Mr. Calsetta would have considered the midpoint a more significant indicator of fair market value.

The final opinion of fair market value began with the RCNLD value; the comparable sales analysis and the revenue expense analysis did not indicate that any significantly higher or lower sale price would be more appropriate as a fair market value. The final opinion of the fair market value for the total unit plus one-third of the common facilities was $4,420,000,000. The total fair market value shown for the undivided interest of EPEC is $682,000,000. (EPEC Ex. No. 1, Vol. 2, Tab 13, at Exhibit AC-7.) Ebasco issued five separate reports, entitled "Valuation Appraisal of Palo Verde Nuclear Unit 2 and Certain Common Facilities" and dated August 1986, to each of the five investment firms which acquired an undivided interest in the facilities from EPEC. The reports were identical except for portions relating to the specific percent undivided interest for each investment firm.

Mr. Calsetta was asked in cross-examination why Ebasco's study did not include the sale of a coal unit in the comparables. He replied that it was not considered relevant, since the goal was to develop the fair market value of a nuclear unit. Had such an analysis included a coal plant, Mr. Calsetta opined, it would have been much more complicated. The analysis of comparability would have had to be viewed over a life cycle of costs so that the effects of operating costs would be included, because while the cost per kW of a nuclear unit would be much higher than the cost per kW of a coal plant, the fuel costs for a nuclear plant would be much lower than for a coal plant. (Tr. at 5101.)

Mr. Calsetta acknowledged that a coal plant could have been included in an analysis of replacement cost (instead of reproduction cost), could have been used as a comparable (with the life cycle adjustments described generally above), and could have been used in the income approach. However, he did not agree that including a coal plant in the valuation studies would have produced a much lower indication of value than appears in the Appraisal Report. He did not agree that inclusion of coal generation was appropriate for the purpose of the valuation analysis done for PVNGS Unit 2. (Tr. at 5101-5104.)

Dr. Ben Johnson, appearing for the City of El Paso, stated that without consideration of the benefits to the lessor, the sale above book value would seem incongruous with EPEC's claimed inability to sell PVNGS at book value, but that because of the uniqueness of a sale/leaseback arrangement, the sales price gives little, if any, clue concerning the actual market value of the property sold. On cross-examination, however, it was established that Dr. Johnson did not know how the appraisal had been done and could not explain how future asset value was determined. (Tr. at 6124-6125.) His testimony included his summary description of the transaction, but as Mr. Cannaliato testified in rebuttal, Dr. Johnson got many of the details wrong.

Dr. Johnson averred that the rent (paid by EPEC) should be significantly reduced below the level that would occur in the absence of tax advantages transferred to the lessor, and that this highly leveraged transaction is feasible only because EPEC is extremely credit-worthy. In cross-examination, Dr. Johnson maintained that it was not imprudent for the lenders to finance any amount over fair market value because lenders take risks as part of their business. (Tr. at 6125-6126.) He had no opinion about whether the investment bankers would have exercised due diligence in marketing the bonds if the financing was above fair market value. (Tr. at 6127.)

In his rebuttal testimony, Mr. Cannaliato challenged Dr. Johnson's statement that the sales price of PVNGS Unit 2 gives little clue to the actual market value of the property sold. Mr. Cannaliato testified that the lessors in this or any facility lease transaction would only finance the actual fair market value of the facility, because it would not be prudent for the lessors to finance anything above that amount. Further, the IRS would disallow any ITCs and depreciation associated with any financing above fair market value. A lessor would have an impossible task convincing his credit personnel to approve financing above fair market value, and the investment bankers would not have exercised due diligence in marketing and selling the bonds. He also noted that EPEC's credit is necessary for *any* kind of financing, and that if EPEC were not creditworthy, it could not have financed this plant by any means.

Dr. Johnson agreed that there were benefits of the sale/leaseback to ratepayers as well as to EPEC. First, he acknowledged that the sale/leaseback of PVNGS Unit 2 will lessen the rate impact associated with placing this unit in service, assuming that traditional ratemaking treatment is the alternative. He essentially agreed with Mr. Johnson that the transaction acts as a form of rate moderation. If the sale/leaseback is equitable (that is, there is no harm to the ratepayers from other aspects of the transaction), it more evenly distributes the ratepaying burden.

Second, a potential benefit described by Dr. Johnson was the transfer of significant tax benefits (investment tax credits and accelerated depreciation) from the lessee (EPEC) to the lessors. In Dr. Johnson's view, the transfer of tax benefits in part explains a sales price which in his view is above market value. Unless the sale price is inflated to reflect the tax benefits, the transfer serves to lower the lease payments, and thus produces lower costs to the lessee. In answers to Requests for Information, EPEC indicated that if the purchaser opted to keep the investment tax credit related to the property, the rental factor would be 4.6019150 percent, but if the purchaser elected not to keep the investment tax credit, the rental factor would be 5.1420537 percent. According to Dr. Johnson, for the tax transfer to result in a net benefit to the lessee, the tax benefits would have to be of greater economic value to the lessor than to the lessee. Dr. Johnson did not, however, do an investigation to determine specifically whether the sales price for EPEC's share of PVNGS Unit 2 and a portion of the common facilities was inflated to reflect tax benefits. (Tr. at 6130.)

With respect to Dr. Johnson's conclusion that the sales price had been inflated to reflect the tax benefits transferred from the lessee (EPEC) to the lessors, Mr. Cannaliato stated that the price cannot include the tax benefits associated with the lessee's sale of the facility to the lessor. The lessor can only reflect the tax benefit savings it enjoys through lower rental payments during the lease term. The higher the benefits received by the lessor, the lower the rental payments by the lessee, enabling ratepayers to pay lower rates.

The third benefit identified by Dr. Johnson was that the sale proceeds provided EPEC with significant cash funds which can be used in a variety of ways. He opined that the financial community could view this in a positive light, especially if the utility is facing a liquidity crisis, but depending on how the Company uses the funds, this could have either a negative or a positive impact on ratepayers. He did not dispute that EPEC redefined its capital structure by retiring debt, thus lowering the cost of capital recovered from ratepayers, but indicated that EPEC should have undertaken to accomplish the same results, even if it had not completed the sale/leaseback, by refinancing expensive long-term debt. Dr. Johnson based this belief on his opinion that the financial markets were generally improving at the time of the sale/leaseback transactions, but he did no analysis to determine at what interest rate EPEC could have issued new debt. (Tr. at 6143-6144.)

The fourth benefit for the Company and its shareholders that Dr. Johnson perceives is that the sale/leaseback could diffuse or confuse the prudence and used and useful issues. To the extent that the transaction helps keep rates low in the near future (at the expense of higher rates in the more distant future), it may allow EPEC to confuse the public concerning the excessive cost of its investment in Palo Verde. Dr. Johnson believes that the public may be given the false impression that the costs are not as great as previously described. It is also possible that the sale/leaseback will confuse matters concerning the used and useful standard normally applied when an asset is placed in rate base, according to Dr. Johnson, and he stated that since the plant is not entering rate base, it may appear that it is not subject to that standard. However, Mr. Cannaliato characterized as incorrect and misleading Dr. Johnson's statement that the sale and leaseback may confuse the public concerning the excessive cost of Palo Verde because much of the cost is deferred into future years, because it misinterprets the true result of the lease, which is to level the payment stream for the Company.

Dr. Johnson also identified several disadvantages to the sale/leaseback. Some of the potential benefits for the Company could lead to costs or disadvantages to the ratepayer. As an example, he cited EPEC's increased liquidity, which EPEC witness Johnson had listed as a benefit. Dr. Johnson stated that, properly distributed, the cash could be used to decrease the ratepaying burden, by reducing the Company's common equity ratio, for example. Acknowledging that use of the funds for retirement of certain financial obligations and construction plans will benefit ratepayers, he also observed that ratepayers could be at risk from EPEC's plans to invest the funds in nonregulated activities. Specifically, Dr. Johnson referred to EPEC's proposal to invest the gain portion of the sale proceeds in an effort to generate the annual difference between the "book break-even" lease payment and the actual lease payment. If the diversification effort fails, Dr. Johnson believes that ratepayers could be asked to fund the shortfall, particularly if the Company claims its financial integrity is in jeopardy.

Dr. Johnson testified that there could be some transfer of investment risk from the lessee to the lessor, depending upon the structure and economics of the lease arrangement. EPEC has the option of purchasing the plant at the end of the lease term for its fair market value at that time, but there is uncertainty about whether the plant will be worth more or less than book value at that time. For example, if the unit proves to be unreliable and excessively costly to operate, the fair market value may be negligible, and the lessor will be forced to absorb a loss. On the other hand, if the plant operates normally, the NRC may be willing to extend the operating license substantially beyond the current life; in this circumstance, the market value may be very large and the lessor will experience a windfall profit relative to book value.

Another potential disadvantage in Dr. Johnson's view is the possibility that if at the end of the lease the fair market value is far above book value and the diversified investments do not pay the difference, the ratepayers will not have been given true "book break-even" treatment over the entire life cycle of the plant. They would instead be forced to pay more than book value over the last 15 or more years of the useful life of the plant. Dr. Johnson warned that 26 years from now, regulators may not recall that the gain on the sale of the asset was used to benefit stockholders by developing EPEC's nonregulated businesses.

Dr. Johnson believes that the impact on ratepayers after the expiration of the lease will be substantial. Since traditional ratemaking and accounting load a disproportionate portion of the life cycle cost into early years, the cost per kWh in the later years is less. But by truncating the "book break-even" calculations at the end of the lease, EPEC could potentially shortchange ratepayers by a substantial sum, according to Dr. Johnson. In addition, if inflation continues or accelerates, power from Palo Verde could be a relative bargain on a per book basis in the final 9 to 24 years of its operation, whereas it may have been an economic burden during the first 26 years. Dr. Johnson believes that it is patently inequitable for EPEC to give up its economic interest in the output during the distant years while forcing ratepayers to absorb the burden during the earlier years, unless EPEC guarantees that ratepayers will not pay more than per book equivalent cost throughout the entire life of the plant, regardless of what happens after the lease expires. He also suggests that a substantial portion of the gain on the sale may reflect the lessors' estimate of the profit to be realized from the sale of power or the sale of its ownership interest after the expiration of the lease, and stated that it is quite likely that a portion of the gain is actually payment by the lessors for an anticipated gain (above book value) at the end of the lease.

To Dr. Johnson's criticism that because of the uncertainty of whether the plant will be worth more or less than book value at the end of the lease term there could be some transfer of investment risk from the lessee to the lessor, Mr. Cannaliato responded by pointing out that the lessor is the financial owner of the facility and assumes the risk and rewards of the residual value at the termination of the lease. He observed that a lessor would hardly absorb a loss if the residual value were not realized at the end of the lease term while forgoing a profit if the residual were higher than anticipated. Dr. Johnson testified on cross-examination that it is conceivable that a lessor would be willing to absorb a loss if the residual value were not realized at the end of the lease while forgoing a profit if the residual were higher than anticipated if the lease payments in the early years were high enough, but he later conceded that normally a lessor would not make that choice. (Tr. at 6152-6153.) Further, Mr. Cannaliato explained that even if an unsophisticated lessor could be found to accept such an arrangement, the IRS would disallow such a lease because it requires the lessor to take all the risk with respect to the financial ownership of the facility, including residual value. (Tr. at 6718-6719.) Dr. Johnson did not know whether the IRS would disallow such a lease. (Tr. at 6153.)

In response to testimony by Dr. Johnson and Mr. DeWard (discussed below), Mr. Cannaliato provided an analysis of the residual value of the facility which took into account the time value of money, and demonstrated the present value of the residual at the end of the 26 1/2 year term using nine, ten, 12, 14, and 15 percent present value factors for a loss of ten, 20, and 50 percent of the residual to the Company. The actual loss in today's dollars is very small. If inflation increases, the present value decreases; inflation thus offsets the effect of a higher purchase price at the end of the lease term. Moreover, the Company has full use of the property for its ratepayers for the initial and renewal lease periods.

In addition, Dr. Johnson believes that it is a disadvantage that most, if not all, of the operational risks associated with nuclear power remain with the Company. For example, EPEC must pay rent in the event that there is destruction of, abandonment of, or theft of, or damage to PVNGS Unit 2. EPEC has also indemnified the lessors in the event of certain changes called "deemed loss events," such as changes in regulations or laws that would subject equity investors to public utility regulation; changes in federal laws or regulations that would have an adverse impact on the equity investor; an expiration, revocation, or suspension of the plant's operating license; multiple (two or more) nuclear incidents, including those occurring outside the United States, with components comparable to those of PVNGS which, among other things, result in a discharge of radioactive materials and produce certain specified levels of radiation contamination; and specified radiation levels in the fuel building of PVNGS Units 1, 2, and 3. If such a deemed loss were to occur, EPEC would be obligated to pay the equity investors an amount in cash which could exceed the equity investors' unrecovered equity investment in the unit. Further, EPEC has indemnified the equity participants against certain losses, including any losses in tax benefits resulting from changes in the tax laws. If such events occur, Dr. Johnson foresees the possibility of a liquidity crisis, possibly forcing EPEC into bankruptcy or, more likely in his view, requiring a bailout by ratepayers.

According to Mr. Cannaliato, however, it is totally unrealistic to expect a financial institution acting as a lessor which enters a transaction solely to gain tax benefits (resulting in lower lease payments for the Company) to assume as well the risks of operation, as Dr. Johnson suggested. Operating risks have never been assumed by a lessor in any true lease transaction of which Mr. Cannaliato is aware. Further, he does not view as unreasonable the Company's indemnification of the lessor for certain "deemed loss events," first, because they are similar to operating risks that the Company would have as owner/operator, and second because it is unreasonable to expect a lessor to be responsible for nuclear accidents or other consequences of operating a plant beyond its own control. With respect to the indemnity for loss of tax benefits, Mr. Cannaliato testified that the transaction could not have closed if the lessor could lose the tax benefits it purchased while the lessee retained its tax benefits in the form of lower rental payments. The operating risks for EPEC are identical with or without this lease. (Tr. at 6739.)

Another disadvantage for ratepayers of the sale/leaseback in Dr. Johnson's view is that although the infusion of cash reduces EPEC's need to enter the capital markets in the near future, this risk reduction is offset by the average investor's perception of the transaction, which is an increased, although indirect, reliance on debt financing. The sale/leaseback involved considerable leveraging, and it requires fixed lease payments with most of the same risk characteristics of fixed debt payments. Dr. Johnson believes that the transaction has undoubtedly increased the perceived level of risk faced by the Company and its bondholders and stockholders. Not only does this translate into a higher cost of capital and requested rate of return, the benefits of higher debt ratio are not reflected in the capital structure for ratemaking purposes. Further, this transaction has precluded alternatives, such as refinancing high-cost debt with low-cost debt, which would have benefited ratepayers. However, on cross-examination, Dr. Johnson admitted that he had not done a detailed investigation to determine the reaction of the rating agencies to this transaction. He further conceded that the investigation he did do revealed no substantial change in EPEC's ratings. (Tr. at 6158-6159.)

According to Mr. Cannaliato, there is no double disadvantage to the ratepayer in the lease increasing the risk (and thus the cost of equity) but not having the benefit of a higher debt ratio reflected in EPEC's capital structure as suggested by Dr. Johnson. The fact that EPEC entered into a lease is not necessarily viewed unfavorably by rating agencies. A lease can be a positive financing tactic for a company, because it provides new sources of equity funds and the company's debt service declines because the tax benefits that cannot presently be used are sold to a party that pays for them. Mr. Cannaliato testified that this sale/leaseback transaction has not increased the perceived level of risk faced by the Company and its bondholders and stockholders. Such a transaction is an acceptable financing method used routinely by utilities and corporate lessees when the lessee cannot fully use all the tax benefits. On cross-examination, Dr. Johnson agreed with these statements. (Tr. at 6161-6162.)

According to Dr. Johnson, a further disadvantage is that some of the investment tax credits sold to the equity investors were repurchased by EPEC at a stepped up basis, but since the investment credit will be normalized in ratemaking, EPEC has benefited at the expense of its ratepayers.

Finally, Dr. Johnson criticized the "book break-even" calculation of the lease payments as not reasonable for ratemaking purposes because under the Company's proposal ratepayers are required to pay twice for taxes associated with the plant. For ratemaking purposes, EPEC normalized the taxes associated with the interest expense (ABFUDC) related to PVNGS Unit 2. Since EPEC already used the interest expense and other capitalized expenses as a tax deduction, it cannot do so again when it sells the plant; thus it must pay income taxes on the difference between the book cost, which includes this interest and capitalized expenses, and the tax cost, which excludes them. According to Dr. Johnson EPEC proposes to recover from ratepayers the taxes associated with this difference; he views that proposal as patently inequitable, since ratepayers have already paid for these taxes under the normalization process used in ratemaking. But on cross-examination, Dr. Johnson stated that he was unfamiliar with EPEC Ex. No. 1A Errata at WJJ-10 which shows that accumulated deferred federal income tax (ADFIT) on capitalized cost and ABFUDC had been removed. (Tr. at 6163.)

In Dr. Johnson's opinion, this inequity is further exacerbated because EPEC's method assumes that no CWIP was included in rate base. The AFUDC interest expense that gives rise to the tax due on sale is substantially higher than what the Company's books actually reflect. According to Dr. Johnson, EPEC wants ratepayers to pay taxes that are not their responsibility under normalized accounting, but to pay for hypothetical taxes that even EPEC would not have to pay if it were to sell the plant for book value.

Dr. Johnson faulted Mr. Johnson's comparison between the present value of the lease payments (and other costs associated with the transaction) and the present value of the revenue requirements developed under traditional regulatory treatment because it was not for the entire life of the plant, it did not employ a variety of discount rates, and did not include various assumptions about what will happen at the end of the lease. Dr. Johnson testified that the way to determine whether the sale/leaseback would benefit ratepayers would be to compare the present value of the lease payment and other costs associated with the transaction to the present value of the revenue requirements associated with traditional ratemaking treatment of PVNGS Unit 2; he acknowledged that he had not performed this analysis. (Tr. at 6163-6164.)

Kimberly Herbig elaborated on Dr. Johnson's criticism of the analysis presented by Company witness Johnson. An overriding flaw, in her opinion, was that the analysis was overly simplistic and failed to consider the specific circumstances of the Texas jurisdiction. She opined that once these corrections were made, the rate base alternative might actually be less costly than the lease alternative. She admitted on cross-examination, however, that this was the first analysis of a sale/leaseback transaction she had done (Tr. at 5708), and that her own analysis was never completed. (Tr. at 5709-5710; 5718-5719.) Ms. Herbig also stated that although Mr. DeWard's analysis of the sale/leaseback was similar to hers, he had made different assumptions. (Tr. at 5711.)

The Company's analysis was performed using total Company figures, but Ms. Herbig believes that in order to determine whether there are benefits to Texas ratepayers, the analysis should be performed on a Texas jurisdictional basis and, more specifically, should take into consideration the Texas AFUDC credits associated with PVNGS Unit 2. In her opinion, the effect of this failure is to assume that the amount of PVNGS Unit 2 which would be included in rate base is significantly higher than the maximum amount actually includable on a Texas jurisdictional basis, because there is no credit for CWIP having been included in Texas rate base. This severely distorts the results, in her opinion, and biases them heavily in favor of the lease-payment alternative. She did not analyze whether the jurisdictional allocation factors used for the lease payment would vary from those proposed by EPEC, so she did not dispute the Company's factors. (Tr. at 5724.)

As had Dr. Johnson, Ms. Herbig critcized EPEC for failing to flow back to ratepayers the investment tax credits (ITCs) associated with PVNGS Unit 2. However, Company witness Moises Rodriguez amended the Company's proposal in that regard, and the ITCs will be flowed back to the ratepayers. (Tr. at 462-464; EPEC Ex. No. 1C; EPEC Ex. No. 1A Errata at Schedule A-7, Adjustments 28 and 30.) Neither Dr. Johnson nor Ms. Herbig was aware of Mr. Rodriguez's amendment. (Tr. at 6138-6139; 5726.) Further, Ms. Herbig viewed the omission of some of the sale/leaseback transaction costs and the line of credit costs (required under the December lease) from the analysis as biasing the results of the study in favor of the lease alternative.

Another adjustment which Ms. Herbig would make to the Company's analysis would be to conduct the study using alternative discount rates, since changes in the discount rate can alter the relationship between the lease alternative and the rate base alternative. She would also present the effect of the lease on EPEC's revenue requirements for the period after the expiration of the initial lease term, since at that time EPEC has the option of renewing the lease at one-half of the average of the prior two lease payments or purchasing the real property and undivided interest of PVNGS Unit 2 at its fair market value at that time. In rebuttal, Mr. Cannaliato observed that Ms. Herbig's claim that EPEC's intentions for the end of the lease term are not clear simply states the obvious. The purpose of having an option to purchase or to renew is to enable the Company to choose the best course of action for the ratepayers at that time. In his opinion, it is not in the best interest of the Company to make that decision early.

Ms. Herbig suggested another variation on the Company's analysis, in that the proceeds on the gain from the sale are given to the ratepayers who then pay the higher actual lease payment. She also viewed as useful alternative analyses one which would compare the "book break-even" lease option to a rate base phase-in for PVNGS Unit 2, and one which would examine both a 50 percent rate base alternative (consistent with the City's prudence recommendation) and a 40 percent rate base alternative (consistent with the City's used and useful recommendation) to determine what portion of the lease payment should be included in the cost of service, consistent with other City recommendations on Palo Verde.

Ms. Herbig also took strong exception to EPEC's proposal to transfer half of the PVNGS Unit 2 AFUDC credits to Unit 1 and half to Unit 3 for accounting purposes, which reduces the investment portion of each of these units by $31,609,300. (Mr. Johnson had calculated the total AFUDC associated with PVNGS Unit 2 as $63,218,600. [City Ex. No. 1.]). Since PVNGS Unit 3 is not yet in operation, this proposal gives ratepayers in this case the benefit of only half the AFUDC credits associated with PVNGS Unit 2 even though EPEC is requesting full recovery of Unit 2 costs. AFUDC credits associated with PVNGS Unit 2 but transferred to Unit 3 will not benefit ratepayers until sometime in 1988 or 1989 when EPEC requests recognition in rates of PVNGS Unit 3. Furthermore, if EPEC sells and leases back PVNGS Unit 3, as it is actively attempting to do, it is not clear how those credits would be treated in its next rate proceeding.

Likewise, according to Ms. Herbig, when PVNGS Unit 2 was sold and leased back, EPEC transferred to Units 1 and 3 the portion of Unit 2 CWIP ($92,205,616) previously included in rate base. This transfer, along with the transfer of AFUDC credits, to PVNGS Unit 3 substantially lowers the amount of AFUDC being accrued on that unit as well as the ultimate cost of the plant. Ms. Herbig testified that the estimated completed cost of PVNGS Unit 3 is $1,672 per kW, compared to costs of $3,205/kW for Unit 1 and $2,395/kW for Unit 2, and charged that EPEC had offered no explanation or justification for its proposed treatment of PVNGS Unit 2 AFUDC credits or related CWIP included in rate base. She recommended rejection of EPEC's proposal in this regard, and treatment of the $63,218,600 of PVNGS Unit 2 AFUDC credits as an offset to rate base or as a reduction to the Unit 2 lease payments over the remaining life of the plant. She further recommended that the Commission make clear to EPEC that PVNGS Unit 3 AFUDC credits will ultimately be returned to ratepayers, even if that unit is sold and leased back or the Company otherwise disposes of that unit.

City witness Thomas C. DeWard also compared normal rate base treatment of PVNGS Unit 2 with EPEC's proposed "book break-even" lease payments through the year 2026 in City Ex. No. 6 at Schedule 58, as modified by City Ex. No. 6A; his assumptions are set forth in City Ex. No. 6 at Schedule 59. His analysis showed the sale/leaseback results in reduced revenue requirements for ratepayers over the first three years with increased costs after that. For the comparison, he used full lease payments through 2013 and renewal payments at one-half the rentals through 2017. He also assumed a 40 year operating life of the unit, accelerated depreciation using ACRS, and the overall rate of return requested by EPEC but with a rate of return on common equity of 12.70 percent recommended by City witness Basil Copeland. He also computed the present value cost using the 11.18 percent overall rate of return, while under the "book break-even" methodology, he used a 10.68 percent rate of return. (City Ex. No. 6 at Schedule 7.) Mr. Cannaliato criticized Mr. DeWard's analysis because he believes it is not fair to assume that EPEC will elect accelerated depreciation using ACRS, since EPEC is not in the top tax bracket.

Mr. DeWard testified that this analysis shows that the sale and leaseback of PVNGS Unit 2 is not only questionable but over the life of the unit may result in significantly higher revenue requirements for the ratepayer. Based on additional analyses (City Ex. No. 6 at Schedules 60, 61, 62, 63, and 64), Mr. DeWard concluded that use of the "book break-even" lease payments in the cost of service (as opposed to more traditional ratemaking) results in a net cost to ratepayers in the early years and over the life of the lease on a present value basis; but represents a net savings to ratepayers in total dollars over the life of the lease. On cross-examination, Mr. DeWard acknowledged that the present value analysis would change if the discount rate in his analysis was changed. (Tr. at 1322.)

From his analysis, Mr. DeWard concluded that the equity investors could pay themselves a return of ten percent per year on their investment through the year 1991, at which time they could repay the entire equity investment and continue to generate sufficient cash so that at the end of the year 2017 there could be an additional $286 million to be distributed to the equity investors. (City Ex. No. 6 at Schedule 61.) Mr. Cannaliato, however, challenged this conclusion as being based upon an unrealistic assumption, specifically, that it would be unreasonable to expect a lessor to accept a ten percent rate of return in a transaction of this complexity and risk because a riskless investment, U. S. government securities of the same maturity, are yielding approximately nine percent. His opinion is that EPEC could raise neither debt nor equity financing at this rate. During cross-examination, however, he testified that he did not dispute that the equity investors would receive cash in an amount equivalent to a ten percent return on the investment over the life of the lease; he criticism went only to the logic of Mr. DeWard's ten percent assumption. (Tr. at 6731-6732.)

Mr. DeWard also criticized EPEC's payment of $2 million in equity placement fees to Systems Marketing, Inc., a subsidiary of Commercial Federal Savings and Loan Association. One of the equity participants in the sale/leaseback, Commercial Federal Investment Corporation, is also a subsidiary of Commercial Federal Savings and Loan Association. Mr. DeWard pointed out that EPEC made a $60 million investment in the preferred stock of Commercial Federal Savings and Loan, and that an executive officer of a subsidiary of EPEC serves on the board of directors of Systems Marketing, Inc. Other equity placement fees were paid as follows: $2.2 million to Babcock and Brown; $1.25 million to Chrysler Financial Corporation; and $1.25 million to Drexel.

Although he stopped short of stating that there was impropriety in EPEC's payment of equity placement fees, Mr. DeWard suggested that the relationship between EPEC and Commercial Federal Investment Corporation, Commercial Federal Savings and Loan Association, and Systems Marketing, Inc. should be reviewed in detail to determine if the fees paid were justified in terms of dollars paid for work performed. On cross-examination, however, he admitted that he had not done an economic analysis of the Company's investment in Commercial Federal Savings and Loan preferred stock to determine what return it might yield. (Tr. at 1171.) Mr. DeWard further conceded that he had never been involved in a sale/leaseback transaction and was not familiar with the types of fees customarily charged in such transactions. (Tr. at 1313.)

Mr. DeWard also did not approve of EPEC's use of the cash received from the sale of PVNGS Unit 2 to pay off short-term debt, invest in non-utility assets, pay industry association dues, grant wage increases, and agree with its outside counsel's discontinuance of the ten percent discount it had given EPEC on its 1986 billings. Although he raised a number of questions about the sale/leaseback transaction, Mr. DeWard's only specific recommendation was that the "book break-even" lease payments be reduced by ten percent, calculated as shown on City Ex. No. 6 at Schedule 52. In his direct testimony, Mr. DeWard seemed to base this recommendation on his assertion that Texas ratepayers had been denied any input through intervention in any of EPEC's decision-making processes, and on his calculation that at an 11.18 percent interest rate, ratepayers would be required to pay an additional $5,424,003 per year to recover the net present value cost to ratepayers at the end of the year 2013 of $45,430,729. However, on cross-examination, he said that lack of ratepayer input was not the basis for his ten percent adjustment to the lease payment (Tr. at 1316-1318), nor was it based on a negative assessment of the relationship between EPEC and Commercial Federal Savings and Loan. He explained that his adjustment was appropriate because EPEC had paid off debt, which he thought was good, but in the process had skewed the capital structure. From a ratemaking perspective, Mr. DeWard thought it would be better to offset the preferred stock or common stock because paying off additional debt placed higher costs on the ratepayer. (Tr. at 1171-1173.)

During cross-examination, Mr. DeWard expressed skepticism at the idea that EPEC would not request relief from the Commission if there is a loss on the investments made from the gain portion of the sale proceeds. He conceded, however, that in this proceeding, the transaction has been structured so that the Company bears the risk of either gain or loss on that portion of the lease obligation represented by the gain on the sale. (Tr. at 1158-1160.) He also testified that he had not concluded that the sale/leaseback was not in the best interests of the ratepayers and that EPEC should not have entered into it, only that the cost of the sale/leaseback was excessive for the ratepayers. He then reversed himself, declaring that the way EPEC had presented the transaction and the costs associated with it, the sale and leaseback was not in the best interests of the ratepayers and the Company should not have entered into it, qualified by his statement that he had not evaluated whether the transaction was good for EPEC. Upon further questioning, he reversed himself again, and testified that, considering just the transaction, it was *not* his professional judgment that the sale/leaseback was not in the best interests of the ratepayers and that EPEC should not have entered into it. (Tr. at 1323-1324.)

Staff witness Robert Reilley agreed with other witnesses that sale/leaseback transactions offer advantages to both the utility and its ratepayers by providing the utility with a large influx of cash which can be used to retire high coupon debt and to finish expensive construction programs.

Another advantage is the ability to sell Investment Tax Credits (ITCs) associated with the asset. Many utilities, including EPEC, have generated more ITCs during the course of construction programs than they can use in the near future because of their depressed taxable incomes. Sale of the asset and transfer of the ITCs to the new owner is particularly attractive since the Tax Reform Act of 1986 will result in the loss of a significant portion of unused ITCs in the next two years. The equity participants often have large amounts of taxable income and are willing to provide more favorable terms if they are allowed to use the ITCs associated with the purchased asset.

According to Mr. Reilley, the structure of the lease payments is generally favorable to the ratepayer because they lower early year revenue requirements and substantially levelize the revenue requirements associated with a generating plant over its life. Such a leveling is desirable because it more fairly allocates the costs associated with PVNGS Unit 2 across different generations of ratepayers more equitably than would traditional ratemaking treatment, since that would result in a steeper first year increase followed by generally decreasing annual revenue requirements. Leveling also tends to make the price of electricity more efficient in terms of economic theory, thus the sale/leaseback provides many of the advantages of sinking fund depreciation without the incremental cost and accounting problems associated with decelerated depreciation techniques.

As Mr. Reilley calculated it, the annual revenue requirement associated with the lease payment for PVNGS Unit 2, including the lease, ITC amortization, transaction cost recovery, and line of credit fees will be $53,674,000. (This amount is subject to some change, but should stay relatively stable over the term of the lease.) Under traditional ratemaking, the annual revenue requirement would range from $74,401,000 in 1987 to $27,959,000 in 2011. Staff Ex. No. 10 at Schedule IV, page 3, is Mr. Reilley's graphic demonstration of this aspect of the sale/leaseback.

Mr. Reilley also presented testimony regarding several other sale/leaseback transactions involving electric generating plants which have been consummated in the past three years. He included some basic information on nine such transactions, several of which involved PVNGS participants, including EPEC's PVNGS Unit 2 sale/leaseback. Seven of the other eight sale/leaseback transactions resulted in a gain on the sale. Although he provided lease rates (annual lease payment divided by the sale price) and implicit rates (the discount rate that equates the present value of the lease payments to the sale price) where possible, Mr. Reilley advised caution in interpreting these data, since many factors impact the effective cost of a lease, including the credit-worthiness of the lessee, the size of the transaction, and the type of facility involved. Overall, he concluded that EPEC's sale/leaseback of PVNGS Unit 2 was very much like those of other utilities.

Mr. Reilley used EPEC's computer model used to create Mr. Johnson's comparison of the cost of service impact of traditional rate base treatment of PVNGS Unit 2 to that resulting from the lease, as shown in EPEC Ex. No. 1A Errata at WJJ-11. Mr. Reilley changed the model to incorporate certain staff recommendations, such as Mr. Bradford's proposed rate of return, and he included additional factors such as ITC amortization, transaction costs, and line of credit fees. Savings were projected at any discount rate between five and 20 percent. (See, Staff Ex. No. 10 at Schedule IV, page 1.)

Under current conditions over the 26 1/2 year life of the lease, Mr. Reilley's model indicates that ratepayers should experience an additional nominal dollar cost of $76,401,000 compared to traditional regulatory treatment. However, on a present value basis at a ten percent discount rate, the lease results in savings of $57,287,000. The diminished "real" revenue requirement results from both a reduction in the early year revenue requirement and the leveling of the reduced annual requirements. The reduction in costs results from the greater use of leverage, the sale of tax benefits, and other factors; the leveling reflects the annual lease payment which is constant over the lease period.

Mr. Reilley's present value calculations allow for the explicit consideration of the time value of money. The extent to which future cash flows should be discounted depends upon several factors, including an entity's cost of capital and its opportunity cost (the rate at which it could earn if it had an additional dollar to save or invest). Various individuals and entities have different costs associated with a delay in cash flows, and the appropriate discount rate for a given customer or group of customers changes over time due to numerous economic factors. Mr. Reilley believes that it is reasonable to consider revenue requirements associated with a given alternative using a range of discount rates in order to better understand how attractive that alternative might be to ratepayers in various economic situations. He believes that the range of ten to 15 percent is most reflective of the ratepayers' discount rate. (Tr. at 1724.)

In justifying selection of an alternative with higher nominal costs, Mr. Reilly pointed out that the *economic* cost of that alternative is lower. The revenue requirements for the PVNGS Unit 2 lease are lower in an economic sense than those that would likely result under traditional regulatory treatment of that plant, a conclusion which holds true across a wide spectrum of discount rates under Mr. Reilley's analysis.

He acknowledged that changes to the assumed rate of return create significant changes to the overall savings resulting from the lease. If the assumed long-term rate of return is above the staff recommendation in this case (10.46 percent), the lease will provide greater ratepayer savings than estimated in his analysis; if it is below 10.46 percent, the cost advantage of the lease is reduced. Under the staff recommendation, the cross- over point between the revenue requirements associated with the lease versus those of rate base treatment occurs in 1997. After that, the lease results in higher revenue requirements than rate base treatment. (Staff Ex. No. 10 at Schedule IV, page 3, upper graph.) Assuming an allowed rate of return of 12 percent, the cross-over point does not occur until 2001. In this second, hypothetical analysis Mr. Reilley demonstrates that the savings associated with the lease is less than that estimated by EPEC, since the Company's calculations are based on its requested rate of return. (Staff Ex. No. 10 at Schedule IV, page 3, lower graph.)

Mr. Reilley believes that the issue of allocation of AFUDC credits (contra-AFUDC) is independent of the sale/leaseback transaction, because whatever allocation methodology is selected, it will impact the revenue requirements under the lease or the rate base treatment equally. He therefore ignored the amortization of AFUDC credits in his analysis of the economics of the sale/leaseback transaction. (Tr. at 1713-1714.) He testified, however, that in terms of nominal dollars, customers should be indifferent to various allocation proposals, but considering present value, customers would realize a slight advantage if the PVNGS Unit 2 CWIP credits (contra-AFUDC) were recognized at this time, the equivalent of assigning them to PVNGS Unit 1. Mr. Reilley recommended to the staff accountants that the Company's proposed allocation be adopted, but he does not oppose different allocation schemes.

Mr. Reilley identified three alternative methods for the regulatory treatment of a sale/leaseback transaction which includes a gain on the sale, and made rough estimates of the incremental revenue requirement under each. He cautioned that with different assumptions, the relative results would differ. (Staff Ex. No. 10 at Schedule V.) The first method involves inclusion of the full rental in the cost of service with no rate base treatment of the gain. This method was used in Public Service Company of New Mexico's PVNGS Unit 2 sale/leaseback. The gain offsets the cost of service through amortization over the lease period. The utility gets the vast majority of the present value of the gain, and the ratepayers receive only a small benefit spread over a long period of time. The cost of service impact of the lease would be approximately $64.3 million per year.

The second method includes the full rental payment in the cost of service with rate base deduction of the book gain on the sale as a source of cost-free capital. As the gain is amortized, the amount of the rate base deduction is gradually decreased. Mr. Reilley is uncomfortable with the implication in this methodology that the gain is somehow the property of the ratepayers. It is his belief that since the plant belongs to the Company, it should retain the gain as long as the revenue required from ratepayers is not increased as a result of the sale. Under this methodology, the revenue requirement would be about $57.7 million annually.

Third, there is the "book break- even" methodology, in which only the "book break-even" portion of the rental is included in the cost of service and there is no rate base offset. The portion of the lease payment to be included in cost of service is calculated as if the asset were sold at cost plus an amount that would allow the utility to recover the taxes associated with the sale. It is Mr. Reilley's view that this approach is more equitable to the ratepayers (Tr. at 1723), and it is logically consistent, although he also recognizes that the calculation of the "book break-even" cost is not entirely straightforward. The primary complexity is determining the tax impact of the sale and the calculation of the "tax on taxes" component of the "book break-even" cost; the estimated annual revenue requirement using this approach is $54 million.

It was Mr. Reilley's opinion that the fact that EPEC realized a gain on the sale and leaseback of PVNGS Unit 2 does not suggest that the transaction was detrimental to the ratepayers, since most utilities involved in sale/leaseback transactions have realized book gains and since the Company's proposed regulatory treatment results in a cost of service impact roughly equivalent to that resulting from a sale at book value. He believes that the sale/leaseback is in the public interest, and he recommended that the Commission adopt the Company's proposed inclusion of $54,426,000 in cost of service (operations and maintenance expense) to reflect PVNGS Unit 2 lease expense. (The $54,426,000 was the amount originally requested by EPEC; however, based on EPEC Ex. No. 1A Errata at WJJ-10, Mr. Johnson amended this request to $54,684,000 when he took the witness stand on August 14, 1987.)

Mr. Reilley also agreed with EPEC's proposal to recover the transaction costs over the life of the lease, analogizing them to the issuance costs of debt and preferred stock. The total amount of these costs as of March 31, 1987, was $3,725,091; the annual amortization is $140,569. Finally, if a portion of EPEC's investment in PVNGS is deemed imprudent, Mr. Reilley recommends that the lease payment be adjusted to reflect the percentage of the plant's costs ultimately determined to be imprudent. For example, if it is determined that ten percent of the plant costs were imprudent, ten percent of the "book break-even" lease payment should be excluded from the cost of service.

D. Analysis and Recommendation

It is clear from the record that the PVNGS Unit 2 sale/leaseback transactions were extremely complicated. Whether such transactions are consistent with the public interest, however, is the determination the Commission must make under PURA §63, which reads as follows:

> No public utility may sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000 or merge or consolidate with another public utility operating in this state unless the public utility reports such transaction to the commission within a reasonable time. All transactions involving the sale of 50 percent or more of the stock of a public utility shall also be reported to the commission within a reasonable time. On the filing of a report with the commission, the commission shall investigate the same with or without public hearing, to determine whether the action is consistent with the public interest. In reaching its determination, the commission shall take into consideration the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged or consolidated. If the commission finds that such transactions are not in the public interest, the commission shall take the effect of the transaction into consideration in the ratemaking proceedings and disallow the effect of such transaction if it will unreasonably affect rates or service. The provisions of this section shall not be construed as being applicable to the purchase of units of property for replacement or to the addition to the facilities of the public utility by construction.

In its brief in Docket No. 7172, EPEC suggested that the language "in this state" restricted the jurisdiction of this Commission to transactions involving utility plant located in Texas. However, the Company did not raise that question in its brief in this docket, and apparently abandoned that legal argument. Further, EPEC had already voluntarily submitted the sale/leaseback transactions to this Commission for review by filing the Sale, Transfer or Merger application and subsequent amendment reporting them. That is at least EPEC's tacit recognition of this Commission's interest in the transactions, if not acquiescence in its jurisdiction. The report therefore does not resolve this legal question; it is moot.

Unfortunately, the two initial briefs which addressed the sale/leaseback issues at length were not as helpful as they might have been. EPEC's brief is simply a summary of the testimony. The City of El Paso's brief, inexplicably, devotes a great deal of discussion to omissions in the first Lease Bond Series Prospectus. (City Ex. No. 50.) This report takes the position, however, that the adequacy of the prospectus for the lease bonds is not an issue over which this Commission has authority.

The legal question to be decided under PURA §63 is whether the sale/leaseback transactions are in the public interest. It is a fair reading of the record evidence on this issue to state that the analysis done by most of the witnesses focused on the effect of these transactions on EPEC's ratepayers. This is not to say that these witnesses necessarily believe that the public interest is identical with ratepayers' interests, and this report does not so conclude. Nevertheless, it is reasonable to assume that in financial transactions of this magnitude, the Company will have insured that at the very least it is not harmed, and at best that it is benefited. The testimony of EPEC witness Johnson supports the conclusion that the sale/leaseback transactions were in fact beneficial to the Company, and there is no need to engage in further analysis of that aspect of the transactions. The real question is the effect of the sale/leaseback transactions on the ratepayers.

The City of El Paso's brief engaged in detailed criticism of Ebasco's appraisal of PVNGS Unit 2 and the common facilities which were the subject of the sale/leaseback transactions. Dr. Johnson apparently believes that there were problems with the sales price, even suggesting (without offering supporting facts) that the transactions might not, in reality, have complied with the legal requirements for a sale and leaseback. (Tr. at 6131.) He also cited no facts in support of his allegations that the appraisal value was inflated. Dr. Johnson's statement that a sale and leaseback at a price in excess of book value was incongruous with EPEC's claimed inability to sell its interest in Palo Verde at book value inappropriately compares EPEC's attempts to sell outright some of its interest in Palo Verde, or the energy from it, with the sale/leaseback transactions, which were financing arrangements.

This inappropriate comparison is carried forward into the City's brief. The City argues that Ebasco's cost approach is invalid because it did not consider replacement cost, which the City asserts is a "fundamental basic concept that would be employed in any appraisal process." Mr. Calsetta, the only witness to testify about appraisal techniques appropriate for the sale and leaseback transactions, flatly disagreed that use of replacement cost was proper for the purposes of this appraisal.

The City's brief further asserts that Dr. Perl's testimony that a purchaser of a baseload unit would be buying energy and not any particular arrangement of nuts and bolts supports use of a coal plant in the cost approach in Ebasco's appraisal. Again, this argument confuses the valuation which would be performed for the sale of a fee interest in a generating plant (or its energy output), with that done for the financing arrangement accomplished through the sale and leaseback transactions. The lessors are not utilities. They did not want to operate PVNGS Unit 2. Most importantly, they were not purchasing a base load generating station; they were purchasing tax benefits.

The City's brief asserts that there were other problems with the Ebasco appraisal; however, none of these claimed deficiencies are supported by evidence of record. For example, the City avers that it is a "double-dip" to include AFUDC in the costs which are then brought to current value using the Handy-Whitman Index, and argues that Mr. Calsetta could find no textbook justification for his methodology. A fair reading of his testimony, however, reveals that he could find no comment one way or the other on that question, and in any event, in this record there is no other expert testimony on the appraisal methodology.

In addition to the expert testimony in this record, there are a number of factors which support the reliability of the appraisal process and the sale price of EPEC's interest in PVNGS Unit 2 and a portion of the common facilities. One is the number of participants in each of the transactions. Ebasco's appraisal report was performed for two other utilities operating in two other states and subject to FERC jurisdiction, and was given to 13 investment firms. Another safeguard is the relatively high level of business sophistication of the participants in the sale/leaseback transaction, and of Ebasco. A third is the special interest of the IRS in sale/leaseback transactions, since if IRS found it unacceptable, the intent of the parties (to transfer tax benefits to the lessors) would be frustrated. There is no evidence in this record to support allegations that the participants in this sale/leaseback transaction inflated the sales price for any reason, or that the appraisal was so flawed that it cannot support the sales price. To the contrary, the record evidence and the consideration of the factors listed above support the conclusion that the appraisal underlying the sale/leaseback transactions is reliable, and that the sales price, even though it resulted in a gain above book value, is reasonable.

The concerns voiced by the City's witnesses about the possible failure of the unregulated investments to earn a sufficient return to cover the portion of the lease obligation related to the gain are legitimate, and the assurances offered by EPEC inadequate. It is simply not enough protection for ratepayers to suggest that any request by the Company for ratepayer reimbursement of its subsidiary's earnings shortfall would be subject to review by the City and any intervenors in Commission proceedings. Since the "book break-even" methodology was proposed by the Company and offered to the Commission as an alternative for alleviating rate shock, along with assurances that this is a benefit for ratepayers, it is appropriate that the Commission now place EPEC on notice that any request that ratepayers make up the earnings shortfall would be subject to the most intense scrutiny; would be treated as rate base deductions if granted; and in fact would likely be denied, absent the imminent collapse of the Company or other extraordinary and compelling circumstances.

Another concern voiced by the City witnesses is related to the residual value of the plant at the end of the lease term. Dr. Johnson's testimony that EPEC (and its ratepayers) were disadvantaged by EPEC having agreed to a purchase option at the fair market value at the end of the lease term is naive. As Mr. Cannaliato testified, and Dr. Johnson agreed, the lessor would not have accepted the risk of loss of residual value had they not also retained the opportunity to benefit from a residual value higher than anticipated. Mr. Cannaliato also demonstrated that the present value of a residual loss is very small. In addition, the IRS would not have approved a transaction in which the lessor had all of the risk, as Mr. Cannaliato pointed out. Finally, EPEC does have the option of either purchasing at the then-current fair market value *or* renewing the lease at one-half the rentals. While this Commission should insure that future regulators know the details of this transaction and how the burdens and benefits were divided between the Company and its ratepayers, it is simply premature and unreasonable to require EPEC to choose now the course of action it will take 25 years hence.

In addition, the Company does not bear any greater operational risks under the sale/leaseback than it would have had as an owner. Despite the intimations by City witnesses that it is somehow improper for EPEC to shoulder these risks, it is clear that the lessors were purchasing only the tax benefits, that operating risks are never assumed by lessors in a true lease transaction, and that the deal would never have closed had EPEC insisted on transferring such risks to the lessors.

Dr. Johnson's statement that the perceived riskiness of this Company to investors has increased was contradicted by his testimony that there was no substantial change in EPEC's ratings in the financial markets following the close of the sale/leaseback transactions. These transactions had been complete for several months (the first one nearly a year) by the time the hearing on the merits in this case convened, and the financial markets had had ample time to react to them. Had the perceived riskiness of EPEC been increased as a result of the sale/leaseback transactions, the rate of return recommended by the City's own witness (discussed below) might have been higher than that requested by EPEC. In fact, the City recommended a rate of return lower than that sought by the Company, even after EPEC amended its application by lowering its requested rate of return.

Finally, while there was general agreement that an evaluation of whether the ratepayers benefit from the sale/leaseback transactions and EPEC's proposed ratemaking treatment would begin with a comparison of the revenue requirement impact of the proposal with that of traditional rate base treatment of PVNGS Unit 2, the testimony of various witnesses pointed out some rather significant difficulties with the evaluations presented by EPEC and the City of El Paso. Ms. Herbig offered some suggestions regarding the kinds of comparisons which a really useful analysis of the two methods would include, but her own analysis was never completed, and that of Mr. DeWard did not incorporate all of her suggestions.

The Company's proposal was criticized by Dr. Johnson and Ms. Herbig for not going beyond the lease term and making the comparisons over the life of the plant. EPEC's analysis also did not include all of the transaction costs and the line of credit costs, and did not utilize various discount rates. Mr. DeWard's comparison contained questionable assumptions, and his amendment to correct a double count of AFUDC credits was extremely confusing. (Tr. at 1192-1196; 1283-1288.) The proposals of Ms. Herbig and Mr. DeWard regarding PVNGS Unit 2 AFUDC credits are incompatible and cannot both be implemented. Ms. Herbig believes all such credits should be used to offset rate base for PVNGS Unit 1, and Mr. DeWard recommends using these credits to reduce the PVNGS Unit 2 lease payments included in cost of service. (Tr. at 5721.)

The staff's analysis, presented by Mr. Reilley, incorporates several of the suggestions offered by Ms. Herbig, such as alternate ratemaking treatments of the lease payments, various discount rates, and inclusion of the transaction and line of credit costs, and thus is the most credible analysis in the record. While it shows that the benefits under the lease alternative are not as great as claimed by EPEC, staff's analysis does support the conclusions that the "book break-even" is the most equitable to ratepayers and results in some savings in the initial years of the lease. It is clear under all the analyses that in the later years, the revenue requirements impact of the lease payments is higher than traditional ratemaking would be. However, use of the lease payments in cost of service is beneficial to ratepayers in that the revenue requirements in the early years are not as great, and the revenue requirements over the term of the lease are relatively stable. Such ratemaking treatment is equitable, in that it spreads the burden more evenly across the time during which ratepayers will be receiving power from PVNGS Unit 2. Finally, the "book break-even" methodology for calculating the cost of service impact of the lease is the fairest way of including costs for PVNGS Unit 2 in rates, since the ratepayers do not pay for more in rates than they would have had EPEC sold this asset at book value.

The City requests in brief that the Commission declare that the sale and leaseback of EPEC's share of PVNGS Unit 2 and a portion of the common facilities is not in the public interest, that the transaction is a voluntary deregulation by EPEC, and that any energy from PVNGS Unit 2 that is used and useful be included at its fair market value using the SPS energy contract as a comparable. None of the City's witnesses testified that the sale/leaseback was not in the public interest, nor did any other witness. There is no evidence to support the claim that the sale/leaseback is a voluntary deregulation, and there is no legal argument on how EPEC could unilaterally achieve deregulation. Finally, there is no record evidence to support the assertion that the SPS energy contract is an appropriate surrogate for pricing energy from PVNGS Unit 2.

The report recommends that the Commission find that EPEC has complied with PURA §63 by reporting the sale and leaseback transactions within a reasonable time. Considering all aspects of these transactions, the Commission should find that these transactions are in the public interest, and that the effect of the transactions will not unreasonably affect rates or service. In addition, the Commission should approve the Company's proposed accounting entries for the sale/leaseback, as recommended by staff witness Mark Young. (Staff Ex. No. 11 at 57.)

To implement the effect of the sale/leaseback, and in accord with the discussion and recommendations in Section VII below, this report recommends that EPEC be allowed to include in cost of service $41,013,000 (75 percent of $54,684,000) for PVNGS Unit 2 lease expense, taxes associated with the sale, and ITC amortization. In addition, the transaction costs should be recovered over the life of the lease. The calculation of the transaction costs and the annual amortization is shown below in Section XI.B.9.c. of this report. All AFUDC credits associated with PVNGS Unit 2 ($63,218,600) should be allocated to PVNGS Unit 1, in accord with the reasoning and recommendation of City witness Herbig, and as discussed below in Section IX.A. of this report.

IX. Invested Capital

The following witnesses presented testimony on invested capital issues: for the Company, William J. Johnson (EPEC Ex. No. 1, Vol 4, Tabs 21 and 22, as amended by EPEC Ex. No. 1A Errata; Tr. at 55-269; on rebuttal, EPEC Ex. No. 41, Tab 8; Tr. at 2445-2484); Dale Schaefer (EPEC Ex. No. 1, Vol. 5, Tabs 30 and 31; EPEC Ex. No. 1D Errata AB Exhibit II; Tr. at 488-510; on rebuttal, EPEC Ex. No. 41, Tab 11; Tr. at 2424-2441); on rebuttal, Frederic E. Mattson (EPEC Ex. No. 65; Tr. at 3572-3619) and Gregg Forszt (EPEC Ex. No. 41, Tab 2; Tr. at 2179-2202); for the City of El Paso, Thomas C. DeWard (City Ex. No. 6 and 6A; Tr. at 1116-1357); Hugh Larkin, Jr. (City Ex. No. 5; Tr. at 1079-1115); for the Commission staff, Candice J. Tye, Regulatory Accountant in the Electric Division (Staff Ex. Nos. 12 and 26; Tr. at 1883-1929 and 6369-6429); Waldon A. Boecker, Manager of Power Plant Engineering in the Electric Division (Staff Ex. Nos. 5 and 27; Tr. at 744-788 and 6460-6467); and Stan Kaplan, Manager of Fuel Analysis in the Electric Division (Staff Ex. No. 16; Tr. at 3459-3572).

A. Original Cost of Plant in Service

The Company's original rate filing package showed an original cost of plant in service of $1,024,745,147. This includes EPEC's share of PVNGS Unit 1 and approximately two-thirds of EPEC's share of the PVNGS common facilities. EPEC no longer owns a share of PVNGS Unit 2 and related common facilities. That unit is in commercial operation, but EPEC leases it from the owners. (The Company is requesting the "book break-even" lease expense in cost of service, as discussed above in Section VIII of this report.) The company is requesting that its entire share of the common facilities which it does own (two-thirds) be included in plant in service. EPEC made a post-test year adjustment to plant in service to reflect the December 1986 journal entries removing the remaining test year-end balance of PVNGS Unit 2 and related Common Plant sold in December 1986. This adjustment included EPEC's reassignment of the respective AFUDC credits to PVNGS Units 1 and 3. (EPEC Ex. No. 1, Vol. 4, Tab 21, p. 45; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 31; EPEC Ex. No. 1, Vol. 7, Schedule B, as amended by EPEC Ex. No. 1A Errata Schedule B.)

EPEC made one adjustment to its test year end balance for non-PVNGS plant in service: the SPS transmission line balance was reduced by $700,000, the amount for contract costs incurred by EPEC for construction delays. (EPEC Ex. No. 1, Vol. 4, Tab 21, pp. 44-45; EPEC Ex. No. 1, Vol. 7, Schedule A-7 (Adjustment No. 31). The non-PVNGS plant in service balance also excluded Rio Grande Units 3, 4, and 5 which were taken out of plant in service and reclassified to plant held for future use in December 1985. This exclusion was $1,770,712 of original cost. The total company non-PVNGS plant in service amount is $443,804,358. Staff concurred in this amount (Staff Ex. No. 12 at 3); no other party challenged this figure or made adjustments to it.

City witness Thomas C. DeWard made several adjustments to PVNGS plant in service; two of them were based on the recommendations of other City witnesses from Ben Johnson Associates, Inc. and MHB Technical Associates. (City Ex. No. 6 at Exhibit TCD-1, Schedules 53 and 54.) In addition, Mr. DeWard proposed an amendment to the Company's proposal regarding the allocation of PVNGS common facilities. Mr. DeWard testified that it is inappropriate to allocate all of the common facilities to Unit 1 because it places an additional burden of return requirements, depreciation expense, and property tax expense on current ratepayers. In his opinion, it is more appropriate to continue to capitalize that portion of common facilities related to PVNGS Unit 3 and continue to accrue AFUDC on these balances until that unit becomes commercially operable. To effect this recommendation, Mr. DeWard reallocated one-half of the remaining common facilities and removed that amount from plant in service. His adjustment on a total company basis was $47,865,853. (EPEC Ex. No. 6 at 15-18 and at Schedule 8.)

Mr. DeWard's second adjustment to plant in service was to reassign Texas AFUDC credits in the amount of $31,609,300 from PVNGS Unit 3 to Unit 1. These are the credits which offset AFUDC accruals and have been provided by Texas ratepayers through the inclusion of CWIP (construction work in progress) balances in rate base while allowing EPEC to earn a current cash return on a portion of CWIP balances. When Unit 2 was sold in the sale/leaseback transactions, the Company had accumulated $63,218,600 of Texas AFUDC credits associated with Unit 2. EPEC allocated one-half of these credits to Unit 1 and one-half to Unit 3. According to Mr. DeWard, had EPEC not reallocated these credits, the "book break-even" lease payments would have been less because the net book value of Palo Verde Unit 2 would have been less. The transfer of only one-half of these credits to the one unit going into rate base (Unit 1) means that the ratepayers are not receiving the full benefit of the credits which have resulted from previous inclusion of CWIP in rate base. (City Ex. No. 6 at 19-20 and at Exhibit TCD-1, Schedule 9.)

Finally, Mr. DeWard removed $7,373 in penalties from plant in service because he believes it is inappropriate for ratepayers to be required to pay a return on penalties which EPEC has chosen not to dispute with the Project Manager. (City Ex. No. 6 at 20-21 and at Exhibit TCD-1, Schedule 10.) The total original cost of plant in service recommended by the City (before implementing the recommendations of Ben Johnson Associates, Inc. and MHB Technical Associates) is $505,214,364. (City Ex. No. 6 at Exhibit TCD-1, Schedule 2.)

Staff witness Waldon Boecker testified that without information concerning the cost and sizing of each PVNGS common facility or system, it was not possible to justify allocation of any common facility costs to any of the three PVNGS generating units. In his opinion, if each common facility is designed to serve all three generating units, the Company's allocation of one-third to each unit would be appropriate. He testified that in the absence of EPEC justification, about $29 million in common costs should be allocated to each generating unit, based on information in the Company's rate filing package. However, because PVNGS Unit 3 is not included in plant in service in this case, he recommended that $26,924,847 in common facility costs should be removed from plant in service, as well as associated AFUDC and other costs. Further, Mr. Boecker did not believe that EPEC had justified including the balance of the common facility costs with PVNGS Unit 1. Finally, he stated that the Palo Verde Unit No. 1 (Station Only) cost of $345,195,082 (without AFUDC; the amount is 15.8 percent of $2,184,779,000) appeared too high compared to PVNGS Unit 3 estimated cost of $1,577,502,000 and Unit 1 disbursed cost (without common) of $2,090,600,000. (Staff Ex. No. 5 at 20-22.)

Staff witness Candice Tye translated Mr. Boecker's recommendation into a $45,665,000 decrease to EPEC's plant in service request. She calculated an adjustment of ($40,887,000) to remove $26,925,000 cash; $20,248,000 related AFUDC; and ($6,286,000) Texas credits. Her reallocation of Unit 2 Texas credits to Units 1 and 3 was based upon the adjusted cash balances at September 30, 1986. Staff's adjustment of ($4,778,000) corrects the Company's use of what the staff characterized as an arbitrary allocation, that is, splitting the Texas credits equally between the two units. (Staff Ex. No. 12 at 2-3 and at Schedule IV).

Ms. Tye made an additional adjustment to plant in service in her supplemental testimony which reflected the recommendations of staff witness Morris H. Jacobs to disallow $28,000,000 in Palo Verde costs. The staff's final recommended original cost of plant in service was $951,080,147, a decrease of $73,665,000 from the Company's request.

This report concurs with the original cost of non-Palo Verde plant in service of $443,804,358. In addition, for the reasons discussed in Section VII of this report above, the report recommends an exclusion of 25 percent of the cash and gross AFUDC components of PVNGS Unit 1 and common facilities, and the reallocation of all PVNGS Unit 2 AFUDC Texas credits to Unit 1, as recommended by the City of El Paso. The report also recommends inclusion of all PVNGS transmission and general plant as requested by EPEC. The total used and useful plant in service recommended by the report is shown on Schedule IV attached to the order.

B. Accumulated Depreciation

The Company's request for $144,510,347 in accumulated depreciation was the per book amount. (EPEC Ex. No. 1, Vol. 7, Schedule B, as amended by EPEC Ex. No. 1A Errata Schedule B.) Included in this amount is $2,975,490 related to PVNGS production plant. (EPEC Ex. No. 1, Vol. 7, Schedule D-1.)

Mr. DeWard recommended an adjustment to increase accumulated depreciation by $4,841,682, which he believed was necessary to offset rate base by one-half the Company's pro forma adjustment to depreciation expense. In his opinion, there is not a proper matching because the Company would be allowed to recover through rates the full amount of pro forma depreciation expense without recognizing the monthly offset to rate base as the accumulated depreciation reserve increases. (City Ex. No. 6 at 21.)

On rebuttal, however, Mr. Johnson pointed out that this adjustment has been rejected by the Commission in recent dockets, most recently in <u>Petition of</u>

Houston Lighting and Power Company for Authority to Change Rates and Petition of Houston Lighting and Power Company for Approval of Proposed Interim Accounting Treatment for Limestone Unit 1, Docket Nos. 6765 and 6766, __ P.U.C. BULL. __ (December 4, 1986). In that case, a similar proposed adjustment to reduce rate base by increasing accumulated depreciation by one-half the recommended increase in depreciation expense was not adopted. (EPEC Ex. No. 41, Tab 8 at pp. 12-13.)

The staff's adjustments to accumulated depreciation were related to the staff's reclassification of common plant from PVNGS Unit 1 to Unit 3. During the test year, EPEC recorded depreciation on common plant in the New Mexico and FERC jurisdictions; the staff adjustment of $105,000 removes that depreciation related to the common plant removed by the staff. (Staff Ex. No. 12 at 3-4 and at Schedule IV.) In supplemental testimony, Ms. Tye recommended removal of an additional $148,400 in accumulated depreciation related to the $28,000,000 disallowance recommended by Mr. Jacobs. (Staff Ex. No. 26 at 1-2 and at Schedule IV Revised.)

This report recommends that the adjustment to accumulated depreciation proposed by the City be rejected. This adjustment does not take into account that EPEC has already lost an incremental depreciation expense over the level authorized in its last rate case. In addition, such an adjustment selects only one component to adjust because of regulatory lag and leaves others unadjusted, resulting in a mismatch.

The accumulated depreciation associated with PVNGS production plant should be adjusted to reflect the reasoning behind the recommended changes in plant balances for PVNGS Unit 1 and common facilities. The total accumulated depreciation recommended by this report is shown on the attached Schedule IV.

C. Nuclear Fuel in Process

EPEC's original request also included $19,199,070 in nuclear fuel in process in plant in service; at the hearing on the merits, EPEC provided amended schedules which removed the entire amount. (EPEC Ex. No. 1, Vol. 7, Schedule B, as amended by EPEC Ex. No. 1A Errata Schedule B.) City of El Paso witness DeWard made the same adjustment, evidently agreeing that since the Company will recover these expenditures from the nuclear fuel trust established to own the nuclear fuel and lease it to the Company (with repayment to the trust as the fuel is burned), the amount should be removed from rate base. (City Ex. No. 6 at 22.) Staff witness Kaplan also agreed that nuclear fuel in process should be removed from rate base. This report concurs.

D. Net Plant in Service

The total recommended net plant in service for the Company is shown on Schedule IV of the order.

E. Construction Work in Progress

The Company requested non-PVNGS construction work in progress (CWIP) of $17,543,727 in invested capital. Staff and City of El Paso witnesses removed the entire amount. This report concurs. EPEC presented no evidence that inclusion of this amount in invested capital was essential for protection of its financial integrity.

F. Working Capital

Mr. Johnson testified that EPEC's working capital calculation includes the 13-month average balance for fuel stock (coal only), materials and supplies and prepayments for the test year ended September 30, 1986. EPEC also hired the public accounting firm of Coopers & Lybrand to perform a lead-lag study for calculation of the cash working capital allowance. This lead-lag study shows that EPEC working capital requirements (excluding Palo Verde O&M) exceed the conventional one-eighth of O&M formula. Thus, EPEC included in working capital a cash working capital amount based on one-eighth of adjusted O&M expenses, excluding recoverable fuel costs, Palo Verde O&M expenses, and materials and supplies and prepayments charged to O&M expense. (EPEC Ex. No. 1, Vol. 4, Tab 21 at pp. 45-46; EPEC Ex. No. 1, Vol. 7, Schedules A-7 [Adjustment No. 33], E-1 and E-4.)

1. Fuel Inventory

EPEC requested $83,215 of fuel inventory (coal only). In his review of EPEC's coal management practices, Mr. Kaplan found problems with the force majeure stockpile at the Four Corners plant. It appears that this coal is so poorly maintained (for example, it has weeds growing out of it) that it would be difficult to load the coal onto the conveyors.

Further, left exposed to air, coal oxidizes and loses heat content. Although EPEC reports the heat content as 8974 btus per pound in its monthly fuel report for Four Corners, the plant operator's documents reveal that in 1978 the heat content of the coal was 8390 btus per pound - below the rejection level specified in the coal supply contract, and low enough to affect the performance of the plant. Mr. Kaplan believes it is unlikely this coal could supply the units at more than half load. EPEC appears to have been unaware of the problem until 1986.

According to Mr. Mattson's rebuttal testimony, EPEC considers the force majeure pile as only part of the coal reserves which would be available in the event of a prolonged interruption to mining operations, since there are significant reserves in the blend, surge, and field piles as well. Mr. Kaplan did not disagree with that, but pointed out that coal from the force majeure pile, which has a separate transportation system, would be required during periods of conveyor or electrical failures. EPEC believes short-term outages are not likely. Hoever, there has never been a major disruption in mining operations, and there have been two short-term stoppages requiring use of coal from the force majeure pile. EPEC's 1986 study considers these stoppages inconsequential. An additional study, authorized by the Four Corners owners, is under way to further evaluate the force majeure supply system.

In light of EPEC's claimed reliance on Four Corners as a base load plant, and the deplorable condition of the force majeure reserves, this report concurs with Mr. Kaplan's exclusion from rate base of $83,215 in coal stockpile working capital, an amount which represents EPEC's share of the force majeure pile.

2. Materials and Supplies

The Company requested $4,680,991 in invested capital for materials and supplies. Staff witness Tye recommended reducing this amount by $1,022,000 based on staff's review of an independent auditor's workpapers for the year ended December 31, 1986, which indicated that $1,500,000 of inventory had been inactive for two years. Of that amount, $478,000 was found not obsolete. The remaining $1,022,000 was considered immaterial and was not written off. Ms. Tye referred to the Touche Ross Management audit which contained a discussion of $1.4 million in inactive or "dead" stock, and found that "inventories of 'critical' or 'strategic' spares are not classified and managed accordingly." It was Ms. Tye's opinion that ratepayers should not be required to pay a return on obsolete inventory because the Company cannot distinguish between "dead" stock and "strategic spares." She included $3,658,991 in materials and supplies.

On rebuttal, EPEC witness Gregg Forszt testified that a strategic spare part classification system has been established. Strategic spares are separately classified and maintained in two separate warehouses so such spare parts can be easily identified and not comingled with other inactive inventory. Even though they are considered strategic spares, these items are included in the Company's inactive stores report when there has been no activity for two years. Mr. Forszt testified that currently there is only $64,000 in inventory which has been inactive for two years and is not considered strategic or critical. According to this witness, this inactive inventory was not found to be obsolete by the independent auditors and was not written off. (EPEC Ex. No. 41, Tab 2 at pp. 10-11.)

The independent auditor's report these witnesses referred to (done by Peat, Marwick & Mitchell) found that $1,022,000 in inactive inventory was immaterial and should not be written down. The report did not find that amount "not obsolete." Out of the $1,500,000 in inactive inventory, only $478,000 (for a Pace Steam Turbine) was found "not obsolete." There is a difference between materiality for accounting and financial reporting purposes and reasonableness of amounts included in invested capital and paid for by ratepayers in return. Ms. Tye's recommended reduction should be made.

3. Prepayments

The Company's $5,264,656 request for prepayments included prepayments for occupational and street rental tax for the Towns of Clint and Vinton and interest on commercial paper. Based on the Commission's last two rate orders for EPEC, Ms. Tye made adjustments for both these items.

The occupational and street rental taxes due the Towns of Clint and Vinton are due on the fifteenth day of February following the year for which they are payable. Accordingly, staff reduced the 13-month average of prepayments by a total of $54,872 ($3,241 for Clint and $51,631 for Vinton). In addition, staff made a $127,211 reduction in the 13-month average for interest on commercial paper, as it is a below-the-line item for ratemaking purposes and should not be included in calculating prepayments. The staff's adjustments to prepayments total $182,083 for a recommended prepayments amount of $5,082,569. The report agrees with the staff's amount for prepayments.

4. Cash Working Capital Allowance

The terms "cash working capital" and "working cash allowance" refer to the component of working capital allowance discussed in P.U.C. SUBST. R. 23.21(c)(2)(B)(iii), which reads in pertinent part:

> A reasonable allowance up to one-eighth of total annual operations and maintenance expense for electric . . . utilities, . . . excluding amounts charged to operations and maintenance expense for materials, supplies, fuel, and prepayments. The factor applied to operations and maintenance expense may be reduced to reflect certain billing practices, such as prebilling of local charges in the case of telephone utilities. Alternative methods of establishing an allowance, including, but not limited to, lead-lag studies and balance sheet methods may be used or required by the commission. Operations and maintenance expense does not include depreciation, other taxes, or federal income taxes. The amount for operations and maintenance expense may be reduced for fuel expense, depending on the method for recovering fuel costs from the consumer, and for other items.

In theory, a lead-lag study can be tailored to determine the working cash needs of a utility. A study analyzing the timing of cash receipts and expenditures for a utility's operating transactions would produce a positive working cash allowance if funds are expended before compensation is received. Conversely, a negative working cash allowance would be produced if revenue is received before the utility pays the associated costs of providing service.

EPEC hired the accounting firm of Coopers and Lybrand to perform a lead-lag study for use in this docket. This lead-lag study utilized the results of a previous study by this firm, done in 1984 and used in Docket No. 6350. EPEC witness Dale Schaefer, a general practice manager in the Austin office of Coopers & Lybrand, presented the lead-lag study in this docket, adopting the prefiled testimony of Alvin Bledsoe, a partner in Coopers & Lybrand, and sponsoring his own testimony on rebuttal. (EPEC Ex. No. 1, Vol. 5, Tabs 30 and 31; Tr. at 488-510; on rebuttal, EPEC Ex. No. 41, Tab 11; Tr. at 2424-2441.) The Company's original lead-lag study produced a cash working capital amount of $22,771,254; this was later revised to $20,652,171. Because this amount exceeds the amount calculated using the conventional one-eighth of O&M formula and EPEC's requested O&M, EPEC's cash working capital request, calculated using the one-eighth rule, is $8,191,748, as revised. (As originally filed, it was $8,333,401.)

City of El Paso witness Hugh Larkin, Jr., CPA and partner in the accounting firm Larkin and Associates, Livonia, Michigan, presented the testimony on the working capital component of invested capital, particularly focusing on EPEC's lead-lag study. Mr. Larkin articulated several criticisms of the procedures used and the conclusions reached in EPEC's lead-lag study, and made revisions to the original lead-lag study filed with the Company's rate filing package. Mr. Larkin's amendments to the Company's procedures and amounts produced a cash working capital amount of ($2,757,090), that is, a negative amount. (City Ex. No. 5 at Exhibit HL-1, Schedule 3.)

Staff witness Tye reviewed the lead-lag study filed by EPEC and made some changes, similar to those made by Mr. Larkin, to account for several events not considered in the original analysis. (Staff Ex. No. 12; Tr. at 1883-1929.) (Mr. Schaefer agreed with several of those changes and incorporated them into his calculations, thus producing the revised amounts.) Ms. Tye derived a working cash allowance of $14,550,793, an amount which was, like EPEC's, in excess of that which would be generated by use of the one- eighth of O&M formula. (Staff Ex. No. 12 at Exhibit CT-2.) She therefore recommended use of that formula, using staff's revised recommended amounts for the components, to calculate her recommended working cash allowance of $6,746,138. (Staff Ex. No. 12 at Exhibit CT-1; Staff Ex. No. 26 at Schedule CT-1 Revised.)

According to the Company, the new lead-lag study is a fully developed study, including depreciation, deferred taxes, return, and cash allowances; the 1984 study included only the components of O&M, other taxes and current federal income taxes. In addition, the new study incorporates certain changes in the 1984 study which were recommended by the Commission in Docket No. 6350, such as the inclusion of the "check-cleared" date for use in determining expense lag days, exclusion of non-cost of service items from the outside services and operating rents categories, elimination of all working capital requirements for operating expenses in the nature of amortizations of asset accounts and, based on Mr. Larkin's recommendation in Docket No. 6350 (adopted by the Commission), inclusion of a negative working capital requirement for interest expense. Mr. Schaefer considers the last adjustment to have been inappropriate in the study used in Docket No. 6350, however, because other cost of money items (preferred dividends and earnings on common) were not considered; thus, the resulting working capital was erroneously understated. Mr. Schaefer's opinion is that cost-of-money items can be included or excluded from a lead-lag study (and in fact, often are excluded, on the theory that working capital requirements related to below-the-line items should not be considered in determining revenue requirements to be paid by utility customers) but *if* the Commission includes an adjustment for *one* cost-of-money item (interest) *all* elements of cost of money should be included.

Mr. Schaefer also included amortizations in the lead-lag study, based on his belief that there is an investment for which the Company will not be compensated if it is excluded, and he explained his position on this question at some length, hoping to persuade the Commission to reconsider its position on this question. Finally, Mr. Schaefer included cash balances in his study, since day to day collections and payments can never be synchronized. His testimony in- cluded a detailed description of the lead-lag study procedures and results by category. (EPEC Ex. No. 1, Vol. 5, Tab 30 at pp. 14-37.)

Mr. Larkin's testimony was based on the lead-lag study as it was originally filed by EPEC. His major criticisms were that:

- the Company had not incorporated a known reduction in the number of days between meter reading and billing in its development of the revenue lag;

- in the development of the expense lag, the Company reflected payments of employees' vacations, which have substantial lead time, at the same expense lag as regular payroll;

- the expense lag included numerous expenses which do not require cash outlays and should not be considered in determination of the cash working capital requirements, such as amortization of prepayments and materials and supplies charged to expense, uncollectible accounts expense, and depreciation and deferred income taxes;

- the expense lag failed to include the expense lag related to its lease payment on PVNGS Unit 2 (which Mr. Larkin believes to be made in arrears, not in advance as stated by EPEC); and

- the Company had improperly included in the expense lag a daily working cash requirement related to common equity return.

Ms. Tye also reviewed the original lead-lag study filed by EPEC and made revisions to the revenue lag based upon three events occurring after the original study had been done. These were a reduction in the billing lag, as noted by Mr. Larkin and a reduction in the collection lag. She also included accounts receivable balances and sales for wholesale customers (although EPEC did not) based on her opinion that revenue lag days must reflect the payment patterns of all customers since the days are applied to a total company revenue requirement and not to a revenue requirement for retail customers only. Staff's recommended revenue lag is 44.0 days. (On rebuttal, Mr. Schaefer changed the Company's revenue lag days to 46.4.) Ms. Tye also made adjustments to components of expense lag as calculated by EPEC. She agreed with the inclusion of cash balances.

There was a great deal of testimony in this record about whether the lead-lag methodology proposed by the staff in Docket No. 6765 (citation below) was a fully developed approach or a cash only approach, and whether the staff's proposal in this docket is consistent or inconsistent with its proposal in the HL&P case. The Examiners' Report in Docket No. 6765, however, notes with approval that the staff removed all non-cash items. (Examiners' Report at 104-105.) Since the Commission has consistently rejected attempts to include non-cash items in a lead lag study (<u>Application of Gulf States Utilities Company for a Rate Increase</u>, Docket No. 5560, 10 P.U.C. BULL. 405 at 445-446 [July 13, 1984]; <u>Application of Texas Utilities Electric Company for a Rate Increase</u>, Docket Nos. 5640 and 5661, 10 P.U.C. BULL. 659 at 718-724 [November 19, 1984]; <u>Petition of Houston Lighting and Power Company for Authority to Change Rates</u> and <u>Petition of Houston Lighting and Power Company for Approval of Proposed Interim Accounting Treatment for Limestone Unit 1</u>, Docket No. 6765, _____ P.U.C. BULL. ______; [December 4, 1986]; <u>Application of West Texas Utilities Company for Authority to Change Rates</u>, Docket No. 7510, _____ P.U.C. BULL. ______ [January 12, 1988]), the same items should be excluded from the lead-lag studies done here. In addition, even though all three witnesses in this case included interest on long-term debt and preferred stock dividends, the Commission in Docket No. 7510 rejected those items as "non-cash"; they should be removed from the studies done here as well. Although there are some adjustments which could be made to each study to make it better, on balance, Mr. Larkin's adjustments to EPEC's study come the closest to complying with the Commission's practice with respect to the proper components of a lead-lag study. The report recommends adoption of Mr. Larkin's finding of a cash working capital requirement of ($2,757,090), a decrease of $10,948,838 to EPEC's amended request of $8,191,748.

The Company had requested that, because its lead-lag study had produced a cash working capital amount so far in excess of that which would be permitted under the Commission's substantive rules, in future cases it be permitted to calculate its cash working capital using the one-eighth formula permitted in the rules. The lead-lag study presented by the Company here, however, simply does not comply with the lead-lag studies the Commission has approved in prior dockets. This report recommends that in its next rate case, EPEC should utilize a cash-only analysis consistent with Commission orders in prior dockets in which this issue has been considered.

5. Summary of Working Capital Allowance

This report recommends a total working capital allowance of $5,984,470, calculated as follows:

Fuel Inventory	$ 0
Materials and Supplies	3,658,991
Prepayments	5,082,569
Cash Working Capital	<u>(2,757,090)</u>
Total	$ 5,984,470

G. Unamortized Deferrals

EPEC's revised requested amount for the unamortized balance of deferred carrying costs for PVNGS operations and maintenance expense and PVNGS Units 1 and 2 plant was $37,872,608, a slight increase from the original request of $35,353,461. (EPEC Ex. No. 1, Vol. 7, Schedule B, line 17; EPEC Ex. No. 1A Errata Schedule B, line 17.)

Ms. Tye recommended inclusion in rate base of the unamortized balance of deferred carrying costs for Palo Verde O&M and for PVNGS Unit 1 plant at test year end as adjusted for staff's recommended disallowance. (Staff did not recommend inclusion of any PVNGS Unit 2 plant or O&M.) Deferred carrying costs on O&M and on plant were recommended by the staff to be $13,822,738. (Staff Ex. No. 26 at Schedule IV Revised.)

Mr. DeWard recommended removal of $28,866,158 from the amount originally requested in order to exclude all amounts relating to Unit 2 and to include in the Unit 1 deferrals the full balance of the Texas AFUDC credits associated with Unit 2, in addition to the amounts of CWIP included in rate base which had previously offset PVNGS Unit 2 AFUDC accruals. (City Ex. No. 6 at 22-26 and at Exhibit TCD-1, Schedules 13 and 38.)

As discussed in greater detail in Section XI.B.8. of this report below, it is recommended that the Company's calculations of the amortization of deferrals be used in finding O&M expense; thus, it is consistent to adopt the Company's calculations of the unamortized deferral balances. The total to be included in invested capital is $37,872,608.

H. Accumulated Deferred Federal Income Tax

EPEC calculated $143,352,028 in accumulated deferred federal income tax (ADFIT). (EPEC Ex. No. 1A Errata Schedules A, A-1, and A-7; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 34.)

Mr. DeWard proposed two adjustments to deferred income tax liability. The first is to match two components of rate base. The deferred income tax liability is increased because EPEC, although accruing AFUDC on the Unit 1 deferral subsequent to September 30, 1986 and continuing through October 31, 1987, failed to offset the deferral with the deferred income taxes associated with ABFUDC. (This adjustment had to be modified to reflect the disallowances proposed by other City of El Paso witnesses.)

Second, in Mr. DeWard's view, the deferred income tax liability must be reduced by three adjustments which reduce deferred tax balances. (The specific adjustments are discussed below in Section XI.I. below on income taxes.) Consistent with his adjustment to accumulated depreciation, he reduced these adjustments to reflect one-half of the pro forma adjustment. A similar adjustment to reduce the taxes associated with ABFUDC subsequent to September 30, 1986 is not required because EPEC included the full balance of deferrals as of October 31, 1987. (City Ex. No. 6 at p. 27; at Exhibit TCD-1, Schedules 2 and 14.

In supplemental testimony, staff witness Candice Tye explained that the staff's previous recommendation regarding ADFIT (which showed no adjustment to EPEC's request) had been amended to reflect the staff's recommended $28,000,000 disallowance of PVNGS plant. Because the disallowance causes the shareholders to pay for this amount of PVNGS, the related tax benefit should also be assigned to the shareholder in the staff's opinion. The staff recommended amount for ADFIT to be included in invested capital is $(140,249,851). (Staff Ex. No. 26 at 2-3 and at Schedule IV Revised.)

Because this report recommends a greater disallowance of PVNGS plant than does the staff, the ADFIT should be adjusted as well. Dividing the dollar amount of plant excluded by this report by the amount recommended by the staff to be excluded and multiplying that result by the staff's adjustment to ADFIT produces the adjustment shown on Schedule IV attached to the proposed order.

I. Other Uncontested Invested Capital Items

The amounts requested by EPEC in the following categories were not contested or adjusted by the City or the staff. They operate as reductions to invested capital. This report finds them reasonable and recommends their adoption. These items and amounts are as follows:

Pre-1971 Investment Tax Credits	($651,847)
Injuries and Damages Reserve	($100,000)
Customer Deposits	($3,298,722)
Customer Advances for Construction	($1,027,910)
Other Deferred Credits	($1,604,411)

(EPEC Ex. No. 1, Vol. 7, Schedule B and Schedule B-2 at pp. 3-6; City Ex. No. 6

at Exhibit TCD-1, Schedule 2; Staff Ex. No. 26 at Schedule IV Revised; Staff Ex. No. 28 at Schedule IV Revised.)

J. Summary of Invested Capital

The total invested capital recommended by this report is shown on Schedule IV of the order.

X. Return

A fair rate of return on invested capital can be defined as that return which results in no confiscation of invested capital and causes no economic exploitation of the consumer; insures an adequate cash flow consistent with the needs of a company; is consistent with the returns available on similar investments at comparable risk levels; and preserves the utility's ability to attract new capital at reasonable cost. Additionally, a fair rate of return does not compensate current investors for a company's past operating performance, does not rectify the results of prior management error, and does not guarantee a level of earnings. The rate of return gives the company the opportunity to earn a fair return on invested capital.

The following witnesses presented testimony on the issues relating to capital structure and cost of capital: for the Company, Robert W. Peticolas, Supervisor of Financial Forecasting and Budgeting for the Company (EPEC Ex. No. 1, Vol. 4, Tab 23; EPEC Ex. No. 1, Vol. 7, Schedules F and F-2 through F-9; EPEC Ex. No. 1, Vol. 8, Schedule N; as amended by EPEC Ex. No. 1A Errata Schedules A and A-1 and by EPEC Ex. No. 1B Errata; Tr. at 359-375); Robert S. Jackson, Senior Vice President of Stone & Webster Management Consultants, Inc. (EPEC Ex. No. 1, Vol. 4, Tabs 24 and 25; EPEC Ex. No. 1, Vol. 7, Schedule F-1; Tr. at 312-356; on rebuttal, EPEC Ex. No. 41, Tab 7; Tr. at 2065-2127); William J. Johnson (on rebuttal, EPEC Ex. No. 41, Tab 8 at 1-6; Tr. at 2445-2484); for the Department of Defense (DOD), Philip R. Winter, Operations Research Analyst in the Office of Procurement, Rate Case Division, General Service Administration (DOD Ex. No. 1; Tr. at 796-891); for the City of El Paso, Basil L. Copeland, Jr., economist specializing in energy and utility economics and a principal in Chesapeake regulatory Consultants, Inc. (City Ex. No. 4; Tr. at 915-1074) and Thomas C. DeWard (City Ex. No. 6 at 9-15 and at Exhibit TCD-1, Schedule 7); Tr. at 1116-1357); and for the Commission, Eugene Bradford, Financial Analyst in the Operations Review Division of the Commission (Staff Ex. No. 6; Tr. at 1358-1466).

These issues were briefed by the Company (Applicant's Phase I Brief at 82-116; Applicant's Reply Brief at 4-6); the City of El Paso (City's Phase I Brief at 3-26; City's Reply Brief at 26-31); DOD (Phase I Brief at 3-7); and general counsel (Reply Brief [Phase I and Phase II] at 2-5).

The recommendations in this section are based on the most credible and appropriate aspects of the testimony of the witnesses, and are made in accord with the standards set forth in PURA §39 and P.U.C. SUBST. R. 23.21(c).

A. Capital Structure

Upon taking the witness stand, Company witness Robert Peticolas amended the original capital structure originally proposed by EPEC. The amendment was made to reflect the redemption of two very high coupon first mortgage bonds totaling $100 million. This debt was comprised of a $40 million mortgage bond issue at 16.35 percent and a $60 million mortgage bond issue at 16.20 percent. The redemption was made with the proceeds of the sale/leaseback of PVNGS Unit 2. (EPEC Ex. No. 1B Errata Schedule F; Tr. at 360-365, 367-368.) The Company's proposed capital structure is as follows:

	Amount (000s)	Percent of Total
Long-Term Debt	$ 642,298	46.73
Preferred Stock	$ 134,183	9.76
Common Equity	$ 598,024	43.51
Totals	$1,374,505	100.00

(EPEC Ex. No. 1B Errata Schedule F.)

City witness DeWard criticized the Company's redemption of long-term debt (although he made no change in that component of EPEC's capital structure), and he made three adjustments to the Company's common equity capitalization amount. (City Ex. No. 6 at 9-15 and at Exhibit TCD-1, Schedule 7.) In Mr. DeWard's opinion, EPEC could have refinanced long-term debt by issuing lower cost debt and using the proceeds to redeem the high cost debt. On rebuttal, however, Mr. Johnson pointed out that the $60 million bond issue prospectus prohibited that sort of redemption prior to August 1, 1987. (EPEC Ex. No. 41, Tab 8 at 1-2 and at Exhibit WJJ-1.) And although Mr. DeWard testified that a number of utilities had refinanced long-term debt by issuing lower cost debt and using the proceeds to redeem the high cost debt, he did not identify the utilities which had done this and he did not know if a premium would be involved in such a redemption. Additionally, Mr. Johnson testified on rebuttal that had the sale/leaseback for PVNGS Unit 2 not been completed, EPEC would not have had the cash to redeem the $40 million/16.35 percent interest bond issue on May 1, 1987, or to retire the additional preferred stock through sinking fund purchases. (EPEC Ex. No. 41, Tab 8 at 3; EPEC Ex. No. 1B Errata Schedule F-4, p. 1 of 2; Tr. at 369.)

Mr. DeWard also pointed out that EPEC did not repurchase common equity with the proceeds from the sale/leaseback, but invested a portion of them in non-utility operations. He also believed that EPEC's redemption of long-term debt was not as beneficial as it might seem at first. Even though the redemption reduced the cost of long-term debt from 10.20 percent to 9.22 percent (based on a Company response to a City RFI), interest is deductible for tax purposes while the return requirements associated with preferred stock and common equity are not. A comparison of the pre-tax rate of return of EPEC's originally proposed capital structure with the pre-tax rate of return for the amended capital structure shows only a slight decrease. Mr. DeWard concluded that the overall impact on rates of the redemption is significantly less than it might appear, because as one element of the capital structure is reduced, the weighting of the other elements is increased.

In Mr. DeWard's opinion, the adjustments to EPEC's capital structure were required to prevent ratepayers from being penalized, through higher return requirements, by EPEC's decision to make non-utility investments instead of re purchasing outstanding common stock with the proceeds from the sale/leaseback. Essentially, he proposed adoption of a capital structure for ratemaking purposes adjusted *as if* EPEC had repurchased common stock. He therefore removed a total of $78.838 million from EPEC's proposed $598.024 million in common equity. First, he removed the undistributed earnings of FL&R from common equity so that ratepayers would not be required to pay a return requirement on this non-regulated entity. Second, Mr. DeWard removed the $10 million which EPEC segregated on its books to be used in the operation of the Rio Bravo Industry Development Corporation. (This organization promotes and implements the retention and expansion of existing business and industry, and locates, develops, attracts and/or acquires new businesses and industries to West Texas and Southern New Mexico.)

Third, Mr. DeWard removed $60 million representing EPEC's subsidiary's investment in the preferred stock of Commercial Federal Savings and Loan Association, the parent company of Commercial Federal Investment Corporation, an equity participant in the sale/leaseback of PVNGS Unit 2. (Commercial Federal Investment Corporation made a $30,777,030 equity investment in the sale/leaseback; EPEC's subsidiary made a $60 million investment in the preferred stock of its parent company.) Because EPEC chose not to redeem common stock, some of which was necessarily issued to finance the construction of PVNGS, but instead used proceeds of the sale/leaseback for non-utility investments and operations, Mr. DeWard believed it was necessary to reduce common equity by the amount of these non-utility investments so that ratepayers would not be subject to the higher return requirements to finance these investments. (City Ex. No. 6 at 13-14 and at Exhibit TCD-1, Schedule 7.) He proposed a capital structure as follows:

	Amount (000s)	Percent of Total
Long-Term Debt	$ 642,298	49.57
Preferred Stock	$ 134,183	10.36
Common Equity	$ 519,186	40.07
Totals	$1,295,667	100.00

Mr. Winter accepted EPEC's capitalization amounts for long-term debt, preferred stock, and common equity, but added $27 million in short-term debt to

EPEC's capital structure. He included short-term debt (even though the Company did not) because EPEC has had short-term debt outstanding on December 31 of each year from 1981 through 1985 (with balances ranging from $35 million to $106 million), and projects a short-term debt balance at the end of each fiscal year through 1990 (with balances ranging from $13 million to $112 million). (DOD Ex. No. 1 at 4; EPEC Ex. No. 1, Vol. 8, Schedule N at 1.) In Mr. Winter's view, the absence of short-term debt is the exception rather than the rule, and he included $27 million (1.91 percent) as a component of EPEC's capital structure. Mr. Winter did not provide capitalization amounts for any capital structure components other than short-term debt, but he testified that he used those proposed by EPEC, including the redemption of the $100 million in long-term debt. DOD recommended a capital structure as follows:

	Percent of Total
Long-Term Debt	45.40
Short-Term Debt	1.91
Preferred Stock	9.48
Common Equity	43.21
Total	100.00

(DOD Ex. No. 1 at 3-4 and at Schedule 1.)

Mr. Bradford utilized EPEC's actual capital structure as of March 31, 1987, which was provided to him in the Company's response to General Counsel's Sixteenth Request for Information, question EB-1. He viewed the capital structure as of that date as more appropriate for use in this case because it is more reflective of the capitalization that will exist when rates set in this docket go into effect than is the capital structure as of September 30, 1986. In addition, Mr. Bradford removed the retained earnings for FL&R, as had Mr. DeWard, although he did not make any other adjustments to common equity capitalization. His proposed capital structure is as follows:

	Amount (000s)	Percent of Total
Long-Term Debt	$ 642,298	46.521
Preferred Stock	$ 134,183	9.719
Common Equity	$ 604,185	43.760
Totals	$1,380,666	100.000

(Staff Ex. No. 6 at 20-21 and at Schedule IX.)

This report recommends that the Commission not adopt any of the proposed adjustments to common equity. First, removal of the undistributed earnings of FL&R is not appropriate, since it is the total structure of the Company (and not just the regulated portion) which investors view. In addition, the City's removal of an additional $70 million ($10 million representing the segregation of funds for the Rio Bravo Foundation and $60 million representing the transfer to an EPEC subsidiary for investment in the preferred stock of Commercial Federal Savings and Loan Association) should not be made. Mr. DeWard's adjustments were made on the basis of his belief that EPEC should have done something else with the proceeds from the sale/leaseback, namely, that the Company should have repurchased outstanding common stock. However, purchase at a price higher than book value dilutes the equity of the remaining shareholders, which Mr. DeWard conceded (Tr. at 1129), and EPEC's common stock price was well over book for much of 1987, according to Mr. Peticolas. (Tr. at 370-371.) Additionally, EPEC has a high debt ratio in its capital structure, which tends to increase the riskiness of EPEC and therefore the cost of capital. (Staff Ex. No. 6 at Schedule II, p. 1 of 2.)

Further, the $10 million and $60 million investments were made from the proceeds of the sale/leaseback, the $60 million investment entirely from the gain portion. As the "book break-even" analysis demonstrates, EPEC's ratepayers will not provide any revenue associated with the gain portion of these proceeds. Removal of the $60 million reduces the equity portion of the composite cost of capital, thus lowering the allowed rate of return on rate base and the corresponding revenues provided by the ratepayers. Because the ratepayers are not paying EPEC for the cost of the gain funds, Mr. DeWard's adjustment gives ratepayers a benefit to which they are not entitled. Further, because EPEC's rate base has been reduced by the book cost of PVNGS Unit 2, application of the composite cost of capital to rate base provides recovery of only a portion of the capital costs. The composite cost of capital associated with the book cost of PVNGS Unit 2 becomes EPEC's obligation. Finally, the effect of removing $78.838 million from common equity reduces the Company's operating income and increases its costs. (EPEC Ex. No. 41, Tab 8 at 3-6 and at Exhibit WJJ-3; Applicant's Phase I Brief at 4-14; General Counsel's Reply Brief [Phase I and Phase II] at 3-5.) Short-term debt should not be included in EPEC's capital structure, because short-term debt was not used in the Company's capital structure in its last rate case. (City Phase I Brief at 9.) The credible evidence supports use of the Company's proposed capital structure, as set forth above.

B. Cost of Long-Term Debt

At the hearing on the merits, Mr. Peticolas amended the Company's weighted average cost of long-term debt to 9.18 percent. (EPEC Ex. No. 1B Errata Schedules F and F-6.) As originally filed, the weighted average cost of long-term debt was 10.20 percent. The amendment reflected the redemption of the two high coupon first mortgage bonds discussed in Section X.A. above. In addition, Mr. Peticolas testified that he had amended the rates on EPEC's floating notes which had been incorrectly stated. (Tr. at 364-365.)

City witness DeWard based his recommended 9.22 percent cost of long-term debt on the Company's response to the City of El Paso's Fifth Request for Information, Question 47. (City Ex. No. 6 at 12 and at Exhibit TCD-1, Schedule 7.) In its initial brief, however, the City proposed use of the 9.18 percent cost of long-term debt. (City's Phase I Brief at 9.)

Mr. Winter, DOD's witness, originally recommended 9.22 percent, based on EPEC's answer to the City's RFI noted above, but at the hearing on the merits, he amended his proposal to 8.68 percent. (Tr. at 798-799.)

Staff witness Bradford based his recommendation of 8.672 percent as the cost of long-term debt on the same RFI response noted above, and on the Company's response to General Counsel's Tenth Request for Information Question EB-9. (Staff Ex. No. 6 at 21 and at Schedules VIII and IX.)

The credible evidence in the record supports use of 9.18 percent as the cost of long-term debt, as proposed by EPEC and agreed to by the City. That cost is based on the most recent changes in the Company's long-term debt, including the redemption of $100 million in first mortgage bonds and the correction of the floating note rates. The report recommends adoption of this cost.

C. Cost of Preferred Stock

The parties agreed that EPEC's cost of preferred stock is 9.88 percent (EPEC Ex. No. 1B Errata Schedules F and F-4; City Ex. No. 6 at Exhibit TCD-1, Schedule 7; DOD Ex. No. 1 at Schedule 1; and Staff Ex. No. 6 at Schedule IX) and this report recommends adoption of that cost.

D. Cost of Equity

Messrs. Jackson, Winter, Copeland, and Bradford all began their determinations of a fair rate of return on the common equity portion of EPEC's capitalization using a discounted cash flow (DCF) analysis. The DCF theory holds that the price of a share of common stock is equal to the present value of all its future dividends. These dividends are assumed to grow at a constant rate (g) into infinity, and the discount rate (k) is the minimum return required by investors given the risk of the security. This model recognizes that the return to the shareholder consists of dividend yield and growth. Equity investors expect to receive a portion of their total required return in the form of current dividends, and the remainder through price appreciation. The model makes two assumptions: first, that investors evaluate the risk and expected return of all securities in the capital markets; then, given these expected returns, investors adjust the price of each stock in order to be adequately compensated for the risks to which they are exposed. The market reveals what investors think a share of EPEC's common stock is worth; thus, the rate of return required by investors can be imputed by approximating their expectations of future dividend growth. The use of the DCF model to estimate the cost of equity is an attempt to duplicate these market pricing mechanisms.

Each witness made modifications to either the DCF model itself or to the results obtained from its use, making direct comparisons of their recommendations difficult. A summary of each party's position follows.

1. The Company's Request

When he took the witness stand at the hearing on the merits, Mr. Jackson amended his testimony regarding the cost of equity for EPEC. In his prefiled direct testimony, included with the Company's rate filing package, Mr. Jackson had recommended a cost of equity of 13.7 percent. At the hearing, however, he stated that he had updated his data, and was amending his recommended cost of equity to 13.25 percent.

Mr. Jackson summarized the DCF theory as stating that the sum of the anticipated growth rate and current yield produces a figure often called the "investor's required return," or the cost rate of common equity capital. If that cost rate is earned by the utility, it will produce a market value approximately equal to the book value of the stock. The rate of growth used in the DCF model is based on historical results, those which produce the current market/book relationship. That rate of growth combined with an unadjusted yield understates the cost of equity, since it does not recognize the need for common stock to command a market price in excess of book. In Mr. Jackson's opinion, if the current cost of common equity is to be realistically measured using DCF techniques, it is necessary to make adjustments to the yield data.

The underlying financial problem for EPEC, according to Mr. Jackson, is the continuing lack of cash flow. For example, one of Standard & Poor's quantitative tests of financial strength for electric utilities is the relationship of annual cash flow to invested capital, pre-tax coverage of interest charges, and the amount of debt leverage. The S&P standard for "BBB" quality rating requires pre-tax coverage of interest charges of from 1.5 times to 3.0 times. The Company had coverages during the years 1983, 1984, and 1985 of 1.9 times, 1.6 times and 1.6 times, respectively, barely qualifying for the lowest investment grade standard. The "BBB" standard for debt leverage is a range of from 50 percent to 58 percent, compared with actual Company ratios of 53 percent, 52 percent, and 56 percent for the years listed above. And finally, using the relationship of cash flow to invested capital, EPEC fails even the "BBB" standard. EPEC had negative results in each of these three years, far below the 2.5 percent to 6.0 percent S&P standard. In September 1986, S&P lowered the senior debt rating from "BBB+" to "BBB," the third derating of EPEC debt in the last two years. In Mr. Jackson's view, the Company's current level of earnings and cash generation is inadequate.

Mr. Jackson began his analysis by developing that cost for a group of comparison utilities, then translating that cost to its equivalent for EPEC. Because this Company must compete for funds in the marketplace, its cost of equity capital can be found through a market-oriented DCF study of comparison companies. These comparison companies were selected from the latest Value Line editions from the electric utilities of which EPEC was one of the 50 such companies listed. The three selection criteria were:

- Timeliness - a ranking from 1 to 5 (highest to lowest) referring to a stock's relative market performance in the year ahead. EPEC's timeliness ranking is 3.

- Safety - a ranking from 1 to 5 (highest to lowest) which considers the stability of market price, company size, financial leverage, earnings quality, overall condition of the balance sheet, etc. EPEC's safety ranking is 4.

- Common stock beta - this is a measure of the sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange composite average. The beta for the 50 companies ranged from 0.50 to 0.90; the beta for EPEC was 0.70.

Mr. Jackson selected comparison companies with timeliness and safety rankings and betas one step higher or lower than EPEC's; 16 companies met those standards. He then calculated annual growth rates for each of the comparison companies for per share earnings, dividends, and book value for several time periods ending in 1986 and as estimated for the future. The historic rates of growth were calculated using the "least squares" methodology in which all of the intervening periods are considered; growth rates were calculated for long-term and short-term periods. Actual growth rates were used for the periods 1975 through 1986, 1980 through 1986, 1982 through 1986; estimated growth rates were used for the period 1987 through 1991.

Mr. Jackson presented the dividend growth rates for each of the comparison companies and for EPEC for several time periods ended 1986, and estimated for the future. The weighted average gives equal weight to each of the actual rates of growth, and a weight of one-half was assigned for the estimated growth rate; negative growth rates were omitted. Although he calculated annual rates of growth in per share earnings and book value, using the same methodology as he used for dividends, he used dividend growth rate in this DCF analysis. He chose dividend growth rate, which was generally between that of earnings and book value in this DCF analysis, because it is more stable over time. Rate decisions, weather, and market prices of securities may all have a dramatic impact on earnings and book value, resulting in wider fluctuations than in dividends. The average growth rate was 3.32 percent; EPEC's was 4.52 percent.

Based on dividends paid and average monthly market prices for the most recent 12 months ended June 30, 1987, Mr. Jackson found the average yield for companies within his comparison group to be 7.71 percent. EPEC's yield was 8.35 percent.

The DCF theory states that the sum of growth and yield produces a cost rate, which, if earned, should result in a market price equal to book value. For the comparison group, the sum of the growth rate of 3.32 percent and the yield of 7.71 percent produces an average DCF cost rate of 11.03 percent. For EPEC, the sum of growth and yield is 12.87 percent.

Based on his review and analysis of several years' worth of data, it was Mr. Jackson's opinion that a market/book ratio of 1.00 is insufficient. The major factor which indicated that a higher ratio is required is the recognition of selling costs, that is, the direct expenses for legal, accounting, and printing costs, plus the underwriting spread incurred with the public offering of common stock. For EPEC, the selling costs ranged between 3.7 percent and 8.0 percent, and averaged 5.1 percent for the nine public offerings since 1977. Mr. Jackson utilized what he termed a conservative market/book range of 1.05 to 1.10, the minimum necessary for the Company to issue stock on non-dilutive terms. This adjustment is applied to the yield portion of the DCF, rather than to the total DCF cost rate.

Combining the adjusted yield component and the growth component produces an indicated total cost of common equity under the DCF approach. For his comparison companies, the indicated current cost ranges from 11.43 percent at a market/book ratio of 1.05 to 11.88 percent at a market/book ratio of 1.10. For EPEC, the equivalent cost is from 13.30 percent to 13.79 percent. The "net proceeds" test for EPEC (based on the specific common stock issue costs of the Company) produces an indicated cost rate of 13.71 percent. The market price of the common stock of the comparison companies increased from October 1985 to September 1986 by 40.4 percent. During the same period, the Dow Jones Utility Index rose by 29.1 percent and the Dow Jones Industrials by 30.2 percent. The normalized DCF cost for the group, ranging from 11.99 percent at a market/book of 1.05 to 12.48 at 1.10, substitutes an average market price increase of 30 percent for the 40 percent actual increase which Mr. Jackson termed abnormal, and a yield of 9.12 percent for the 8.53 percent used in the DCF study. EPEC's stock increased from $13.81 in October 1985 to $18.06 in September 1986, an increase of 30.8 percent.

Because the result for a group of companies is more meaningful than that for an individual company, Mr. Jackson determined that a fair and reasonable return for EPEC is 13.25 percent, based on the updated information which he presented at the hearing on the merits. (EPEC Ex. No. 1, Vol. 4, Tabs 24 and 25; Tr. at 312-356.)

2. City of El Paso Position

City witness Basil F. Copeland, Jr., had a principal recommendation of a cost of equity of 12.7 percent for EPEC. This was qualified, however, and was his recommendation only if the Commission accepts the rate base and revenue adjustments for imprudence recommended by the other witnesses for the City of El Paso. If these other adjustments are not adopted, Mr. Copeland's recommended cost of equity is 10.8 percent. His reason for this double recommendation was his belief that there is a "two-tier" market for utility stocks, which depends upon investors' perceptions of the degree of exposure of a given firm to "nuclear risk." Mr. Copeland uses this term as an umbrella covering a variety of factors plaguing utilities with on-going or recent construction of nuclear generating capacity, such as cost overruns, imprudence and excess capacity adjustments, rate shock, phase-in plans, etc. A common denominator which he perceives is the heightened degree of risk, or the probability that a utility will not fully recover its investment in these facilities, and/or may experience cash flow problems which threaten the security of the dividend.

To Mr. Copeland, the difference in investor perceptions of risk between utilities with nuclear exposure and those without is evident in market-based measures of the required return and cost of equity. His main recommendation of a 12.7 percent return on equity was based on his view of investor perceptions of EPEC as a company exposed to nuclear risk, that is, facing the possibility of deferrals or write-offs. If the Commission does not accept the imprudence and/or excess capacity disallowance recommended by the City's witnesses, then Mr. Copeland believes that investor perceptions of the risk of EPEC's common stock would be unfounded and thus undeserving of the higher risk reward implicit in his 12.7 percent recommendation. If those imprudence/excess capacity reductions are not adopted, in Mr. Copeland's view it is as if EPEC's investors are exposed to no nuclear risk. In that instance, the fair rate of return on equity is the 10.8 percent estimate of the cost of equity he derived for companies without exposure to nuclear risk.

Mr. Copeland also utilized the DCF formula, recognizing both its widespread use in estimating the cost of equity and required rate of return for public utilities and the significant disagreements about the details of its implementation. As he explained, in its normal implementation, the DCF model is a constant growth model, that is, it assumes that dividends, earnings, book value, and stock price all grow at a uniform rate. He identified three ways of estimating this growth rate: 1) various extrapolations of historical trends in earnings, dividends, or book value; 2) security analysts' projections; and 3) fundamental analysis based upon a more detailed analysis of the underlying determinants of growth. A further complication in using the DCF methodology is the fact that the various underlying growth factors - dividends, earnings, and book value - may not grow at a uniform rate. In that event, Mr. Copeland believes that the proper measure of expected growth is expected price appreciation. Where growth is not uniform, that is, non-constant, Mr. Copeland cautioned that dividend growth, earnings growth, and growth of book value must be used carefully.

Mr. Copeland used a combination of security analysts' projections and fundamental analysis. He is reluctant to use the consensus forecasts published by IBES (Institutional Brokerage Estimate Service) with a constant growth DCF model because those estimates are short-term in nature and not necessarily reflective of the growth factor to be employed in a constant growth model. In addition, their usefulness is limited because they are estimates of earnings growth only; there are no comparable estimates of dividend growth. Earnings growth can be a reasonable substitute for dividend growth only as long as dividends and earnings are expected to grow at comparable rates. Mr. Copeland explained that once the constant growth assumption is dropped, earnings growth is no longer a reliable proxy for the growth factor used in the DCF model.

Nevertheless, Mr. Copeland used the IBES estimates, somewhat indirectly, as a confirmation of the reasonableness of the earnings forecasts published by Value Line. He also used Value Line's growth projections for dividends, earnings, book value, and price appreciation, as well as the underlying data series, from which he developed the implied return on equity and payout ratio. He also derived an estimate of annual price appreciation by employing a non-constant growth DCF model for two groups of utilities, a nuclear group and a non-nuclear group.

For the nuclear group, the average yield was 8.4 percent, and the average non-constant growth estimate was 4.2 percent. The average combined yield plus growth for the nuclear group at December 31, 1986, was 12.5 percent. For the non-nuclear group, the average non-constant growth rate was 4.3 percent, the average yield 6.4 percent, and the average combined yield plus growth 10.6 percent. The difference between the averages for the two groups, 190 basis points, is indicative of the nuclear "risk premium" identified by Mr. Copeland, one which he believes must be taken into account in determining a fair and reasonable rate of return for EPEC.

As Mr. Copeland acknowledged, he and Mr. Jackson used different samples of comparison companies, different time periods to calculate the dividend yield, and different methods of estimating growth. The most significant difference, in Mr. Copeland's view, was the choice of the time period for calculating the dividend yield. Opining that Mr. Jackson's selection methodology was more restrictive than his, Mr. Copeland explained that his approach was to use the entire industry, subject to the availability of the necessary data, and then refine the selection process by dividing the industry into the two sub-groups, nuclear and non-nuclear.

Interestingly, Mr. Copeland believes that Mr. Jackson's method of estimating growth results in growth estimates that are too low. The reason for this, he suggested, was that the dividend growth for his comparable companies has been depressed because of cash flow constraints associated with their nuclear construction programs. Mr. Jackson's reliance on growth estimates which were biased downward masked the gravity of what Mr. Copeland believed to be the real deficiency in Mr. Jackson's analysis: an unrealistic time period for the determination of the yield portion of his DCF estimate. Mr. Copeland testified that a 12-month average tends to incorporate price data that is less likely to reflect current investor expectations than is an average based on more recent data; he believes that a six-month average is sufficient to smooth out daily or monthly fluctuations. Mr. Jackson's 12-month average includes a period of time in which prices were rising strongly in reaction to reduced inflation and interest rates. In addition, Mr. Jackson's methodology improperly weights the earlier months in the 12-month average, giving less weight to the more recent months which Mr. Copeland believes more strongly indicate investors' current expectations.

Finally, Mr. Copeland objected to the use of a market/book adjustment as unnecessary and excessive. Mr. Jackson's adjustment increases the unnormalized cost of equity 45 to 95 basis points. In Mr. Copeland's opinion, a reasonable estimate of flotation costs is three to five percent. (City Ex. No. 4; Tr. at 915-1074.)

3. DOD Position

In arriving at his recommended cost of EPEC's common equity of 12.5 percent, Mr. winter began with a review of macroeconomic conditions which define the environment for the current credit market. Included in this review were expectations for, and recent trends in, the inflation rate, current Federal Reserve policy on monetary growth, and loan demand at large commercial banks. He believes these interrelated factors are primary determinants of the cost of money. Then he performed a current market analysis of utility stocks in general, and reviewed Company specific data to determine EPEC's current cost of equity. Finally, he reviewed the cost of capital trends to form conclusions about the prospective cost of the Company's equity for the period during which rates set in this case will be in effect.

Mr. Winter discussed at length the current macroeconomic conditions and recent trends. He described a scenario of moderating monetary growth and relatively low and stable inflation rates. He concluded that if inflation continues at a rate of three to five percent and credit demands are consistent with allowed monetary growth without oil price shocks or other price shocks, interest rates should remain within recent ranges. A more restrictive monetary growth coupled with strong demands for credit would exert upward pressure on current rates. Mr. Winter offered the consensus opinion from the June 1, 1987, issue of <u>Blue Chip Financial Forecasts</u> that there will be relatively trendless capital costs during late 1987 and mid-1988, with seasoned A-rated utility bond rates between 9.9 percent and 10.1 percent.

Reviewing utility stocks in general and EPEC's stock prices in particular, Mr. Winter noted that the Company's stock price had a greater percentage decline than either utility index during the period February 27 through June 12, 1987. There was a decline of almost 18 percent during the first 14 weeks of that period, followed by a relatively trendless pattern in price changes. As had the other witnesses, Mr. Winter found current stock prices useful for estimating EPEC's cost of equity. He viewed EPEC's recent stock price trends indicating an increase in investor return requirements on the stock, at least over the short term, and he elaborated on the underlying factors influencing EPEC's stock prices.

In determining EPEC's cost of equity, Mr. Winter relied most heavily on the DCF approach; he also used an historical risk premium analysis and a review of current return requirements on alternative investments of varying risks as checks on the reasonableness of the results of the DCF methodology. In his view, the primary assumptions in the application of the DCF method are that the price paid for a security is an equilibrium price and is equal to the discounted stream of investor-expected dividends and price appreciation over the investor-holding period. The discount rate that equates a company's stock price to these expected returns is an indication of the investor's required rate of return.

Mr. Winter used a two-stage form of the DCF model that requires explicit consideration of prospects for price and dividend growth rates over both the near and long term. He testified that the "yield plus growth" form of the DCF model is obtained from the longer version (shown in DOD Ex. No. 1 at Schedule 8) only if the assumption is made that price and dividends grow each year at a constant rate. If the "yield plus growth" version is properly used, Mr. Winter explained, the analyst concentrates on making a determination of an expected long-term growth rate, instead of relying solely on near-term estimates. Because forecasts and expectations beyond the four to five year period are not generally available from the investment community, Mr. Winter selected a five-year period for the initial stage of the DCF model.

In estimating growth rates for use in this model, Mr. Winter relied on investment firm growth forecasts for EPEC for the near and long term. Further, he reviewed long-term growth histories for indices of utility stocks and unregulated firms. He summarized the expectations for EPEC's annual dividend, earnings, and book value compound growth from the end of 1986 to the end of 1990 reported in Value Line's forecasts (April 24, 1987), Prudential-Bache's March 1987 Universe Research report, Merrill Lynch's February 1987 Quantitative Analysis report, Salomon Brothers' Electric Utility Monthly dated May 5, 1987, and the April 15, 1987, I/B/E/S Monthly Summary Data. Near-term dividend growth rates estimated by these firms, and the median IBES estimate for near-term earnings growth, range between 3.0 percent and 5.7 percent.

Given the historical short-term relationships between price and dividend growth, Mr. Winter concluded that EPEC's stock price will probably grow at a rate less than that forecasted for dividends over the near term. Investment market expectations for near-term dividend growth ranging between 3.0 and 5.7 percent are likely to overstate the near-term growth rate range appropriate for use in the DCF model, since price may not grow at the same rate as dividends over the near-term. He also concluded, based on historical data, that investor near- term growth rate expectations fall between 3.0 percent and 4.5 percent, which he used in his DCF model to estimate current investor return requirements. After consideration of long-term growth histories for stock price and dividends and a long-term growth forecast, Mr. Winter concluded that there is no significant difference between near-term and long-term growth prospects. For the second stage of his DCF model, he used a growth rate range of 3.0 percent to 4.5 percent.

He found EPEC's current dividend yield to be 8.44 percent, computed as the average of the quotients of end-of-week stock prices and effective annual dividend rates from the 16-week period February 27 to June 12, 1987, a period long enough to level the effects of temporary price fluctuations. EPEC's stock price varied from $16.75 to $20.375 during this period, based on end-of-week prices, and the indicated annual dividend was $1.52 per share. A current dividend yield of 8.44 percent, with near- and long-term expected growth rates of 3.0 percent to 4.5 percent produce investor requirements of between 11.69 percent and 13.32 percent. Because he used identical near- and long-term growth rate findings, the results are the same as would result from use of a constant growth DCF model.

As a check on the reasonableness of his DCF findings, Mr. Winter calculated historical risk premiums between a portfolio of utility stocks and long-term government bonds. He found that during the period 1929 to 1985, utilities returned approximately 178 basis points more than long-term government bonds. He also computed the average of the premiums that would have been realized over all whole-year holding periods of one year to ten years during 1929-1985. The average premium from this analysis was 365 basis points for utility stocks over government bonds.

In addition, he considered recent statements from the investment community concerning the relative volatility risk of stocks and bonds. He believes that recent publications reflect the opinion that there is an unusual degree of interest rate volatility, and that bonds have become as risky as, if not riskier than, common stocks. He concluded that the 178 to 365 basis point premiums calculated for utility stocks over long-term government bonds should be the starting point for determining the risk premiums applicable to EPEC's stock. Since the average yield on long-term Treasury securities during the 16 weeks from February 27 through June 12, 1987, was 8.3 percent, his DCF findings of 11.7 percent to 13.3 percent offer risk premiums of 340 to 500 basis points. Considering EPEC's relative credit standing and bond price volatility, Mr. Winter found the 340 to 500 basis points adequate and consistent with his DCF findings.

As a final check on the reasonableness of his DCF findings, Mr. Winter compared them with recent required returns on other competing investments. He used competing investments with associated risks ranging from very low to very high levels. Using the April, May, and June 1987 issues of the S&P Bond Guide as his source, and confirming that the required returns in that publication are directly comparable to his DCF findings, he found that EPEC's common equity has lower liquidity risk than most corporate bonds, regardless of the bond's credit rating, and that EPEC's common equity can be sold almost instantaneously at less than a one percent price sacrifice. Given the Company's credit rating of "BBB" by S&P and other data, Mr. Winter determined that the "credit risk" component of investor return requirements on EPEC's common stock is less than or equal to the "credit risk" component of investor return requirements on bonds rated near single-B by S&P.

In addition to these comparisons, Mr. Winter reviewed the typical objectives of investors who purchase EPEC's stock and the after-tax returns offered by both utility stocks and corporate bonds. Although the Company's stock price has recently been more volatile than bonds rated single-B, other factors including liquidity risk, credit risk, tax effects, and investor objectives place the Company's stock near the single-B risk class. Required returns corresponding to a risk rating of single-B ranged from 12.0 percent to 12.5 percent, based on data from S&P's Bond Guide for May and June 1987. Mr. Winter's point estimate for EPEC's cost of equity is 12.5 percent, the mid-point of his DCF range, with no adjustment for anticipated trends or flotation costs necessary. (DOD Ex. No. 1; Tr. at 796-891.)

4. Staff Position

Staff witness Eugene Bradford began his testimony with some general observations on the cost of equity and the risk-return concept, which includes consideration of uncertainties associated with particular investments as well as those related to more general economic conditions. He stated that reasonable estimates of a firm's cost of equity can be made by analyzing information about the company and current financial market conditions. Various quantitative approaches are used as guides in determining investors' minimum required returns, but in the end, the estimate of the cost of equity is a judgmental decision based on all the information available to the analyst.

In estimating the cost of equity to EPEC, Mr. Bradford used two techniques. First, he applied the DCF methodology directly to EPEC market data to estimate the cost of equity implicit in the recent market price of the Company's common stock. Second, he applied the DCF methodology to a group of comparable electric utilities as a reflection of investors' expectations about utilities with risks similar to those of EPEC.

Mr. Bradford developed a dividend yield for EPEC using an average of two analysts' projections of EPEC's quarterly dividend as the dividend for the coming year ($1.55) and a representative market price per share of $17.00. The dividend yield (1.55/17.00) is 9.1 percent for EPEC. He did not include a market/book adjustment because the Company does not plan any major issues of stock during the time that rates set in this docket will be in effect.

The growth component in the DCF model is the reflection of growth expectations that investors have embodied in the current price of the stock, with an emphasis on average long-term growth. Mr. Bradford used three approaches in estimating growth for EPEC. First, he reviewed EPEC's expected earnings retention ratio and earned returns on equity which can be combined to produce an implied growth estimate. Second, he looked at the historical trends in net book value per share, earnings per share, and dividends per share. Third, he examined the projections of investment advisory services.

The implied growth approach is based on the premise that a firm's internal growth is produced by the retention and reinvestment of earnings. Any increase in a stockholder's interest in a utility company occurs mainly because some profits are retained and reinvested in assets upon which a return is earned. Investors can thus look at a company's retention ratio as an indication of its future earnings power. Mr. Bradford found that EPEC has generally had a retention ratio in the 40 to 50 percent range, while the return on equity has been between 18.5 percent and 19.5 percent. In 1986, however, these ratios fell, with the retention rate dropping to 34.48 percent and the return on equity falling to 13.98 percent. With the completion of the construction at Palo Verde, Mr. Bradford believes that investors will expect a change in earned return on equity and retention rates from the levels experienced during the period of Palo Verde construction. Looking at the 1986 ratios and those prior to 1978, earned return on equity has generally been between 12 and 17 percent, and the retention ratio between 25 and 35 percent. From these ranges, Mr. Bradford derives an implied prospective growth rate for EPEC ranging from 3.0 to 6.0 percent.

In addition to the implied growth evaluation, Mr. Bradford analyzed historical growth trends in net book value, earnings per share, and dividends per share. He found that growth in earnings per share has been somewhat erratic, but dividends per share and net book value have grown smoothly over the last 15 years. Because the rapid recent growth in earnings per share and net book value is attributable mainly to the accumulation of AFUDC on Palo Verde construction costs, he considered the growth rates for 1971-1986 to be the most relevant. The smoothed 15-year growth rate for net book value is 6.49 percent; for earnings per share, 7.81 percent; and for dividends per share, 4.92 percent. The latter is probably the most meaningful indicator of future growth because it is not inflated by AFUDC "earnings." Mr. Bradford, aware that historical data may have limited value in estimating future growth expectations, was cautious in his interpretation of this information.

The third investigation, review of projections by various investment advisory services, produced estimates ranging from 3.0 to 5.0 percent. Based on all the information and his own judgment, Mr. Bradford concluded that a growth estimate of 3.5 to 4.5 percent reflects investors' perceptions of EPEC's growth and is therefore appropriate for use in this DCF analysis. Using the dividend yield of 9.1 percent and a growth estimate of 3.5 to 4.5 percent, his DCF analysis produced an estimated cost of equity in the range of 12.6 to 13.6 percent.

To confirm the reasonableness of his company-specific DCF analysis, Mr. Bradford selected a group of comparable firms which resemble EPEC and performed an analysis of their equity costs. He used a series of screens to select electric utility companies with characteristics similar to those of EPEC; the screens were applied to those utilities included in the June 2, 1987, edition of Salomon Brothers Inc.'s Electric Utility Monthly. The result of Mr. Bradford's screening process is as follows:

- All of the sample companies had been involved in the construction of a nuclear plant.

- All of the sample companies obtain the majority of their revenue from electric sales.

- Only those utilities with a 1987-1989 construction/gross plant estimate below 35 percent, according to Salomon Brothers' April 22, 1987, Electric Utility Quality Measurements - Quarterly Review were included in the sample group.

- Only those utilities with bond ratings of A/BBB or Baa/A were included in the sample group. (EPEC currently has a split bond rating of A3 [Moody's] and BBB [Standard & Poor's].)

- Companies which omitted or reduced dividends were excluded from the sample group.

Mr. Bradford believes that the sample companies (listed on Staff Ex. No. 6 at Schedule V) are as representative of EPEC as any sample could be, although he noted that EPEC's indicators are generally below those of the comparables. For the comparables' DCF analysis, he used four methods for estimating the growth rates. First, he used actual historical growth of earnings per share, dividends per share, and book value per share. These were smoothed using a linear regression model. The range he found was 2.6 percent to 3.3 percent. Second, he applied the implied growth analysis to the sample group and found that growth ranged between 1.7 percent and 5.0 percent. Third, the projected growth estimated by Value Line, Salomon Brothers, and Merrill Lynch resulted in an average of 2.8 percent, with 3.9 percent and 2.3 percent as the upper and lower limits.

Finally, by combining each of the three previously mentioned growth calculations into one estimate, Mr. Bradford was able to capture the expectations of those investors who do not depend exclusively on one estimation methodology. He believes that this approach is the most reasonable and he placed the most emphasis on it in his sample company dividend growth analysis. The average of all three approaches produces a growth range of 2.2 percent to 4.1 percent.

The dividend yield for the comparable companies was computed using the same methodology, described in detail on Staff Ex. No. 6 at Schedule VI at pp. 2-3, and resulted in a dividend yield of 8.9 percent. Mr. Bradford's surrogate company DCF results are as follows:

	Yield		Growth		Cost
Historic Growth	8.9%	+	2.6% - 3.3%	=	11.5% - 12.2%
Implied Growth	8.9%	+	1.7% - 5.0%	=	10.6% - 13.9%
Projected Growth	8.9%	+	2.3% - 3.9%	=	11.2% - 12.8%
Combined Growth	8.9%	+	2.2% - 4.1%	=	11.1% - 13.0%

(Staff Ex. No. 6 at 19.)

Using the results of his comparable DCF analysis, which produced estimates of 11.1 percent to 13.0 percent, and his direct DCF analysis of EPEC, which produced estimates of 12.6 percent to 13.6 percent, and taking into account current economic and market conditions, Mr. Bradford concluded that the best estimate of the cost of equity to EPEC is 12.75 percent to 13.25 percent. As a point estimate, he recommended a cost of equity for EPEC of 13.0 percent. (Staff Ex. No. 6; Tr. at 1358-1466.)

5. Discussion and Recommendation

Even though Mr. Jackson updated his recommendation on the cost of equity, his use of a 12-month historical period for determining the yield portion of the DCF, plus his weighting of the earlier months, probably incorporates price data that are not representative of current investor expectations. The cost of equity prior to June 1987 is likely immaterial to investors' current expectations, yet Mr. Jackson's analysis includes price data back to July 1986. In addition, his market/book adjustment is inappropriate, first because it is unnecessary (EPEC anticipates no stock issues in the forseeable future) and second because cost of equity findings from DCF techniques are indicative of investor return requirements on all common equity outstanding at the time of the analysis.

Mr. Copeland's non-constant growth calculation is not a DCF analysis. In a DCF analysis, the discount rate, or required rate of return, is determined on the basis of the expected future stream of dividends. Under Mr. Copeland's non-constant growth model, the discount rate is determined on the basis of the joint assumption that price appreciation should be measured and that the market return is expected to be equal to the required return in each future period. There is no such assumption underlying the DCF method.

Further, Mr. Copeland's reliance on price appreciation makes it crucial that the price data he uses reflect market expectations. His model, however, produces market prices inconsistent with the prices projected by Value Line, the only source of his data for all other aspects of his calculations. If investors rely upon Value Line projections, it would be reasonable to include its projection of price in calculating the non-constant DCF cost of equity. Mr. Copeland instead derived projected prices which conflict with the Value Line projections.

Mr. Copeland's definition of "nuclear risk" is also too narrow. It is doubtful that investors would regard a utility with an ownership interest in a nuclear plant as a non-nuclear utility simply because a regulatory authority did not make prudence and excess capacity disallowances. Nuclear risk includes operating problems, licensing problems, retrofitting, and other problems, including the most obvious risk of catastrophic accident.

Mr. Winter's use of the historical growth experience of Moody's 24 utilities over the period 1929-1986 is also questionable. It is implausible that investors today would form their expectations about EPEC's future growth by looking at the historic growth for a groups of utilities with a different growth history than EPEC. Further, the historical data indicate a great diversity of growth rates; investors would not likely find this information a very helpful indicator of EPEC's future growth.

The cost of equity recommendations in this docket range from a low of 10.8 to a high of 13.32, as follows:

The Company	13.25 percent
City of El Paso	10.8 (if no disallowances); 12.7 (with disallowances)
DOD	11.69 to 13.32 (midpoint 12.5)
Staff	12.75 to 13.25 (midpoint 13.0)

The determination of a fair and reasonable cost of equity for EPEC is based on informed judgment, and there is clearly record support for each of the recommendations offered. The staff's recommendation is stronger because Mr. Bradford has not made the kinds of questionable adjustments (either to the DCF model itself or to its results) made by other witnesses, and in general, it employs more current information than other proposals. Because of the testimony of Mr. Winter and Mr. Copeland, however, the lower end of the range proposed by Mr. Bradford appears to be the more reasonable and well supported cost of equity for this company, and the report recommends that the Commission adopt a cost of equity for EPEC of 12.75 percent.

E. Overall Rate of Return

This report recommends an overall rate of return on invested capital of 10.8016 percent for the Company, derived as follows:

Source	Amount	Percent of Total	Cost	Weighted Cost
Long-Term Debt	$ 642,298	46.73	9.18	4.2898
Preferred Stock	$ 134,183	9.76	9.88	0.9643
Common Equity	$ 598,024	43.51	12.75	5.5475
Total	$1,374,505	100.00		10.8016

XI. Cost of Service

A. Fuel and Purchased Power

EPEC requested an increase of $17,478,602 to test year fuel expense of $41,598,398 for a total fuel expense of $59,077,000. The Company's requested purchased power expense of $22,622,900 is a decrease of $39,991,149 to test year expense of $62,614,049. Thus EPEC requests a net decrease of $22,512,547 in total fuel and purchased power expense.

The following company witnesses testified on fuel and purchased power issues in EPEC's direct case as follows: William J. Johnson provided a brief summary of the fuel and purchased power costs and adjustments, the fixed fuel factors, an analysis of fuel cost recovery by month from August 1985 through January 1987, and the treatment of the displacement fuel credit for PVNGS Units 1 and 2. (EPEC Ex. No. 1, Vol. 4, Tab 21 at pp. 29-31; Vol. 8, Schedule Q-2; Tr. at 55-269.) Frederic E. Mattson, Manager of the Resource Development/Contracts Department for the Company, gave an overview of EPEC's fuel supply situation and explained the basis for the test year fuel and purchased power estimates used in the fixed fuel factors. (EPEC Ex. No. 1, Vol 2, Tab 14 at pp. 1-9 and Tab 15 at Exhibit FM-1; and Vol. 7 at Schedules A-7 (Adjustments 2 and 3), G-2.8, G-2.9, G-2.10, G-2.11, and G-6.2; Tr. at 270-312.) Joseph E. Wasiak, EPEC Vice President in charge of energy supply, testified on the Company's operation of its local generating units and the Four Corners plant, and offered background information on the performance of EPEC's non-nuclear generating units. (EPEC Ex. No. 1, Vol. 5, Tab 34 at 1-14 and Tab 35; Tr. at 516-556.)

Stan Kaplan, Manager of Fuel Analysis in the Electric Division, discussed the management of EPEC's coal and nuclear fuel procurement, his proposed reconciliation, and his projected reconcilable coal and nuclear fuel costs for use in the fixed fuel factors and capacity costs to be included in base rates. (Staff Ex. No. 16; Tr. at 3459-3572.) Charles Griffey, Fuel Analyst in the Electric Division, testified on his reconciliation review of EPEC's natural gas and fuel oil supplies and contracts, and his projected natural gas prices for the rate year. (Staff Ex. Nos. 15 and 15A; Tr. at 3374-3420.) Waldon Boecker, Manager of Power Plant Engineering for the Electric Division, addressed power plant performance, generation mix, and projected reconcilable fuel costs and projected purchased power costs for EPEC for the rate year. (Staff Ex. Nos. 5 and 27; Tr. at 744-788 and 6460-6467.) Staff Economic Analyst Paul Ramgopal presented a short-term forecast of EPEC's total sales (MWH) for use in calculating total fuel cost. (Staff Ex. Nos. 8 and 8A; Tr. at 1572-1606.) City of El Paso witness Thomas C. DeWard proposed one cost of service adjustment for purchased power expense. (City Ex. No. 6 at 30-31 and at Schedule 15-1.)

Rebuttal testimony for EPEC was given by Mr. Johnson (EPEC Ex. No. 41, Tab 8 at 15-17; Tr. at 2445-2484); Mr. Mattson (EPEC Ex. Nos. 65 and 65A; Tr. at 3572-3619); and Mr. Hicks (EPEC Ex. No. 41, Tab 6; Tr. at 2406-2423).

The record presents some difficulties in calculating the fixed fuel factors. Neither the Company nor the general counsel briefed fuel issues; based on the stipulation, these parties agreed that EPEC's proposed fixed fuel factors should be adopted and reconciliation postponed until EPEC's next rate case. In addition, the staff's proposals on some of the costs to be used in the fixed fuel factors are based on an incorrect standard. The staff's evaluation of EPEC's prudence and efficiency in fuels procurement and management for purposes of reconciliation was also used to derive some of the fuel costs recommended by staff to be used in the fixed fuel factors, an approach the examiners believe is not contemplated by Rule 23.23(b)(2)(B) and (C), which read in pertinent part (emphasis added):

> . . .
>
> (B) *Known or reasonably predictable fuel costs* shall be determined at the time of the utility's general rate case, fuel reconciliation proceeding, or interim fuel proceeding under subparagraphs (D) and (E) of this paragraph.
>
> > (i) In determining known or reasonably predictable fuel costs, the commission shall consider all conditions or event which will impact the utility's fuel-related cost of supplying electricity to its ratepayers *during the period that the rates will be in effect*. These conditions or events include generation mix and efficiency, the cost of fuel used to produce the utility's generation, purchased power costs, wheeling costs, hydro generation and other costs or revenues associated with generated or purchased power as approved by the commission.
> >
> > . . .
>
> (C) The utility shall recover its *known and reasonably predictable fuel costs* through a fixed fuel factor. *The utility's fixed fuel factor* shall be established during a general rate case, fuel reconciliation proceeding or interim fuel proceeding . . . and *shall be determined by dividing the utility's known or reasonably predictable fuel cost, as defined in subparagraph (B) of this paragraph, by the corresponding kilowatt-hour sales during the period in which the factor will be in effect.* . . .

Under the standard in this Rule, the focus is not upon historical data or the reasonableness and necessity of the fuel costs; rather, projected rate year costs are used to establish the fixed fuel factors. There is no need to evaluate the prudence and reasonableness of the expense before it can be included in the calculation of the fixed fuel factors; indeed, the only requirement for inclusion of fuel costs in the calculation of the fixed fuel factors is that they must be known or reasonably predictable.

Under the Commission's current practice, a utility's recovery of its fuel expense is subject to adjustment until there is a final reconciliation, at which time the intensive review of the prudence, necessity, and reasonableness of fuel expenses is undertaken, since PURA §39(a) and P.U.C. SUBST. R. 23.21(b) limit a utility's recovery of operating expenses to only those that are reasonable and necessary. Since the actual level of a utility's fuel expense will never be known until after the incurrence of that expense, the final reconciliation enables making the determination of the reasonableness and necessity of fuel expenses actually incurred as required under the statute and the rules.

1. Fuel Costs

a. Natural Gas Costs

EPEC has three gas-fired stations: Newman (477 MW) and Copper (69MW) in Texas and Rio Grande (246 MW) in New Mexico. El Paso Natural Gas Company (EPNG) supplies interstate natural gas to Rio Grande Station and is an alternate supply source for the Newman Station. EPNG also transports spot market natural gas for use at Rio Grande Station through EPNG's subsidiary El Paso Hydrocarbons Company (EPHC). Through its subsidiary El Paso Gas Transportation Company, Inc. (EPGT), El Paso Hydrocarbons Company of Odessa, Texas supplies intrastate natural gas to Newman Station and Copper Station in Texas. Recently, EPEC & EPGT signed an agreement under which EPGT will transport, at EPEC's request, spot gas to the Newman Station.

Mr. Mattson views the drop of fuel oil prices over the last year as beneficial to EPEC because this has fostered competition between fuel oil suppliers and natural gas suppliers and pipelines for sales to customers with the capability of burning either fuel oil or natural gas for boiler fuel. A large transportation market has been created, enabling EPEC to obtain a 70/30 mix of spot/contract gas from February 1986 through December 1986 at the Rio Grande plant and lowering its fuel costs.

EPEC's estimated average intrastate natural gas price for 1987 is $1.97 per MMBTU. EPEC's current price for interstate natural gas from EPNG is $3.09 per MMBTU, including adder, adjustments, and tax, but EPEC expects this price to rise to $3.13/MMBTU because of likely results of settlement of an EPNG petition pending before the FERC. EPEC anticipates spot gas for Rio Grande Station from El Paso Gas Marketing (EPGM) to be an average price of $2.13/MMBTU in 1987. Assuming an 80/20 mix of spot/contract gas, EPEC expects an average gas price of $2.33 at Rio Grande Station in 1987. EPNG also supplies natural gas to Four Corners Units 4 and 5; prices there are expected to be stable at an average of $2.93/MMBTU in 1987.

Mr. Griffey believes that in the rate year for EPEC, calendar year 1988, the natural gas market will continue to be characterized by excess supply and lackluster demand, much as it has been for the last five years. He reached this conclusion based on his review of a number of forecasts and predictions about the natural gas market and its prevailing trends. He also evaluated the regulatory actions of the FERC and the likely impact of some recent important orders (Order 436 and Order 500) on natural gas prices. In Staff Ex. No. 15 at Schedule CSG-7, Mr. Griffey presented a comparison of the staff's forcasts of natural gas prices per MMBTU for interstate gas (EPNG) and for intrastate gas (EPHC) for the rate year 1988 with those of EPEC for 1987, and showed the derivation of his prices in Staff Ex. No. 15 at Schedule CSG-8. That comparison is as follows:

	INTERSTATE		INTRASTATE	
Month	EPEC	Staff	EPEC	Staff
January	2.22	2.15	1.87	1.82
February	2.22	2.26	1.93	1.93
March	2.22	2.26	1.92	1.93
April	2.29	2.21	1.93	1.87
May	2.29	2.21	1.94	1.87
June	2.29	2.26	1.95	1.93
July	2.36	2.32	1.98	1.98
August	2.36	2.37	1.98	2.04
September	2.36	2.32	1.98	1.98
October	2.41	2.32	2.01	1.98
November	2.41	2.37	2.04	2.04
December	2.46	2.43	2.09	2.09

Mr. Mattson's rebuttal testimony faulted Mr. Griffey's comparison for not using EPEC's 1988 estimates which were provided to the staff in RFI responses. The Company's estimates for 1988 were $2.04/MMBTU for intrastate natural gas (compared to Mr. Griffey's $1.96/MMBTU) and $2.35/MMBTU for interstate natural gas (compared to Mr. Griffey's $2.29/MMBTU). Mr. Mattson also disagreed with some of the assumptions underlying Mr. Griffey's forecast of interstate gas prices, one of them being the ability of EPEC to purchase 100 percent transportation volumes in 1988. Based on a mix of 85 percent transportation and 15 percent commodity natural gas, EPEC projects a $2.35/MMBTU price for interstate natural gas in 1988.

This report recommends use of the staff's projected intrastate price of \$1.96/MMBTU and interstate price of \$2.29/MMBTU for natural gas in calculating the fixed fuel factors for EPEC. These costs are projected for the rate year in compliance with the directives in P.U.C. SUBST. R. 23.23(b)(2)(B). Mr. Griffey's evaluation of EPEC's management of its natural gas procurement during the reconciliation period was favorable, and so did not result in his recommended prices to be used in calculating the fixed fuel factor being based on a determination of the reasonableness of the prices. Further, the staff's prices are supported by evidence of record. EPEC's projected gas prices for 1988 may have been furnished to the staff in an RFI response, but they were not otherwise supported in the record evidence.

b. Coal Costs

EPEC buys coal for use in the Four Corners power plant, located on the Navajo Indian Reservation in northwestern New Mexico. The Four Corners Station contains five generating units. Units 1, 2, and 3 were built in the 1960s and are solely owned and operated by Arizona Public Service (APS). EPEC has no ownership interest in these units. Units 4 and 5 are owned by six utilities; EPEC's share is seven percent, equivalent to 110 MW. Unit 4 went into commercial operation in 1969 and Unit 5 in 1970. APS, a 15 percent owner of these units, is the operating agent for the owners of Units 4 and 5, and is responsible for the operation and maintenance of Units 4 and 5 on behalf of all the owners.

The primary fuel burned at all five Four Corners units is subbituminous coal supplied from the Navajo Mine located adjacent to the plant on land leased from the Navajo Tribe. The mine is owned and operated by BHP-Utah Minerals International (generally referred to as Utah International), a subsidiary of the Australian firm Broken Hill Proprietary. Since Four Corners is a mine mouth plant, a transportation agreement with a third party is not required.

Coal is supplied to the Four Corners units under two contracts, which can be referred to as Fuel I and Fuel II. Fuel I is a contract between Utah International and APS for coal supply to Units 1, 2, and 3, entered into on August 18, 1960. Mr. Mattson explained that by virtue of its ownership in Units 4 and 5, EPEC is a party to the original fuel supply agreement for those units which was entered into in September 1966 and was last amended in 1981; this is the Fuel II contract. The agreement assures a coal supply to Units 4 and 5 for 35 years from first date of operation, plus an optional 15-year extension. Land and water rights are also included, as are peripheral agreements providing for ash handling and disposal. Even though APS is the administrator of the contract (as the operating agent for the owners), EPEC maintained the right to determine that the fuel supply contract is being administered properly and that the coal being supplied to Units 4 and 5 is in compliance with the terms and conditions outlined in the contract.

Both Fuel I and Fuel II contain provisions for reopening the price. The first (of two) price renegotiations of Fuel II took place during the 1978-1981 time period. In the second, which began in February 1986, EPEC and the other owners of Units 4 and 5 entered into negotiations with Utah International for a downward adjustment of the coal price paid under the contract. Utah International, however, believes that an upward adjustment is called for. Mr. Mattson testified that negotiations were not expected to be completed until the end of 1987. Fuel II coal is less expensive than Fuel I, but the price paid by all Unit 4 and 5 owners is the weighted average of the price of all Fuel I and Fuel II coal delivered to all of the Four Corners units each month. Thus, the price EPEC pays under Fuel II is determined in part by Fuel I, even though EPEC is not a signatory to that contract.

Staff witness Stan Kaplan presented extensive testimony regarding the operation of the Four Corners plant and the mining operations at the Navajo Mine. He also reviewed the coal costs, in particular the Fuel I and Fuel II contracts and the prudence of the 1978-1981 renegotiation, and presented his rationale for disallowing a portion of both the reconcilable coal costs incurred during the period March 1984 through May 1987, and prospectively as an adjustment to the costs EPEC will be allowed to charge in the fixed fuel factors to be determined in this case. This report will not rehearse that testimony, for two reasons. First, as noted above, Mr. Kaplan used a more stringent standard for determining fuel costs to be included in the calculation of the fixed fuel factors than is set forth in P.U.C. SUBST R. 23.23(b)(2)(B); his computer model simulating the terms of the Fuel I and Fuel II contracts, which he used to develop his price forecast for the rate year, contains his recommended disallowance based on imprudence. Second, Mr. Kaplan recommended that final reconciliation of coal expense not be made in this docket, and in any event, no reconciliation of fuel expense will be undertaken in this docket, for reasons explained in Section XVI below.

Mr. Kaplan's computer model for estimating the unit price ($/MMBTU) for Four Corners coal for the rate year of calendar 1988 simulates the terms of the Fuel I and Fuel II contracts. For estimates of the escalation of various contract price components during the rate year, he used forecasts developed by Data Resources, Inc. As noted above, however, the following unit prices include his disallowance:

First Quarter, 1988	$1.03/MMBTU
Second Quarter	$1.035/MMBTU
Third Quarter	$1.038/MMBTU
Fourth Quarter	$1.042/MMBTU

Mr. Kaplan's projected coal costs are more representative of those EPEC will incur in 1988 than is EPEC's estimate of 1987 costs of $1.01/MMBTU. (EPEC Ex. No. 1, Vol 7, Schedule G-2.10, at p. 2 of 5.) Additionally, Mr. Kaplan's price excludes the costs for disposal of coal ash and scrubber sludge, estimated by Mr. Kaplan to be $308,539, which are non-reconcilable under P.U.C. SUBST. R. 23.23(b)(2)(B)(ii). On cross-examination, Mr. Kaplan was able to estimate the dollar amount of his recommended prospective disallowance as about a cent per million btu, or $64,000. (Tr. at 3466-3467.) This report recommends using Mr. Kaplan's projected coal costs for 1988 without the $64,000 penalty. The $308,539 should be included in base rates. (Staff Ex. No. 16 at 71.)

c. Nuclear Fuel Costs

Mr. Mattson explained that the uranium fuel supply for Palo Verde is governed by various contracts covering the supply of U_3O_8 concentrates or yellowcake, conversion, enrichment, and fuel assembly fabrication. ANPP staff secure and administer the various nuclear fuel contracts and submissions of requests for bids, and negotiate on behalf of the Palo Verde participants. EPEC maintains the right to determine that the fuel supply contracts are being administered properly, and that the fuel supplied to the Palo Verde units is in compliance with the terms and conditions of the contracts. EPEC has an undivided interest in the nuclear fuel purchased and to be purchased for the operation of PVNGS Units 1, 2, and 3. An adequate supply of uranium concentrates is assured through the 1990s under existing fuel contracts. A summary of the contracts relating to nuclear fuel appears in EPEC Ex. No. 1, Vol 7, Schedule G-2.11 at pp. 9-16. EPEC's nuclear fuel cost methodology is summarized in EPEC Ex. No. 1, Vol. 7, Schedule G-2.10 at pp. 3-4.)

Mr. Kaplan gave a detailed description of the nuclear fuel cycle which begins with the mining of uranium ore and ends with the disposal of spent nuclear fuel. This cycle takes years; the contractual arrangements are long-term and span the changing market conditions and erratic changes in uranium prices in the 1970s and 1980s. Because the fuel is in-process for years, a major component of final cost is the carrying cost.

Rio Grande Resources Trust (RGRT) owns EPEC's share of the Palo Verde nuclear fuel. This trust was created in 1978; under a 1979 purchase contract between EPEC and RGRT, EPEC sold all its nuclear fuel in-process to RGRT and assigned all of its nuclear fuel contracts to the trust. Since then, EPEC has continued to sell its nuclear fuel to RGRT. As payments for the fuel come due (per invoices to EPEC from ANPP), EPEC's payments are immediately reimbursed by RGRT. EPEC repays RGRT for its costs plus capitalized carrying costs (RGRT's cost of money, fees paid to the credit bank for maintaining its line of credit, and the trust's management fee, $5,000 per month in 1986) as the fuel is consumed in the reactor. RGRT, using 100 percent debt financing, has lower carrying costs than EPEC; therefore, this financing arrangement provides a savings in total fuel expense. According to Mr. Kaplan, even after including the various fees associated with the trust and credit arrangements, the effective carrying cost of RGRT at the end of 1986 was only 7.2 percent. All responsibility for oversight and management of nuclear fuel contracts remains with EPEC.

In his reconciliation review of EPEC's nuclear fuel procurement and management, Mr. Kaplan found a number of items which he recommended disallowing. As stated above and explained further below, reconciliation will not be effected in this docket; thus discussion of the evidence on that issue is not relevant to the decisions to be made in this docket. (This is not to say, however, that these matters are unimportant; to the contrary, Mr. Kaplan raised a number of troubling questions about the Palo Verde Uranium Venture; the loans by RGRT to EPEC's unregulated subsidiary, FL&R; and the actual oversight on nuclear fuel matters actually exercised by EPEC.) Additionally, Mr. Kaplan was unable to quantify the amount of his disallowance recommendation, and he recommended use of the Company's estimates for Palo Verde fuel costs for the rate year 1988, shown on the following schedule:

(mills per kWh)

	Unit 1	Unit 2
1988		
January	9.88	11.48
February	9.96	11.27
March	9.77	-
April	9.76	-
May	9.81	11.37
June	9.87	10.00
July	9.72	9.99
August	9.67	9.94
September	9.76	9.90
October	9.57	9.83
November	9.35	9.80
December	13.32	9.58

(Staff Ex. No. 16 at Schedule SK-D-2.)

This report concurs in the use of the Company's estimates of nuclear fuel costs for PVNGS for the rate year 1988.

d. Fuel Oil Costs

There was extensive testimony from Mr. Griffey and from Mr. Mattson on rebuttal regarding the Big Bend Resources Trust (BBRT) and the prudence of its activities in lending money to FL&R, an unregulated subsidiary of EPEC, and in its handling of excess fuel oil inventory. Mr. Griffey offered detailed information on the creation and operation of this trust which is the financing vehicle for EPEC's fuel oil. Mr. Griffey's analysis was performed for reconciliation and, in any event, could not have any impact on base rates or on the fixed fuel factor because EPEC did not request inclusion in cost of service of any of the carrying costs for fuel oil, nor is there any fuel oil in rate base. (See, Staff Ex. No. 15 at Schedule CSG-10; EPEC Ex. No. 1A Errata Schedule A-7 Adjustment 10.) His analysis of and challenge to the propriety of capitalizing the trustee's fees was based on his reconciliation review and his recommended disallowance is prospective only. Since there is no fuel oil in rate base or carrying costs in cost of service, there is no need to address this issue further with respect to this docket. However, these issues should be addressed in any future reconciliation proceeding for EPEC.

e. Purchased Power

EPEC's purchased power contracts are summarized in EPEC Ex. No. 1, Vol. 7, Schedule G-2.9 at pp. 1-11. EPEC's contract with Southwestern Public Service Company (SPS) allowed EPEC to purchase up to 100 MW in January 1987 and 75 MW each month thereafter in 1987. (EPEC Ex. No. 1, Vol. 7, Schedule G-2.10 at p. 5.) In 1988, however, EPEC can purchase 75 MW in January and 50 MW each month thereafter. EPEC's estimated purchased power expense (exclusive of demand charges) for this contract using 12 months of purchases at 75 MW, more than EPEC can purchase during 11 of the 12 months of the rate year (calendar 1988), is $16,592,000. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 3; EPEC Ex. No. 1, Vol. 8, Schedule Q-2.) The Commission staff adjusted this amount to account for the changes which will take place in the rate year; staff's amount of $15,407,000 for reconcilable purchased power (Staff Ex. No. 27 at Schedule WB10) should be adopted because it is the most accurate depiction of reconcilable purchased power costs for the rate year.

2. Generation Efficiency and Productivity

P.U.C. SUBST. R. 23.23(b)(2)(B)(i) requires that in determining known and reasonably predictable fuel costs, the Commission shall consider the utility's generation mix and efficiency.

EPEC witness Joseph E. Wasiak discussed a number of specific cost-saving measures EPEC has employed in its system operations and the efficiency and productivity of the local generation and the Four Corners plant. He provided a copy of an EPEC study entitled, "Optimizing Capacity Factors of Large Gas

Generating Units," ordered by the Commission in Docket No. 5700 and provided in evidence in Docket No. 6350. In addition, Mr. Wasiak explained the maintenance and outage schedules for Palo Verde and Four Corners.

Staff witness Waldon A. Boecker addressed EPEC's generation efficiency and productivity. He explained that there are two key performance indicators. The first, unit efficiency, is measured in terms of net heat rate, the fuel energy consumed per kilowatt-hour generated, (less kilowatt-hour requirements at the plant and as measured on the high voltage side of the generating unit's main transformer.) The second, unit productivity, can be measured in terms of three annual averages. Equivalent Availability Factor (EAF) is the percentage of time a unit is available for full load operation, whether it is operated or not. Equivalent Unplanned Unavailability (EUU) is the percentage of time a generating unit is operated at reduced load or out of service because of unplanned outages. Capacity Factor is the ratio of actual generation to potential generation during a given period of time and strictly defines the productivity of each unit.

Because generating units serve different purposes in the supply of kilowatt-hours, productivity for different units is measured in different ways. The capacity factor is generally a sufficient measure of productivity for units scheduled for continuous base load duty. Units which are cycled on and off in response to demand in the intermediate or peaking modes of operation may have inherently low capacity factors, so the productivity of these load-following units is better measured by EAF along with EUU.

In addition, Mr. Boecker explained, other factors such as weather, system demand, forced outages of baseload units, major generating unit overhauls scheduled about every three or four years, and fuel cost and quality greatly impact system performance and vary from year to year. Future events cannot be predicted accurately, such as the commercial operation dates for units under construction, generating unit forced outages, major disruptions in foreign oil supply, loss of existing surplus natural gas deliverability, balanced supply and demand for out of state coal and development of Texas lignite reserves. Operation during a 12-month period probably does not provide the best indication of how generating units have operated in the past or how they will operate in the future; therefore, a longer period of time is considered.

Mr. Boecker made several comparisons of the performance of EPEC's major gas, coal and nuclear generating units with similar plant groups. First, he compared EPEC's historical performance to its test year performance; EPEC to Texas average performance; and EPEC to national average performance. (Staff Ex. No. 5 at Schedules WB1 and WB2.) Because of significant unit design and use, fuel quality, and various other characteristics, Mr. Boecker warned that Texas and national comparisons may not be as meaningful as comparisons of a specific unit's recent performance to past performance.

With respect to nuclear operations, the capacity factor for PVNGS Unit 1 during its first year of commercial operation was about 57 percent, compared to about 58 percent for 800+ MW nuclear pressurized water reactors generating units, based on NERC data for 1982 to 1985. The NRC Systematic Assessment of Licensee Performance (SALP) Board conducts periodic evaluations of PVNGS performance primarily from a safety perspective which impacts economic performance. In its most recent assessment, the SALP Board considered ANPP satisfactory, but its performance had declined somewhat in the areas of security and safeguards and licensing activities since the last SALP evaluation. Mr. Boecker reported that compared with other new plants, Unit 1 had about an average number of Engineered Safety Feature actuations (automatic actuation of the Reactor Protection System, or reactor trips), and Unit 2 had more than the average number. According to NRC reports, Units 1 and 2 are experiencing significantly more trips than the 1986 industry average and somewhat more than other new plants.

In addition, ANPP's performance in the area of security and safeguards was evaluated in the poorest category, resulting in a proposed penalty of $50,000 which was *doubled* because NRC had given notice of similar problems during the last three years, and because several violations involved multiple examples. In Mr. Boecker's view, reduction in the number of personnel errors, generating unit trips and security/safeguard violations could be expected to result in not only safer operations in the future but also improved economic performance.

During the test year, Mr. Boecker testified, EPEC reported a coal plant capacity factor of about the same as that reported by other utilities in the United States while reported efficiency was better than average. During the test year, EPEC's natural gas fired units had EAFs significantly higher than the average reported for other utilities with 100 to 299 MW units, and about the same as other Texas utilities with 1-99 MW generating units. In his opinion, the test year efficiency compares well considering the operating mode of natural gas fired units.

Mr. Boecker concluded that EPEC's generating system has been operated in a reasonably efficient manner. He recommended that even though EPEC does not have direct control over the operation of the coal and nuclear units the Company should improve its knowledge of planning concerns and operating problems experienced by ANPP which have major cost impacts on EPEC. He urged a continuing effort by EPEC to maximize nuclear unit generation and to comply fully with all health and safety requirements, and he suggested specifically that EPEC should work with ANPP to prevent or minimize unwarranted safety system actuations and violations of operating license provisions.

3. Generation Mix and Fuel Requirements

Mr. Mattson testified about use of the computer program PROMOD to model EPEC's test year system dispatch adjusted to include PVNGS Units 1 and 2 in service and the annualized test year MWH requirements in order to calculate associated fuel and purchased power expenses. The monthly dispatch performed by PROMOD uses selected input data, such as projected fuel prices and availabilities, hourly load data, projected system peak loads and energies, along with individual generating unit data including scheduled maintenance outages, unit equivalent forced outage rates (availability), and unit heat rates. Estimated purchased power price and availability data is considered in the overall dispatch simulation. PROMOD output is on a monthly basis and shows estimates of fuel usage and cost by unit, unit heat rates and generation, unit operation and maintenance expense, and estimates of purchased power amounts and costs.

PROMOD dispatched EPEC's system using PVNGS and Four Corners as baseload units, purchasing power from SPS and the economy market to meet the intermediate load, and dispatching the Newman, Rio Grande and Copper Units to follow intermediate and peak loads, using the latest estimates for fuel and purchased power prices and each unit's input heat rate and availability.

The total estimated fuel expenses using PROMOD, shown in EPEC Ex. No. 1, Vol. 2, Tab 15 at Exhibit FM-1, are $59,077,000. This amount was used to calculate the fixed fuel factors shown in EPEC Ex. No. 1, Vol. 8, Schedule Q-2.

Mr. Boecker's approach in developing the rate year generation mix for the EPEC system relied on projected system dispatch for the rate year provided by the Company in RFI responses. For the rate year, calendar 1988, EPEC projects nuclear generation to be greater than that shown on Exhibit FM-1, due primarily to the addition of generation from PVNGS Unit 3. Since Unit 3 is not yet recognized as in service, Mr. Boecker did not include Unit 3 fuel costs in reconcilable fuel and purchased power costs. Instead, he replaced the PVNGS Unit 3 generation projected by EPEC with economy energy at the EPEC estimated 1988 price. In addition, he replaced some EPEC-projected 1988 economy energy purchases with increased generation from PVNGS Units 1 and 2.

Mr. Boecker explained his consideration of some of the factors which affect the accuracy of projections for rate year reconcilable fuel costs, such as the PROMOD inputs and generating unit performance, particularly the projected capacity factors for PVNGS Units 1 and 2. He acknowledged that depending upon the capacity factors these units are able to achieve in 1988, staff estimates for fuel and purchased power costs could be wrong. Much of his evaluation, however, concerned the possibility and timing of PVNGS Unit 3 going into commercial operation during 1988. He therefore rejected any inclusion of PVNGS Unit 3 as not known or reasonably predictable as required by P.U.C. SUBST. R. 23.23(b)(2)(B). Staff projected rate year reconcilable fuel costs are $62,256,000. (Staff Exhibit No. 27 at Schedule WB9 and Schedule WB10.)

4. Kilowatt-Hour Sales

In calculating the fixed fuel factors, EPEC used the annualized kWh sales developed by Mr. Hicks, discussed in Section XII above. Mr. Ramgopal performed a short-term forecast of total sales (MWH) for EPEC for use in calculating total fuel cost. This was a different analysis than that performed by Ms. Frazier, who reviewed the Company's adjusted test year sales, as noted below in Section XII of this report.

EPEC's Basic Native System is defined as its retail customers (Texas and New Mexico Residential, Commercial and Industrial-Small, Commercial and Industrial-Large, Street Lights, and Other Public Authorities), plus sales to Rio Grande Electric Cooperative. Mr. Ramgopal added three other components, TNP Alamogordo sales, IID sales, and TNP Lordsburg sales, to Basic Native System to arrive at total sales. Mr. Ramgopal's forecasted total sales of 4,756,318 MWH (Staff Ex. No. 8 at Exhibit PR-1) exceeds staff recommended adjusted test year sales by 210,105 MWH, a 4.6 percent difference, and it exceeds the Company's proposed adjusted test year sales by 213,212 MWH, a 4.7 percent difference.

Mr. Ramgopal stated that his "rule-of-thumb" definition of short-term forecast usually covers a period of up to two years. He performed a short-term forecast specifically to comply with the requirements of Rule 23.23(b)(2)(C); he did not consider adjusted test year sales to be a reasonable projection of MWH sales for 1988 because total sales (MWH) is an economic time series driven by several factors such as weather, local economic activity, price of electricity, and number of customers, that is, total sales is a function of certain identifiable relationships plus random phenomena. EPEC, however, took only one factor - customer growth - into account in developing its forecast, a methodology which ignores other factors which drive sales and implicitly makes the assumption that new customers joining the system will have usage patterns similar to those of customers already on the system.

In developing his forecast of total sales, Mr. Ramgopal used a univariate State Space Model, described in detail in Staff Ex. No. 8A. A state space model consists of a set of the most relevant information from the present and past history of the variable, for example MWH, that is sufficient to predict it's future behavior. (The statistical results of the state space model used to develop his forecast are presented in Staff Ex. No. 8 at Appendix I.) The steps involved are explained in simple terms, below.

First, a data series for total sales and a data series for the dummy variable are created. The dummy variable is related to EPEC's sales under the Alamogordo contract which ended in December 1984. A forecast of total sales for 1988 would be biased upward if the effect of these sales were allowed to continue into the future, so the dummy variable takes on the value of zero for those months in the historical data set when the TNP Alamogardo sales were present, and the value of 1 for those months in which the contract had expired. In effect, this zeroes out the sales. Mr. Ramgopal used a dummy variable because he did not have actual historical monthly sales figures for this contract.

Then the total sales series is rendered stationary by trying a variety of mathematical transformations (described in Staff Ex. No. 8 at Appendix I). The objective of stationarity is to insure the same statistical behavior of total sales at each point in time, reducing the forecast error. Mr. Ramgopal explained on cross-examination that he had to make one algebraic transformation. This transformation followed satisfactory mathematical behavior, which he determined by looking at some key statistics, such as the autocorrelation function, the Ljung-Box Test (Portmanteau or Q Test), and the Durbin-Watson Statistic. (Tr. at 1595.)

Third, a canonical correlation analysis (described more fully in Staff Ex. No. 8A) is performed on the total sales to determine the state space model. Historical total sales is divided into two groups, the past set and the future set, and an analysis is done between the two to determine how much information from the past is sufficient to explain the future. Mr. Ramgopal used a chi-squared test to determine whether a correlation is significant or not. (Tr. at 1597-1598.)

Next a Kalman Filter algorithm (a method that forecasts and minimizes the forecast error at each step of the state space model) is used to develop the forecasts. This is explained in greater detail in Staff Ex. No. 8A. Finally, the forecasts are then retrended to introduce the mean historical trend in the forecasted series. When the series is made stationary, the historical trend is eliminated or minimized. The forecasts of such a series excludes extraordinary behavior such as seasonality. Retrending reintroduces the behavior into the model so that the forecasts of the variable correctly incorporate its historical behavior.

On cross-examination, Mr. Ramgopal explained that he made no separate adjustments for weather or customer growth for two reasons. First, in the short term, major structural changes are not expected so it is unnecessary to introduce explanatory variables in the model directly. Second, a time series model, as Mr. Ramgopal used, reasonably captures growth and examines variables such as weather, customer growth, customer loss, price of electricity, etc. He emphasized that the key difference between a regular econometric model and a univariate time series model is that the relationships of the variables are accounted for in the latter model. The variables are implicit in the one variable selected, namely, total megawatt-hour sales, because total sales are a function of all these factors. (Tr. at 1579-1581; 1593.)

On cross-examination, Mr. Ramgopal explained the need for the dummy variable for the TNP-Alamogordo contract which had expired, and he also observed that if a sales amount was included in historical data and there was reason to know it would not be there in the future, it could be necessary to eliminate that amount from the data base regardless of the number of megawatt-hours. However, he did not agree that it is necessary in doing a short-term forecast to take into account every possible small change in MWH sales; most analysts involved in load forecasts usually take into account factors that are so significant that a major error will result if they are not accounted for. (Tr. at 1599-1601.)

Finally, Mr. Ramgopal testified that the accuracy of a forecast is not necessarily related to how far into the future the forecast goes. Any model would be less precise the farther it goes into the future, but it is not necessarily true that the shorter time period the forecast covers the more accurate it will be. In his opinion, it depends on the model being used; in the short term, it is possible to develop a fairly precise forecast if the methodology is adequate, but in the absence of an adequate methodology the fact that the forecast is for the short term reveals nothing about its accuracy. (Tr. at 1604-1605.)

In his rebuttal testimony, Mr. Hicks defended the Company's approach as straight-forward and producing accurate results without the encumbrances of an overly sophisticated forecasting technique. Given the limited context of annualized kWh sales in a rate filing, the limitation of the forecast period to the historical test year, and the restrictions inherent in applying the "known and measurable" standard, the methodology used by EPEC is, in his opinion, appropriate. He pointed out also that this annualization methodology has been successfully used in every Company rate filing in all three jurisdictions (Texas, New Mexico, and FERC). Last, this annualization methodology can be readily verified and understood by all the parties to the rate proceeding, a critical point in explaining to a particular customer group why the kWh sale level for that group should be adjusted to develop the appropriate rate or allocate the appropriate level of costs.

Mr. Hicks verified the reasonableness of using adjusted test year figures as the anticipated sales level during the rate year by comparing them to the historical sales for the most recent 12-month period, that ending July 1987. This comparison showed that the total system sales for this 12-month period were 5.1 percent greater than the annualized total system sales. If the same growth rate continues unchanged in 1988, Mr. Hicks observed, the annualized kWh sales will still be within five percent of actual sales.

The most serious flaw in Mr. Ramgopal's recommendation is the use of separate sales forecasts for developing anticipated fuel expenses and for determining all other sales related expenses and allocations for cost of service runs and rate design, according to Mr. Hicks. In order to properly calculate the additional fuel expense, in his view, a production modeling program with revised inputs for energy and peak demand must be run to simulate dispatch of the generating units, and there must be a change in the allocators used in the jurisdictional and class allocation of fuel expense. Third, the increase in fuel expenses causes an increase in fuel revenues, impacting all revenue related expenses which must then be properly allocated. Mr. Hicks believes that Mr. Ramgopal was not properly concerned with any other considerations, such as jurisdictional and class allocators, annualized revenues, and billing determinants for rate design. In his view, if an error in the sales forecast is to be tolerated, it is better for it to be in the fuel factors, since they can be immediately revised on an interim basis.

On cross-examination, however, Mr. Hicks agreed that Mr. Boecker had presented the system dispatch using Mr. Ramgopal's projected sales figure, but he stated again that no new system peak demand had been made based on the new forecast. (Tr. at 2420.) He further acknowledged, reluctantly, that his quarrel was with allocation, and that there was a rate design phase of this case in which those concerns could be addressed. (Tr. at 2422.) Finally, he conceded that he had not analyzed the technical adequacy of Mr. Ramgopal's model. (Tr. at 2422.)

This report recommends use of Mr. Ramgopal's total sales (MWH) in the calculation of the fixed fuel factors. His model clearly complies with the requirements of Rule 23.23(b)(2)(C) in that it produces a forecast of the total sales during the rate year of 1988. Mr. Hicks's annualization of test year sales, based as it is on a known and measurable standard, simply does not produce the projected sales required by the rule. Further, the technical sufficiency of Mr. Ramgopal's model was not assailed, and its sophistication is not a reason to reject it. Any allocation problems resulting from use of different kWh sales for fuel can be addressed in rate design.

5. Fuel Factors

Mr. Boecker used the projected MWH for the rate year developed by Mr. Ramgopal, and he added pump sales of 33,634 MWH and losses of 395,548 MWH for a total of 5,185,500 MWH at supply to be used in calculating the fixed fuel factor at supply. This report recommends adoption of the staff's total MWH for use in calculating the fixed fuel factor at supply. After making the appropriate jurisdictional adjustments to determine the Texas retail base fuel factor, pursuant to P.U.C. SUBST. R. 23.23(b)(2)(C)(ii) the Texas retail base factor should be further adjusted for the line losses at the three different voltage service levels to determine the fixed fuel factors for EPEC's transmission, primary and secondary voltage level Texas customers. In accord with the recommendations below in Section XVI of this report, transmission level service will be at three different voltage levels, and the fuel factors should be calculated to include these distinctions within the transmission level service.

6. Non-Reconcilable Costs

EPEC had included only the demand component of the SPS contract in its non--reconcilable fuel costs. This amount was $6,030,900, based on EPEC's purchase of 75 MW per month. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 3; Tr. at 287-295.) Mr. DeWard recommended reducing this amount based on the 50 MW per month EPEC could purchase beginning in February 1988, and including it in the fixed fuel factor and not in base rates. (City Ex. No. 6 at 30-31; and at Schedule 15-1.) EPEC had also requested $2,256,967 (Account 565) in wheeling expense. (EPEC Ex. No. 1, Vol. 7, Schedule G-7, p. 3.)

Mr. Kaplan recalculated not only the demand charges in the SPS contract but also the capacity costs associated with EPEC's interconnection agreement with SPS and its agreements to buy transmission line capacity from the Salt River Project and Public Service of New Mexico. Those amounts for the rate year calendar 1988 are as follows:

Salt River Project	$567,300
Public Service NM	$900,000
Subtotal (Acct. 565)	$1,467,300
SPS	$4,188,125

(Staff Ex. No. 16 at 71-72; and at Schedule SK-D-3.)

Mr. Kaplan had also removed from rate year coal costs $308,539 in coal ash and scrubber sludge handling costs. Mr. Boecker included both this amount and the SPS demand charges in the non-reconcilable fuel costs shown on Staff Ex. No. 27 at Schedule WB10. The staff recommends total non-reconcilable fuel and purchased power costs of $4,496,664, to be recovered in base rates and a $789,667 reduction in requested wheeling expense.

Mr. DeWard's recommendation does not comply with Rule 23.23(b)(2)(B)(ii) which states that purchased power capacity costs will not be included as known or reasonably predictable fuel costs to be recovered through the fixed fuel factor. The staff's recommendation complies with the Commission's rule, and should be adopted.

7. Summary

The fuel factors should be calculated using the reconcilable fuel and purchased power expense recommended herein, the staff's short-term forecast of sales, and the line loss factors recommended below in Section XVI.I.1. of this report.

B. Operations & Maintenance

The following witnesses testified regarding various operations and maintenance adjustments: for the Company, William J. Johnson (EPEC Ex. No. 1, Vol 4, Tabs 21 and 22, as amended by EPEC Ex. No. 1A Errata; Tr. at 55-269); Daniel G. Ellis (EPEC Ex. No. 1, Vol. 4, Tabs 28 and 29; Tr. at 3347-3374); James Mayhew (EPEC Ex. No. 1, Vol 6, Tabs 40 and 41, Schedules ?; Tr. at 621-714); and Donald B. Karner (EPEC Ex. No. 1, Vol. 6, Tab 42; Tr. at 5249-5255); for the City of El Paso, Thomas C. DeWard (City Ex. No. 6 and 6A; Tr. at 1116-1357); Hugh Larkin, Jr. (City Ex. No. 5; Tr. at 1079-1115); and Dale G. Bridenbaugh (City Ex. Nos. 47 and 47A; Tr. at 5412-5513); for the Commission staff, Robert Reilley (Staff Ex. No. 10; Tr. at 1672-1733); Mark Young (Staff Ex. Nos. 11 and 28; Tr. at 1734-1882 and 6430-6459); and Waldon A. Boecker (Staff Ex. Nos. 5 and 27; Tr. at 744-788 and 6460-6467); and on rebuttal for the Company, Mr. Johnson (EPEC Ex. No. 41, Tab 8; Tr. at 2445-2484); Robert L. Gaeckle (EPEC Ex. No. 41, Tab 3; Tr. at 2206-2248); Joseph E. Wasiak (EPEC Ex. No. 41, Tab 14; Tr. at 2295-2301); and William P. Wright (EPEC Ex. No. 41, Tab 15; Tr. at 2270-2294).

The recommendations in the section of the report are based on the most credible and appropriate facets of witnesses' testimony; the levels of expenses recommended have been found to be reasonable and necessary in the provision of electric utility service to the public, in accordance with the standards set forth in P.U.C. SUBST. R. 23.21(b).

1. Salaries and Wages

EPEC adjusted test year payroll of $24,061,441 by annualizing gross payroll, excluding overtime, based on pay periods ending December 14, 1986, for operating employees and December 21, 1986, for confidential employees. Included in the annualization is the six percent across-the-board pay increase. (Every employee did not receive a six percent raise. The amount of any individual employee's raise was discretionary based upon meritorious performance. The net effect of the December 1986 raises, however, was a six percent increase in total payroll.) Gross wages before overtime were $29,565,293. This amount was further adjusted to include test year overtime ($561,887) and summer employee wages ($78,000). Test year management fees ($104,884), security guard salaries ($11,689) and marketing salaries ($32,496) allocated to or associated with FL&R were deducted from gross salaries and wages, as was payroll for Renaissance 400 ($28,642) to yield adjusted gross salaries and wages of $30,027,469. EPEC then applied the test year payroll expense factor of 88.57 percent to arrive at adjusted salaries and wages expense of $26,595,329. (EPEC Ex. No. 1A Errata at Schedule A-7, Adjustment No. 4, pp.1 & 2.)

Mr. Young annualized the April 14, 1987, regular operating payroll and the April 8, 1987, regular confidential payroll to calculate an average annual salary per employee, then multiplied the average annual salary by the test year end number of employees less one (Mr. Bostic retired after test year end) to derive staff's total annual base payroll expense of $27,780,064. He selected April 1987 pay periods for annualization in order to incorporate a two percent mandatory union raise effective March 1, 1987, as well as other increases for meritorious performance granted through April 1987. In addition, Mr. Young added the same test year overtime expense and deducted the same FL&R related expenses for management fees and security guard salaries as did EPEC. Mr. Young deducted only $13,584 for Renaissance 400 salaries and an annualized amount of $37,140 for FL&R marketing salaries, yielding staff's recommended total payroll cost of $28,174,694. To this was applied the calendar year 1986 payroll expense ratio of 88.04 percent, resulting in total recommended payroll expense of $24,805,001. Mr. Young's payroll expense factor is based on his analysis of the expense ratios from 1981 to 1986 (for which he discerned no definite trend) and his observation that the completion of Palo Verde during the test year indicated to him a decrease in the capitalization ratio and a corresponding increase in the expense ratio. Staff's recommendation was a $743,560 increase to test year expense, and a $1,790,328 reduction to EPEC's request. (Staff Ex. No. 11 at 10-13.)

In his annualization of salaries and wages, Mr. DeWard did not recognize a six percent wage increase for executive payroll; because that group had had a ten percent increase in December 1986, he believed the additional six percent was not appropriate. He agreed with EPEC's removal of the Renaissance 400 payroll. He also agreed with removal of FL&R-related marketing salaries, but opined that the amount removed should be the annualized salaries rather than the test year salaries because those salaries were included in the gross annualized payroll. His calculation of the marketing salaries to be removed is $56,293; EPEC conceded the validity of this argument in its reply brief. Finally, Mr. DeWard's expense ratio of 87.48 percent was based on a three year historical average, chosen to reduce the effects of unusual events on the capitalization ratio. His recommended expense for salaries and wages is $25,972,922. (City Ex. No. 6 at Exhibit TCD-1, Schedule 16.)

This report recommends use of the staff's annual total annualized base payroll of $27,780,064, since it includes the effects of the wage increases in 1987 but eliminates the effect of increased employee levels which may be related to post test year customer growth. Mr. DeWard's recommendation that the additional pay raise to executive employees was inappropriate was not based on anything other than his personal opinion. Further, Mr. Johnson successfully defended the reasonableness of this pay increase when he testified that these employees had not had cash increases in compensation during the two years of the cash containment program and, unlike other employees, could not sell the stock they received in lieu of cash raises. To this amount should be added test year overtime expense of $561,887 (per EPEC, staff and City) and test year summer help expense of $78,000 (per EPEC and City), and from this amount should be deducted the FL&R test year management fee of $104,884 (per EPEC, staff and City), the FL&R allocated test year security guard salaries of $11,689 (per EPEC and staff), FL&R annualized marketing salaries of $56,293 (per City and EPEC) and Renaissance 400 salaries of $28,642 (all three parties recommended the adjustment; the number is EPEC's). This results in an adjusted gross expense for salaries and wages of $28,218,443, to which should be applied the staff's expense ratio of 88.04 percent. EPEC's expense ratio has been above 88 percent for four out of the past six years, and in its brief, EPEC agreed with use of the staff's expense ratio. The recommended salaries and wages expense is $24,843,517, a decrease of $1,751,812 to EPEC's request.

2. Employee Benefits

a. <u>401-k Plan Expense</u>. EPEC proposed to include in cost of service the amount of the plan contribution made during the test year, $180,192. Mr. Young's review of the plan revealed contributions of $400,924 in 1985 (the year of inception) and $439,254 in 1986. Mr. Young recommended including $386,719 (the result of multiplying the 1986 contribution amount by staff's payroll expense ratio of 88.04 percent), an increase of $206,527 to EPEC's request. Mr. DeWard made no specific adjustment for this employee benefit, but in brief the City argued that this Commission has an obligation not to increase the level of expense requested by the applicant and that the staff's adjustment should be eliminated from cost of service. But, as pointed out in general counsel's reply brief, there is no legal basis for the City's position; the Commission's mandate is to set just and reasonable rates. This report concurs in the staff's recommendation on 401-k Plan expense.

b. <u>Pension Expense</u>. The Company's request of $1,966,049 was based on the minimum funding requirement of $2,219,769 in the actuarial report for the plan year ending December 31, 1985, multiplied by the Company's proposed 88.57 percent payroll expense ratio. Mr. Young used the actuarial report for the plan year ending December 31, 1986, (which had not been available when EPEC filed this application), to utilize a more current minimum contribution amount of $2,094,786. He applied to that the staff's payroll expense ratio of 88.04 percent, resulting in a pension expense of $1,844,250.

Mr. DeWard's only adjustment was to change the payroll expense ratio from 88.57 percent to his recommended ratio of 87.48 percent. Based on this recommendation, a pension expense of $1,941,854 would result.

This report recommends use of the staff's recommended pension expense amount, since it is based on more recent information and on a payroll expense ratio supported both by credible evidence in the record and EPEC's acquiescence in its use.

c. Employee Insurance. EPEC multiplied total test year insurance cost of $1,986,351 by its test year payroll expense factor of 88.57 percent to derive its adjusted insurance benefit expense of $1,759,311. Mr. DeWard made no adjustment to this expense other than to use his recommended expense ratio of 87.48 percent, which would result in an adjusted employee insurance expense of $1,737,659.

This report recommends adoption of the staff's insurance benefit expense because it segregates FL&R related amounts and is calculated using the staff's payroll expense ratio. In calculating this amount, Mr. Young reviewed December 1986 invoice amounts for voluntary accident, disability, dental, and group accident insurance plans. Annualized premiums were $420,648. He also obtained the January through June 1987 medical insurance premiums and annualized them (excluding amounts reimbursed by employees, retirees, and FL&R) to derive a total annual medical insurance cost of $1,531,925. The staff's recommended total annual premiums of $1,952,573 were then multiplied by the 88.04 percent expense ratio, resulting in a total insurance expense of $1,719,045. This amount is an increase to test year of $85,860 and a decrease of $40,266 to the Company's request.

d. LESOP Expense. EPEC originally requested $2,920,900 in LESOP (Leveraged Employee Stock Option Plan) expense, then later amended this request to $2,420,900. (A detailed explanation of the LESOP is contained in Mr. Gordon's cross-examination of Mr. Johnson, Tr. at 93-100.) City witness DeWard recommended disallowance of the entire amount. He believes the LESOP is unnecessary and, in his opinion, results in excessive fringe benefits for EPEC employees, because the Company already has other fringe benefits available for retirement, namely, the pension plan and the 401-k plan. Mr. DeWard thought the expense was too high, and that part of it should have been capitalized to construction.

Mr. Young calculated this expense using the same methodology as EPEC; however, he made some additional calculations and capitalized part of the resulting total expense. During the presentation of the Company's direct case (after Mr. Young had already filed his direct testimony), EPEC witness Johnson explained that the LESOP expense amount was being reduced by $500,000. He personally had been negotiating with the Bank of New York for a reduction in the annual principal payment, and although the restructuring had not then been accomplished, he went ahead and reduced the principal payment amount by $500,000.

Mr. DeWard based his recommendation nothing more than his personal opinion that EPEC has too many fringe benefits for its employees. This report recommends inclusion of LESOP expense calculated using Mr. Young's number (reduced by $500,000) and the formula articulated in his testimony, as follows:

1987 LESOP principal payment	$3,000,000*
1987 interest	1,069,101
Total	$4,069,101*
Less:	
Investment income	61,967
Estimated 1987 dividends on undistributed LESOP shares	1,725,078
Required Contribution	$2,282,056*
Times expense ratio	.8804
Recommended LESOP benefit expense	$2,009,122

*Reduced by $500,000

The recommended amount is a $465,568 increase to test year and a decrease of $411,778 to EPEC's amended request.

e. TRASOP Expense. The Company requested TRASOP (Tax Reduction Act Stock Option Plan) expense in the amount of $957,377. Mr. Young reduced that amount by use of the staff's payroll expense ratio of 88.04 percent, and recommended inclusion of $842,875.

Mr. DeWard recommended exclusion of the requested amount because he believes it was never intended to be an expense borne by the ratepayers but rather was to be funded through investment tax credits (ITCs) allowed under the Internal Revenue Code. He noted that the Commission rejected EPEC's request for this item in cost of service in the company's two previous rate cases, Docket Nos. 5700 and 6350. He further noted that the expense is non-recurring.

The Company's brief offers an enlightening summary of the mechanics of the TRASOP (an employee stock option plan predecessor to the LESOP), the different tax ramifications of TRASOP and LESOP, and the Commission's treatment of the Company's prior requests for this item in cost of service. The Company points out in its brief that its recapture of some of the ITCs - as a result of the sale/leaseback - has resulted in the ITCs being unavailable to cover the TRASOP expense with tax savings. This, according to the brief, goes to the heart of the Commission's actions in Docket Nos. 5700 and 6350, since in both dockets the agency's orders were premised on the assumption that EPEC would not incur any out-of-pocket expense for the TRASOP because of the ITCs. EPEC urges that not only is that assumption no longer valid, the contrary is now the case: the Company is now certain that the ITCs will not be available and there will be no tax savings to offset the expense. (Applicant's Brief-Phase I-Revenue Requirement at pp. 54-58.)

In its reply brief, the City of El Paso argues that the fact that once-anticipated tax benefits are no longer available to fund the plan because of activities (the sale/leaseback) which benefit subsidiary operations does not justify charging the expense to ratepayers. (Reply Brief of the City of El Paso at pp. 16-17.)

The Company's brief quotes at length from the Examiners' Report in Docket No. 5700 about why TRASOP expense should be included in the cost of service; however, the Commission did not adopt the examiners' recommendation in that case. Unfortunately for EPEC the evidence on TRASOP was not very well developed in the record here, as candidly stated in EPEC's brief. The Examiners' Report in Docket No. 5700 cannot substitute for evidence in this record and, given the Commission's past rulings on this question, there is simply not enough evidence here to support inclusion of this expense. The report recommends excluding all TRASOP expense.

f. Other Employee Benefits. The Company requested $560,998 in other employee benefits; Mr. Young adjusted this amount by including only 88.04 percent of it, which is $493,903. This amount is a reduction of $67,095 to both test year expense and EPEC's request. Mr. DeWard made no adjustment to this amount. The report concurs in the staff's adjustment and recommends adoption of the staff amount for other employee benefits.

g. Summary of Employee Benefits. EPEC requested a total expense for employee benefits of $8,012,420. The staff's recommended reduction to this expense, $608,803, results in a total staff recommended expense of $7,403,617. (Staff Ex. No. 28 at Schedule II Revised shows the staff expense for this amount to be $7,903,617, but this is because staff did not incorporate EPEC's $500,000 reduction in LESOP expense in the Company amount in Column 3.) The City's recommended employee benefit expense is $4,588,297. The report recommends $6,453,039, as explained above.

3. Advertising, Contributions and Dues Expense

EPEC originally requested a total of $253,433 in advertising expense and dues, but later amended this amount to $226,585.

The amount EPEC requested in Account 909 was $88,192. Staff reduced this amount by $7,872 to eliminate payroll amounts already included in Salaries and Wages. City witness DeWard recommended removing $9,681 in expense for advertising microwave ovens, and half the $6,030 in expense for promoting use of solar screens and tinted windows and half the $6,873 expended in advertising efficient air conditioners. Mr. DeWard's theory is that this is the type of advertising provided by manufacturers to sell products, not by utilities to provide electric service. He conceded that the solar screen/tinted windows and air conditioner ads in part promoted efficient use of electricity; thus he only excluded half these costs. His total adjustment to this account is $16,133.

The Company originally requested $30,665 in Account 930.1, but reduced it by $2,234 (EPEC Ex. No. 1A Errata at Schedule A-7, Adjustment No. 6) apparently in agreement with Mr. DeWard's adjustment to eliminate the expense for ads promoting EPEC employees. Mr. DeWard also proposed other adjustments for this account which would remove expenses for ads promoting industrial development, subcontractors, the Sunbelt, and ads about the history of the Company. His addi- tional adjustments were $12,600. Mr. Young made the same adjustment in this account as in Account 909 above to deduct $3,009 in payroll already included in Salaries and Wages.

EPEC's request of $130,220 for Account 930.2 included $24,614 in expenses related to Big Bend Resources Trust. Staff removed them, and EPEC amended its request to exclude that amount, agreeing with staff. (EPEC Ex. No. 1A Errata at Schedule A-7 Adjustment No. 10.)

In rebuttal, Mr. Johnson testified that Mr. Young inappropriately removed test year payroll from advertising expense, regulatory commission expense, and injuries and damages, as follows:

	Account No.	Amount
Advertising Expense	909	$ 7,872
General Advertising	930.1	$ 3,009
Regulatory Commission Expense	928	$694,205
Injuries and Damages	925	$108,866

According to Mr. Johnson, the payroll amounts in these accounts had been added to total test year payroll of $24,061,441, as shown in EPEC Ex. No. 1, Vol. 9, Workpapers, Schedule G-1, Page 24 of 24 Workpaper; EPEC's adjustments to these accounts were to other items of expense in those accounts, and did not include adjustments to the payroll in these accounts. Mr. Johnson concluded that the staff's recommended adjustment to remove the payroll amounts from these accounts would result in EPEC recovering only the increases to payroll, not the base test year amounts. (EPEC Ex. No. 41, Tab 8, pp. 13-15.)

But Mr. Young's recommended payroll expense began with annualization of payroll for two pay periods in 1987, so *all* payroll amounts, base wages and raises alike, would be included in the staff's recommended salaries and wages expense. In addition, it appears that EPEC double-counted these expenses. For example, the $694,205 payroll amount in Regulatory Commission Expense appears in the $24,061,441 Total Payroll charged to O&M (EPEC Ex. No. 41, Tab 8, Exhibit WJJ-9 [Schedule G-1, Page 24 of 24 Workpaper]; EPEC Ex. No. 1, Vol 7, Schedule A-6, line 36, column 1; EPEC Ex. No. 1A Errata at Schedule A-7 Adjustment No. 4) as well as in the total amount requested for Regulatory Commission Expense (EPEC Ex. No. 1A Errata, Schedule A-7 Adjustment No. 8). It appears that Mr. Young's adjustment to remove payroll amounts from these accounts is correct.

This report recommends against adoption of Mr. DeWard's proposal to exclude half the cost of advertising expense for solar screens/tinted windows and air conditioners because his rationale - that the ads promote the products themselves - is illogical. The ads do not mention any particular manufacturer or distributor, and it would seem impossible to give customers useful information about energy efficiency without describing generally the products available for achieving that goal. In addition, Mr. DeWard articulated no basis for excluding half the costs. His recommendation regarding microwave oven advertising, however, was not rebutted by the Company, and should be adopted.

The Commission has only recently voiced concern over this type of expense, in Docket Nos. 7195 and 6755 - <u>Application of Gulf States Utilities Company for Authority to Change Rates</u> and <u>Inquiry of the Public Utility Commission of Texas into the Prudence and Efficiency of the Planning and Management of the River Bend Nuclear Generating Station</u>. The recommendation here is based on the record developed prior to the Commission articulating these concerns.

In summary, the following amounts should be included in expense for advertising, contributions and dues:

Account 909	$ 70,639
Account 930.1	12,822
Account 921	4,356
Account 930.2	105,606
Total	$193,423

4. Regulatory Commission Expense

EPEC's original request for a $1,872,454 increase to test year expense of $2,772,991 (for a total expense of $4,645,445) was amended at the beginning of the hearing on the merits to an increase of $1,392,033 (for a total expense of $4,165,024) to account for a change in the expense requested for the ANPP audit, discussed below. This total amount has several components.

a. Payroll. EPEC included $694,205 in payroll expense; Mr. Young removed it to avoid counting it twice, since all EPEC payroll is in staff's recommended Salaries and Wages. Although EPEC challenged this adjustment on rebuttal, it should be adopted, for the reasons given in Section XI.B.3. above.

b. Arizona Nuclear Power Project Prudence Audit (Four State Audit). The Company's original request for this category was $1,116,062, which was the amortization amount for one year (out of three originally requested) for this expense. Mr. Mayhew adjusted this amount to remove some consultants' fees and to change the amortization period from three years to one year, that is, to recover the entire amount as an expense. EPEC justified inclusion of this expense on the Commission's requirement that EPEC participate in this prudence audit.

Mr. DeWard recommended that the response costs be disallowed entirely. These were the costs of researching, tracking, and responding to the auditors' requests for information; since EPEC withdrew voluntarily from the audit, none of the benefits will be realized.

Mr. Young also recommended elimination of all ANPP Prudence Audit expenditures. He acknowledged that the Commission had required EPEC to participate in this audit, but he pointed out that EPEC had voluntarily withdrawn from the audit because it had "concluded that the audit could not be objective and impartial." Still, EPEC requested that ratepayers bear the cost of expense incurred to date because despite its withdrawal, "the Company took prudent action to protect the ratepayer from funding an audit which was being improperly managed due to lack of impartiality in the review process." Mr. Young could not find sufficient justification that ratepayers benefitted from expenses incurred.

The Commission did require EPEC to participate in this audit, with the understanding that its expenditures would be reimbursed in cost of service. The benefit to ratepayers was the completion of the audit, not whether the audit was favorable to EPEC or not. A completed audit could have confirmed the Company's claims that it was prudent, or could have concluded that there was some imprudence, or could have come to some other conclusion about EPEC's prudence with respect to Palo Verde. Withdrawal from the audit has closed off the opportunity for ratepayers to have a final evaluation on that question. Whether EPEC was justified in concluding that the audit was not being conducted fairly and impartially is not in issue; the inescapable conclusion, however, is that ratepayers simply obtain no benefit from an incomplete prudence audit. This report concurs with Mr. Young and Mr. DeWard that all expense for the ANPP Prudence Audit should be disallowed.

c. Prudence Hearing Expense. The Company requested a total of $1,102,042 for the expenses it expected to incur during the prudence phase of this docket. Mr. Young's view was that many of the anticipated expenses had not been incurred to date and, being unknown and immeasurable, these expenses should not be included in EPEC's cost of service in this case. However, he also suggested that EPEC record its prudence hearing expenses in FERC Account 186, Miscellaneous Deferred Debits, and that the costs recorded in this account be reviewed in the next rate case for reasonableness and possible inclusion in rate case expense at that time.

Mr. DeWard recommended that costs incurred by ANPP in developing a prudence review to be used in regulatory proceedings should be allocated to EPEC at the 15.8 percent, rather than 22.2 percent, and amortized over the forty year life of the plant, instead of the three years requested by EPEC. The affirmative costs were incurred to defend against any possible adverse results from the prudence audit in rate cases or other hearings conducted by regulatory bodies, but in Mr. DeWard's view, ANPP would have incurred such costs to justify its expenditures for Palo Verde even if regulated entities were not involved. He therefore concluded that all owners, not just those which are regulated, should share in the affirmative costs in proportion to each one's ownership interest in Palo Verde. Additionally, Mr. DeWard recalculated the ANPP affirmative audit expenses allocable to EPEC, and he recommended a $53,016 decrease in

EPEC's requested prudence phase expenses relating to the travel allowance for EPEC's employees. The adjustment was based on the difference between the cost of a round trip between El Paso and Austin in the Company's airplane and the cost on Southwest Airlines.

At the hearing, EPEC witness Mayhew confirmed that as of June 30, 1987, EPEC had booked $1,353,383 for expenditures related to the prudence phase of this docket, which represented consultants' and attorneys' billings through May 31, 1987, but did not include any expenses for the hearing itself (the prudence phase of which began on September 14, 1987). (Tr. at 675-677.) Mr. Mayhew also testified that this is an important case for EPEC, and the most complex case he had ever been involved in. (Tr. at 682-683.)

While it is not surprising that the Company would have spent a great deal of money preparing for and participating in this docket, the actual booked amounts reported by Mr. Mayhew may include unreasonable levels of expenditures, such as the cost of travel on the Company's airplane as reported by Mr. DeWard; those are not known. EPEC's reply brief (pp. 33-34) indicated agreement with Mr. Young's proposal, and the report recommends adoption of that resolution.

d. <u>City of El Paso Rate Case Expenses</u>. The Company did not include an estimate for City rate case expenses in its request for Regulatory Commission Expense. Mr. Mayhew testified that EPEC would reimburse the City when its expenses were known and recoup them in a one-time surcharge to ratepayers living within the corporate limits of the City of El Paso, based on the Commission's order in <u>Application of El Paso Electric Company for a Rate Increase</u>, Docket No. 1981, 4 P.U.C. BULL. 436, 480 (November 9, 1978). (EPEC Ex. No. 1, Vol. 6, Tab 40 at pp. 6-6.1.)

Mr. DeWard included his estimate of City rate case expenses based on the expectation that the hearing would last ten weeks; as of the hearing, the amount was $1,005,355 (City Ex. No. 6 at TCD Exhibit 1-Schedule 25-1; Tr. at 1118) and was estimated to increase at the rate of approximately $11,900 per week for each week of hearing after the tenth week. (City Ex. No. 6 at 50.) In its brief, the City observed that the tenth week of hearing concluded on October 22, 1987, and requested $12,000 per week for each week of hearing after that date. (Brief of the City of El Paso-Phase I-Revenue Requirement, p. 55.) Since the hearing adjourned on December 9, 1987, seven weeks after October 22, the City has requested an additional $84,000 in rate case expenses, for a total of $1,089,355. In addition, Mr. DeWard challenged EPEC's proposal to charge only the ratepayers in the City of El Paso, citing Commission orders in EPEC rate dockets subsequent to Docket No. 1981 in which no specific assignment of City rate case expense was made. Mr. DeWard asserted that although the City of El Paso intervenes on behalf of its constituency, all ratepayers benefit from the City's participation.

Mr. Mayhew confirmed on cross-examination that the hourly rates for the City's experts and attorneys were reasonable, and that the City's total rate case expense of $1,005,355 was reasonable. In fact, he thought it was low. (Tr. at 689-695.) He further acknowledged that if there was a reduction in the cost of service for all ratepayers which could was directly attributable to the City's participation in the rate case, then all ratepayers would have benefitted from that participation. (Tr. at 700-702.)

The evidence in this docket demonstrates that through Requests for Information to the Company from the City of El Paso, the Company became aware of an error it had made with respect to Palo Verde property taxes paid to Maricopa County, Arizona. As a result, EPEC amended its 1987 tax filings and realized total tax savings of $1,791,000. (City Ex. No. 3, p. 2 of 2; Tr. at 411-424.)

This report recommends inclusion of the amount of City rate case expenses supported by credible evidence, that is, $1,005,355. Any amounts in excess of that are not known with any confidence, but could be requested in the Company's next rate case after the exact amount is determined, as suggested in EPEC's reply brief. The method for recovery of the City's rate case expenses is addressed below in Section XIV.

e. <u>Other</u>. EPEC requested $454,753 in general rate case expense; $1,067,990 in rate case expense; and $200,000 in expense for the Touche Ross Management Audit. There was no challenge to these requested amounts; the examiners find them reasonable and recommend their inclusion.

f. Summary. The total Regulatory Commission Expense recommended by this report is $2,728,098, calculated as follows:

Payroll	$ 0
General Rate Case Expense	454,753
Rate Case Expense	1,067,990
ANPP Prudence Audit	0
Prudence-Docket No. 7460	0
Touche Ross Management Audit	200,000
City Rate Case Expense	1,005,355
Total	$2,728,098

5. Rio Grande 3, 4, and 5

In December 1985, EPEC reclassified Rio Grande Units 3, 4, and 5 from plant in service to plant held for future use. Since these units are not included in rate base, EPEC removed $4,014 in associated test year expense. No party challenged this adjustment, and the report agrees that it should be made.

6. Other O&M

Because of amendments EPEC made at the time the hearing on the merits convened, this category of expense is now ($125,193). The report recommends that it be included, since it incorporates all the corrections which EPEC made to its summary of adjustments to O&M. (EPEC Ex. No. 1A Errata Schedule A-7, Adjustment 10.)

7. PVNGS Operations and Maintenance

Since EPEC is requesting PVNGS Unit 1 in rate base, and since the Company remains responsible under the PVNGS Unit 2 lease for operations and maintenance expenses, property taxes, and decommissioning expense on that unit, EPEC has requested $30,061,000 for annualized O&M expenses for both units in cost of service. Mr. Johnson used Palo Verde O&M Budget Forecast No. 20, November 1986, prepared by ANPP Project Manager Arizona Public Service Company (APS). Mr. Ellis, Director of Budgets and Forecasts for APS, provided an overview of budgeting for PVNGS and prepared estimates of 1987 O&M expenses for PVNGS.

EPEC's O&M adjustment excludes fuel costs, includes all other production and A&G (administrative and general) expenses on PVNGS Units 1 and 2 and common facilities, but excludes all PVNGS Unit 3 A&G expenses. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 11.) Palo Verde nuclear fuel costs have been discussed previously (Section XI.A.1.c. above).

Mr. Bridenbaugh's review of the requested O&M expense was not based on a strict standard of reasonableness; instead he looked at whether the 12-month test period is representative of the future period in which rates will be collected, noting that forecasted or budgeted amounts are difficult to analyze because of the judgmental nature of the budget process and that historical information developed prior to a nuclear unit's first refueling outage is atypical of subsequent operations. He believes that since neither PVNGS Unit 1 or 2 has had its first refueling outage a major piece of information is missing.

Mr. Bridenbaugh compared the Company's requested PVNGS O&M expenses to those reported at other plants, reviewed information about specific PVNGS activities, and considered the allocation of common and water reclamation facilities (WRF) cost among each of the three PVNGS units. Although he found that PVNGS O&M expenses fall in the high end of the range (and he could determine no particular reason for that), he also noted that they are not grossly out of line with other plants that have been in service a number of years. (City Ex. No. 47A.) He did, however, challenge the allocation of all common facilities and WRF expenses to Unit 1. He recommended excluding one-third of the O&M expenses for the common facilities and the WRF (along with their proportionate shares of A&G), and that the question of capitalization or amortization of those amounts be deferred until PVNGS Unit 3 is considered for rate treatment.

In implementing Mr. Bridenbaugh's recommendation, Mr. DeWard removed one-third of the common and water reclamation facilities expenses from requested Palo Verde O&M because even though Unit 3 has not yet been recognized in rates, EPEC's request includes all O&M expense related to common facilities. In his opinion, common facility costs should be borne equally by all three PVNGS units. The adjustment is a reduction of $2,113,667, one-third the total adjusted common facility expense of $6,341,000.

Based on Mr. Boecker's exclusion of a portion of the common facility costs, Mr. Young reduced requested O&M expense by $440,000. This was based on an allocation of Unit 3 and common and WRF costs using the percentage of common plant assigned to Unit 3 as recommended by Mr. Boecker. The resulting $29,621,000 in expense was reviewed by Mr. Boecker, who determined that it appeared to be a reasonable expense amount.

Mr. Boecker divided the $29,621,000 in expense by the expected generation from PVNGS Units 1 and 2 (2,202,300 MWH) to derive an expense of 13.45 mills per kWh (without fuel). In his opinion, this is reasonable, considering the length of time Units 1 and 2 have been in operation and comparing that to actual expenses for other nuclear generating units. Mr. Boecker reported that average O&M expenses for nuclear plants are reported by utilities and summaries are published by the U.S. Department of Energy. Based on his review of published information, between 1982 and 1985, average O&M expenses increased from 8.11 mills/kWh (without fuel) at an average rate of about 8.9 percent per year to 10.47 mills/kWh (without fuel). If O&M expenses continue to escalate at that rate, the average in 1988 would be about 13.58 mills/kWh (without fuel). (Staff Ex. No. 5 at 19 and at Schedule WB6.)

On rebuttal, Mr. Johnson used his argument regarding classification of common facilities (discussed above) as the basis for including all common facility expense in O&M in this case, that is, allocating none of the common facility O&M expenses to PVNGS Unit 3.

Consistent with the determination made above in Section IX.A. of this report, it is not appropriate to exclude the PVNGS common facility expenses, either by one-third as proposed by the City or by the same proportion as common facility capital costs have been excluded, as recommended by the staff. Using the full amount of PVNGS O&M requested by EPEC and the staff's expected generation for Units 1 and 2 and the staff's methodology for calculating a per/kWh expense yields a 13.65 mills/kWh expense (without fuel). This compares favorably with the 1988 average reported by Mr. Boecker. The Company's request should be adopted; Palo Verde O&M expense in the amount of $30,061,000 should be included in cost of service, as requested. The appropriateness of not reducing PVNGS expenses even though a portion of the capacity is not necessary is discussed at greater length in Section VII.E.3. above.

8. Deferred PVNGS O&M Expense

The Commission's order in Docket No. 6350 permitted EPEC to defer those costs currently being capitalized and the depreciation which would be recorded for PVNGS Unit 1, the cost of owning, operating, and maintaining its share effective with the commercial in-service date of PVNGS Unit 1 as determined by the Commission. Mr. Johnson testified that beginning in March 1986, EPEC capitalized to deferred charges the cost of Unit 1 and Common Plant allocated to the Texas jurisdiction in accordance with the Commission's order in Docket No. 6350. PVNGS Unit 2 was placed in commercial operation in September 1986; the following month, EPEC began deferring operating and maintenance expenses, property and payroll taxes, and continued to accrue AFUDC on the remaining portion of Unit 2 in the same manner as the Commission had permitted with respect to Unit 1.

Mr. Johnson explained that the Company's request and the Commission's approval of the deferral order on Unit 1 was to preserve the Company's financial position until the next rate case in which PVNGS Unit 1 could be considered in service for the purpose of setting rates. The decision was based on the magnitude of EPEC's investment in PVNGS and the harm which could result from the lag between the in-service date and rate base recognition of Unit 1. Upon that predicate, and the fact that the same accounting and financial issues apply to PVNGS Unit 2, the Company construed the Commission's order in Docket No. 6350 to include deferrals on PVNGS Unit 2 at the time of commercial operation. In Mr. Johnson's view, this insures the matching of revenues with expenses.

Mr. Johnson also described the Company's accounting treatment in other jurisdictions; in New Mexico, EPEC capitalized to deferred charges related to Unit 1 and common plant for March 1986, ceasing AFUDC on Unit 1 and one-third of common plant as of February 28, 1986, and expensing in April 1986 all costs related to Unit 1 and Common Plant. EPEC began depreciating one-third of common plant allocable to the New Mexico jurisdiction in April 1986. The Unit 1 costs capitalized to deferred charges for the 12 month period ending September 30, 1986 were:

	Texas	New Mexico
Operating Costs	$ 6,100,000	$ 400,000
AFUDC	15,100,000	1,100,000
Total	$21,200,000	$1,500,000

Mr. Johnson further explained that EPEC began depreciating the FERC jurisdictional portion of Unit 1 and all Common Plant in March 1986 and the New Mexico jurisdictional portion of Unit 1 and one-third of Common Plant in April 1986. No depreciation has been expensed for the Texas jurisdictional portion of Unit 1 and Common Plant or the New Mexico jurisdictional portion of two-thirds of Common Plant. Pre-commercial operation fuel cost and fuel cost incurred during a deferral period is accounted for as purchased power expense. Fuel cost related to Palo Verde power sold to customers of a jurisdiction which has recognized its portion of a Palo Verde unit in rates is accounted for as fuel expense.

Since March 1, 1986 for PVNGS Unit 1 and October 1, 1986 for PVNGS Unit 2, EPEC has been capitalizing to FERC Account 186 the Texas allocation of all O&M expenses including fuel and displacement credits, property taxes and payroll taxes. The Company also continued capitalizing AFUDC as a "carrying cost" to FERC Account 186. These carrying costs have been included on a jurisdictional basis based on the Texas allocable in-service balance.

Even though EPEC was permitted to defer depreciation expense with the commercial in-service date of Unit 1, the same purpose was achieved by truncating the depreciable life of PVNGS Unit 1 for the Texas jurisdiction. The Company proposes that for ratemaking and financial reporting, the depreciation life based on the forty-year operating license be reduced by the length of time from the in-service date to the date the plant is included in rates. Mr. Johnson explained that the staff's recommendation in Docket No. 6350 was that book depreciation be deferred until Unit 1 is in rate base and the related depreciation is recognized in cost of service. Then the deferred charges were to be amortized over a 10-year period with the unamortized balance included as a rate base item. Mr. Johnson acknowledged that although this plan complies with current ratemaking methods and with the treatment suggested in the Statement of Financial Accounting Standards No. 71 (FAS 71) Exposure Draft, it is not as beneficial to the ratepayer as the Company's proposed treatment. Under the staff proposal, the ratepayers compensate the Company for the deferred depreciation over ten years; under EPEC's proposal, the unrecovered and unrecorded depreciation expense is spread over the remaining life of the plant.

Since, in the Company's view, the purpose of the deferral order was to permit EPEC the opportunity to recover the operating and carrying costs realized on PVNGS Units 1 and 2 during the time between commercial operation and inclusion in rates, EPEC is requesting that it be granted in the order in this case all deferrals up to the expected date of the new rates. Based on an assumption that rates in this docket would become effective in November 1987, EPEC made pro forma adjustments to the test year end balances for deferred O&M, property taxes and AFUDC "carrying charges" through October 1987 to be included in cost of service. The Company further proposes a three-year amortization of the deferred O&M expenses and property taxes with no return on the unamortized balance. EPEC views a three-year amortization as appropriate, given that the deferrals represent operating costs expected to be incurred over a 13-month period. For the deferred capital costs, EPEC proposes that they be treated as a separate Texas jurisdictional asset with the amortization of carrying costs on the plant equal to the remaining depreciable life, as follows:

Deferred Carrying Charges On:	Cost of Service Amortization Period	Rate Base Return Requested?
Palo Verde Plant	38 1/3 years	yes
Non-Fuel O&M	3 years	yes
Displacement Cost Credits	3 years	yes

(*See also*, EPEC Ex. No. 1A Errata Schedule A-7, Adjustment No. 17.1.)

Mr. Bridenbaugh analyzed only the requested deferred O&M expense for PVNGS Unit 1, based on his understanding that EPEC did not have authority to defer amounts for Unit 2. Based on actual data for 1986 and the first four months of 1987, he calculated an average monthly cost for Unit 1 of $8.27 million (including the common and WRF costs and the A&G amounts). He proposed that the Commission evaluate the reasonableness of the deferred expenses on a "used and useful" standard. Because, in his opinion, Unit 1 had an unreasonable amount of outage time due to control problems and steam generator tube leaks, he recommended that the recovery of the O&M costs for one-half of the 71 days of forced outage on PVNGS Unit 1 be disallowed. He quantified this disallowance for EPEC at $1.5 million.

Mr. DeWard also took the position that clearly all deferrals related to PVNGS Unit 2 should be excluded because the Commission's order in Docket No. 6350 covered only deferrals for Unit 1, and even though the Company could have come to the Commission any time and asked for similar relief with respect to Unit 2, it did not do so. In his view, such a proceeding would have afforded all interested parties an opportunity to review the facts and present evidence. He further opined that allowing EPEC to recover any deferrals associated with Unit 2 would not only be unauthorized, it would constitute retroactive ratemaking.

Mr. DeWard made several adjustments to the deferred costs associated with Unit 1. The first relates to AFUDC and CWIP. After the in-service date of Unit 1, EPEC accrued AFUDC on the plant balances net of AFUDC credits, and offset the accrual by a portion of the total CWIP balance which was included as a part of rate base in Docket No. 6350. When Unit 2 was sold, EPEC transferred half the Texas AFUDC credits to Unit 1 and half to Unit 3. In January 1987, CWIP balances which were included in rate base (and therefore resulted in the accrual of Texas AFUDC credits) were transferred to offset AFUDC accruals for Unit 3.

In Mr. DeWard's opinion, it is inappropriate to permit EPEC to defer costs on Unit 1 without offsetting those deferrals for the full balance of Texas AFUDC credits associated with Unit 2, in addition to the amounts of CWIP included in rate base which had previously offset Unit 2 AFUDC accruals. The failure to offset deferrals burdens ratepayers in that deferred costs included in rate base are overstated as is the amortization of these costs, thereby causing increased return requirements and amortization expense. The total adjustment he recommends is a decrease of $6,775,677 to EPEC's proposed carrying cost balance at October 31, 1987. (City Ex. No. 6 at 26 and at Exhibit TCD-1, Schedule 13.)

The second adjustment proposed by Mr. DeWard was to properly record the deferred income tax liability; these adjustments are discussed below in Section XI.I. of the report.

Mr. Reilley and Mr. Young also noted that the deferral order in Docket No. 6350 specified that costs associated with PVNGS Unit 1 were allowed to be deferred; however, both were willing to proceed on the assumption that EPEC's application in this docket constituted a request to be permitted to defer costs associated with Unit 2. Mr. Reilley determined the impact of denial of the requested PVNGS Unit 2 deferral on EPEC as requiring the Company to book approximately $22,000,000 in Texas retail expenses in 1987 without offsetting revenues, resulting in a reduction in net income of $28,914,000 (34 percent). In addition, EPEC would be obligated to write off about $2.8 million of PVNGS Unit 2 deferrals booked in 1986. Mr. Reilley's original prefiled direct testimony analyzed the request for Unit 2 deferrals under the strict financial integrity standard articulated in Petition of Houston Lighting and Power Company for Authority to Change Rates and Petition of Houston Lighting and Power Company for Approval of Proposed Interim Accounting Treatment for Limestone Unit 1, Docket Nos. 6765 and 6766, _____ P.U.C. BULL. _____ (December 4, 1986). Using that standard, Mr. Reilley found that key ratios relied on by authorities on creditworthiness were not materially affected, and concluded that the deferral of Unit 2 expenses is not absolutely necessary to maintain the financial integrity of the Company. He was not convinced that lack of a deferral order on Unit 2 EPEC's cost of capital would be affected. On the basis of that analysis, Mr. Reilley recommended disallowance of deferred accounting for PVNGS Unit 2.

He did articulate other considerations, however, first among them the fact that the loss of over $30 million of income (even non-cash income) is an important financial event, making the Company clearly worse off. Mr. Reilley also believes that it is not equitable to deny EPEC the opportunity to recover expenses legitimately incurred in providing service. Since the Commission does not permit post-test year adjustments to rate base, the deferral accounting treatment is the only means by which the utility may collect from ratepayers the full capital costs associated with a new generating plant. Further, the inability of a utility to recover the expenses of new generating plant could influence investors' opinions about the quality of utility regulation in Texas. Finally, he noted that the need for deferrals related to a nuclear plant were not comparable to those associated with a lignite plant (the subject of the deferral request in Docket No. 6765), indicating that the magnitude of the costs might justify a deferral order for nuclear-fueled facilities such as PVNGS.

Mr. Reilley also suggested a methodology for adjusting deferred balances to incorporate findings with respect to imprudent investment. The deferred balances should be adjusted for any findings of imprudence before the amortization is calculated, but it should be pointed out that the appropriate amounts to be disallowed will depend on the nature of the disallowance. For example, the costs associated with disallowed capacity (such as capitalized return and deferred lease payments) would require different treatment than deferred operating expenses and fuel costs.

On cross-examination, Mr. Reilley acknowledged that there was then pending before the Commission a docket (since decided by the Commission) in which a different standard was proposed for analyzing the need for deferred accounting treatment, Petition of West Texas Utilities Company for Deferred Accounting Treatment of Certain Oklaunion-Related Costs, Docket No. 7289, _____ P.U.C. BULL. _____ (September 11, 1987). He testified that if the Commission adopted the Examiner's Report proposing the "measurable harm" standard, then under that standard, EPEC would be entitled to a deferral order with respect to PVNGS Unit 2. (Tr. at 1715-1721.)

On rebuttal, Mr. Johnson testified about the likely effects on the Company of the write-off of Unit 2 deferred amounts. (EPEC Ex. No. 41, Tab 8 at pp. 10-11 and at WJJ-5 and WJJ-6.) These exhibits demonstrate a deterioration of EPEC's ability to cover its interest and dividend payments, as well as restrictions on its ability to issue bonds or other securities, should a write-off be required. Mr. Johnson disputed Mr. Reilley's conclusion that there would not be a downrating of EPEC's debt, and EPEC witness Gaeckle testified that any further downrating of the Company's First Mortgage Bonds will result in at least one of the rating agencies, if not both, rating all of EPEC's debt below investment grade. (EPEC Ex. No. 41, Tab 3, p. 10.) Both Mr. Gaeckle and Mr. Johnson depict a gloomier financial picture for EPEC if there is no deferral order for Unit 2.

Mr. Young testified that should the Commission grant deferral of Unit 2 costs, he would include his own calculation of the deferral amounts (Staff Ex. No. 11 at Exhibit MY-1) in the staff's recommended revenue requirement in this case. He acknowledged on cross-examination that the method by which EPEC has been accounting for Unit 2 deferrals is proper, should the Commission permit such treatment (Tr. at 1858); however, he noted that EPEC's proposed deferrals for both Unit 1 and Unit 2 were calculated using actual and estimated expenses through October 1987.

The staff used actual booked deferred costs through March 1987 to figure adjustments to EPEC's requested PVNGS Unit 1 deferrals. The Unit 2 deferrals were also adjusted to use actual booked deferrals through March 1987 to be consistent with the staff's calculations on Unit 1 deferrals. Mr. Young also adjusted the deferral amounts because of the staff's proposal for different treatment of the nuclear fuel expense and displaced nuclear fuel revenues (discussed below) than was proposed by EPEC, and the staff's recommendation that a portion of the O&M expense for common facilities be allocated to Unit 3, which would logically result in allocation of a portion of the common O&M deferral to Unit 3.

EPEC included in its deferred PVNGS O&M request a net credit relating to nuclear fuel expense and displaced nuclear fuel revenues. The net displaced credit estimated by EPEC through October 1987 is $16,322,977. Requested deferred carrying cost includes a credit of $1,372,361, which is carrying cost on the net displaced nuclear fuel credit. The credit is $5,898,446, calculated as follows:

Net displaced nuclear fuel credit	$5,440,992
Carrying cost on net credit	485,441
Total	$4,955,551

Consistent with the Commission's deferral order in Docket No. 6350 and with Substantive Rule 23.23(b)(2)(D)(ii), EPEC continued to defer nuclear fuel savings after PVNGS Units 1 and 2 went into service, and the nuclear fuel displacement credit was recorded in a FERC Account 186 subaccount. In Mr. Young's opinion, the net credit relating to nuclear fuel is a kind of fuel overrecovery, and since the credit was recorded in a different FERC Account 186 subaccount than other fuel over/underrecoveries, the overrecovery in the fuel account was understated, that is, should have been a bigger amount. Mr. Young explained that because the off-setting accounting entry to record the deferral of the net nuclear fuel credit increased reconcilable fuel expense, there was a decrease to the fuel overrecovery amount refundable to ratepayers. He views the post in-service net displaced fuel amounts recorded in FERC Account 186 as a segregated fuel overrecovery due ratepayers.

Mr. Young disagreed not only with EPEC's proposed treatment of this credit (which is to include the credit in deferred amounts amounts to be amortized over three years) but also with its calculation of the fuel overrecovery relating to nuclear fuel amounts. Staff recommended that the balance of deferred displaced nuclear fuel credits be reclassified to regular fuel over/underrecovery upon implementation of rates in this docket, and to refund those amounts with interest as with any other fuel overrecovery reconciliation. In addition, Mr. Young challenged the Company's use of the 67.1596 deferral allocation factor as inappropriate for calculating nuclear fuel savings overrecovery amounts. He proposed using the allocators on the fuel cost reports to calculate the amount of the deferral, and his calculation using those monthly fuel allocators showed a total balance through March 1987 of $9,250,496, (compared to EPEC's total of $8,968,629). (Mr. Young also calculated other fuel over/underrecoveries for the period December 1986 through March 1987 along with interest on those amounts through March 1987, for the purpose of determining fuel overrecovery refunds. However, this overrecovery seems to have been addressed in Project No. 7758 and removed from consideration in this docket. The examiners requested that the parties advise what effect the Commission's order in Project No. 7758 would have on the issues in this docket, but only ASARCO responded. The status of fuel over/underrecoveries in this docket should be addressed by the parties in exceptions.)

On rebuttal, Mr. Johnson challenged the staff's proposals regarding nuclear fuel expense and displacement credits as inconsistent with staff's agreement with EPEC's three-year amortization of other deferred O&M costs. He defended EPEC's treatment of deferred nuclear fuel savings as being in accord with the Commission's order in Docket No. 6350. Mr. Johnson pointed out the discrepancy in Mr. Young's proposals, that is, that he would return the benefits of lower fuel costs for Palo Verde on a current basis while amortizing the costs associated with the operation and maintenance over a three-year period, and stated that the two amortization periods should be consistent. In addition, he pointed out that EPEC calculated a lower carrying cost amount on the deferred costs because the fuel displacement credits lowered those amounts. By refunding these amounts through the fuel over/underrecovery reconciliation, the deferred carrying costs would be higher because the total deferrals would increase.

The Company clearly is incorrect in asserting that the Commission's order in Docket No. 6350 applies to deferrals for PVNGS Unit 2. While it is true that the facts and policy considerations may be similar, or even identical, the order itself permits deferral accounting treatment only for Unit 1. However, since there is no prescribed forum or procedure by which a utility may request deferral accounting treatment, the Company's application herein can be considered a request for deferral accounting for Unit 2. Under this construction of the Company's application, all interested parties have been given the opportunity to review the facts and present evidence, thus satisfying Mr. DeWard's concerns.

In its brief, EPEC acknowledges that failure to secure deferral accounting for Unit 2 will not impair its financial integrity to the same extent as would have been the case had it been denied for Unit 1, mainly because of the cash from the sale/leaseback. That is supported by the testimony of staff witness Reilley. However, the Commission's order in Docket No. 7289 establishes a second test which provides for deferral accounting treatment in the event that there would be measurable harm to the utility without it. Mr. Johnson, Mr. Reilley, and Mr. Gaeckle all testified that not permitting the deferral of Unit 2 expenses would have severe financial consequences for the Company, and all support the granting of deferrals on Unit 2 under this second standard.

This report recommends granting deferral of PVNGS Unit 2 expenses until such time as the rates set in this docket go into effect. The amounts to be included in rates resulting from this docket should be calculated using EPEC's estimated deferrals from March 1986 through October 1987 for Unit 1 and from October 1986 through October 1987 for Unit 2. EPEC should continue to defer actual Unit 1 and 2 O&M expenses after October 1987 until rates from this docket go into effect, and to accrue a carrying charge on such O&M expense to FERC Account 186 until EPEC's next general rate case. In EPEC's next general rate case, the estimated deferred amounts should be "trued-up" to actual booked deferred amounts. In addition, the staff's adjustment regarding immediate refund of the nuclear fuel savings should not be adopted, since it results in a mismatch of the amortization periods for fuel savings and O&M expenses. In addition, not reclassifying the balance of the fuel displacement credits lowers both the total amount of deferred expenses to be recovered over the three year amortization period as well as the carrying costs on those deferred amounts. Finally, because this report agrees that all PVNGS common facilities and water reclamation facilities should be recognized in rates as of the Unit 1 in-service date, no common O&M deferred expense should be removed from the deferred expense account. In essence, the report agrees that the Company's requested $4,265,907 in deferred PVNGS O&M expense should be adopted in this case, along with the requested amortization periods, conditioned on the recognition that the deferred amounts will be trued-up in the next rate case for the Company. (It would be preferable to use actual booked deferred expenses, but those do not appear in the record. Staff simply incorporated actual booked deferred expenses for Unit 1 through March 1987 into its calculations.)

9. Palo Verde Unit 2 Sale/Leaseback

a. Lease Payments. In accord with the discussion above in Section VIII of this report, the requested PVNGS Unit 2 lease payments of $54,684,000 should be reduced by 25 percent and included in O&M expense. The amount to be included is $41,013,000.

b. Deferred Lease Payments. EPEC included in its cost of service the PVNGS Unit 2 lease payments made during the period following the sale/leaseback transactions (during which time two payments were made) until rates set in this docket become effective, originally estimated to be November 1987. The proposed amortization period for the deferred lease payments was three years. The total deferred payment amount is $28,173,680. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 13.1.)

Mr. DeWard, having concluded that it is improper to include any deferred costs associated with PVNGS Unit 2 in this proceeding, excluded the entire amount of the deferred lease payment. He testified that "technically" the PVNGS Unit 2 payments are paid in advance (because the lease specifies that the first lease payments are due April 1, 1987, and July 1, 1987), but "practically" they are made in arrears. Apparently he based his opinion on the fact that the lease payments in the Arizona Public Service Company sale and leaseback are made semi-annually and in arrears, and on his belief that the equity participants in the lease did not advance EPEC cost-free funds for the period from the dates of the sales until the first payment dates. Mr. DeWard, unsure of the Company's motives, believes a plausible explanation for EPEC's position (that the lease payments are made in advance) is that if the payments were recorded as being made in arrears, EPEC would have recorded an expense monthly from the dates of consummation through October 31, 1987, creating a much larger write-off for EPEC to absorb in the event these costs are disallowed by this Commisison.

Mr. Reilley's analysis of the need for inclusion of deferred lease payments was made in conjunction with his review of the need for all requested deferrals on PVNGS Unit 2. Based on the discussion of that issue in Section XI.B.8.b. of this report above, it is recommended that EPEC be allowed to recover 75 percent of the deferred lease payments over a three year amortization period. The total deferred lease payment is $28,173,680; the annual amortization amount is $9,391,227 (total Company) and the Texas portion of that payment (0.671596) is $6,307,110. The Texas amount reduced by 25 percent is $4,730,333.

c. Transcaction Expense. EPEC's original request was for a 26 1/2 year amortization of estimated transaction expenses of $3,500,000 at an annual amount of $132,075. The Company also requested recovery of an additional $77,044 (7/12 of $132,075) as the deferred portion of transaction expense. The total request was $209,119.

Mr. DeWard would exclude all fees and expenses of the Chrysler Capital Corporation ($358,125) from transaction expense because under the Participation Agreement the Owner-Trustee is responsible for these; the balance would be amortized over the 26 1/2 year life of the lease. Consistent with his exclusion of all deferrals of PVNGS Unit 2 expenses, he removed the $77,044 in deferred transaction costs.

Mr. Reilley recommended a 26 1/2 amortization of the $3,725,091 in actual transaction costs through March 31, 1987, for an annual amortization amount of $140,569. Mr. Young's schedules reflect inclusion of this amount, which apparently does not include deferred transaction expense.

This report recommends use of the actual transaction costs through March 31, 1987, less the fees and expenses of the Chrysler Capital Corporation, the balance to be amortized over 26 1/2 years, plus 7/12 of the annual amortization amount in deferred transaction costs, calculated as follows:

Transaction expense (3/31/87)	$3,725,091
Less Chrysler Capital Corp.	
fees and expenses	358,125
Total	$3,366,966
Annual amortization	$ 127,055
Deferred transaction expenses	74,115
Total	$ 201,170

The recommended amount is a decrease of $7,949 to EPEC's request.

10. Property Insurance

EPEC excluded Palo Verde expense of $187,238 from its test year property insurance expense of $2,091,823 for a net test year expense of $1,904,586. This amount was then reduced by $152,062, based on an analysis of current property insurance premium costs; the Company's original request was $1,752,523. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, line 17.)

There is some confusion in the record, however, as to the amount EPEC is actually requesting for this expense, based on a comparison of the Company's original Schedule A-7 and its errata Schedule A-7. The Company's original schedules and supporting Adjustment Nos. 10, 11, 12, and 14 showed a property insurance per books expense of $2,091,823 less test year Palo Verde expense of $187,238 for a net per books expense of $1,904,586. Schedule A-7, Adjustment No. 11 shows $187,238 as the Account 924 (Property Insurance) per books expense for Palo Verde. However, in its amendment (EPEC Ex. No. 1A Errata Schedule A-7), the per books amount for property insurance (line 17) is $2,091,823 ($187,238 greater than in the original schedule, and the original unadjusted test year per books amount which included test year Palo Verde expenses). In addition, the Other Unadjusted O&M is $18,503,301 on Errata Schedule A-7, which is $187,238 less than on original Schedule A-7. So apparently the $187,238 was included in Other Unadjusted O&M on original Schedule A-7. (See, EPEC Ex. 1, Vol. 7, Schedule A-7 at page 1 of 2, column headed "Books," lines 17 and 19 and at Adjustment No. 14, page 1 of 1.)

Mr. DeWard recommended a $686,275 reduction in the expense amount for the non-Lloyd's of London portion of the premium on an insurance policy identified as All Risk Property - Boiler and Machinery. The total premium is $1,597,112; the non-Lloyd's portion is $1,372,549. In discovery, Mr. DeWard learned that, in the opinion of an EPEC employee, the cost of the insurance would be reduced significantly effective with the policy being rewritten September 1, 1987. It was his interpretation of this information that premiums on the non-Lloyd's part of this policy should be reduced by 50 percent, the amount of his reduction above.

On cross-examination, however, Mr. DeWard acknowledged that the Company's best estimate of the premium cost for this portion of the policy was $850,000. (Tr. at 1230-1233.) Yet he continued to assert that his adjustment was appropriate because it had been confirmed, more or less, by the Company's estimate.

Mr. Young's adjustment results from multiplying EPEC's requested current premium cost by a ratio of .742. The staff recommends property insurance expense of $1,300,372. The expense factor is based on the ratio of test year end CWIP to test year end total plant balances in recognition that a portion of property insurance should be capitalized to CWIP.

There is no basis for Mr. DeWard's adjustment other than his personal opinion. EPEC concedes that the policy was to be rewritten, but at the time Mr. DeWard and the witnesses for the Company were on the witness stand (prior to September 1, 1987), the only information about the premium was that the non-Lloyd's part would be about $850,000, not $686,275 as suggested by Mr. DeWard. Mr. DeWard's adjustment should not be adopted; however, an adjustment to reflect the decrease in this premium, based on the Company's estimate, should be made.

The report recommends adoption of the staff methodology and expense factor. Since Palo Verde O&M is a separate category of O&M expense, the property insurance expense should be the test year per books amount excluding Palo Verde expenses ($1,904,586) less the Company's $152,062 reduction in current premium costs, and less the difference between the $1,372,549 originally included for the non-Lloyd's part of the All-Risk Property - Boiler and Machinery Policy and the $850,000 anticipated premium effective September 1, 1987, times the staff's expense/capitalization factor of .742. The amount to be included for property insurance expense is $912,641, calculated as shown below. This is a reduction of $839,883 to EPEC's original request of $1,752,524.

Adjusted Property Insurance	$1,904,586
Less adjustment for current cost	152,062
Less All-Risk Policy adjustment	
($1,372,549 - $850,000)	522,549
Total	$1,229,974
Times expense factor	.742
Total allowed	$ 912,641

11. Injuries and Damages

The Company requested a $1,750,536 increase to test year injuries and damages expense of $1,605,336 for a total request of $3,355,872. According to Mr. Young, EPEC's request is based on actual 1987 injuries and damages costs, plus $108,866 of test year payroll. Mr. Young used only the 1987 actual injuries and damages cost of $3,247,006 and applied staff's 88.04 percent payroll expense ratio in recognition of the fact that amounts charged to injuries and damages include amounts related to workers' compensation cost, which in turn relates to EPEC employees who charge their payroll time to both expense and capital projects. The report recommends adoption of the staff's adjustments to remove $108,886 in payroll expense, as discussed above in Section XI.B.3, and to include only the portion of this cost allocable to expense. The amount to be included is $2,858,664, a decrease of $497,208 to the Company's request.

12. Energy Efficiency Expense

EPEC's request of $569,812 should be reduced by $131,345, as recommended in Section V. of this report.

13. Wheeling Expense

The Company's request for $2,256,967 in wheeling expense should be reduced by $789,667, as recommended in Section XI.A.6. of this report.

14. Miscellaneous Other O&M Adjustments

Mr. DeWard proposed a number of additional adjustments to O&M which are included under this heading for organizational convenience. A brief discussion of each proposed adjustment follows.

a. <u>Account 513 - Non-Recurring Expense</u>. Mr. DeWard removed $305,710 from Account 513 because EPEC had characterized such expenses as "non-recurring," and associated primarily with a major overhaul and necessary repairs for Unit 6 at the Rio Grande Station. Mr. Wasiak on rebuttal explained that these repairs were made during scheduled maintenance of Rio Grande Unit 6. While expenditures for scheduled maintenance may not be incurred yearly for every unit, some level of repair expense for these units will be recurring because there are ten generating units in operation. Mr. Wasiak further explained the particular circumstances of the Rio Grande Unit 6 overhaul and testified that similar repairs have been required on other units as a direct result of cyclic duty and are common. Further repairs of this nature are in fact anticipated, and so the expense is not non-recurring as to all units. Mr. DeWard's adjustment should not be adopted.

b. <u>Account 567 - Rents</u>. EPEC included in test year expense a payment for the first five years of a forty year lease agreement with the Bureau of Land Management. Mr. DeWard recommended that only one-fifth of that cost relates to test year, and four-fifths should be removed. His $78,080 reduction in this account should be made, as EPEC did not rebut this proposal.

c. <u>Account 923 - Outside Services</u>. Mr. DeWard recommended removing a total of $133,300 in expenses related to its outside accountants and legal counsel which should not have been expensed but instead either charged to FL&R, charged against an accrual account, included as part of rate case expense, deferred and recovered through other means, or charged below the line. This adjustment was not rebutted by EPEC and should be made.

Mr. DeWard also removed $29,336 from this account for legal services relating to the prudence of Palo Verde; these amounts should have been deferred to Account 186. The adjustment should be made.

In addition, Mr. DeWard recommended removal of $6,664 in legal expenses associated with Del Norte Foundation and Rio Bravo Industry Development Corporation. This adjustment should also be made.

Finally, Mr. DeWard determined that this account was understated for the test year by the amount of credit balances he discovered; he recommended increasing this account by $54,866 to remove the effect of these credits. This adjustment should also be made.

The net adjustment to Account 923 is a decrease of $114,434.

d. <u>Directors and Officers Liability and Excess Liability Insurance</u>. Based on his belief that these costs should not be borne entirely by ratepayers, Mr. DeWard reduced the level of the expense for these insurance premiums by half. The current cost of premiums on these policies is $2,826,410, compared to test year cost of $1,034,871 and a 1983 premium of $69,065. Acknowledging the general trend of increasing insurance premiums, Mr. DeWard stated his belief that a "very likely" cause for the increase in these premiums is EPEC's involvement in Palo Verde. He chose 50 percent as the appropriate disallowance because other witnesses for the City of El Paso were recommending a similar disallowance of Palo Verde costs, and because decisions in New York have also removed a portion of D&O insurance premiums because of nuclear power plant construction.

On rebuttal, Mr. Wright explained first that Excess Liability Insurance does not provide coverage for directors and officers liability, and is not related to nuclear coverage. He also explained in detail the insurance carried by EPEC for directors and officers liability. In his opinion, approximately 19 percent of the total directors and officers liablity insurance premiums is attributable to EPEC's participation in Palo Verde. Further, Mr. Wright found Mr. DeWard's emphasis on Palo Verde as a cause of premium increases in recent years unwarranted; he believes that the so-called "insurance crisis" or "hard market" which has affected businesses in general is more to blame.

Mr. DeWard's reason for making this adjustment in insurance expense having been successfully rebutted, the adjustment should not be made.

e. <u>Line of Credit Fees</u>. It was Mr. DeWard's opinion that EPEC has on hand an excessive line of credit, a total of $157.270 million. While the Company needs cash to pay day-to-day operating expenses, Mr. DeWard thought a less costly alternative would be for the Company to arrange for compensating balances, so that costs are incurred when funds are needed. Opining that ratepayers should not be required to support excessive lines of credit which are required because the Company has chosen to take available cash (from the sale/leaseback) and expend them for non-utility investments, he removed one-half the $638,993 test year expense for line of credit fees. His adjustment was $319,497.

On rebuttal, Mr. Johnson explained EPEC's line of credit arrangements, and demonstrated that, using a nine percent opportunity cost rate for compensating balances, the line of credit arrangement saved EPEC $457,446. Mr. DeWard's adjustment should be rejected.

f. Employees Transferred to PasoTex Corporation. Because EPEC has transferred employees from its utility operations to its non-utility operations (PasoTex Corporation), Mr. DeWard asserted, the utility should be compensated for the training these employees received while they worked for the utility, so that non-utility operations do not benefit. Mr. DeWard recommended removal of $32,500 from O&M expense.

This adjustment is not appropriate. Employees come and go; employers do not reimburse each other for the skills employees pick up during their careers. There is no reason to penalize EPEC because one or more of its employees transfers to non-utility operations.

g. Non-Recurring Expenses. Each of these items relates to the expensing of work orders originally set up for the construction of plant for which no major items of construction took place and the amounts of overhead were expensed. In Mr. DeWard's opinion, since these were related to construction which did not take place, they are not representative of on-going O&M expense and should be removed from cost of service. This report concurs and recommends adoption of the following reductions in these accounts:

Account 580	$10,309
Account 582	$ 1,246
Account 593	$ 4,827
Account 594	$ 3,047
Account 596	$ 525
Total	$19,954

h. Account 912 - Demonstrating and Selling Expenses. Mr. DeWard observed that EPEC had removed $32,496 of payroll expense from this account twice. That appears to be the case (see, EPEC Ex. No. 1A Errata Schedule A-7 at Adjustment Nos. 4 and 10); however, there is no need to adopt this recommendation because the report recommends use of the staff's annualized amount for salaries and wages.

i. Account 920 - Administrative and General Salaries Other Than Officers. Mr. DeWard pointed out that the Company's methodology of annualizing salaries but removing only test year amounts results in including the increases for these employees in cost of service. That appears to be the case, but the adjustment does not need to be made because the report adopts the staff's annualized expense for salaries and wages.

j. Account 921 - Office Supplies and Expenses. The adjustment recommended by Mr. DeWard here resolves a discrepancy between the general ledger and the amount of office supplies and expenses being removed by the Company relating to the Company aircraft. EPEC agreed that an additional $11,563 should be removed from Account 921, and the Company in fact amended its request to make the additional reduction. (EPEC Ex. No. 1A Errata Schedule A-7, Adjustment No. 10.) This report agrees that the adjustment should be made.

k. Account 585. Because a debit was recorded in this account during the test year and the compensating credit was recorded outside the test year, in order not to overstate test year expense for this account, Mr. DeWard recommended removing the $20,375 expense in this account from the Company's cost of service. EPEC did not offer any explanation for why this adjustment should not be made. The report recommends adoption of this adjustment.

14. Summary of Other O&M Adjustments. The total amount of miscellaneous other adjustments to O&M is $232,843.

15. Other Unadjusted O&M

The amount shown on Schedule II of the order is reasonable and necessary, and should be included in the Company's cost of service.

16. Uncollectible Expense

EPEC's requested $1,371,924 expense for uncollectible accounts was derived by multiplying an effective uncollectible rate (.00384877) by the Company's requested total revenue requirement. This uncollectible rate is based on the ratio of test year bad debt expense to test year retail sales.

Mr. Young employed the same methodology, but his uncollectible rate (.003101) is based on the average ratio of bad debts written off to retail sales or revenues for 1984, 1985, and the test year, and he also used the staff's proposed total revenue requirement. Staff's amount for uncollectible expense, $1,161,167, is a decrease of $210,757 to EPEC's request.

This report recommends use of the methodology used by both EPEC and the staff, utilizing staff's uncollectible rate and the revenue requirement recommended by this report. The recommended uncollectible expense is shown on Schedule II of the order.

17. Summary of Operations and Maintenance Expense

The total operations and maintenance expense found reasonable and necessary is shown on Schedule II of the order.

C. Decommissioning Expense

EPEC witness Thomas S. LaGuardia, President of TLG Engineering, Inc., testified on direct and rebuttal regarding the decommissioning study performed for PVNGS and the estimated costs of decommissioning. (EPEC Ex. No. 1, Vol. 5, Tabs 32 and 33; EPEC Ex. No. 84, Vol. 3, Tab 4; Tr. at 5374-5411.) William J. Johnson testified on direct and rebuttal about the Company's requested expense for decommissioning. (EPEC Ex. No. 1, Vol. 4, Tab 21 at pp. 43-44 and Tab 22 at Exhibit WJJ-12; Tr. at 55-269; EPEC Ex. No. 41, Tab 8 at 11-12 and at WJJ-7; Tr. at 2445-2484.) City of El Paso witness Dale G. Bridenbaugh, President of MHB Technical Associates, San Jose, California (City Ex. Nos. 47 and 47A; Tr. at 5412-5513) and staff witnesses Keith Allen Rogas, Electric Utility Engineer in the Power Plant Engineering Section of the Electric Division (Staff Ex. No. 29; Tr. at 6621), and Eugene Bradford, Financial Analyst in the Operations Review Division (Staff Ex. No. 6; Tr. at 1358-1454), also testified on the decommissioning issues.

Mr. Johnson explained that EPEC has included in cost of service a revenue requirement of $1,700,000 to cover the required decommissioning on PVNGS Units 1 and 2. The Company plans to use an external funding method, with funding requirements computed using a pretax investment rate of 7.71 percent and an escalation rate of three percent. These funding requirements are based on the immediate dismantling decommissioning methodology supported by the PVNGS site-specific study presented by Mr. LaGuardia. There are two issues: the validity of the estimate of decommissioning costs and the equity of the funding proposal.

Mr. LaGuardia and Mr. Bridenbaugh discussed the three basic decommissioning alternatives. The first, prompt removal/dismantling (DECON) consists of removing from the site, packaging, and shipping for controlled burial all spent fuel assemblies and all radioactive wastes from plant operations. (The operating license would be converted to a possession-only license which permits the owner to posses radioactive materials but prohibits operation of the reactor.) The radioactive fission and corrosion products and all other radioactive materials having activities above accepted unrestricted levels would be removed, packaged, and shipped for disposal. The reactor vessel and supporting structures would be removed using remote tooling. The site may then be released for unrestricted use with no requirement for a license, and the remainder of the reactor facility may be dismantled to make the site available for reuse.

The second alternative for decommissioning, safe storage entombment or ENTOMB, consists of removing from the site all fuel and radioactive wastes from operations. A possession-only license would be obtained, and all radioactive components and structures would be sealed within an entombment barrier. The security intrusion monitoring system would be maintained operable, and adequate surveillance, inspections, and continuing facility repairs and maintenance would be provided to ensure entombment integrity. A refinement of this option includes entombment with delayed dismantling, with the dismantling activities the same as described above.

SAFSTOR, or safe storage mothballing, is the third decommissioning alternative. This consists of the same basic site deactivation steps as in the entombment method, but the radioactive components are kept in place. Piping and components would be drained, dried, and left on site. A security force would be maintained on the site (thereby increasing annual maintenance costs when compared with entombment), and dismantling activities as described above are delayed until a later date. Delayed decommissioning following mothballing should not exceed 50 years, and delayed decommissioning following entombment should not exceed 100 years, as no significant dose reduction advantage can be gained for further delay beyond these periods.

TLG Engineering, Inc. prepared a decommissioning study for the three PVNGS 1270 MW units. This study was commissioned by Arizona Public Service (APS) as project manager and operating agent for PVNGS. The purpose of the study was to estimate the cost of decommissioning the PVNGS units in order to establish a decommissioning fund. The study is not a decommissioning plan and does not commit the project participants to a specific course of action following final plant shutdown. Mr. LaGuardia presented costs, period length and plant years for each of the three decommissioning alternatives described above. The costs were presented in constant 1986 dollars and include a 25 percent contingency. The cost estimate does not include future inflation. The breakdown of costs by percent of major cost component is shown in EPEC Ex. No. 1, Vol. 5, Tab 33 at Exhibit TSL-2.

The study for PVNGS was developed using the detailed engineering drawings, plant description, and inventory documents provided by APS to identify the general arrangement of the facility and to determine estimates of building concrete volumes, steel quantities, numbers and sizes of components, and degree of site restoration required. Mr. LaGuardia made a personal inspection of the plant, and had access to the facility to determine movement of heavy equipment (cranes, fork-lifts, front-end loaders, etc.) close to the structures for demolition and removal work.

The study also used representative labor rates for each geographical region and each craft or salaried work group to determine site-specific estimates for the decommissioning costs. Rates for shipping radioactive wastes for burial were obtained from a reputable carrier with many years of experience in handling radioactive fuel and low-level radioactive wastes to estimate more accurately the shipping costs. The study assumed that all radioactive wastes would be shipped to a hypothetical burial ground within 500 miles of the site and used the burial rates for Hanford, Washington.

The methodology used to develop the cost estimate followed the basic approach in the AIF/NESP-036 study report, "An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives," and the U.S. Department of Energy Decommissioning Handbook. These reports use a unit cost factor method for estimating decommissioning activity costs to standardize the estimating calculations. Unit cost factors for activities such as concrete removal ($/cu. yd.), steel removal ($/ton), and cutting costs ($/in.) were developed from the labor and material information provided by APS. With the item quantity (cubic yards, tons, inches, etc.) developed from plant drawings and inventory documents, the *activity-dependent* costs for decontamination, removal, packaging, shipping, and burial were estimated. The activity duration critical path was used to determine the total decommissioning program schedule.

The program schedule is then used to determine the *period-dependent* costs, such as program management, administration, field engineering, equipment rental, quality assurance, and security. The costs for conventional demolition of non-radioactive structures, materials, backfill, landscaping, and equipment rental were obtained from conventional demolition references. The activity- and period-dependent costs were added to develop the total decommissioning costs. A 25 percent contingency was added to allow for the effect of unpredictable program problems or costs. Such as contingency is appropriate for a project of this size and type, in Mr. LaGuardia's judgment. He prepared cost and schedule estimates for each of the three decommissioning alternatives as follows:

	DECON	ENTOMB	SAFSTOR
Unit 1	$208,241,300	$233,645,600	$237,033,800
Unit 2	$194,978,500	$216,822,800	$224,831,200
Unit 3	$212,436,200	$235,319,800	$242,483,900
Total	$615,656,000	$685,788,200	$704,348,900

(EPEC Ex. No. 1, Vol. 5, Tab 33 at Exhibit TSL-1.)

Mr. LaGuardia recommended the prompt removal/dismantling (DECON) alternative as the most technically and financially prudent, because in his opinion, it provides the best means for terminating a possession-only license in the shortest time, thus relieving APS of its regulatory and liability obligations at the site. DECON avoids the long-term costs and commitments associated with maintenance, surveillance and security requirements of the delayed dismantling alternatives, SAFSTOR and ENTOMB. Further, DECON permits use of the plant's knowledgeable current operating staff, a valuable asset to a well-managed and efficient decommissioning program. All the equipment needed to support decommissioning operations, such as cranes, ventilation systems, and radioactive waste processing systems would be fully operational. Finally, the site would be available for alternative uses at the earliest possible time.

Mr. LaGuardia described in detail the activities which would take place in the prompt removal/dismantling of a nuclear power plant, and the estimated time for each kind of work. Briefly, approximately two years prior to final shutdown, engineering and planning would begin on the preparation of the Decommissioning Plan and Environmental Assessment. These documents must be submitted to the NRC and other regulatory agencies for review, approval, and authorization to proceed.

Period One involves site preparation, conversion of the license to possession-only, removal of spent fuel and loading for shipment (not part of decommissioning work and not included in the cost estimates), removal from the site of all fluids and wastes remaining from plant operations, and isolation and draining of all systems not essential to decommissioning. This work is estimated to take about 12 months.

Decommissioning operations, Period Two, begins upon receipt of the dismantling order from the NRC. This phase involves the removal of radioactivity from the site (decontamination and removal of all contaminated components for controlled burial) and termination of the license. (Decontamination does not remove residual radioactivity; all contaminated components must be removed for controlled burial. Decontamination permits workers to work in the immediate vicinity of most components to cut and remove them for packaging and disposal.) All piping will be cut and removed; steam generator connection points will be sealed and closed so that the generator can be shipped as its own container for disposal. Smaller components will be loaded into containers for burial.

The reactor vessel and its internal parts will be segmented to fit into steel liners within heavily shielded shipping casks for transport to the burial facility. Because of the high radiation levels of the reactor vessel, all cutting must be done under water or behind heavy shields using remotely operated cutting torches. The concrete immediately surrounding the reactor vessel is to be removed by controlled blasting. Sections of interior floors in the containment and other buildings will have surface contamination from exposure to contaminated water, and will be decontaminated using surface removal so that burial will not be required. Pipe hangers, supports, and electrical components will be removed and disposed of by controlled burial. Finally, a radiation survey will be performed to insure that all radioactivity has been removed from the site and the facility may be released for unrestricted access. Period Two activities are estimated to take 36 months.

Period Three, dismantling of remaining structures, is expected to take 24 months. This involves demolition of all non-radioactive or remaining structures to a depth of three feet below grade, use of clean rubble on-site for fill, and covering each subgrade structure with clean soil. The site would be graded.

Mr. LaGuardia testified that the cost estimate prepared for APS is based on current, state-of-the-art technology, and on current federal and state regulations. No provision is made to include future costs (improvements in technology, major regulatory changes, inflation factors, etc.) to eliminate double counting for such factors when projecting costs to the expected date of decommissioning. He further stated that he recommends that EPEC thoroughly review this estimate periodically, and to revise it if necessary to account for cost increases or decreases as influenced by future technology and regulations.

The real controversy in this area arose from the inclusion of a 25 percent contingency in the cost study. According to Mr. LaGuardia, the purpose of the contingency is to allow for the costs of high probability program problems when the occurrence, duration, and severity cannot be accurately predicted and have not been included in the basic estimate. He cited as an example the situation which might arise if the radioactive waste burial facility is located in a wet climate (possibly the Northern Arizona mountains to avoid seasonal flooding rains). Shipments to that area might be detained during inclement weather because of muddy road conditions and potentially unsafe conditions in the burial trenches, thus seriously decreasing productivity and increasing costs. He pointed out that even though it is impossible to predict weather conditions existing at the time these shipments will be made and the impact on total cost, it is imprudent to ignore the high probability of such occurrences.

Other examples he offered were specialty tool breakdown, material delivery delays (a function of such factors as adverse weather, material shortages, production problems, shipping damage, etc.), scheduling of manpower (due to illness, variability of individual productivity, work stoppages, or strikes), material removal delays (dismantled or demolished piping components and structures could cause problems with laydown space availability), changing regulatory requirements, all of which are beyond the control of even the most efficient management. Mr. LaGuardia also referred to other studies of decommissioning cost estimates which included 25 percent contingency allowances.

Confident that Palo Verde could be completely dismantled, Mr. LaGuardia pointed out that there is extensive experience in the United States and other countries for the complete dismantling of nuclear plants. He also explained that the basic activities of cutting pipe, segmenting vessels, demolishing reinforced concrete and decontaminating contaminated systems and structures are independent of the size of the structure or megawatt rating of the plant on a unit cost factor basis. Much of the technology involved is not unique to decommissioning, another factor indicating the feasibility of decommissioning. Mr. LaGuardia gave examples of how the techniques which would be used in dismantling Palo Verde have been used in the decommissioning of other plants and in other industries.

City of El Paso witness Dale G. Bridenbaugh criticized the TLG Engineering study because it failed to account for the likelihood that in 40 years there may be new technology and new technical options, and that there are some uncertainties, among them availability for waste disposal, federal policy on waste disposal, cost of capital 40 years from now, and changes in state and local regulations. In his opinion, the decision for inclusion of decommissioning costs in rates should be based on the following guidelines: 1) allocate the reasonable cost to contemporaneous users; 2) minimize the risk that there will be insufficient funds to cover the costs of decommissioning; and 3) keep technical options open.

Mr. Bridenbaugh questioned the omission of escalation rates in the estimates prepared by TLG Engineering, and the assumption of a real growth rate of 4.71 percent over the life of the fund. He agreed that the DECON option was reasonable, but not for the reasons Mr. LaGuardia states. In his opinion, in order to retain all technical options, it is important for planning purposes to consider the most expensive option. By doing so, in effect, a contingency is provided. He declared that it is too early to make a finding that DECON is the most technically prudent option, because there are significant health and safety concerns associated with immediate removal and dismantling which could be avoided by using the delayed dismantling options which would allow radioactive decay to reduce the volume and potency of waste materials. In addition, there may be substantial experience with decommissioning which will shed new light on decommissioning methods and problems.

Mr. Bridenbaugh conceded that he had not performed an independent decommissioning study for PVNGS, nor evaluated every cost assumption made in the TLG Engineering study; nevertheless, he challenged the need for a 25 percent contingency. He believes that DECON would be the most expensive option, and that there is therefore already a contingency built into the estimate. He recommended that the contingency be adjusted to 15 percent, with the annual payment adjusted accordingly. (City Ex. No. 47 at 30-35.)

With respect to funding the decommissioning, Mr. Bridenbaugh opined that EPEC's proposed external sinking fund does not provide adequate assurance that the funds will be available when needed, and he recommended that the actual cost of decommissioning 40 years from now and the interest rate on the fund should be reassessed periodically. Further, in the event of premature closing for economic reasons, the fund may not be adequate for decommissioning costs. There is also the possibility that another participant in PVNGS would not be able to pay its share, raising the accompanying possibility that EPEC would be required to assume part or all of that burden.

Mr. Bridenbaugh concluded that EPEC's funding proposal is not reasonable, since in his opinion the Decommissioning Trust Agreement does not provide complete assurance that the funds will not be used by EPEC for some other purpose, and the agreement gives EPEC the right to remove the trustee at any time and to dissolve the Trust (resulting in all trust assets reverting to EPEC). He offered six suggestions for improving the decommissioning proposal. First, the cost estimate should be adjusted to lower the contingency to 15 percent for both units. Second, the fund should be reevaluated frequently to assess its adequacy and the underlying assumptions about costs, discount rates, technical options, and plant life expectancy. Third, there should be a formal readjustment mechanism to be used if the fund is found to be accruing a surplus or a deficit. Fourth, the Commission should establish a policy regarding the possibility of premature closing; Mr. Bridenbaugh suggested holding the shareholders responsible for insufficient funds because of premature plant clsoing. Fifth, the Commission should insure that the trust funds will be used exclusively for decommissioning, that if EPEC files for bankruptcy or reorganization the fund will remain in trust outside the control of EPEC, and that the trust can make only certain types of investments. Finally, the Commission should insure that shortfalls in the fund caused by default of other participants will not become the responsibility of EPEC ratepayers.

The decommissioning cost estimate for PVNGS Unit 1 and Unit 2 should be reduced to $370,800,000 under Mr. Bridenbaugh's recommendation, and the annual contribution of $1,700,000 requested by EPEC should be reduced to $1,560,000. (City Ex. No. 47 at 39-40.)

Staff witness Keith Rogas recommended one change in the DECON decommissioning cost estimate, and that was a change in the contingency amount from 25 percent to 10 percent. Mr. Rogas faulted Mr. LaGuardia's reliance on other decommissioning studies as supporting his inclusion of a 25 percent contingency. Further, Mr. Rogas does not believe that current ratepayers should have to pay rates based upon a decommissioning cost estimate that is a worst-case scenario. He also stated that many of the events included in the category contingencies in the AIF study should not have been included in the PVNGS decommissioning cost estimate, and he listed these.

Mr. Rogas believes that contingencies such as changes in the project's original scope and changes in the project's original schedule should not be included because they are beyond the scope of the current cost estimate. Since there is substantial uncertainty in any estimate of the scope and schedule of the eventual decommissioning of the plant, upward or downward adjustments can be made to the cost estimate in the future. Possible events which include the possible underestimation of certain decommissioning activities because of higher than anticipated contamination levels are of questionable validity in Mr. Rogas's opinion, because estimates can be too high or too low, and there is the possibility that the contamination levels could be lower than anticipated.

Another group of possible adverse events were not related specifically to decommissioning activities in the TLG Engineering study, and included such potentialities as labor agreement changes with respect to crew size needed to perform an activity. Mr. Rogas testified that if the crew size needed to perform certain decommissioning activities increases in the future, the increases can be accounted for in periodic revisions to the estimate, just as improvements in technology which might allow decreased crew size can be accounted for in the future.

In addition to his concerns about the inclusion of certain kinds of contingencies, Mr. Rogas voiced his belief that current ratepayers should not have to finance a worst-case scenario even though such a scenario is possible. He did agree, however, that some contingency was warranted. He believes a contingency well below 25 percent is warranted, although he conceded that how far below 25 percent was a judgment call. He recommended a ten percent contingency. The cost per PVNGS unit for DECON is as follows:

Unit 1	$183,252,300
Unit 2	$171,581,080
Unit 3	$186,943,900
Total	$541,777,280

(Staff Ex. No. 29 at 14; and at Schedule KR-1.)

Staff witness Eugene Bradford testified about the guidelines developed by the NRC and the IRS concerning the various plans for financing the decommissioning of a nuclear plant. The NRC criteria for evaluation of decommissioning financing requirements are: assurance that sufficient funds will be available for decommissioning, the cost to the ratepayer, flexibility in the face of technological or inflationary changes, and equity to different generations of ratepayers. The IRS has issued rules dealing with the tax deductibility of decommissioning expenses, in effect mandating certain financing arrangements. Mr. Bradford's analysis considered the financing arrangements necessary to accumulate funds necessary for decommissioning PVNGS in the 2026-2032 time frame, based on the current dollar estimate of costs ($354,833,380 x .158 = $56,063,674) supplied to him by Mr. Rogas.

Mr. Bradford assumed that EPEC will begin accumulating funds for the decommissioning of Units 1 and 2 (both of which went into commercial operation in 1986) when rates set in this case go into effect in 1988, and that the units will continue for 38 years until retirement in 2026. He assumed that decommissioning would begin in the year after the plants are retired. He escalated the current dollar costs using a four percent inflation factor to account for the effects of inflation in the years between now and the time decommissioning begins, 2027. He allocated the total EPEC decommissioning costs into the amounts needed for each year of the plant decommissioning, then escalated the costs from 1986 dollars to the estimated cost for each year of decommissioning. The 1986 cost for year one of decommissioning was escalated at an annual rate of four percent to the amount in 2026 when the funds will be needed. In a like fashion, the funds for each year of the decommissioning schedule have been escalated at a four percent inflation rate until the year they will be used.

Since there will be changes in the estimated cost of the decommissioning resulting from changes in technology and regulation, and since the rate of inflation is unlikely to remain stable over the life of the plant, Mr. Bradford pointed out that the amount of annual decommissioning expense to be included in rates should be adjusted as part of each rate case until decommissioning is complete. He computed the impact of selected inflation rates on the total decommissioning cost. (Staff Ex. No. 6 at 23-24 and at Schedule XII, page 2.)

Mr. Bradford differed from Mr. Bridenbaugh, testifying that EPEC's proposed external fund invested in tax exempt bonds provided strong assurance that the funds will be available when needed, even if EPEC suffers severe financial problems between now and the time of decommissioning. Investing in tax-exempt securities is attractive because they currently offer higher yields than are available from similarly secure taxable securities on an after-tax basis.

In Mr. Bradford's opinion, EPEC's financing plan conforms with all NRC and IRS guidelines, and he believes that the projected yield of 7.71 percent pretax for taxable investments is somewhat conservative in the present circumstances (that is, at the time he testified). He used an eight percent after tax yield, which he believed was reasonable. Using that yield on a straightline fund and Mr. Rogas's cost estimates resulted in an annual contribution of $1,029,855 from ratepayers, compared to EPEC's requested $1,700,000. (Staff Ex. No. 6 at 25 and at Schedule XIII.) However, Mr. Bradford did not propose use of a straightline payment stream.

Just as inflation escalates the total cost of decommissioning the plant over time, it also changes the economic value of the level stream of payments. The cost of decommissioning PVNGS Units 1 and 2 is $56,063,674 in 1986 dollars. An annual contribution of $1,700,000 is three percent of this cost, but by 2026, an inflation rate of four percent raises the cost of decommissioning to $269,162,853. An annual contribution of $1,700,000 is only 0.6 percent of this cost. The result is that ratepayers in later years are not contributing an equal share to the cost of decommissioning because inflation has reduced the value of their contributions. Mr. Bradford recommended an inflation-adjusted payment stream to compensate for this problem, so that each year ratepayers are contributing the same percent of the cost of decommissioning. He based his recommendation on the staff's cost of decommissioning PVNGS Units 1 and 2 and an eight percent yield; under these assumptions, each year ratepayers would contribute one percent of the cost of decommissioning. Even though this recommendation requires periodic changes to the level of decommissioning expense, such adjustments would be needed in any event to reflect changing assumptions about the inflation rate, interest rates, and the cost of decommissioning which can be made easily in future rate cases.

On rebuttal, Mr. Johnson testified that although an inflation-adjusted payment stream is an alternative to the straight line payment stream proposed by EPEC, altering the payment stream increases the risk that the decommissioning reserve may not be fully funded when the costs are actually incurred. He referred to Internal Revenue Code Section 468A(d)(2), which allows a current tax deduction for level payments to a nuclear decommissioning reserve. In his opinion, the straight line method provides a higher degree of assurance than the inflation-adjusted stream that the funds will be available when needed. (EPEC Ex. No. 41, Tab 8 at pp. 11-12.)

The credible evidence in this record supports the use of Mr. LaGuardia's estimates of decommissioning cost, including the 25 percent contingency. The purpose of the contingencies is not to try to predict now which of these events will or will not occur, but to state examples of the ways and reasons current estimates can fall short of the mark. In addition, any current underestimation of decommissioning costs will be charged to future ratepayers, a violation of the principle of equity among generations of ratepayers. The estimates in the TLG Engineering study are based on actual field experience. Additionally, the contingency is not padding; it is a real cost of decommissioning and is fully expected to be spent. Neither Mr. Bridenbaugh nor Mr. Rogas supported their reductions to the contingency, and their recommendations should not be adopted.

It is clear from the testimony of all the witnesses who testified on this issue that decommissioning reserves should be funded by those ratepayers who benefit from the nuclear plant. Changing the payment stream does not, in and of itself, threaten the sufficiency or availability of the decommissioning reserve. All witnesses suggested periodic review and update of the decommissioning study, the inflation rate, and the yields on the trust's investments. Changes in any of those components - which should and will be made - will change the level at which current ratepayers contribute to the reserves. A payment stream adjusted for inflation poses no greater threat to the sufficiency and availability of the decommissioning reserves than does a payment stream adjusted for any other changes.

In addition, the inflation-adjusted payment stream serves generational equity just as an accurate estimate of decommissioning cost does. The report recommends that the amount to be included for decommissioning expense for EPEC be based on the Company's proposed decommissioning costs for PVNGS Units 1 and 2 and calculated using Mr. Bradford's inflation-adjusted payment stream using a four percent inflation rate and an eight percent after-tax yield.

D. Depreciation Expense

EPEC requested a total depreciation expense of $28,956,842. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 17; EPEC Ex. No. 1A Errata Schedule A-7.) The parties recommended no adjustment to the non-PVNGS portion of depreciation expense, $13,468,243, and that amount should be adopted.

EPEC's PVNGS-related depreciation expense of $15,488,599 included PVNGS production (Unit 1 and all common facilities), transmission, and general plant. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 17.) The Company included recovery of deferred depreciation expense on Unit 1 and common facilities by using a 38.333333-year life, instead of a 40-year life. Palo Verde transmission and general plant were depreciated using the rates recommended in the Stone & Webster Depreciation Study (EPEC Ex. No. 1, Vol. 7, Schedule G-6.1).

City witness DeWard first reduced depreciation expense by $1,248,677 consistent with the City's recommendation to exclude one-third of the PVNGS common facilities as allocable to PVNGS Unit 3. He also recommended a second adjustment of a $824,592 reduction to depreciation expense to recognize his proposed reallocation to PVNGS Unit 1 of the PVNGS Unit 2-related AFUDC credits which EPEC had assigned to PVNGS Unit 3. (City Ex. No. 6 at 70 and at Exhibit TCD-1, Schedules 36 and 37.)

The staff made two adjustments to EPEC's requested depreciation expense, both related to PVNGS. The first was the staff's proposed adjustment of the depreciation rate for PVNGS Unit 1 to recognize a longer deferral period than that proposed by the Company. The staff recalculated the PVNGS Unit 1 depreciation rate to recognize a 22-month deferral period. The second adjustment related to the staff's recommended test year end PVNGS Unit 1 plant balances which included the $28,000,000 disallowance as recommended by Mr. Jacobs. The total staff adjustment was a decrease of $1,868,816 to the Company's request. (Staff Ex. No. 11 at 33-35; Staff Ex. No. 28 at 2-3 and at Schedule I Revised.)

This report recommends use of the Company's proposed depreciation expense for all non-PVNGS plant, and for PVNGS transmission and general plant. Depreciation expense on PVNGS production plant should be calculated using the examiners' recommended plant balances and a shortened plant life to recognize a 24-month deferral period (March 1986-March 1988) for this plant. The total depreciation expense recommended is shown on Schedule I of the order.

E. Amortization Expense

EPEC's requested amortization expense is $1,934,553, comprised of $478,758 for amortization of limited-term electric plant and $1,455,795 for amortization of deferred carrying cost (AFUDC) on PVNGS Units 1 and 2 and the associated O&M deferrals. (EPEC Ex. No. 1, Vol. 7, Schedule G-5; EPEC Ex. No. 1A Errata Schedule A-7, Adjustment No. 17.1). The carrying cost is calculated using AFUDC rates applied to the O&M deferrals and the portion of EPEC's investment in PVNGS Units 1 and 2 not currently included in rate base. The AFUDC is compounded semi-annually. EPEC requested a 38.3-year amortization period on the carrying cost related to PVNGS and, consistent with the requested recovery period for O&M deferrals, a three-year amortization of the carrying cost on the O&M deferrals.

Mr. DeWard's adjustments to amortization expense related to his recommended disallowance of all PVNGS Unit 2 deferrals. (City Ex. No. 6 at 70 and at Exhibit TCD-1, Schedule 38.)

Mr. Young used the same methodology as EPEC to recalculate the staff's recommended carrying cost associated with deferred O&M and PVNGS plant; however, the staff's deferred carrying cost recommendation was based on the staff's recommended $28,000,000 disallowance and excluded carrying cost associated with PVNGS Unit 2 plant and deferred O&M expense. In addition, the staff's deferred carrying cost recommendation provides for recovery of the Unit 1 O&M deferrals through March 1987, utilizing actual AFUDC rates through that month, whereas EPEC's request was based on estimated carrying cost calculations through November 1987.

Based on the discussion above in this report regarding inclusion of deferrals for Unit 2, this report recommends inclusion of the Company's requested amortization of deferred carrying cost for PVNGS Units 1 and 2 and the associated O&M expense in the amount of $1,455,795, plus the uncontested amount of $478,758, for a total amortization expense of $1,934,553.

F. Interest on Customer Deposits

The balance of customer deposits was uncontested. Interest should be calculated on these deposits at the rate of six percent per annum, the interest rate established by the Commission in December 1987. The expense should be $197,923, a decrease of $51,319 to EPEC's request of $249,242. Mr. DeWard recommended this adjustment, and it should be adopted. (City Ex. No. 6 at 71 and at Exhibit TCD-1, Schedule 39.)

G. Taxes Other Than Income Taxes

Company witness Moises Rodriguez presented testimony on tax issues. (EPEC Ex. No. 1, Vol. 4, Tabs 26 and 27; EPEC Ex. No. 1, Vol. 7, Schedules A-7 [Adjustments 18 through 30] and G-7.1 through G-8; Tr. at 375-487) On rebuttal, EPEC presented the testimony of Robert C. Hahne. (EPEC Ex. No. 41, Tab 5; Tr. at 2249-2269.) City witness DeWard also proposed adjustments to taxes. (City Ex. No. 6; Tr. at 1116-1357.) Staff witness Mark Young also testified on tax issues. (Staff Ex. Nos. 11 and 28; Tr. at 1734-1882 and 6430-6459.)

1. Non-Revenue Related Taxes

a. Ad Valorem Taxes. EPEC witness Moises Rodriguez explained that test year property taxes of $3,852,651 were annualized based on each taxing authority's effective rate times test year-end plant balances. (EPEC is assessed property taxes in three states: Texas, New Mexico, and Arizona.) The annualized PVNGS Units 1 and 2 and related Common Facility property taxes were computed based on the in-service cost time the Maricopa County assessment ratio (30 percent) times the respective property tax rate. (EPEC Ex. No. 1, Vol. 4, Tab 26; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 19.) The Company requested an $8,585,996 increase to test year property taxes, for a total expense of $12,438,647.

City witness DeWard's adjustment to property taxes comprised three elements. First, he made an adjustment to remove those amounts associated with common facilities which in his view should be assigned to Unit 3 and therefore capitalized. Second, he reduced property taxes for the Texas AFUDC credits which were associated with Unit 2 but which he recommends should be used as an offset to plant in service. Third, he reduced property taxes because he believed that EPEC had overpaid property taxes because it records AFUDC on a gross basis and does not deduct the offsetting deferred income tax; thus, in his view, it is appropriate to adjust the taxable base by the deferred taxes associated with the ABFUDC. (City Ex. No. 6 at 71-72 and at Exhibit TCD-1, Schedule 40.)

Mr. Young utilized actual property tax reports to derive the 1986 property tax amounts assessed for each of the three taxing jurisdictions in order to calculate effective property tax rates, believing actual amounts assessed in 1986 to be more known and measurable than the Company's 1987 estimates. These amounts are the numerators in the staff's effective rate calculations for the three taxing jurisdictions, and the physical property balances for the three jurisdictions at January 1, 1986, are used as the denominators. These effective rates were applied to staff's recommended test year-end total company plant balances, including the $28,000,000 recommended disallowance for PVNGS Unit 1. Mr. Young made further adjustments to the staff's test year-end plant balances to incorporate the effect of EPEC changing from the gross method to the net method of accounting for AFUDC, since property taxes are based on book value. The staff's recommended property tax amount is $11,075,752, a $1,362,897 decrease to the Company's request. (Staff Ex. No. 11 at 37-39 and at Schedule III; Staff Ex. No. 28 at 4-5 and at Schedule III Revised.)

This report recommends use of the staff's effective rates and the staff's methodology in applying those effective rates to the examiners' recommended test year-end plant balances for the three taxing authorities, including the adjustment for calculating AFUDC on a net basis.

b. Deferred Property and Payroll Taxes. EPEC requested $2,477,021 in deferred property and payroll taxes This represents one year's amortization of the total $7,431,062 deferred property and payroll taxes from March 1986 through October 1987, based on monthly accruals, to be amortized over three years. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 19.1.)

Mr. DeWard adjusted this amount to exclude all costs associated with PVNGS Unit 2 and the reallocation of a portion of the common facilities to Unit 3 and recalculation of Unit 1 plant balances on the net AFUDC methodology. (City Ex. No. 6 at 72 and at Exhibit TCD-1, Schedules 40 and 41.)

Mr. Young recalculated the staff's recommended PVNGS deferred property and payroll tax expense to exclude deferrals related to Unit 2 and to utilize actual property taxes paid instead of property tax accruals. The actual amount of property taxes paid for 1986 was $7,675,168; half this amount was paid in 1986 and the other half was paid in 1987. Based on EPEC's responses to staff's informal RFIs, 90 percent of these taxes related to production plant, three percent to transmission plant, and 7 percent to nuclear fuel. Mr. Young used these allocations for calculating staff's deferred property tax expense recommendation. He then used ratios equal to the relative amount of total PVNGS plant assigned to Units 1, 2, and 3 in the staff's PVNGS plant recommendation in order to allocate the production and transmission portion of the 1986 property taxes to the generating units. He also allocated the nuclear fuel related property taxes 50 percent to Unit 1 and 50 percent to Unit 2, based on the assumption that there is approximately the same amount of nuclear fuel at the plant site to be taxes to both PVNGS units. The staff's calculated portion of 1986 property taxes applicable to PVNGS Unit 1 is $1,494,375, or $124,531 per month. (The Unit 2 amount of $1,568,068 was not included in staff's recommendation.) The monthly deferral amount was then multiplied by the number of deferral months in 1986, since the property taxes paid are 1986 taxes. The staff recommended 10 deferral months for payroll and property taxes for Unit 1 (March 1986 through December 1986) and 3 for Unit 2 (October 1986 through December 1986).

Based on the staff's recommended disallowance of $28,000,000 in PVNGS costs, Mr. Young calculated a "percentage of Palo Verde allowed." He did this by dividing the recommended disallowance of $28,000,000 by staff's recommended PVNGS Unit 1 plant balance at test year end of $535,275,789 to yield a 5.2309483 percent disallowance. He then concluded that that percentage of Unit 1 and common deferred property taxes should be disallowed, since property taxes are assessed on physical plant property. The staff recommended total PVNGS Unit 1 deferred property and payroll tax expense amount when amortized to cost of service over three years, as requested by EPEC, yields a staff recommended annual PVNGS Unit 1 deferred property and payroll amortization of $472,797, a $2,004,224 reduction to the Company's request. The staff's recommended deferrals for payroll and property taxes went through November 1986 and December 1986, respectively; Mr. Young recommended that EPEC continue to book Unit 1 property and payroll tax accruals to FERC Account 186 until EPEC files its next rate case, at which time the 1987 accruals to Account 186 should be adjusted to reflect actual 1987 property taxes paid. (Staff Ex. No. 11 at 39-42 and at Schedule III; Staff Ex. No. 28 at 5-6, at Exhibit MY-2 Revised, and at Schedule III Revised.)

Because the staff's adjustment incorporates several changes not recommended by this report, as discussed above in this report, it is recommended that the Company's requested deferred property and payroll tax amount of $2,477,021 be included in cost of service, and that EPEC continue to book to FERC Account 186 the payroll and property tax for the period November 1987 until rates set in this docket go into effect. In EPEC's next rate case the amounts can be trued-up to the actual amounts paid for the deferral period.

c. Payroll Taxes. According to Mr. Rodriguez, EPEC's requested payroll taxes were computed using the adjusted taxable wage base up to the ceiling of $43,800 and the 7.15 percent tax rate applied to annualized salaries using the O&M payroll ratio. (EPEC Ex. No. 1, Vol. 4, Tab 26 at 13; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 20.)

Mr. DeWard used the test year percent of wages subject to FICA tax to estimate the taxable salaries and wages at the going-forward level. He also used his recommended three-year average capitalization ratio to determine the amount of FICA taxes to be charged to expense. Mr. DeWard's adjustment was a reduction of $55,802. (City Ex. No. 6 at 73-74 and at Exhibit TCD-1, Schedule 44.)

Mr. Young recalculated FICA tax expense to recognize the staff's recommended salary and wage expense using the 1987 FICA tax rate of 7.15 percent and the FICA ceiling of $43,800. The staff's recommended payroll tax expense of $1,715,775 is a $142,307 decrease to EPEC's request.

The report recommends use of the 1987 FICA tax rate and wage ceiling with the examiners' recommended salary and wage expense discussed above in Section XI.B.1. of this report.

d. Other Non-Revenue Related Taxes.

(i) Texas franchise tax. The Company's request for $2,546,792 in Texas franchise taxes was based on adjusted test year data, the adjusted capital structure, and the latest Texas franchise tax rate. In addition, the Company's franchise tax calculation utilizes a "percentage of business in Texas" factor. This factor is an average of three allocators: the percent of payroll in Texas, the percent of property in Texas (both based on book balances at test year end), and the percent of revenue in Texas (based on revenues at proposed rates in this case and shown on EPEC Ex. No. 1, Vol. 10, Schedule P(B)). (EPEC Ex. No. 1, Vol. 4, Tab 26 at 13; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 21.)

Mr. DeWard's adjustment reflected the impact of the sale/leaseback on a going-forward basis, and was a $33,737 decrease to EPEC's request. (City Ex. No. 6 at 73 and at Exhibit TCD-1, Schedule 43.)

The staff disagreed with the Company's use of a revenue allocator based on proposed rates on the ground that such an allocator, being based on the outcome of this docket, was not known and measurable. Mr. Young recalculated franchise tax expense using the percentage of business in Texas shown on EPEC's actual franchise tax return for the period May 1, 1987 through April 30, 1988, and the capital structure recommended by staff witness Bradford. The staff recommended a franchise tax expense of $2,690,910, an increase of $144,118 to the Company's request.

This report recommends use of the staff' methodology but substituting the capital structure recommended in this report in Section X.A. above.

(ii) NRC nuclear power reactor operating license fee. EPEC's request for $300,200 was based on the NRC's imposition of an annual fee for fiscal 1987 of $950,000 for every power reactor licensed for operation as of October 1, 1986. EPEC's share of this annual fee is $300,200 for PVNGS Units 1 and 2. (EPEC Ex. No. 1, Vol. 4, Tab 26 at 12; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 18.)

The City recommended that the entire amount be excluded to insure that this fee is not duplicated in the Company's pro forma adjustments and in billings from ANPP. (City Ex. No. 6 at 73 and at Exhibit TCD-1, Schedule 42.)

The staff's review revealed that EPEC was allocated its $535,946 share of operating review license fees billed from APS during 1986. EPEC classified these fees as O&M costs instead of taxes other than federal income taxes; in addition, because these were Palo Verde O&M, a portion was deferred (capitalized) and a portion (32.8404 percent) was expensed. Staff imputed a test year expense of $176,007 ($535,046 times .328404) based on the operating license review fees paid during 1986. Staff further assumed that the $535,946 was paid during the test year. The staff deducted the imputed test year expense of $176,007 from the requested operating license fee expense, resulting in a recommended expense of $124,193.

The report finds the staff's approach to be preferable to that of either the Company or the City, and recommends adoption of the expense recommended by the staff.

2. Revenue Related Taxes

a. Texas PUC Assessment. The Company applied an effective PUC assessment rate to its proposed revenue requirement to derive the requested PUC assessment tax expense of $461,165. The Company's effective tax rate was calculated based on the ratio of adjusted Texas electric revenues to adjusted total operating revenues (.64886) applied to the statutory PUC assessment rate of .1667 percent. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 24.)

Mr. Young's methodology was similar to that of EPEC. He calculated an effective PUC assessment rate based on test year PUC taxes assessed to adjusted test year revenues, which are test year booked revenues increased to include the booked provisions for fuel refunds, deferred fuel, and fuel interest. The staff's effective PUC assessment rate (.0012015) was then multiplied by the staff recommended revenue requirement to obtain the staff recommended PUC assessment tax expense, $449,901, a decrease of $11,264 to EPEC's request. (Staff Ex. No. 11 at 45; Staff Ex. No. 28 at 6-7 and at Schedule III Revised.)

This report recommends use of the staff's effective Texas PUC assessment rate and the revenue requirement recommended in this report to derive the Texas PUC assessment tax expense.

b. New Mexico PUC Assessment. EPEC's request for $406,882 for New Mexico PUC assessment tax expense was calculated using the same methodology as the Texas PUC assessment tax expense. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 26.)

The staff used the same methodology for this expense as for the Texas PUC assessment tax expense, with one exception. Since the 1986 New Mexico PUC amount assessed was virtually the same amount as the test year booked expense, staff utilized the test year booked tax expense to develop an effective tax rate of .00231783. The staff recommendation of $326,220 for this expense is a decrease of $80,662 to the Company's request. (Staff Ex. No. 11 at 46; Staff Ex. No. 28 at 6-7 and at Schedule III Revised.)

This report recommends use of the staff's effective New Mexico PUC assessment rate and the revenue requirement recommended in this report to derive the New Mexico PUC assessment tax expense.

c. Texas State Gross Receipts Tax. The Company requested $4,790,714 in Texas gross receipts tax expense. This expense is calculated based on an effective Texas gross receipts tax rate multiplied by the Company's requested revenue requirement. EPEC's effective gross receipts tax rate is based on taxes assessed by stated tax rate divided by total electric sales, net of uncollectible expense. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 23.)

Mr. Young used a methodology similar to that of the Company in calculating staff's recommended Texas gross receipts tax expense. The staff's effective rate (.0125759) is based on the ratio of gross receipts taxes assessed during the test year to the staff adjusted test year total company revenues. The staff's recommended Texas gross receipts tax expense is $4,709,035, a reduction of $81,679 to EPEC's request. (Staff Ex. No. 11 at 46-47; Staff Ex. No. 28 at 6-7 and at Schedule III Revised.)

This report recommends use of the staff's effective rate and the revenue requirement proposed by this report to derive the Texas gross receipts tax expense.

d. Texas Occupational and Street Rental Tax. EPEC requested $4,511,600 in Texas occupational and street rental tax expense, an increase of $308,607 to test year expense. This expense was based on the use of an effective Texas occupational and street rental tax rate multiplied by the Company's requested revenue requirement. The effective tax rate is based on rates of taxes assessed to gross Texas electric sales. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 22.)

The staff derived an effective tax rate of .0110229 based on the ratio of taxes assessed during the test year to adjusted test year total revenue. This effective rate was then applied to the staff's proposed revenue requirement to yield the staff's recommended $4,127,516 in expense for Texas occupational and street rental tax. (Staff Ex. No. 11 at 47-48; Staff Ex. No. 28 at 6-7 and at Schedule III Revised.)

This report recommends the use of the staff's effective Texas occupational and street rental tax rate and the revenue requirement recommended by this report to calculate the Texas occupational and street rental tax expense.

e. New Mexico Occupational and Street Rental Tax. EPEC's request for $736,493 in New Mexico occupational and street rental tax expense was based on multiplication of an effective tax rate by the Company's requested revenue requirement. The effective rate used by EPEC was based on rates of taxes assessed to gross New Mexico electric sales, less tax exempt sales, uncollectible accounts, and sales to schools. (EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 25.)

Mr. Young also applied an effective rate for New Mexico occupational and street rental tax to the staff's recommended revenue requirement in this case. The staff's effective rate was calculated based on a ratio of taxes assessed during the test year to adjusted test year revenues. The staff recommended

$591,742 for this expense, a decrease of $144,751 to the Company's request. (Staff Ex. No. 11 at 48; Staff Ex. No. 28 at 6-7 and at Schedule III Revised.)

The report recommends use of the staff's effective rate for New Mexico occupational and street rental tax and the revenue requirement recommended by this report to calculate the New Mexico occupational and street rental tax expense.

H. State Income Taxes

The Company originally requested $538,351 in state income taxes for New Mexico income taxes. (EPEC Ex. No. 1, Vol. 4, Tab 26 at 13; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustment No. 27.) However, in its amendment, EPEC deleted all amounts for New Mexico state income taxes. The expense included for this item should therefore be zero. (EPEC Ex. No. 1A Errata at Schedules A and A-1.)

I. Federal Income Taxes

Company witness Moises Rodriguez adjusted EPEC's federal income taxes to reflect the revenue and operating expense adjustments proposed by other EPEC witnesses in this docket. In addition, he used the new federal corporate tax rate (passed in the 1986 Tax Reform Act) in the calculation of EPEC's federal income tax expense, and adjusted the accumulated deferred tax account to reflect the normalization requirements arising from the 1986 Tax Reform Act and adjustments related to timing differences resulting from differences between book and tax accruals. (EPEC Ex. No. 1, Vol. 4, Tab 26 at 2-3; EPEC Ex. No. 1, Vol. 7, Schedule A-7, Adjustments 28, 29, and 30; EPEC Ex. No. 1, Vol. 7, Schedules G-7.1 through G-8 and associated workpapers.)

Mr. Rodriguez explained that the 1986 Tax Reform Act changes several significant items regarding the calculation of federal income tax for public utilities, among them, changes in the corporate tax rate, additional minimum corporate tax preference items, and revised accelerated depreciation lives. Although the new tax act allows for a transition rate of 40 percent for 1987, Mr. Rodriguez used the 1988 rate of 34 percent. Based on the regulatory lag between the filing of the case and implementation of new rates, he believed that the 34 percent rate would more accurately reflect EPEC's actual federal income tax expense.

He did not make a separate adjustment to reflect the effect of the lower corporate tax rate as it relates to the proposed accumulated deferred federal income tax (ADFIT) balance, because ADFIT essentially reflects the collection of deferred taxes from ratepayers based on two major components. The Company has previously collected deferred taxes from ratepayers at the existing corporate federal income tax rate in connection with accelerated tax depreciation and Allowance for Borrowed Funds Used During Construction (ABFUDC). The change in the corporate federal income tax rate created an excess deferred tax balance because of unreversed timing differences previously normalized. The tax act requires EPEC to amortize the excess deferred taxes associated with IRS normalization requirements no facter than the average remaining life of the plant assets.

EPEC previously reflected a deficiency in its accumulated deferred taxes with respect to normalization requirements dictated by FERC Order 144. To comply with that order, EPEC proposes that the deferred tax effect relating to the change in tax rate from 46 percent to 34 percent will be reversed over the remaining book life of the plant assets. According to Mr. Rodriguez, a current exposure draft of the Financial Accounting Standards Board (FASB) has taken a consistent position as to reversing these deferred taxes over the remaining book life of the plant assets. Any amortization of excess deferred taxes should, in his opinion, be treated according to the normalization rules set forth in FERC Order 144, and amortized over the remaining life of the asset.

Mr. Rodriguez testified that FERC Order 144 requires deferred taxes to be provided on all timing differences between book and tax income, and that deferred taxes be provided on unreversed timing differences when they had been in existence prior to the time normalization requirements were issues in FERC Order 144. Even though EPEC has provided deferred taxes on depreciation differences with respect to method differences since 1954, it did not start providing deferred taxes on timing differences resulting from basis differences until 1979. In Mr. Rodriguez's view, FERC Order 144 requires the Company to adjust its accumulated deferred federal income taxes in an amount sufficient to cover the tax effect of all unreversed timing differences with respect to all property included in plant. The current accumulated deferred federal income tax balance does not fully reflect the timing difference that occurred prior to 1979, particularly as to the accruals made for the timing differences for ABFUDC for Palo Verde. Anny difference made to reduce the excess amount of deferred ABFUDC taxes related to the change in the tax rate would be required to be offset by an amount sufficient to recapture the tax effect of any timing differences existing prior to 1979. Mr. Rodriguez included two exhibits, one which reflects the deficiency in existence prior to the change in the tax rate, and one which reflects the effect of the change in tax rate on accumulated deferred income tax. Since the adjustment for the deficiency in accumulated deferred income taxes and the adjustment to the change in the tax rate essentially offset each other, Mr. Rodriguez proposed that the net adjustment should be made over the remaining life of the plant. Mr. Rodriguez computed an adjustment to the accumulated deferred federal income tax balance for the combined effect of the deficiency in that balance and the result of the change in the tax rate.

Although EPEC did not propose to recover a minimum tax (under the Tax Reform Act of 1986), Mr. Rodriguez pointed out that EPEC may become liable for a minimum tax as a result of certain tax preference items such as the use of accelerated tax depreciation lives. The Tax Reform Act of 1986 provides for a tax preference item equal to the difference between net income per books and adjusted taxable income. As an example, Mr. Rodriguez explained that EPEC could have elected to take ten-year accelerated depreciation for tax purposes for PVNGS Unit 1 instead of an optional 25-year straight-line method. Initially, the ten-year method may have lowered the revenue requirement because the additional accumulated deferred income taxes would have reduced rate base. But the Company might become liable for minimum tax as a result of the increased difference between its taxable income and net income per books. In that event, EPEC would request that the ratepayers make up any revenue requirement shortfall occasioned by the minimum tax incurred.

IRS grants taxpayers a credit against income taxes payable for minimum tax previously paid, but EPEC would have to pay the minimum tax before the credit would be granted, requiring recovery for the minimum tax when incurred. Mr. Rogriguez recommended that since any accelerated tax deductions taken in the past resulted in lower revenue requirements for the ratepayer, the Commission should grant the Company a recovery of any minimum tax incurred in the future. When the Company is granted a credit against income taxes payable, it should then be used to adjust federal income taxes included in cost of service.

Mr. Rodriguez made additional timing difference adjustments to the federal income tax calculation. He made an adjustment to reverse a credit made on EPEC's income statement in September 1986 for TRASOP credits to reflect the reversal of approximately $4 million TRASOP credits initially expensed in 1983 which were utilized as a result of the sale/leaseback of PVNGS Unit 2. He also made an adjustment of approximately $800,000 for the TRASOP credits for which EPEC will not derive any tax benefit as a result of the sale/leaseback.

EPEC is currently recognizing interest expense accrued by the Rio Grande Resources Trust (RGRT) as a current deduction on its federal income tax returns; for book purposes, these amounts are being capitalized. These costs will be recovered by EPEC as part of the cost of fuel as EPEC leases the fuel from RGRT or as the Company recognizes amortization of the fuel purchases from RGRT. The Company included these costs as part of the fuel cost for ratemaking purposes. The deferred taxes associated with the timing difference resulting from the difference in tax and book treatment (with respect to the interest expense incurred by RGRT) are being reflected in the income statement of the Company. The corresponding deferred tax liability is reflected on the balance sheet as part of the total accumulated deferred federal income tax.

Mr. Rodriguez further explained that since EPEC has reflected the deferred tax associated with such timing differences on its balance sheet, it has also reflected the corresponding deferred federal income tax on the income statement. But the computation of total federal income tax for cost of service purposes is not affected by the timing difference of the interest expense from RGRT; the calculation of total federal income taxes does not change regardless of whether the timing difference is recognized. The Company uses the deferred method of accounting for investment tax credit and, in addition, normalizes for all timing differences in accord with FERC Order 144. Thus, there is no effect on cost of service of the difference in treatment for book and tax purposes of the interest expenses associated with the RGRT; any deferred taxes provided for this timing difference serve to reduce rate base.

Mr. Rodriguez did not include any tax savings resulting from consolidation of EPEC and its subsidiaries; he computed taxes on a "stand-alone" basis for EPEC and FL&R. He stated that any reduction in income tax payable to IRS as a result of consolidation is not attributable to EPEC. The Company and FL&R have signed an intercorporate tax allocation agreement under which the consolidated tax liability is allocated between entities based on each entity's contribution to the consolidated tax liability. Tax savings generated by FL&R are included in the unconsolidated financial statements of FL&R as negative income taxes which come about from both permanent and timing differences in FL&R's investments. The permanent tax savings arise mainly from the dividend-received exclusion; timing differences are generally the result of the difference between tax and book depreciation accruals. The tax savings from timing differences are only temporary in nature; when they reverse in the future, there will be a related liability. In future years when FL&R begins reflecting taxable income as a result of the reversal of these timing differences, EPEC will have to pay for the additional tax liability resulting from consolidation. Otherwise, Mr. Rodriguez explained, a confiscation will have occurred if the revenue requirement in this case is reduced by the "savings due to consolidation."

In addition, such a reduction to cost of service would violate the depreciation normalization requirements of the IRS, which require consistent treatment for book and tax-timing differences in the computation of cost of service and rate base. A reduction to cost of service from a "savings due to consolidation" could be viewed as a reduction of deferred taxes provided on book and tax-timing differences. This reduction in cost of service would not be reflected as an adjustment to rate base since it is related to non-utility operations. It is this inconsistency which Mr. Rodriguez believes could violate IRS depreciation normalization requirements. Therefore, he believes that the calculation of taxes to be included in the cost of service must be based on utility operations only.

A permanent difference arises with respect to the AEFUDC component of AFUDC because such amounts are not recognized for tax purposes. When such an amount is accrued per books, a permanent difference is reflected in the calculation of federal income taxes, and when such AEFUDC is included as part of total book depreciation, a reversing permanent difference must be recognized in the computation of federal income taxes. The adjustment Mr. Rodriguez made for AEFUDC reflects the in-service status of PVNGS Unit 1 and common facilities in the test year.

Tax adjustments resulting from the sale/leaseback of PVNGS Unit 2 included removal of all the taxes recorded on the books relating to this transaction because of the Company's use of the "book break-even" method of including this transaction in ratemaking. The interest deduction for federal income taxes was based on utility plant multiplied by the weighted cost of long-term debt in the Company's requested capital structure. The net deduction is determined by subtracting the timing difference for deferred taxes related to the interest deduction for CWIP not included in rate base. The adjustment for investment tax credits reflects the elimination of any intercorporate tax allocation recorded on the books, with the net effect being that total federal income taxes for the adjusted tax year reflect an investment tax credit equal to the adjusted test year amortization.

The adjustment for ITC amortization reflects the amortization of all investment tax credits generated and used by EPEC associated with non-PVNGS property, along with PVNGS Units 1 and 2 and related common facilities. (EPEC's initial filing did not include any ITC amortization associated with Unit 2, but Mr. Rodriguez amended his testimony to include such ITC amortization.) (EPEC Ex. No. 1, Vol. 4, Tab 26 at 3-12.)

City witness DeWard proposed six adjustments (summarized on City Ex. No. 6 at Exhibit TCD-1, Schedule 45) which he believed were required to state properly EPEC's level of federal income tax expense. The increase in taxable income shown on City Ex. No. 6 at Exhibit TCD-1, Schedule 45 is offset by the reduction to the AEFUDC offset calculated on City Ex. No. 6 at Exhibit TCD-1, Schedule 46. The net increase to taxable income is then added to the decreased interest expense (calculated on City Ex. No. 6, Exhibit TCD-1, Schedule 51), which he decreased because of the adjustments to rate base and the reduction in interest cost. He then multiplied the total increase in taxable income by the current federal tax rate of 34 percent; the additional federal income tax expense is then offset by adjustments (shown in City Ex. No. 6, Exhibit TCD-1, Schedules 47 through 50).

Mr. DeWard explained that his adjustment to AEFUDC is necessary to offset EPEC's adjustment which increased taxable income because AEFUDC is a permanent difference which is not dedcutible for tax purposes and which thus increases current income tax expense. His adjustment reducing EPEC's amount was based on his adjustments to plant in service and the disallowance of plant recommended by other witnesses for the City of El Paso.

His adjustment of the flow back of excess deferred income taxes (detailed on City Ex. No. 6, Exhibit TCD-1, Schedule 47) relates to the change in corporate tax rates from 46 percent to 34 percent; he proposed that this excess should be returned to ratepayers over a three-year period. Mr. DeWard disagreed that FERC Order 144 requires ratepayers to make up "so-called" deficiencies from earlier years, and pointed out that the Commission rejected this argument in EPEC's last rate case, Docket No. 6350. He believes that to allow such a recovery would be retroactive ratemaking. Further, he challenged the Company's calculation of these deficiencies, and stated that it is inappropriate to ask current ratepayers to pay for these deficiencies while the benefits flowed through as increased earnings to the Company and its shareholders. In the view of this witness, it is appropriate to flow back the current excess deferred taxes to ratepayers over as short a time as possible so that the excess collections could be returned to the ratepayers who provided those dollars.

Mr. DeWard believed his adjustments to reverse timing differences were necessary because EPEC's calculation of income tax expense is based on the current 34 percent tax rate. Elements of depreciation expense and nuclear fuel were previously provided for at the 46 percent rate. When these timing elements reverse, it is appropriate to reverse the timing differences at 46 percent and not at the 34 percent implicit in EPEC's calculation. When all of the excess deferred taxes have been returned to ratepayers over a three-year period, Mr. DeWard stated, this adjustment would no longer be required. (City Ex. No. 6 at 77 and at Exhibit TCD-1, Schedules 48 and 49.)

The City calculated the impact of the reversal of deferred taxes associated with EPEC's estimated level of nuclear fuel expense, but Mr. DeWard pointed out that this amount would need to be adjusted based on the level of nuclear fuel ultimately included after taking into consideration the disallowance of PVNGS Unit 1 and 2 costs recommended by other City witnesses. Further, Mr. DeWard included as part of its investment tax credit amortization an amortization associated with projected nuclear fuel costs, which was based on the Company's projected level of nuclear fuel expense. This adjustment would also need modification to reflect the recommendation of City witnesses to exclude 60 percent of Palo Verde costs. (City Ex. No. 6 at 77-78 and at Exhibit TCD-1, Schedules 48, 49, and 50.)

An interest synchronization adjustment was proposed by Mr. DeWard as necessary to calculate the proper level of interest expense to deduct in the federal income tax calculation. The calculated amount using the rate base and weighted cost of debt recommended by Mr. DeWard should be compared to the amount included in EPEC's tax calculation, and the decreased interest expense must then be added to the other adjustments to operating income. (City Ex. No. 6 at 78-79 and at Exhibit TCD-1, Schedule 51.)

Staff witness Mark Young explained the staff's federal income tax calculation, shown on Staff Ex. No. 28 at Schedule V Revised. The staff's methodology is to calculate federal income tax as a derivation of return. Since the return component of the cost of service represents the amount of money necessary for EPEC to recover its debt costs and to provide an after-tax return on equity, the staff begins with return dollars, less an amount for debt interest, plus any non-normalized timing differences for which deferred taxes have not previously been provided or which are direct offsets to taxes payable. The after-tax income is then "grossed-up" to derive the net taxable income before income tax. The taxable income, multiplied by the federal income tax rate of 34 percent and reduced by tax credits and other tax savings, is the staff's recommended federal income tax expense. Because the computation begins with the return amount after income taxes, the tax timing differences are normalized, and in Mr. Young's view, inclusion of any timing differences in this formula would be inappropriate. (Staff Ex. No. 11 at 48-49.)

Mr. Young proposed several changes to the components of the Company's federal income tax calculation. The first concerns the staff's calculation of the interest deduction, which is computed by multiplying the staff's weighted cost of debt (as recommended by staff witness Bradford) by the staff's invested capital (as recommended by staff witness Tye). The capital structure proposed by the staff does not include the unamortized accumulated balance of investment tax credits. In addition, Mr. Young recommended two changes to EPEC's calculation of ITC amortization. The first related to the ITC for nuclear fuel, which he recommended be amortized over the life of the nuclear fuel rather than over the life of the non-nuclear plant, as proposed by EPEC. The second concerned Mr. Young's recommendation that 50 percent of the ITC relating to PVNGS Unit 2 be included in the balance of ITC subject to amortization to ratepayers. (Mr. Rodriguez incorporated this second change during the hearing on the merits.)

A further staff adjustment to the Company's federal income tax calculation was related to the LESOP dividends. Under its LESOP plant, EPEC receives a tax deduction for dividends paid on stock held by the LESOP trust as long as those dividends are used to make principal and interest payments on the debt of the trust. This deduction is a permanent book to tax timing difference and, in Mr. Young's opinion, amounts relating to this deduction should have been reflected in EPEC's federal income tax calculation using the return method. According to EPEC responses to informal staff RFIs, this adjustment should be a decrease of $3,649,683 to the FIT calculation.

Mr. Young's testimony offered a detailed explanation of the differences between the staff's presentation of excess deferred taxes and depreciation add-back and that of the Company. He pointed out that EPEC's adjustment for unfunded tax liability (shown as $(1,240,992) on EPEC Ex. No. 1, Vol. 7, Schedule G-7.8) is a combination of a depreciation add-back adjustment for ABFUDC, pensions, and taxes of $(90,994) and a flowback of excess deferred taxes related to these items of $(1,149,998). Mr. Young combined the depreciation add-back adjustment for ABFUDC, pensions, and taxes with the depreciation add-back adjustment for AEFUDC, shown on one line entitled "depreciation add-back" on Staff Ex. No. 28 at Schedule V Revised. He showed the flow-through of excess deferred taxes adjustment as a separate line entitled "excess deferred taxes" on that same exhibit.

As Mr. Young explained, EPEC's request only flows back excess deferred taxes associated with depreciation-related timing differences. The staff's recommendation extends this adjustment to include flowing back excess deferred taxes relating to other timing differences. He used the staff's recommended accumulated deferred tax balances at test year end as the starting point for this adjustment and he calculated excess deferred taxes on all items which have a reversal period of at least one year. To determine the amount of excess deferred taxes, he grossed up these balances by 46 percent (the income tax rate during the period that most of the timing differences originated), and then multiplied by 12 percent, the difference between the old and new tax rates. The Tax Reform Act of 1986 restricted the time period over which depreciation-related excess deferred taxes could be flowed back to the ratepayers by requiring use of the average rate assumption method, which essentially flows back the excess deferred taxes over the life of the associated asset.

Mr. Young recommended that excess deferred taxes for all timing differences be flowed back over the remaining life of the associated timing difference, resulting in a better match in the cost of service between the expense which generated the timing differences and the benefit of reversal of excess deferred taxes. At the time he prepared his prefiled direct testimony, he did not have the information he needed to make this adjustment, so for all those differences for which EPEC failed to provide lives or estimated reversals, he recommended flowback over one year. The timing differences relate to deferred rate case expense, research and development costs, preliminary survey charges, fuel enrichment costs, and nuclear fuel interest. For Palo Verde O&M expense, spent fuel pay DOE, amortization of nuclear fuel lease, and nuclear fuel displacement credits, the Company did not indicate which portion of the accumulated deferred taxes related to deferrals and which portion related to plant life, nor did the Company provide estimated reversals for 1987 and 1988. Because of the insufficiency of information, Mr. Young calculated the reversal for these items over the three-year amortization recommended by the staff for the Palo Verde O&M deferrals.

For the portion of the depreciation add-back related to ABFUDC, capitalized pensions, and taxes, staff proposed to use the amount in EPEC's 1986 Form 10-k, which states that at December 31, 1986, the cumulative net amount of income tax timing differences on which deferred income taxes have not been provided approximated $17,000,000. EPEC did not reconcile this amount to the $51,604,969 in unfunded future tax liability (shown on EPEC Ex. No. 1, Vol. 4, Tab 27, Exhibit MR-1, page 1 of 2), stating that the $17,000,000 is representative of total unreversed timing differences at December 31, 1986, for which no deferred taxes were provided, while the calculation of $51,604,969 is based on total unreversed timing differences compared to the deferred tax balance existing as of September 30, 1986. Based on this information, Mr. Young stated that $17,000,000 is the appropriate balance to use in calculating the depreciation add-back. He also proposed two major adjustments to EPEC's requested depreciation add-back for AEFUDC. First, he recalculated the AEFUDC depreciation add-back related to PVNGS using the staff's recommended amount to be included for PVNGS plant in service, and he corrected the depreciation rate used to calculate the depreciation add-back for non-PVNGS production plant, because the rate used by the Company did not reconcile with the depreciation rate schedule proposed by EPEC in this docket.

By the time Mr. Young took the witness stand in Phase I, however, he had received updated information from EPEC, and he made several amendments to his FIT calculation based on that new information. In addition, when he filed supplemental testimony in Phase II, he incorporated the effect of the staff's recommended $28,000,000 disallowance of PVNGS costs into his calculation of federal income tax expense. Further, he adjusted the ITC amortization to reflect the disallowance recommendation made by Mr. Jacobs. He adjusted the Palo Verde Unit 1 qualified progress expenditure (QPE) subject to amortization to reflect the $28,000,000 disallowance. (He multiplied the balance of QPEs subject to amortization by an allowance factor of 94.7690517 percent [which is the result of dividing the $28,000,000 disallowance by the staff's recommended PVNGS Unit 1 plant balance at test year end of $535,275,789] to obtain the PVNGS Unit 1 QPEs subject to amortization after disallowance.) The adjusted balance of PVNGS Unit 1 QPEs subject to amortization was then multiplied by the staff's recommended PVNGS depreciation rate to derive the staff's revised PVNGS Unit 1 ITC amortization. In addition, Mr. Young added the ITC amortizations related to PVNGS Unit 2 (including the amendments he made during cross-examination in Phase I), non-PVNGS, and nuclear fuel. The total staff recommended ITC amortization amount is $3,912,516. (Staff Ex. No. 28 at 7-9 and at Schedule V Revised.)

In his supplemental testimony, Mr. Young also revised his original recommendation regarding excess deferred taxes. He adjusted the PVNGS-related excess deferred taxes by multiplying the 1988 PVNGS depreciation-related excess deferred tax reversal amount (provided by EPEC) by the 94.7690517 percent PVNGS depreciation-related reversals after disallowance. This calculation resulted in a $1,113,371 amount for excess deferred taxes.

The depreciation add-back component was also affected by the staff's disallowance recommendation, and Mr. Young recalculated the AEFUDC component of the staff's depreciation add-back adjustment to reflect the PVNGS disallowance recommendation. This was done by reducing the staff's original PVNGS AFUDC amount by $12,040,000 (the portion of Mr. Jacobs's total disallowance recommendation which the staff calculated to be related to AFUDC) before applying the percentage factor representing nuclear AEFUDC. The revised staff nuclear AEFUDC amount was then multiplied by the staff's recommended PVNGS depreciation rate to yield the staff's revised AEFUDC depreciation add-back amount, which, when added to the staff's ABFUDC depreciation add-back amount results in the revised $3,260,902 depreciation add-back amount. (Staff Ex. No. 28 at 9-10 and at Schedule V Revised.)

In its Reply Brief, the City of El Paso argues that use of the depreciation add-back was specifically rejected by this Commission in Docket No. 6350, and argues that there is no requirement that ratepayers make up the deficiencies from prior years. The City suggested that some of the deficiencies may be attributable to years before EPEC's first rate proceeding (in which case the benefit of the flow-through inured to the Company and its shareholders while now the Company is requesting that current ratepayers shoulder the burden), or that some of the deficiencies may be related to taxes paid but not collected in the past five years. Since FERC Order 144 was promulgated in 1981, and since EPEC did not seek this remedy in any docket prior to Docket No. 6350, the implication is that the deficiencies claimed by EPEC either do not exist or have been forfeited by the failure to request them before Docket No. 6350.

The Company's brief points out that before the creation of this Commission and the institution of the normalization requirement, the Company flowed through the benefit of the timing differences to the ratepayers by recording the deductions when they arose, relying upon the recovery of the additional tax expense from ratepayers when it later came due. Thus, the ratepayers at the time the deduction arose received the benefit of the deduction, and ratepayers at the time the taxes were to be paid had to meet the expense. This system would have continued to work had it not been for FERC Order 144, which required EPEC to provide for deferred taxes (both in an account for the future payment of tax expense and as an offset to rate base when doing so) for all unreversed timing differences existing prior to the issuance of the order. The order requires EPEC to adjust its accumulated deferred federal income taxes in an amount sufficient to cover the tax effect of all unreversed timing differences with respect to all property included in plant. The Company's accumulated deferred federal income tax balance does not fully reflect the timing differences which occurred prior to the issuance of FERC Order 144 in 1979; EPEC witness Rodriguez calculated the deficiency existing prior to the change in tax rate at EPEC Ex. No. 1, Vol. 4, Tab 27 at Exhibit MR-1.

Further, on rebuttal, Company witness Hahne testified that to the extent that tax benefits of the past have been flowed through to ratepayers, the tax costs that result from reversals of past timing differences must be recovered from future ratepayers. (EPEC Ex. No. 41, Tab 5 at 10.) There was a great deal of testimony in this record about the various methods for reinstating the reserves, among them the South Georgia method and the add-back, in which the taxes are charged in the year of the reversal. Mr. DeWard testified that permitting such reinstatement of the deferred tax balance is retroactive ratemaking, but Mr. Hahne did not believe this to be the case. In his opinion, the recovery of the tax benefits of past flow-through was a necessary product of the flow-through process, applying that methodology consistently in light of current normalization requirements, and affecting only the timing - not the amount - of the recovery of the past flow-through. (EPEC Ex. No. 41, Tab 5 at 11.)

Additionally, Mr. Hahne, the chairman of the American Institute of Certified Public Accountants Subcommittee on Public Utilities, testified that if recovery of these previously flowed through benefits were held to be retroactive ratemaking, the independent public accountants for EPEC would have to seriously consider establishing a reserve for deferred taxes for all previously flowed through items without providing a comparable deferred asset offsetting it on the basis of the promise of recovery in the future. Historically, accountants have not required the recording of deferred taxes for flow-through items based on the implicit promise of the regulator that they would be recovered over time as such timing differences reversed. If accountants did not have confidence in that recovery, the gross liability would have to be recorded. Under APB-11, there is a requirement that deferred taxes be provided for all industries in general, and the only exception is the utility industry, based on the implicit promise of the regulator of future recovery. If that promise is violated, Mr. Hahne testified, it would require the recording of the gross liability with no offsetting asset; that is, EPEC would be required to write off the total amount of the deficiency in its deferred taxes.

The second major tax issue relates to the excess deferred taxes resulting from the change in the tax rate. Both Mr. Rodriguez and Mr. Young believed that the average rate assumption - under which the taxes are returned to the ratepayers over the period of time during which the underlying timing differences will reverse - is required to be used for the return of these excess deferred taxes under the same revisions to the Internal Revenue Code which gave rise to the excess. (EPEC Ex. No. 1, Vol. 4, Tab 26 at 4; Staff Ex. No. 11 at 53.) Mr. DeWard conceded that his adjustment, amortizing the excess deferred taxes back to ratepayers over a three-year period, could result in that portion of the deferred taxes having a deficiency if tax rates are raised. His adjustment left just enough in the deferred tax account to reverse the timings at the 34 percent level. If the tax rate increases, future ratepayers will have to fund the taxes because the excess will have been amortized back.

The recommendation of this report is that the staff's methodology for computing federal income taxes be utilized, including the separate adjustments for deficiencies for the flow-through items and for the excess deferred taxes; however, the staff's methodology should be applied using the recommendations of this report as to capital structure, weighted cost of debt, etc. The Company successfully rebutted the proposal of the City of El Paso that the deficiencies due to flow-through items should not be funded and that all excess deferred taxes should be amortized to the ratepayers over three years; however, the staff's methodology is preferable to that of the Company because it separates the deferred tax adjustments and permits better review of these adjustments in future rate cases.

J. Return

The recommended dollar amount of return for EPEC is shown on Schedule I of the order.

XII. Annualization and Other Revenue Adjustments

The following witnesses addressed ammualization and other revenue adjustments: Company witness Michael C. Hicks, Supervisor - Rate Research for EPEC (EPEC Ex. No. 1, Vol. 5, Tabs 36 and 37; Vol. 7, Schedule A-7, Adjustment No. 1; Vol. 8, Schedules O-1(A), O-1(B), O-1(G), O-1(H), O-2, O-3, O-4, and O-5; as amended by EPEC Ex. No. 1E Errata; Tr. at 717-739; on rebuttal, EPEC Ex. No. 41, Tab 6; Tr. at 2406-2423); City of El Paso witnesses Hugh Larkin, Jr. (City Ex. No. 5 at 4-8 and at Exhibit HL-1, Schedule 1; Tr. at 1079-1115) and Thomas C. DeWard (City Ex. No. 6 at 28-29 and at Exhibit TCD-1, Schedules 4, 5, and 15; Tr. at 1116-1357); and staff witness Vickie Frazier, Economic Analyst in the Commission's Electric Division (Staff Ex. No. 9; Tr. at 1607-1617).

A. Customer Growth and Loss of Load Adjustments

The annualization procedure Mr. Hicks used in this case is the same as that approved in Docket Nos. 4620 and 5700 and proposed by EPEC in Docket No. 6350, and is performed on a jurisdictional basis. The annualization for Texas rates begins with categorizing the rate classes into three general groups. Group I includes Rate Classes 01 (with Subrates 05, 06, and 21-partial), 11, 22, 23, 24 (with Subrates 02 and 21-partial) 25, 26, 34, 41, and 54. Test year sales for this group were restated to reflect the level of sales which would have occurred had the number of customers in each rate class at the end of the test year been on the system every month throughout the test year. This adjustment to kWh sales was obtained by developing an average kWh per customer usage level for each individual Rate and Subrate class on a monthly basis and multiplying the resulting average by the customer differential established by that month's customer total subtracted from the customer total at the end of the test year.

Group II comprises Rate Classes 15, 29, 30, and 31, which are single customer classes and as such received no customer adjustments. Group III is made up of Rate Classes 08 and 28, the lighting classes in Texas, and was annualized by multiplying the number of lamps at the end of the test year by an annual usage amount.

Loss of load adjustments were made to test year sales for Rate Classes 15, 25, and 29 to reflect the effects of cogeneration or the shutdown of a major facility. Rate Class 15 - Electrolytic Refining Service (in which there is a single customer, Phelps-Dodge) was adjusted to reflect the installation and operation since September 1986 of approximately 9.3 MW of cogeneration capacity. The Company determined that this was a significant loss of load, and would not be readily replaced by an influx of customers in this class. The adjustment to test year sales was calculated by assuming an annual capacity factor for the combined capacities of each unit of the cogeneration facility of approximately 69 percent. Test year sales for another single-customer class, Rate Class 29 - Transmission Voltage (ASARCO), were adjusted to recognize the closing of ASARCO's antimony plant in May 1986. (<u>See</u>, EPEC Ex. No. 1, Vol. 5, Tab 37, Exhibit MCH-1, page 2 of 3.)

In Rate Class 25, a major customer, Providence Memorial Hospital, will be supplying its full load requirements from a cogeneration plant of approximately 3.9 MW capacity beginning the first quarter of 1987. The adjustment for this class was calculated by subtracting the test year sales for Providence Memorial Hospital from the test year sales total.

Changes in rate design prompted other changes in the annualization process. In Rate Class 24, EPEC is proposing to redefine its applicability criteria to reflect only those customers with an annual average billing demand greater than

15 KW. This results in the reclassification of 2,182 customers to Rate Class 02, which will be reinstated as a separate rate class. In addition, there were a number of rate design changes and consolidations which were proposed and approved in Docket No. 6350 which, although they have not been implemented as a result of a court-ordered stay during appeal, were retained in this filing and their effects incorporated into the annualization process.

Mr. Hicks also explained that the Company's New Mexico jurisdiction sales and revenues were annualized in the same manner as the Texas sales and revenues, using the tariff currently in effect for New Mexico. The MWH sales and revenues for EPEC's wholesale customers under the FERC jurisdiction were annualized as follows. The FERC annualized kWh sales for Rio Grande Electric Cooperative at the Dell City and Van Horn, Texas delivery points were based on test year sales. Annualized kWh sales to Texas-New Mexico Power Company's delivery point at Lordsburg were based on EPEC's 1987 Budget Year energy forecast (instead of test year sales) because of a change in certain contract provisions specifying TNP-Lordsburg's minimum contract demand. Annualized sales to Imperial Irrigation district were also based on the Company's 1987 Budget Year energy forecast. Annualized revenues for all FERC jurisdictional customers were based on settlement rates in the stipulation in FERC Docket No. ER86-368.

Based on Ms. Frazier's testimony (which utilized EPEC's methodology and proposed only mathematical corrections to the Company's calculations), Mr. Hicks made some corrections to his original prefiled testimony. Texas jurisdiction MWHs decreased 36,198 (1.2 percent) to 2,993,712 from test year MWHs of 3,029,911. Annualized Texas revenues are $201,886,397, of which $50,610,320 are fuel revenues. Of the remaining amount, $150,094,079 is derived from sales of electricity under the rates set in Docket No. 6350; $869,902 is derived from miscellaneous service revenues; and $312,096 is derived from rents and other revenues.

Under this methodology, the annualized sales were within 3.1 percent of the long-term sales forecast of 3,089,509 MWHs for the year 1987, and 3.3 percent of the 1987 Budget Year forecast for Texas sales of 3,096,774 MWHs for EPEC. The main reason for the differences between the annualization MWHs and the forecast and budget MWHs is that the latter include adjustments for weather, price elasticities, and local economic activity. In Mr. Hicks's view, the annualization procedure properly excludes such adjustments, for two reasons. First, there is a need to maintain a consistent and straightforward approach in developing a sales estimate upon which rates and associated revenues are stated. Consistency across jurisdictions is necessary to insure that an equitable allocation of costs results. Elimination of adjustments based on econometric modeling or weather sensitivities also eliminates the controversy attendant on such adjustments. Second, since the recovery of revenues is a function of the rates designed on the adjusted kWh, an increased potential for mismatch of revenues with expenses exists with the inclusion of independent variables not easily quantified. Unless the variables upon which the kWh adjustments are made can be accurately quantified, and unless their functional relationships with kWh sales can be accurately described, in Mr. Hicks's view, it is preferable to exclude them from consideration when developing the level of sales and demands for rate design.

Mr. Larkin proposed a modification to EPEC's annualization procedure for the Texas jurisdiction, identical to that which he proposed and which was adopted in Docket No. 6350. He criticized EPEC's annualization procedure because it assumes that all new customers added during each month entered the system on the first day of each month and, therefore, consumed the same average amount of energy as those customers who had in fact been on-line for the entire month. In his opinion, it is far more probable that customers would enter and leave the system at different times during the month, and use only a fraction of the average energy usage for one month. The effect of assuming that all new customers enter the system on the first day of the month is to understate the average kWh usage per customer for each month. Mr. Larkin's modification is to alter that assumption, and instead to assume that customers come on-line ratably during the month, rather than the first day of the month, and the average number of customers is used to compute the average usage per customer.

Mr. Larkin recalculated the Texas kWh sales for each Rate Class affected by changes in customer levels during the test year. He computed the average kWh usage per customer for each month by dividing monthly per book kWhs by the average number of customers (obtained adding the number of customers at the beginning of the month to the number of customers at the end of the month and dividing the total by two) on the system for each month. These average usage figures were then applied to the difference between the number of customers at the end of the year and the average number of customers to compute the kWh adjustment for each month. The total of the monthly kWh adjustments were added to the per book kWh for the 12 months of the test year to yield the kWh sales reflecting end-of-test-year customer levels. The current tariffs (established in Docket No. 6350) were applied to the adjusted kWh sales to compute the amount of non-fuel revenue to be included in the test year. Mr. Larkin's proposal increases EPEC's original Texas test year kWhs by 6,191,262 for a total of 2,996,796,861 kWhs, and annualized revenues by $245,370. (City Ex. No. 5 at Exhibit HL-1, Schedule 1.)

On rebuttal, Mr. Hicks challenged Mr. Larkin's methodology on the basis that his assumption - that customer growth is linear with time - has not been demonstrated. EPEC's methodology is based on the equally plausible (but equally undemonstrated) assumption that customer growth is more likely to be skewed toward the beginning of the month in recognition of "the inherent tendency to initiate business activities at each month's beginning rather than the middle or end of the month." Mr. Larkin's proposal, as conceded by Mr. Hicks, has the effect of spreading the uncertainty associated with the timing of customer growth evenly throughout the month.

Again, as conceded by Mr. Hicks on rebuttal, each methodology has merit and neither has been supported by an investigation of the timing of customer growth on EPEC's system. Mr. Hicks also did not supply any support for his assertion that there is an inherent tendency to initiate business activities at the beginning of a month. Further, Mr. Larkin's adjustment is reasonable because it spreads the uncertainty of customer growth evenly throughout the month and use of it would be consistent with the adjustment made by the Commission in Docket No. 6350. However, Mr. Larkin did not make similar customer growth adjustments for the New Mexico and FERC jurisdictions and, further, the City did not challenge the Company's jurisdictional allocators. While Mr. Larkin's adjustment is based on a reasonable assumption, it is inconsistent to make this adjustment for one jurisdiction and not the others. In addition, using Mr. Larkin's adjustment for revenues only probably unfairly underallocates costs to the Texas jurisdiction. The revised customer growth adjustments proposed by EPEC and supported by the staff should be adopted by the Commission. (Staff Ex. No. 9 at 5; EPEC Ex. No. 1E Errata at Revised Schedule O-1(A).)

B. Unbilled Revenues

Mr. DeWard proposed an adjustment to account for revenues representing service provided but no billing rendered with the test year, which results from meters being read on a cycle basis with the subsequent rendering of bills. According to Mr. DeWard, any service provided prior to the end of the test year which was not billed during the test year represents unbilled revenues which should be included in test year revenues. In order to determine the incremental level of unbilled revenues, the amount of unbilled revenues is calculated at both the beginning and the end of the test year, with the difference being the change in the incremental level of unbilled revenues. He recommended an increase of $244,223 to effect this adjustment.

On rebuttal, however, Mr. Hicks explained that revenues were assumed to be recovered concurrent with the level of kWh sales anticipated for the rate year. Twelve months' of billing determinants were isolated based on the adjusted test year kWh sales, and then were used to generate an amount of revenues based on rates in effect. To adjust these annualized revenues by an unbilled revenue adjustment implies that these kWh sales would generate more in revenues than is actually anticipated.

This report recommends that Mr. DeWard's adjustment not be adopted. Under the Company's methodology, the revenue lag at the beginning of the 12-month revenue block is matched by the lag at the end of the block.

C. Miscellaneous and Other Revenues

There was no challenge to EPEC's requested $869,902 in miscellaneous revenues or its $312,096 in rents and other revenues. This report finds these amounts reasonable, and recommends their adoption.

XIII. Cost Allocation

A. Introduction

There are three major steps that must be taken to allocate the costs of providing service as part of a traditional embedded cost of service study: (1) functionalization; (2) classification; and (3) allocation.

Functionalization refers to the arrangement of plant and other rate base components, as well as plant-related operating and maintenance expenses, according to the different functions performed by the electric system. Plant and operation accounts can be grouped into five major functions--production, transmission, distribution, customer, and general support. The production function consists mainly of power generation operation, including the exchange and pooling of power, fuel management, and a portion of system engineering and facilities planning. The transmission function involves all of the direct and indirect costs of power delivery, involving bulk transmission, subtransmission, and part of system engineering and facilities planning. The distribution function involves all of the costs associated with delivering electricity within the service area to the different classes of customers. The customer function covers the costs associated with measuring customer service, billing, collection of bills, and customer information and assistance. Finally, the general support function involves administrative and general expenses.

At each functional level, there is a classification of costs into demand, energy and customer components. Demand related costs are those costs which are related to the kilowatt demand placed on the system by the various customers. The amount of demand determines, in whole or in part, the size of the production, transmission and distribution facilities which must be built in order to provide service to meet all customer demands. Energy related costs are those costs which generally vary with the amount of electricity produced. Fuel is the primary energy related cost. Customer costs are those which the utility incurs as a consequence of serving a customer, regardless of the demand imposed or energy consumed by the customer. The costs associated with meters and service drops are prime examples of customer related costs.

Cost allocation refers to the assignment of classified costs either to different jurisdictions, or to the various customer classes within a jurisdiction. Because EPEC is a mulijurisdictional utility, costs must first be allocated on a jurisdictional basis, then later to the various Texas retail classes.

B. Jurisdictional Cost Allocation

EPEC operates in three separate jurisdictions: Texas, New Mexico, and interstate, which is subject to authority of the FERC. EPEC's production plant serves all three jurisdictions, as do most of its major transmission lines. Thus it is necessary to allocate costs among jurisdictions to ensure that each jurisdiction pays its fair share, but no more, of EPEC's revenue requirement.

EPEC has proposed utilizing the 12 coincident peak (12 CP) methodology at the jurisdictional level to allocate production and bulk transmission costs. Coincident peak methodologies looks to each classes' demand at the time of the monthly peak. A simple CP methodology looks only at the highest monthly peak (the system peak demand for the year). The 3 CP and 4 CP methods are usually used with summer peaking utilities, and use average figures based on the three or four summer months' peaks. A 12 CP methodology uses each classes average based on all 12 monthly peaks. EPEC has consistently utilized the 12 CP method in each of the three jurisdictions it operates in. Prior decisions of this Commission have adopted use of the 12-CP allocation methodology, and AFUCD credits in rate base, due to the allowance of CWIP in rate base, have been calculated utilizing a 12 CP allocation.

Border Steel witness Randall P. Goff testified that a 3 CP method (utilizing the average for the months of July, August and September) would be a more appropriate allocation method, both on the jurisdictional and Texas retail levels. But Mr. Goff stated that while he does not entirely agree with EPEC's methodology, he would not take issue with its use in this proceeding. The examiners believe it would be most reasonable to continue with the 12 CP allocation methodology in this docket. Mr. Goff simply did not present sufficient reasons to utilize a 3 CP method, nor did he do a cost of service study utilizing that method. Further, the lowest monthly peak is no less than 70 percent of the highest monthly peak, a situation that has occurred over the past several years, and during which time the 12 CP methodology has been utilized. Continued use of the 12 CP method will also ensure consistency among the jurisdictions, and with past Commission decisions.

Staff witness Pheng Kol did not take issue with use of the 12 CP methodology production and transmission related expenses, nor with EPEC's proposed energy allocation factor. Dr. Kol did, however, recommend several changes to allocation factors utilized to allocate certain operation and maintenance expense accounts (Account Nos. 502-steam expenses; 505-electric expense; 512-maintenance of boiler plant; 513-maintenance of electric plant; and 514-maintenance of miscellaneous steam plant). Dr. Kol bases his 50 percent demand/50 percent energy allocation on the Commission's Order in Docket No. 5700. In response, Mr. Mayhew testified that the Company interpreted the Commission's Order to require those allocations at the class (Texas retail) level, and not at the jurisdictional level, and he thus allocated those accounts at the jurisdictional level in accord with the allocation utilized by the FERC staff. The Examiner's Report in Docket No. 5700 is less than clear on this point. Jurisdictional matters were covered first, followed by allocation issues at the class level. Then the issue of allocation of the above five accounts was taken up. As the examiners read that Examiner's Report, the 50 percent demand/50 percent energy allocation was to take place at the class level, not the jurisdictional level, and they thus conclude that EPEC has not allocated them inappropriately in this docket.

Dr. Kol also recommended that Account 510 (Production-Maintenance Supervision and Engineering) be allocated on the basis of demand, rather than energy. The Company again used the FERC staff allocation classification to allocate this account. There is little testimony on this issue. The examiners believe that it is reasonable to utilize EPEC's allocator. Dr. Kol simply did not present sufficient testimony as to why the Company's proposal, based on FERC staff guidelines, was inappropriate.

Dr. Kol also changed the Company's allocation of several administrative and general expense accounts. The Company did not take issue with Dr. Kol's recommendations on rebuttal. Thus, Account Nos. 925.2 (Palo Verde Injuries and Damages), 926.2 (Palo Verde Pension and Benefits), and 930.2 (Palo Verde Miscellaneous Expense) should be allocated on the basis of the 12 CP demand allocator.

Finally, Dr. Kol made allocation recommendations for two additional items that staff had recommended be utilized in the calculation of FIT. The examiners have recommended the inclusion of those items in the FIT calculation, and thus recommend that Dr. Kol's proposed allocators be utilized for LESOP dividends and excess deferred taxes. The latter includes a wide range of items, each with its own allocator. (Staff Ex. No. 32 at 9.)

C. Class Cost Allocation

1. Production Plant Allocation

a. Proposals of the Parties. In the past, the Commission has approved the use of a 12 CP methodology for allocation of production costs at the class level. In response to previous dockets, wherein the parties and this Commission expressed a desire that EPEC use a methodology that included energy as a statistic in the derivation of class responsibilities, EPEC has proposed in this docket the use of an average and excess-four coincident peak (A&E-4CP) methodology. That methodology is designed to allocate costs in part based on energy usage, and in part based on demand. A portion of the production plant (total plant multiplied by average load factor) is allocated using an energy allocator, which in this instance is average demand on the system. The remaining portion of the plant is allocated based upon the amount of peak demand in excess of the average system demand, utilizing an excess demand allocator.

Many of the other parties' witnesses (Border Steel, ASARCO, DOD) preferred the use of a strict demand allocator (either 3 CP or 4 CP), but acquiesced in EPEC's proposal because the actual results of the A&E-4CP method were not signficantly different than those reached under either the 3 CP or 4 CP methods. Staff witness George Mentrup concurred with the Company's use of the A&E-4CP method. The only party actively opposed to EPEC's proposal is the City.

City witness Johnson has proposed two different allocation methods for production plant; one for Palo Verde, the other for all other production plant. The rationale for both methods derive from his view that the basic product being sold is kilowatt hours of electricity, and thus kwh sales provide a reasonable basis for allocation, because they closely reflect the benefits received by each class from the investments and expenses in question.

With respect to non-Palo Verde production plant, Dr. Johnson has proposed an unnamed "three tiered" methodology (the examiners will refer to it as that henceforth in this Report) that is akin to an average and peak methodology but, in Dr. Johnson's view, ameliorates or corrects the most important faults in that type of methodology. The three tier methodology divides peak demand into three tiers: base, mid-range, and peak. The base component, equal to the lowest demand placed on the system during the year, represents the demand present on the system at all times throughout the year (in this case, 286 MW). The mid-range component represents the difference between the base component and the lowest monthly peak demand placed on the system (in this case, 634 MW minus 286 MW, or 348 MW). The peak component is the difference between the minimum and maximun monthly peak demands placed on the system during the test year (938 MW minus 647 MW, or 291 MW).

Each tier is then allocated as follows. The base tier, or 30.49 percent of the Company's production plant (286 MW divided by 938 MW), was allocated 100 percent based on energy (average demand). The 38.49 percent of production plant represented by the mid-range component was allocated 50 percent based on energy, and 50 percent based on demand (4 CP, in an effort to minimize disagreement with the Company). The remaining 31.02 percent of production plant, representing peak demand, was allocated on a 100 percent demand basis, again using a 4 CP methodology to minimize conflict with the Company.

According to City witness Kimberly A. Herbig, the effective allocation of production plant is thus 50.27 percent to demand, and 49.73 percent to energy.

In earlier dockets, Dr. Johnson's proposals had been attacked on the basis that his general approach, while allocating the high capital costs associated with base load units based on kwh sales (energy), did not then allocate the high fuel costs associated with peaker units based on KW demand. In other words, the low load factor classes were relieved of an undue share of the high capacity costs associated with base load units, but the high load customers were not granted the same relief with respect to the high fuel costs of peaker plants, thus resulting in high load customers paying for both high capacity costs and high fuel costs. In order to alleviate this perceived problem, Dr. Johnson recommended that the above-average fuel costs associated with EPEC's peaker and intermediate plants (Copper Station and Rio Grande Units 6, 7 and 8) be allocated on the basis of KW demand, instead of kwh sales.

With regard to Palo Verde production plant, Dr. Johnson proposed a different methodology. First, Dr. Johnson determined that, based on the Company's statements over time, Palo Verde was built as a nuclear unit for reasons of reliability, fuel diversity and fuel savings (i.e., effective cost per kwh, not per KW). Such considerations are related primarily to the need to furnish energy on a year around basis, and not to meet peak demands. Dr. Johnson concluded that because the Company's investment in Palo Verde was not linked to peak demand, but to kwh generation at a low total cost, the investment in Palo Verde should be allocated primarily on the basis of kwh usage, and not peak demand.

The actual methodology utilized was to compare the cost of Palo Verde to the average cost of coal-fired plants that have either recently come on line or are scheduled to come on line from 1987 forward. Analyzing 12 coal-fired units produced an average cost per KW of $1,135, as compared to $2,424 per KW for Palo Verde. The difference, $1,289 per KW, or 53.2 percent of Palo Verde costs, was deemed to be unrelated to base load nameplate capacity and justified only on the basis of fuel cost savings, and was thus allocated based on kwh sales. The remaining portion of the Palo Verde investment was allocated utilizing the non-Palo Verde production plant allocation factor set out above. In sum, the total investment in Palo Verde was allocated 76.5 percent to kwh sales, and 23.5 percent to 4 CP demand.

As will be detailed below, the examiners believe that none of the proposed allocation methodologies are perfect. But they believe that the City's proposals are significantly flawed, and thus recommend that EPEC's A&E-4CP methodology be utilized.

b. Analysis of EPEC's Proposed Methodology. As Dr. Johnson recognizes, the A&E-4CP method does assign a significant portion (62 percent) of production plant costs based on system average demand (kwh sales). His complaint that the methodology does not account for the difference in capital costs of base load and peaker plants, and thus understates the share of total production plant costs that are incurred to provide energy, is correct. When 62 percent of production costs are allocated based on energy, a simple percentage of the total cost is allocated. To properly reflect differing capital costs, 62 percent of total MW capacity should be calculated, and then individual base load units should be allocated based on energy until 62 percent of capacity has been allocated. The remaining plants, consisting of peaker and intermediate plants, and probably some base load units also, would then be allocated based on peak energy demand. But, to properly follow through with such an allocation scheme, fuel costs would need to be allocated in a similar manner, because base load units utilize the lowest cost fuel. Not to allocate fuel in an identical manner would result in classes with high energy consumption being allocated high capacity costs, but not the correspondingly low fuel costs, resulting in a mismatch. P.U.C. SUBST. R. 23.23(b)(2)(C) requires fuel to be recovered based upon an average cost per kwh. Thus, while production costs are allocated on an average KW basis, fuel costs are also allocated on an average kwh basis. While one can argue that both production and fuel costs should not be allocated on a strict average per KW and per kwh basis, if one cost component is to be allocated on an average basis, the other cost category should also be allocated on an average basis. As will be seen with Dr. Johnson's proposals, when this point will be further examined, to mix and match is even more inappropriate than to simply use averages in the first place. The examiners would also note that Dr. Johnson admits that his own proposals do not consider the higher cost per KW of base load plants (City Ex. 57 at 19-20), and thus EPEC's proposal can hardly be singled out for this criticism.

The examiners also find Dr. Johnson's second criticism of the A&E-4CP methodology to be overstated. That criticism is that the A&E-4CP method treats all the seasonal and daily load variations of lower load factor classes as detrimental to the system, imposing "excess" costs beyond those costs attributable to the higher load factor customers. It is true that if all customers had a 100 percent load factor (average demand equal to peak demand), the utility would still have to have capacity in excess of average demand, for reliability and scheduled maintenance purposes. Thus, not all of the capacity on the system needed to meet the "excess" demand caused by the lower load customers is without benefit to the higher load customers. But Dr. Johnson fails to address the fact that the lower load customers, by spiking up the peak demand, require additional capacity on the system in excess of that peak demand in order to ensure that that peak demand level can be met. A few examples can make this point clearer. (The following examples are derived from methodologies and facts in evidence. The examples do not correspond to the Company's acutal system, and are being used only as an illustration of certain ideas at issue.)

Assume a system with two customer classes. The first has a 100 percent load factor at a 50 MW demand level. The second class' demand varies from 10 MW to 40 MW, with a 50 percent load factor. It is true that, with a 20 percent reserve margin, if the system had only the first customer class, it would need not 50 but 60 MWs of capacity. Thus, that additional 10 MWs of capacity, while being used to serve the needs of the second class, also provides a benefit to the first class. But due to the peak demand imposed by the second class, the system requires 108 MWs of capacity (90 MWs times 1.2). Thus, 48 additional MWs of capacity are needed beyond that required by the first class alone (108-60). Applying an A&E-4CP allocation methodology, the first class will be allocated 55.56 percent of the costs of the 108 MWs of capacity, equal to the costs associated with just a fraction more than 60 MWs of capacity. (See Examiners' Exhibit No. B, Scenario No. 1.) That is the amount of capacity that would be required by the first class if it were the only customer class on the system. Thus, the first class is effectively paying for the entire 60 MWs that would be required to serve it alone. The fluctuating load characteristics of the second class do not cause it to subsidize the cost of service to the first class. Indeed, as long as the load factor for the first class remains equal to 100 percent, the load characteristics of the second class are irrelevant: the allocation will always be 60 MW to the first class, and 48 MW to the second class. (See Examiners' Exhibit B, Scenario No. 2.)

Continuing on with the example, if one varies the load factor of the first class, the allocation of capacity will still result in 60 MWs of capacity being allocated to the first class, as long as the first class' peak demand occurs at the time of the system peak. (See Examiners' Exhibit B, Scenario Nos. 3 and 4.) As those two scenarios show, if the first class and the second class both have their peak demand at the time of the system peak, both will continue to be allocated the amount of capacity that would be needed to serve each class if it were the only class on the system. However, as soon as one class' peak is not coincident with the system peak, but the other class' peak is, the class with the noncoincident peak begins to benefit: the amount of capacity allocated to it is less then the amount that would be required if it were the only class on the system. In Scenario No. 4, the class that benefits is the lower load factor class. Scenario No. 5 is just the reverse situation, with the high load factor class not peaking at the time of the system peak, and thus benefiting. It should be noted that the class that peaks at the time of the system peak is "penalized" only to the extent it does not benefit by having a second class on the system: the amount of capacity allocated to it is the same amount that would be needed if it were the only class on the system. Scenario Nos. 6 and 7 show what happens if neither class' peak is at the time of the system peak. Each class benefits from having the other class on the system, but the degree of the benefit varies, depending on which class has a higher KW load at the time of the system peak.

Ultimately, as all of the above scenarios show, the amount of capacity in MW that is allocated to each class equals the ratio of coincident peak demand to noncoincident peak demand times the amount of capacity that would be needed if that class were the only class on the system. Thus, depending upon the system's load characteristics, both classes may benefit from having the other on the system, although, again, one class may benefit comparatively more than the other, depending on the timing of the classes' peaks. But to say, as Dr. Johnson does, that the A&E-4CP methodology inequitably allocates the "excess" investments to the low load factor classes is incorrect. Coincidence with the system peak is the important factor.

In brief, the City argues that the A&E-4CP method proposed by the Company is, except for one small difference, identical to a strict 4 CP demand methodology. The one difference is what is referred to as a "negative excess." A negative excess occurs when a class' coincident peak demand is less than its average demand. Rather than assign that class a negative excess, the excess is set equal to 0. The testimony of staff witness Mentrup and Dr. Johnson supports the City's argument (Tr. at 8222-8224, 8518-8519), and the examiners agree. Scenario Nos. 1 through 7 on Examiners' Exhibit No. B all allocate costs identical with a 4 CP method (assuming, for the sake of simplicity, that the peak figures presented in those scenarios represent 4 CP average figures, instead of 1 CP figures). Scenario No. 8 represents a situation where there would be a negative excess, but that negative excess is set equal to zero. As can be seen in comparison to Scenario No. 7, the allocation of capacity costs remains the same, even though the classes' contribution to the system peak has changed. Under Scenario No. 8, a 4 CP allocation would result in only 36 MWs being allocated to the high load factor class, instead of 42 MWs. Thus, a class that is able to reduce its coincident peak demand below its average demand reaps no benefit from doing so.

Thus, with the exception of classes that have a negative excess, the Company's proposal is identical to a 4 CP methodology. And while there are numerous classes with a negative excess (Rate 08-Municipal Street Lighting; Rate 15-Electrolytic Refining [Phelps Dodge]; Rate 21-Off Peak Water Heating; Rate 25-Large Power [transmission level service only]; Rate 28-Private Lighting; Rate 29-Transmission Voltage [ASARCO]; and Rate 34-Cotton Gin), the amount of that negative excess is only a little more than 3 percent of the positive excess, so the zeroing out of negative excess figures results in only a minor deviation from the results that would be reached using a strict 4 CP demand allocation method.

But even though the Company's proposal reaches results almost identical to the 4 CP method, the examiners are not convinced that the A&E-4CP methodology does not assign the bulk of production costs (almost 62 percent in this case) based on energy usage. In response to a question by one of the examiners concerning rate design, Dr. Johnson first testified that, as concerns the average and excess method:

> On the one hand, they [the Company] claim that their average and excess method gives substantial evidence to kWhs. And I don't necessarily agree with that, because they in essence introduce something that you might think of as negative kWhs through the way they calculate the excess, so they take away the emphasis on kWhs.

(Tr. at 8491.) Shortly thereafter, on redirect examination, Dr. Johnson was asked to explain how the lower kwh percentage weighting in his method actually took energy into account more than did the Company's method. In response, Dr. Johnson basically repeated his earlier testimony, without further detailing how the Company's method includes "negative kWhs," by simply stating that the excess portion of the average and excess method:

> in effect, mathematically contains an element of negative kilowatt-hours. So in a sense what happens is, they take the kilowatt-hours and they add it or weight it in with another factor that has negative kilowatt-hours in it, thereby negating the emphasis on kilowatt-hours that is nominally present.

(Tr. at 8518.) What Dr. Johnson has not explained is just how the excess demand contains negative kilowatt-hours. It is true that excess demand is equal to peak demand minus average demand, and that average demand is equivalent to kwh usage or energy. But that does not show how allocating 38 percent of production costs by excess demand somehow negates the allocation of 62 percent of production costs by average demand. Without that showing, without that explanation, the examiners are not willing to say that the Company's methodology does not allocate production costs in part based on energy.

In sum, the examiners do not find either of Dr. Johnson's two main criticisms of the Company's A&E-4CP methodology to be valid. While the Company's methodology, like all allocation methodologies, has some faults, at least until the Commission changes the manner in which fuel costs are allocated and recovered, the A&E-4CP methodology is appropriate for this Company.

c. <u>Analysis of City's Proposed Methodologies</u>. Dr. Johnsons' proposals were attacked by various parties on numerous grounds. On a general philosophical basis, Dr. Johnson's view, which serves as the philosophical underpinning for many of his recommendations, is that the product that the utility sells is electricity, or kwh, and thus energy should be the foremost factor in allocating costs. The examiners agree with the other parties that an electric utility does more than just sell kwhs. EPEC also provides instantaneous access to its system. More importantly, it also provides the customer with the rate of delivery (kw demand) that the customer desires, whenever the customer desires it. These additional services can be thought of as customer and demand services, and the costs associated with them should not be allocated on an energy basis. Further, as brought out on cross-examination of Dr. Johnson, demand is a very important aspect of providing service to a customer. A utility could otherwise meet the kwh usage requirements of a customer, but still not be able to meet his demand requirement at any given point in time, due to a lack of capacity or transmission facilities. (Tr. at 8398-8404.) Thus, kwh usage is but one component, and not necessarily the most important component, of the service provided to the Company's customers.

As concerns Dr. Johnson's non-Palo Verde three tier methodology, it too was attacked by several parties on various grounds. Foremost among them was the view that the methodology double counts energy usage. The examiners agree that energy usage is being counted more than once. However, due to the three tiers being used, the examiners are unable to determine just how much more than once energy usage is being counted. The difficulty with the three tier method is where Dr. Johnson has drawn the boundaries between the tiers.

Company witness Richard D. Treich stated on clarifying examination that he couldn't see any reason to use 286 MWs, the <u>lowest</u> absolute demand on the system, as a dividing line, especially when that portion of demand is going to be allocated using an average demand allocator. (Tr. at 8708.) The examiners agree. Clearly, the lowest system demand level should be considered as base load, and thus, if one is to use an energy allocator, it should be allocated on the basis of energy. But to allocate it separately, instead as simply part of average demand, does not make sense. Average demand (kwh sales) is being used as an allocator, but the average level of demand is not the amount of demand that it is being used to allocate. An allocator should bear some relationship to what it is used to allocate; but average demand (kwh sales) is in no way related to either lowest system demand or lowest monthly peak demand. There is no reason why a class' contribution to average demand should be used to allocate, as the City's witnesses do, an amount of demand different from average demand. Essentially, the City is using a two component allocator (average demand and peak demand) to allocate a demand level it has divided into not two, but three components. While the examiners cannot say that doing so is always inappropriate, Dr. Johnson has failed to explain why doing so is ever appropriate.

Dr. Johnson's methodology is also flawed in that the intermediate tier of demand is simply allocated 50 percent to energy and 50 percent to demand. Such an arbitrary allocation is unsupported: City witness Herbig simply stated that the midrange tier: "is not purely peak related, nor is it present at all hours of the year. Therefore this percentage of production-related [plant--sic] was split with 50% weight to the KWH allocation factor and 50% weight to the KW (or 4CP) factor." (City Ex. 58 at 4.) One would presume that the proper way to allocate this intermediate range would be to examine the actual load data for the test period. But to allocate this midrange demand in such a fashion would result in a return to a two component methodology: average demand would be allocated using an energy allocator, and the remainder would be subject to a demand allocator. The whole three tier system would vanish. To prevent this from happening, a whole component of demand is not allocated based upon load data or any other supporting data. Instead, some 38.49 percent of total non-Palo Verde capacity is subjected to a simple, arbitrary 50/50 split between allocators. The failure to utilize some set of actual data in order to allocate the intermediate range demand hints at the flaws inherent in the proposed methodology: a three tier allocation method cannot rely on only two allocators.

As to double counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50 percent of the intermediate demand, includes within it an energy component. Dr. Johnson has elected to use a 4 CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy. As Mr. Triech notes, Dr. Johnson avoided the pitfalls of including energy as a component of a demand allocator in Docket No. 5700 when he utilized "peak demand above average demand in order to derive demand responsibility" for production plant. (Docket No. 5700, Examiner's Report at 113.) Interestingly, Dr. Johnson failed to do the same for his CWIP and transmission expense allocations in Docket No. 5700, with the examiner concluding that Dr. Johnson proceeded to double count like the other parties. In this docket, by utilizing a peak rather than an excess demand allocator, Dr. Johnson again fails to prevent counting energy more than once. The examiners are unable to determine the exact extent of the overcounting due to the fact that the energy allocator does not relate to the amount of demand that it is being used to allocate. Whether the exact extent is that the 519 MW average demand level is being counted twice, or 467 MWs (the base component plus the half of the intermediate component allocated using the energy allocator) is being counted twice, is irrelevant. A substantial portion of average demand is being utilized in two different allocators, and thus "double-dipping" is taking place. As in Docket No. 5700, the existance of that double-dip is a major flaw in Dr. Johnson's proposal. While Dr. Johnson has testified that it is appropriate, indeed superior, to allocate peak related capacity using a coincident peak allocator instead of an excess allocator, the examiners are unable to follow his reasoning. Dr. Johnson states that under his proposal, "customer classes with high load factors (above 100%) are properly assigned some responsibility for the plant investment needed for maintenance and reliability." (City Ex. 57 at 20.) The record does not demonstrate how a class can have a load factor greater than 100 percent, and thus the explanation loses credibility at this point. The examiners have also explained above that coincidence, not load factor, is the determinative factor in the proportional allocation of peak related capacity.

A final flaw in Dr. Johnson's analysis deals with fuel symmetry. Dr. Johnson, in response to previous criticism, has allocated the higher fuel costs associated with intermediate and peaker plants based on KW demand, in order to avoid allocating higher cost base load units to high load factor customers without also passing along to those customers the lower cost fuel those units burn. The whole issue of fuel symmetry will be examined in greater detail below, when considering Dr. Johnson's allocation of Palo Verde production plant. It is sufficient at this point to note that regardless of the allocation of fuel costs done by Dr. Johnson, his rate design proposals do not follow through and alleviate the fuel symmetry problem. This is because the Commission's Substantive Rules require that fuel be recovered utilizing a system-wide fuel factor, varying only for line losses. Without class differentiated fuel factors, fuel allocation is irrelevant. Indeed, one could allocate fuel costs on, for example, a customer basis, and it would have no effect on the fuel factors, or the amount of money recovered from each class through those fuel factors. Dr. Johnson's proposal is appearance without substance.

Turning now to Dr. Johnson's proposal for allocating Palo Verde production plant, although Dr. Johnson nowhere uses the term capital substitution, that is in fact what his proposal comprises. Granted, in previous cases base load plants have been compared to gas fired peaker plants, while in this docket the comparison is between a nuclear fueled base load unit and a coal fired base load unit. But that does not alter the fact that capital substitution is the basis of the allocation methodology: the reason for the investment in the unit is studied; overall operating costs, and in particular lower fuel costs, are determined to be the deciding factor in the decision to build a nuclear unit; the additional cost per KW resulting from that decision vis-a-vis constructing some other type of generating unit is determined; and that additional construction cost is allocated on a kwh basis, as representing an effort to achieve a lower cost per kwh as compared to the comparison generating unit.

As Mr. Treich notes, capital substitution, or reasonable equivalents, were presented in three previous dockets before this Commission, including Docket No. 5700, and were rejected in each instance. Capital substitution was also presented as an alternative in the recent Gulf States Utilities rate case (Docket Nos. 7195 and 6755), and has been rejected by the examiners in that proceeding (a decision by the Commission is pending).

On a theoretical basis, the examiners believe that capital substitution may have some merit. Increased capital costs may be incurred in order to take advantage of lower fuel and operating costs, such that over the life of the plant the cost per kwh is less than the alternatives. However, in practice, capital substitution runs into major difficulties.

Regarding the advantages of a nuclear option over coal, Dr. Johnson relies in part upon testimony by a Company witness in Docket No. 5700 that EPEC chose to participate in Palo Verde for reasons of, as Dr. Johnson reads that testimony, diversity, reliability, and fuel savings. Dr. Johnson then testifies that those considerations "are related primarily to the need to furnish energy on a year-round basis, not to the need to meet peak demands during a few hours of the year." (City Ex. 57 at 24.) The examiners do not believe that Dr. Johnson has proven up this statement. Diversity is a benefit during peak periods, especially winter peaks. If one source of fuel is interrupted, plants fueled by other fuels can remain on line. Thus, if a utility is 100 percent gas fired, and gas is curtailed, the utility may have problems meeting the demand on its system. The same holds true for coal delivery disruptions. A utility with a diverse fuel mix can more easily cope with such problems. Reliability also is a consideration with regard to peak demand. Indeed, the need for a reserve margin reflects the fact that, for whatever reason, not all plants may be available at the time of peak demand, and thus it is necessary to have back up units available. Reliability of units is very important in planning for the system peak. The examiners agree that both diversity and reliability also relate to the need to furnish energy on a year-round basis, and that fuel savings is related solely to kwh sales over the long run. But the important point is that diversity and reliability are not related solely, or even necessarily primarily, to energy usage. Thus the examiners cannot agree with Dr. Johnson that "the cost of providing energy, not capacity, is EPE's only possible justification for participating in Palo

Verde." (City Ex. 57 at 25.) The examiners agree that the cost of providing energy was an important, and perhaps the major, consideration--but not the only one.

The difficulty with capital substitution is that it assumes that reliability and diversity considerations relate solely to energy usage, and thus the "additional" capital costs can be allocated 100 percent to energy. But reliability and diversity are not so limited, and thus not all of the additional construction costs can be so allocated. How to then allocate the additional costs between energy and demand is problematic, as it involves trying to assign "causation percentages" to the various reasons underlying a decision made years ago, which in turn requires trying to ascertain exactly why a utility (which itself is a collection of individuals with varying views and beliefs) did what it did. Further, problems arise if the reasons for the decision change over time. Dr. Johnson, by viewing the Company's decision as relating solely to total cost per kwh, sidesteps these problems, but the examiners believe that they cannot so easily be ignored.

The examiners next question, as does the Company, why capital substitution is not the methodology utilized for all production plant, instead of simply nuclear generating units. If, on a theoretical basis, capital substitution is the most appropriate methodology for allocating production costs, why did Dr. Johnson not utilize it across the board? Dr. Johnson failed to explain why he utilized two different methodologies for plant with the same functionalization. This mixing of allocation methods tends to suggest either that neither of the two methodologies is truly able to allocate all production plant appropriately, or that the City is mixing its allocation methods in such a manner as to gain a production plant allocation that is more favorable to it than would be produced by either of the two methods alone.

The examiners find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal, one must recognize the need to de-average the allocation of operating costs and fuel. Otherwise, as noted earlier, the high load factor classes, which will bear higher cost responsibility for base load units, will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units. Dr. Johnson and Ms. Herbig have not attempted to do so with regard to Palo Verde operating costs: power production expenses as a whole are allocated using the allocation factors resulting from their three-tier non-Palo Verde allocation methodology. The power production expenses for Palo Verde are not separated out and allocated according to the D-6 allocation factor applied to Palo Verde production plant itself.

As for fuel, Dr. Johnson allocated the fuel costs associated with peaker and intermediate plants based on 4-CP demand, in order to apportion the higher fuel costs associated with such plants to the low load factor classes. The examiners do not see why the fuel costs for <u>all</u> plants should not be allocated in the same manner, respectively, as is the plant itself. At least for Palo Verde, which would be allocated by the City based upon a capital substitution methodology, it would be necessary to allocate fuel costs in some manner other than on a kwh basis. Using the same allocator for fuel as for the plant itself may be one means of trying to alleviate the fuel symmetry problem. A more exacting means would be to try to allocate fuel costs based on hourly load data. As ASARCO witness Moore discusses (ASARCO Ex. 4 at 11-12), even an hourly examination will not produce an exact allocation. Utilities must be able to meet projected changes in load over the course of a day, but generating units have a limited ability to change output levels within specified time periods (ramping capability). Thus, during off-peak hours, a utility may have to operate generating units at less efficient minimum load levels, or operate units that have higher fuel costs, in order to maintain sufficient ramping ability. Thus, the load swings caused by low load customers can result in higher costs than would otherwise be incurred, even during off-peak periods.

An additional fuel symmetry problem arises when considering the capital substitution methodology, as is explained by Mr. Moore. (ASARCO Ex. 4 at 12-13.) The foundation of the capital substitution methodology is that higher capital costs are incurred in order to reap lower operating and fuel costs, such that overall kwh costs are lower. The time period that the capital substitution methodology examines in its focus on total kwh costs is not one year or several years, but the life of the plant. The difficulty is, while a nuclear plant may, over its lifetime, be less costly than a coal or gas fired plant, that benefit may not be realized until well into the 35 to 40 year life of the plant. But how many customers will be on the system for that entire period? Initially, both capacity and operating/fuel costs may be higher than a comparable plant. Thus, high load customers who are on the system when the plant first comes on line may pay much more than if a coal or gas fired plant had been built, while high load customers who are on the system 30 years hence may reap enormous benefits from the nuclear plant. By focusing on a 35 to 40 year time frame, instead of examining how the plant is actually used during the test year, the capital substitution method assures that customers who are not on the system for the entire life of the plant will be either be unfairly penalized or rewarded.

A final problem with capital substitution is that allocation of production plant on an energy basis results in a decrease in the cost assigned to energy consumed during on-peak periods, and an increase in the cost assigned to energy consumed during off-peak periods. As Mr. Moore notes (ASARCO Ex. 4 at 15), the resulting price signals will encourage on-peak energy consumption and increase peak demand. Such a result will hasten the need for additional capacity, is contrary to the off-peak pricing provisions of many of the Company's rate schedules, and conflicts with the Commission's goal of encouraging reductions in peak demand through conservation, load management and other means.

d. Examiners' Recommendations. In sum, the examiners find that Dr. Johnson's proposed production plant allocation methodologies have serious and, for purposes of this proceeding, fatal flaws. Even if such flaws did not exist, the examiners are reluctant to make such a large change in cost allocation formulas, particularly at a time when an enormous increase in plant in service is occuring due to rate base recognition of Palo Verde. Even Dr. Johnson agreed that consistency in allocation factors is important, and that major changes should be phased in over a period of up to 10 years. (Tr. at 8501-8502.) But Dr. Johnson did not propose phasing in his proposals, even though they are a major change from the previous allocation methodologies approved by this Commission. The Company's proposal is itself a change, but not a large one. For all the reasons detailed above, the examiners find the Company's proposed production plant allocation to be the most reasonable one in evidence, and recommend its adoption.

2. Transmission Plant Allocation

a. Proposals of the Parties. Except for some directly assigned radials serving customers in Rate Classes 24, 25 and 30, the Company utilized the same A&E-4CP allocation that it utilized for production plant.

Each other party presenting evidence on this issue--except for the City--recommended use of the same demand allocators that it had recommended for production plant. But, as before, they all acquiesced in the Company's proposal.

The City, through its witness Dr. Johnson, recommended that transmission plant be allocated 35 percent based on kwh, and 65 percent based on 4 CP demand.

b. Analysis of the Parties' Proposals. The Company's proposal is the same as for production plant, for the same reasons, and none of the parties directly attacked the company's proposals. (Dr. Johnson's views were presented in support of his own proposal, and did not directly attack the Company's testimony, although they are inconsistent with that testimony.)

Dr. Johnson's recommendation is in essence a continuation of his capital substitution views. He argues that Four Corners--a remote, mine-mouth generating station--was built to take advantage of the local fuel source, and thus was built as a coal fired plant and sited where it was due to fuel savings considerations. Comparing Four Corners to a peaker plant that could have been built in the El Paso area, Dr. Johnson concludes that the transmission facilities serving Four Corners are thus energy related. Having already determined that Palo Verde was built in great part due to fuel savings considerations, Dr. Johnson again concludes that the transmission facilities bringing power from it are also energy related. As to the transmission facilities linking the company with Southwestern Public Service Company (SPS), Dr. Johnson relies upon a discovery response in Docket No. 5700 that the reasons for the intertie were increased system reliability, cheaper fuel sources, and economic buy/sell transactions. Finding those reasons to be closely tied to kwh sales, and not KW demand, Dr. Johnson concludes that those transmission facilities should be allocated primarily based on energy rather than demand. Dr. Johnson also believes that overhead costs, not being clearly identifiable with any given cost causative factor or customer class, should also be allocated in large part based on kwh consumption. Finally, because the actual design of the lines is based on KW demand, and apparently because transmission lines located within the El Paso service area are not energy related, Dr. Johnson allocates a great portion of total transmission plant based on demand (65 percent).

The examiners believe that, leaving aside the issues detailed earlier as to whether capital substitution is an appropriate methodology, and leaving aside the issue of whether transmission plant should be allocated utilizing such a methodology when production plant is not being so allocated, Dr. Johnson has not done a complete capital substitution analysis. Properly done, the cost of the actual transmission lines connecting Palo Verde and Four Corners to the company's system must be compared to the hypothetical cost of transmission facilities serving a peak load unit located within the service territory of the company. The additional cost would then be allocated based on energy, and the remainder allocated based on demand.

As for the lines connecting EPEC with SPS, Dr. Johnson has again fallen prey to the inappropriate view that system reliability relates only to year-round reliability. Indeed, in this case it is blatant. The discovery response from the company mentions "increased reliability to each system", but in characterizing the reasons for the intertie Dr. Johnson testifies that one of the reasons was to "increase <u>year-round</u> reliability." (City Ex. 57 at 33, emphasis added.) The phrase year-round is inserted by Dr. Johnson, in order to substantiate his views. But that is not what the company stated. As with production plant, increased reliability favorably impacts a utility's ability to meet peak demand, as well as reduce total costs per kwh.

The fatal flaw with Dr. Johnson's proposal is its arbitrariness. The 35 percent energy/65 percent demand allocation split is in no way justified. Dr. Johnson apparently just picked it without offering any explanation for his views. While sometimes cost allocation involves somewhat arbitrarily chosen percentages, as will be seen below with distribution costs, that is not necessary or proper here. Dr. Johnson, if he wanted to present a complete and internally consistent proposal, should first have done a complete capital substitution analysis for all of the transmission plant that he thought was primarily energy related, to determine the appropriate allocation for such plant. Then he should have determined a proper allocation for the remaining plant--be the allocation 100 percent to demand, or some split between demand and energy. Finally, he should have produced weighted composite allocation percentages. But Dr. Johnson did not do so, and the examiners do not believe that, for these costs, an arbitrary formulation need or should be adopted.

c. <u>Examiners' Recommendations</u>. Dr. Johnson's proposal is seriously flawed and should not be adopted. The company's proposal is reasonable, and does in fact take into account energy usage. The examiners recommend that transmission plant be allocated using the company's A&E-4CP allocation methodology.

3. Distribution Plant Allocation

The major area of disagreement concerning distribution plant allocation is the weighting, if any, to be given to customers and energy. As with all other allocation issues, the ultimate question is whether particular plant accounts can be clearly traced to causative factors. While for production and transmission plant the general view is that cost causative factors can be determined, although experts will disagree as to the weight to be given the factors, it is much more difficult to do so for distribution plant (contrary to some of the arguments of the parties).

a. <u>Proposals of the Parties</u>. EPEC has proposed that that Accounts 360 through 368 (Land, Structures and Improvements, Station Equipment, Pole Towers and Fixtures, Overhead Conductors and Devices, Underground Conduit, Underground Conductors and Devices, and Line Transformers) be allocated based on noncoincident peak demand (NCP). The NCP method looks at the maximum demand placed on the system by each class, regardless of when that maximum demand occurs. The maximum demands of all the classes are summed, and each classes' allocation is based upon its relative contribution to the total. For Accounts 369 (Services) and 370 (Meters), the company has proposed a 100 percent customer allocation, using the year end customer count and weighted costs per customer.

W. Silver witness Stanley recommended that Accounts 364 through 368 be allocated based upon both demand and customers. The appropriate percentages for each account were derived using a minimum system analysis. That type of analysis looks at the costs that would be incurred to provide service to a customer that has the smallest need for power, or in other words, the lowest connected load on the system. Then:

> For each specific distribution account, the minimum size equipment currently installed for serving the customer, along with the respective total cost of materials and capitalized labor of installation is identified. This cost is multiplied by the number of units currently on the system. The result would be the theoretical cost of replacing the entire system with plant that provides the lowest load carrying capacity available, in current dollars. This cost is compared to a trended total cost of each account. . . . It is necessary to calculate trended total cost by distribution account, to establish an analysis of plant balances on a consistent basis. The ratio of the current replacement cost to the trended total cost by account defines the customer related investment on the system, with the remainder relating to dollars invested by the utility due to additional demand on the system.

(W. Silver Ex. 1 at 7-8.) Mr. Stanley based his calculations upon a February 1985 distribution study done by the Company, and, agreeing with the remainder of EPEC's proposals, reached the following percentage splits:

Account	Customer	Demand	Energy
360	0%	100%	0%
361	0	100	0

Account	Customer	Demand	Energy
362	0	100	0
364	100	0	0
365	40	60	0
366	40	60	0
367	40	60	0
368	30	70	0
369	100	0	0
370	100	0	0

Mr. Stanley also recommended changes to the functionalization of Accounts 364 and 366. EPEC had split Account 364 on a 97.3 percent primary/2.7 percent secondary basis, and split Account 366 on a 75.8 percent primary/24.2 percent secondary basis. Mr. Stanley disputed the company's rationalization for the functionalization of those two accounts, but was unable to develop any alternate figures due to a lack of sufficient detail in the Company's accounting system. Because the Company has a more detailed account of the service nature of lines than of poles or conduits, Mr. Stanley recommended using the percentages from the respective line accounts (365 and 367) as a proxy. This would change the functionalization of Account 364 to 74.9 percent primary/25.1 percent secondary, and Account 366 to 30.5 percent primary and 69.5 percent secondary.

For the City, Dr. Johnson recommends that the allocations remain identical to those approved by the Commission in Docket No. 5700, the last contested rate case. Those percentages are as follows:

Account	Customer	Demand	Energy
360	0%	70%	30%
361	0	70	30
362	0	70	30
364	20	50	30
365	20	50	30
366	20	50	30
367	20	50	30
368	20	50	30
369	50	25	25
370	75	0	25

Dr. Johnson follows the rationale given in Docket No. 5700, in which his recommendations were adopted, that distribution plant is not clearly identifiable with demand, customer or energy components, and thus an allocation which spreads some of the costs of such plant to energy is more comprehensive, better associated with reality, and not in conflict with settled traditional classifications. In the absence of any evidence that the Company's distribution system has changed since Docket No. 5700, Dr. Johnson sees no reason to alter the weightings approved in that docket.

Finally, staff witness Mentrup agrees in part with both the Company and Dr. Johnson. His recommendations are as follows:

Account	Customer	Demand	Energy
360	0%	100%	0%
361	0	100	0
362	0	100	0
364	20	50	30
365	20	50	30
366	20	50	30
367	20	50	30
368	20	50	30
369	100	0	0
370	100	0	0

Mr. Rudolph did not directly testify as to Accounts 360, 361 and 362, simply leaving them as proposed by the Company. As to Accounts 369 and 370, he testified that those accounts have a nearly one-to-one relationship to the existance of a customer, and thus agreed with the Company's classification. As to the remaining accounts, Mr. Rudolph feels they are less likely to be totally assignable to any one classification category, and thus recommended that the Docket No. 5700 allocations be continued.

b. Analysis of the Parties' Proposals. The issue that must ultimately be confronted is, when certain costs are not directly caused by either demand, energy usage, or the number of customers on the system, how should such "unallocable" costs be allocated? Even the Company, which argues for 100 percent allocators for all accounts, recognizes that not all costs can be allocated based on cost causation. Mr. Treich testified that there are certain overhead costs and additional costs caused by geographical conditions that are not truly allocable. (EPEC Ex. 135 at 20.) The Company's answer to unallocable costs is to allocate them in accordance with how allocable costs have been allocated. Because the allocable costs have all been traced to either demand or customers, depending on the account, the result is 100 percent allocations.

The Company certainly has one answer to how to allocate unallocable costs. The other is that presented by Dr. Johnson: unallocable costs should be allocated to the other factors. Thus, if 50 percent of the costs are demand related, and the other 50 percent are unallocable, that other 50 percent should be allocated to energy consumption and to customers. Dr. Johnson correctly notes that in competitive markets, such as the one the neighborhood gas station finds itself in, overhead costs are often recovered through the price of the product sold. Thus, customers who purchase large amounts of gasoline will pay more of the overhead costs than those who purchase only small amounts. While the Company is correct that this is not always the case, the Company's testimony does not disprove Dr. Johnson's testimony, but simply proves that in competitive markets, overhead costs may be recovered in variety of manners.

The examiners believe that while either approach is acceptable, to spread the costs to the other cost factors is preferable. As the Company has argued, the services it provides are access to the system, the ability to meet the peak load demanded, and the ability to provide power over a period of time. Phrased in other words, these are customer, demand and energy related services. It is thus proper to allocate "unallocable costs" to all of these services. As stated by Professor Bonbright in the portion of Principles of Public Utility Rates quoted by Mr. Mentrup:

> While, for the reason just suggested [an increase in customers does not necessarily beget an increase in the cost of a minimum-sized distribution system], the inclusion of the costs of a minimum-sized distribution system among the customer related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.
>
> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the

> reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully-distributed cost analyst dare not avail himself of this solution . . . . He is therefore under the impelling pressure to "fudge" his cost apportionments by using the category of customer costs as a dumping ground for costs he cannot plausibly impute to any of his other categories.

Because any allocation of unallocable costs will by definition not be based on cost causative factors, there is no reason to "dump" those costs solely on the customer factor. The examiners believe that to simply allocate them equally to the other cost factors is the most logical approach, and that is the one they recommend.

It must be noted that, where there has not been a delineation of allocable and unallocable costs, this approach would always result in a one-third/one-third/one-third split, regardless of the fact that most of the costs could properly be allocated to one of the cost causative factors. For those accounts where no reasonable evidence has been presented as to what costs can properly be allocated to at least one of the cost categories, the examiners believe that it would be preferable to simply allocate the entire account to the cost factor causing most of the costs in that account. For example, land costs are based in great part on anticipated KW demand. But no party attempted to determine what percentage of land costs are due to demand, and which are unallocable (Dr. Johnson's split of land costs is not based upon any study, but is simply a recommendation to stay with the status quo). Thus, land costs should be allocated 100 percent to demand. The examiners believe that such an approach remains truer to assigning costs based on cost causation principles than would an even split approach.

Before turning to the allocations, it is first necessary to address Mr. Stanley's functionalization recommendation. The examiners find Mr. Stanley's arguments to be persuasive. Mr. Stanley has testified that for Accounts 364 and 366, the procedure was that if a pole or conduit had a primary conductor attached to it, it would be classified as primary, regardless of whether or not it also had secondary conductors attached to it. This procedure inappropriately shifts costs to the primary function. The company's normal practice is that if plant has both primary and secondary functions, it is classified as "combination." The combination total was then split based upon the weighting of the identifiable primary and secondary components. Thus, the procedure with regard to Accounts 364 and 366 resulted in a two-fold shift to the primary function: once by inappropriately classifying the plant as primary, and then again when the combination total was assigned based upon an inordinately high primary component.

Company witness Michael C. Hicks testified on rebuttal that Mr. Stanley did not provide any basis for his claim that the secondary portion of Accounts 364 and 366 were too low, but simply did not like the results calculated through the Company's procedure for classifying distribution plant as primary or secondary. The examiners find to the contrary. Mr. Stanley laid out the basis for his reasoning, and Mr. Hicks did not rebut it by explaining why the company had done what it did. What should have been classified as combination was instead classified as primary, and a misallocation resulted. Mr. Stanley's suggestion to use Accounts 365 and 367 as proxies is appropriate, and the examiners so recommend.

Regarding allocation of the distribution plant, Accounts 360, 361 and 362 should be allocated 100 percent based on NCP demand. While the costs in these accounts are not caused solely by anticipated KW demand, absent a study dividing the costs into demand related and unallocable costs, these accounts should be allocated to demand.

For Accounts 364 through 368, Mr. Stanley used a distribution plant study performed by the company in order to determine the percentage of plant in those accounts that was caused by KW demand considerations. On rebuttal, the Company argued that it did not rely on its own study because it was inherently flawed. Mr. Stanley agreed that the study had some flaws, and could be further refined, but felt that it nonetheless could be relied upon. The examiners agree with Mr. Stanley. The study is not perfect, but it can reasonably be relied upon in this docket, in the absence of a more detailed or less flawed study. With one major exception, use of the study will produce an allocation closer to cost causation reality than use of either the Company's 100 percent demand allocation or Dr. Johnson's and Mr. Mentrup's arbitrary allocations. The exception is Account 364, which Mr. Stanley assigns 0 percent to demand. The examiners do not find that result to be credible because, as they understand it, it implies that demand has absolutely no impact on the number, size or cost of the poles, towers and fixtures needed. The examiners agree with Mr. Hicks that demand does play the major role in the engineering design of the plant in that account. Accounts 365, 366 and 367 are allocated 60 percent to demand, and the examiners will use that allocation as a surrogate for Account 364. Thus, in accordance with the recommendation made earlier as to unallocable costs, for Accounts 364 through 367, the allocation is 60 percent to demand, with the remaining unallocable 40 percent to be split equally between customers and energy. For Account 368, the allocation is 70 percent demand, with the remaining unallocable 30 percent to be allocated equally to customers and energy.

For Accounts 369 and 370, not all of the costs are customer related, but certainly the number of cutomers is the primary original cost causative factor. Without any determination as to the level of costs that are customer related and the amount of costs that are unallocable, these two accounts should be allocated 100 percent to the customer category.

c. Examiners' Recommendations. The examiners believe that use of a minimum system analysis is reasonable. The distribution plant study done by the Company and relied upon by Mr. Stanley is not without its flaws, but is the best evidence in the record. The examiners anticipate that the Company will perform a revised and more detailed study, covering all distribution plant accounts, and present it as part of EPEC's next general rate case filing. For unallocable costs, it is reasonable to split them among the remaining cost categories. Where no type of minimum system or similar analysis has been done, allocating the costs 100 percent to the known primary cost causative factor is appropriate.

Account 364 should be split 74.9 percent to primary and 25.1 percent to secondary. Account 366 should be split 30.5 percent to primary and 69.5 percent to secondary. Distribution plant should then be allocated as follows:

Account	Customer	Demand	Energy
360	0%	100%	0%
361	0	100	0
362	0	100	0
364	20	60	20
365	20	60	20
366	20	60	20
367	20	60	20
368	15	70	15
369	100	0	0
370	100	0	0

4. Intangible Plant Allocation

EPEC proposed allocating plant using an A&E-4CP demand allocation. Staff witness Mentrup recommended that it be allocated on a general plant allocator basis. The Company did not present any rebuttal testimony on the issue, and the examiners assume that EPEC does not disagree with the reallocation. In any event, Mr. Mentrup's testimony is the only evidence in the record directly on point, and it is reasonable. The examiners thus recommend allocation of intangible plant utilizing a general plant allocator.

5. Account 904--Uncollectible Expense Allocation

The company has proposed to allocate uncollectible expense on the basis of per class test year write-offs. Mr. Mentrup recommends that bad debt expense be allocated on the basis of operating revenue. Again, the Company did not sponsor any rebuttal testimony on this issue. And again the examiners find Mr. Mentrup's reasoning to be persuasive. Bad debt expense is "external" to the system. It is not directly related to rate class. Rate classes are defined so as to group customers according to similar electrical usage characteristics. Financial characteristics, such as the ability or proclivity to pay, are irrelevant to what class a customer receives service under. To assign bad debt on a class basis, when it is not related to electrical usage characteristics, unfairly penalizes the members of that class that do pay their bills and who have no choice but to receive service under that rate. Further, at least for EPEC, the existance of several single customer rate classes poses problems for a class-based allocation of bad debt. If one of those customers causes a bad debt expense, who is left to pay it? Or what if there is a two member class: must the one remaining customer have to pay off the entire bad debt of the former customer? The examiners conclude that Mr. Mentrup's proposal is both the most equitable and the most practical, and recommend it be adopted.

6. Account 928--Regulatory Expense Allocation

The Company has proposed that the rate case expenses incurred by the City be recovered via a surcharge on the residents of the City. The surcharge would be applied in the same basic manner as fuel revenues are recovered: a factor would be determined based upon forecasted kwh usage and the amount of rate case expenses to be recovered. The expenses would then be recovered through application of the factor to a particular billing month.

Mr. Mentrup recommends that the City's rate case expenses not be recovered through a surcharge to the City's resident ratepayers, but be allocated on the basis of total cost of service revenues.

The City's witnesses did not directly address City rate case expenses. The City did allocate all Account 928 expenses based on annualized base rate revenues.

There is very little testimony on this issue, and almost all of it comes from the Company's witness. The question that must be answered is whether all of the ratepayers should be forced to pay for the expenses incurred by the City. This is in essence a policy issue, and good arguments can be put forth on both sides. In support of a direct surcharge is the argument that people residing outside of the City should not be forced to pay for the City's involvement in these proceedings. Non-residents of the City are unable to elect the City Council, and should not have to pay for decisions made by public officials over which they have no influence, especially in those instances where the non-residents do not support the positions taken by the City. On the other hand, the City's participation can be beneficial to all ratepayers. For example, the City discovered that the Company was paying too much in Arizona state property taxes, and the Company has taken steps to rectify that error, and has applied for a refund of approximately $1,791,000. Also, to the extent that the City, through the testimony of its witnesses, is able to help decrease the Company's overall revenue requirement, most ratepayers would feel that they have benefited from the City's participation. Thus, even though the non-resident ratepayers have not authorized the City to participate, they may nonetheless benefit from the City's participation.

The examiners believe that it would be appropriate to balance the competing interests. The City's participation likely provides benefits to all ratepayers. Yet the City should not be given a "blank check" to spend the money of the ratepayers who live outside the City. A direct allocation of some of the costs to the City's residents will help ensure that the City's residents, at the least, maintain a watchful eye over the actions that their elected officials take in rate case proceedings such as this one. Where to place that split is a pure policy question. The examiners recommend that 30 percent of the City's rate case expenses be surcharged directly to the ratepayers living inside the City's corporate limits, in the manner requested by the Company. The revenue related taxes and uncollectible expense associated with the surcharge will not be added to the surcharge amount, but instead will be allocated to base rates in the same manner as is set out below for the remaining 70 percent of the City's rate case expenses.

As to the other 70 percent of the expenses, the examiners recommend that they be allocated based not on revenues, but on customers. The City's efforts to reduce the increase in revenues requested by the Company helps all customers. But in the rate design area, the City's proposals are definitely weighted heavily in favor of low load, low usage ratepayers (primarily residential and small commerical customers), at the expense of large power and industrial customers. Thus, a customer allocator better reflects the relative benefits to the classes of the City's participation in these proceedings.

7. Primary Voltage Discount

The Company has proposed a decrease in the primary voltage discount (PVD) from 22 cents per KW to 21 cents per KW. A primary voltage discount applies to rate schedules which offer service at either the primary or secondary voltage levels. Rates are set based on service at the secondary voltage level, and thus customers who buy their own transformation facilities and are able to take delivery at the primary voltage level should receive a credit: the primary voltage discount. W. Silver witness Stanley, pursuing a different methodology than did the Company, testified that the primary voltage discount be increased to 44 cents per KW.

The examiners agree with Mr. Hicks' rebuttal testimony that the mere fact that the Company's proposed demand charge for the Large Power class (Rate 25) involves a 41 percent increase does not necessitate an increase in the PVD. Nor does a comparison between EPEC and other Texas electric utilities of the percentage of the PVD to the demand charge necessarily prove that the proposed PVD is too low. But those factors do suggest that the proposed PVD may not be at an appropriate level. And Mr. Hicks failed in his rebuttal testimony to address the major point raised by Mr. Stanley: that the PVD should be calculated by comparing the proposed cost study and one that removes <u>all</u> secondary voltage level distribution costs. Mr. Hicks testified that Mr. Stanley's study was correctly done from a methodological approach, but Mr. Hicks did not feel that the accounting records the Company had were sufficiently detailed to do that type of study, and termed the data that Mr. Stanley had relied upon as "approximations" that the Company had developed. (Tr. at 8665.) Rather than utilize approximations, the Company decided not to try to divide each account into primary and secondary components, but simply removed all of Account 368 and figured it would be a wash.

> Q Okay. Your study removed the entirety of Account 368 [Line Transformers]?
> A Yes, sir.
> Q Okay. What you're saying is, that already overstates the level of the discount because you've knocked out the primary transformation from the cost study: and therefore, you don't need to remove the identifiable secondary portion of the other accounts because you've already, in removing the entirety of Account 368, overstated what the discount should be?
> A Yes, sir, based on our cost-of-service analysis that we have performed.
> Q So I guess the converse would also be true, that if you had not removed the entirety of Account 368, but only that those [sic] costs which can be segregated to the secondary voltage level, and then removed all the secondary voltage level costs from the other accounts, you're saying that the discount you proposed would be more than the discount that would flow from that type of analysis?
> A No. I haven't said that. I'm saying it would probably be a wash. I don't know for certain because we have not done that. Quite honestly, at this point I don't have the accounting records to make that determination.

(Tr. at 8663-8664.) The examiners conclude that Mr. Stanley's proposal is more likely to reflect the actual level of avoided costs than is the Company's unique attempt to quantify those avoided costs by assuming a removal of more than the appropriate amount of costs from one account would equal the amount of costs that should be removed from the other accounts. The examiners would also note that Mr. Hicks' other criticism of Mr. Stanley's proposal, that Mr. Stanley adjusted the embedded cost discount to reflect replacement costs (Tr. at 8666-8667), is not justified. Mr. Stanley testified that it would be appropriate, after determining a unit discount on an embedded basis, to trend it forward to a current unit discount, but he did not do so in this docket. (Tr. at 8386-8387.)

Because the examiners have allocated Accounts 364 through 368 on a basis other than 100 percent to demand, it is necessary to recalculate the appropriate PVD. The appropriate PVD should be calculated by following the methodology set out by Mr. Stanley on pages 26 and 27 of his testimony, and the examiners so recommend.

XIV. Summary of Revenue Requirement and Revenue Deficiency

Based upon the examiners' overall cost of service recommendations, EPEC's total system revenue requirement is $348,339,517, the components of which are detailed on Schedule I. Applying the examiners' recommended jurisdictional allocation proposals, EPEC has proven it has a Texas retail base rate revenue deficiency of $30,124,691, requiring an increase of 20.07 percent over adjusted test year revenues. Combined with a decrease in Texas retail reconcilable fuel and purchased power expenses of $13,445,610 (20.56 percent), and a decrease in Texas retail miscellaneous revenues of $17,184 (1.45 percent), the recommended total Texas retail rate increase is $16,661,897, or 7.69 percent over adjusted test year revenues. The base rate, fuel and miscellaneous revenue allocations as between jurisdictions are detailed on Schedule VI.

XV. Revenue Distribution

A. Rate Moderation Plan

The Staff has proposed that a rate moderation plan (RMP) be implemented to cushion the effects on ratepayers of the increase in rates resulting from this proceeding.

The Company did not propose an RMP, but does not object to the implementation of either a phase in/inventory or expense/revenue deferral type of RMP. The Company also argues that any RMP should comply with the accounting standards set out in Statement 92 of the Financial Accounting Standards Board (FASB 92). Failure to meet those standards will require, for financial reporting purposes (but not for ratemaking purposes), the immediate expensing (write-off) of all costs that are to be deferred and recovered at some future date.

The City agrees that, if its revenue requirement recommendations are rejected, particularly as they relate to Palo Verde, some form of rate moderation will be necessary. The City does not, however agree with the staff's proposal, primarily because the City believes that the rate path set out by the staff has been developed based upon how quickly the Company will meet certain financial indicators, rather than upon the impact of the rate increases on ratepayers. The City also urges this Commission to remember that it is not bound by FASB 92, and that FASB 92 controls only financial reporting requirements, and not ratemaking. The City argues that this Commission should not adopt an RMP that meets FASB 92 just to meet FASB 92 requirements: if the RMP that is selected does meet those requirements, so much the better; but if it does not, the RMP should not be modified solely in order to meet FASB 92 requirements.

The examiners recommend that no RMP be adopted. Because of their revenue requirement recommendations, the magnitude of the rate increase, while certainly substantial, is not nearly as great as that proposed by the staff or the Company. The examiners' proposed Texas retail base rate revenue increase, which excludes the City rate case expenses to be recovered through the direct surcharge, is approximately 19.87 percent. When one includes the decrease in fuel costs, the total Texas retail rate increase is only 7.55 percent (7.69 percent if all of the City's rate case expenses are included). The examiners would note that the base rate percentage increase is only slightly more than the first year percentage increases proposed by Mr. Reilley <u>under his RMP</u>, and the total increase is actually slightly lower. With Mr. Reilley's RMP (either his two unit or three unit RMP), the first year base rate revenue increase is 19.55 percent, for a total first year revenue increase of 8.04 percent. (Staff Ex. 36A, Schedule II at 1.) [It should be noted that Mr. Reilley's figures are not the same as those presented by Mr. Mentrup. (Staff Ex. 33, Schedule GM-1.) Mr. Mentrup, utilizing the data supplied by Dr. Kol's jurisdictional cost of service study, has calculated the base rate revenue increase at $178,117,447, as compared to the $179,430,760 figure testified to by Mr. Reilley. Utilizing Mr. Mentrup's data, the base rate increase under the Staff's RMP is 18.67 percent. The staff did not resolve the difference between the two numbers.] This first year increase is followed, under Mr. Reilley's two unit RMP, by base rate increases of 7.9 and 7.0 percent the next two years, corresponding to total revenue increases of 6.72 and 5.27 percent. The examiners believe, in light of the decrease in reconcilable fuel and purchased power expenses, and in tandem with moderate revenue distribution guidelines, that it would be preferable to simply reflect the entire increase in base rates at this time. The examiner would note that, based on Mr. Reilley's RMP schedules, which rely upon the Company's estimates for future revenue requirement increases, reconcilable fuel and purchased power expenses are due to rise only about $139,000 during the second year of the RMP, and are actually predicted to go down the following two years. Thus, even using the Company's own data, reconcilable fuel expenses are expected to remain essentially flat for the next few years. This should alleviate the concern that fuel reductions should not be used to alleviate a large increase in base rates because fuel prices may increase dramatically in the future. The reduction in fuel and purchased power expenses provides perhaps a unique opportunity to allow for rate recognition of a nuclear plant without four or five years of increases and without an unduly large one-time increase in rates. Finally, a one-time increase will remove any problems or uncertainties associated with an RMP, and it will also be less costly overall than would be the case with an RMP.

B. Revenue Distribution

The increase in rate base caused by Palo Verde results in current revenues producing a rate of return of under 1 percent, using the Company's cost of service study. (EPEC Ex. 131, Tab 8 at 2.) While the examiners have not adopted the Company's cost of service recommendations in full, that figure likely would not change to any great degree. Because the rate of return is so low, classes have wildly diverging relative rates of return (ranging from -5.626 to 10.900), and only minor changes in revenues cause enormous changes in the relative rate of return (if revenues from the residential class had been $1,000,000 [1.46 percent] greater than they actually were, the residential class' relative rate of return would be not 0.442, but 1.34). Thus, current relative rates of return are of only some help in attempting to determine an appropriate revenue distribution. They indicate that some classes may be deserving of smaller or larger increases than the system average, but no fine tuning can be done by looking at those current relative rate of return figures. Those figures do intimate that Rates 2 (Small Commercial), 15 (Electrolytic Refining [Phelps-Dodge]), and 22 (Irrigation Service) likely are deserving of smaller increases than the system average, while Rates 24 (General Service), 28 (Private Security Lighting), 30 (Electric Furnace [Border Steel]) and 34 (Cotton Gin), likely should receive increases larger than the system average. Starting with those likely distributions, attempting to move all classes towards a unity relative rate of return, but recognizing that the base rate increase recommended herein is significant and that gradualism is a concept that should be applied, the examiners' recommendations are as follows.

Rate 15 will remain substantially above a unity relative rate of return even if no increase in base rate revenues is granted. While no increase for Rate 15 would not be unreasonable, the examiners believe that, with rate recognition of Palo Verde in this docket, no customer should be given a price signal that indicates that base costs are remaining stable. The examiners thus recommend that for Rate 15 the increase be limited to 0.4 times the system average increase. The examiners would note that while Mr. Mentrup did not propose a floor, an increase of 0.4 times the system average was the lowest increase he presented, other than a zero increase for this very rate class.

On the other end, Rates 28 and 30 will remain will below a unity relative rate of return even with an increase well above the system average. For those two rates the examiners recommend an increase of 1.5 times the system average. This is consistent with the 1.5 times system average increase recommended by Dr. Johnson for these two classes, and only slightly above the 1.4 times the system average increase cap recommended by Mr. Mentrup. While this will be a rather large increase, it will be moderated somewhat for Rate 30 by the continuance of the Economic Recovery Rider, discussed later in this Report. Otherwise, the examiners believe that the range of increases should extend from 0.5 times the system average to 1.3 times the system average. The 0.5 times system average increase will apply to Rates 2 and 22. The 1.3 times the system average increase will apply to Rate 34. The examiners recommend that the remainder of the revenue increase be spread to the other classes in such a manner that each class has an identical relative rate of return. The results of the above recommendations are shown on Schedule VII, attached to this Report.

XVI. Rate Design

Rate design involves the manner in which the costs that have been assigned to each class are to be recovered from the ratepayers in that class. To the extent not discussed below, the proposals of the Company should be adopted.

A. Rate 01--Residential

1. Customer Charge

The current customer charge is $6.50 per month. The Company proposes to raise that to $10.25 a month. Staff witness Jeff Rudolph and Dr. Johnson both recommend that the charge not be modified.

The Company had initially requested a $10.50 per month customer charge; after filing revised revenue requirement related numbers, the requested charge had dropped to $10.25 per month. The Company did not address the customer charge issue in its direct testimony. The Company did put on rebuttal testimony, but that testimony did not address the specifics of exactly what accounts had been included in the determination of the costs to be recovered from the customer charge. The Company has indicated it based the customer charge on its cost of service study, leading the examiners to believe that all costs that were delineated as being customer related were included.

Mr. Rudolph testified that there was a general consensus among experts that certain costs are customer-related, such as meter reading, billing and collections. For costs such as the annual carrying charges and O&M costs associated with meters and drop lines, he indicated that many analysts also include those costs. As for distribution and overhead accounts, Mr. Rudolph testified that there was a great divergence of opinion. Mr. Rudolph based his customer charge upon the following costs:

Customer Accounts Expenses:
- Account 901--Supervision
- Account 902--Meter Reading Expenses
- Account 903--Customer Records and Collection Expenses

Distribution O&M Expenses
- Account 586--Meter Expenses
- Account 597--Maintenance of Meters

Carrying Charges Related to Accounts 369 (Service Drops) and 370 (Meters):
- Depreciation
- Property-Related Expenses
- State and Federal Income Taxes
- Return Dollars

Based upon the above costs, Mr. Rudolph figured the monthly customer charge should be approximately $3.05. Rather than decrease the current charge, he recommended that it remain unchanged.

Dr. Johnson followed a similar analysis. Looking only at Accounts 901 through 903, Dr. Johnson reached a customer charge of $1.71 per month. Adding in Accounts 586, 904 (Uncollectibles), 905 (Miscellaneous Customer Account Expenses) and 907-910 (various Customer Service and Information Expense accounts) increased the charge to only $2.69 per month. Adding in the carrying costs associated with the Company's investment in meters increased the monthly charge to only $3.28 per month. Thus, while Dr. Johnson felt a moderate reduction in the charge would be appropriate, to be conservative he recommended that the charge should remain at its current level.

The examiners will reject the Company's proposal. Not all costs classified as customer costs truly vary with the number of customers. Further, as Dr. Johnson testified, higher customer charges produce lower kwh charges. Lower kwh charges are do not help to promote the goal of energy conservation, while higher customer charges tend to fall the heaviest on low income, low kwh users. Thus, the examiners believe that while the customer charge should accurately reflect the costs in the accounts to be included, the accounts to be included in calculating the charge need not be as all inclusive as the Company proposes.

The examiners also reject Mr. Rudolph's comparative analysis. What the other electric utilities in this state are authorized to charge is irrelevant. Different utilities will have different customer costs. If there is to be consistency as between utilities, that consistency should be as to the costs to be included in calculating the customer charge, and not some dollar level or range. Further, as is implied by the fact that two witnesses recommended no change to a customer charge that is significantly above the level of customer related costs that they feel the charge should be based on, the customer charges for all utilities could be higher than is presently justified, but because they are all in the same range, no one recommends a reduction.

Between them, Mr. Rudolph and Dr. Johnson have included a number of accounts that can be included in calculating the customer charge. The examiners believes that, with one exception, all of the accounts mentioned by the two witnesses should be included. The exception is Account 904 (Uncollectibles), which the examiners do not believe to properly be included as customer related (the account is allocated based on revenues). Thus, the customer charge should be based upon the following costs: Accounts 586, 597, 901, 902, 903, 905, 907, 908, 909, and 910, as well as the carrying charges (depreciation expense, property-related expenses, state and federal income taxes, and return) on Accounts 369 and 370. Rounding up to the nearest 50 cents produces a customer charge of $4.00, and the examiners recommend that the residential customer charge be set equal to that amount.

2. Space Heating

a. Proposals of the Parties. EPEC has proposed changing the space heating rider so that the reduced charge per kwh will apply to usage above 550 kwh per month during the winter billing months, as compared to the current 800 kwh switchover level. The difference between the two charges will also increase from 2.773 cents to 2.971 cents per kwh. The Company has no Texas retail space heating cost data available: the 4.241 cent per kwh charge for usage over 550 kwh is identical to the proposed rate for water heating service, for which the Company does have cost data. Mr. Mayhew testified that the basis for the change in the kwh cutover level is that the Company, through a regression analysis, estimated that the average use of a customer during the winter billing months is only 563 kwh, and thus the current tariff does those space heating customers little good.

Dr. Johnson recommended that the cutover level remain at 800 kwh, and that the discount be reduced from its current level to 2.0 cents per kwh. Dr. Johnson felt that the load characteristics of the space heating customers did not justify any discount, and that the reduction in the discount begun in Docket No. 5700 should continue.

Mr. Rudolph agreed with Dr. Johnson that the space heating rider was not cost based, and proposed two options. The first option is to institute a summer/winter differential for all customers. In the summer (June through September billing months), all customers would pay a rate of 6.420958 cents per kwh. In the winter (October through May billing months), the basic kwh charge would be 5.920958 cents per kwh. In addition, space heating customers would receive a reduced kwh rate for usage over 800 kwh a month during the November through April billing months, but the difference would be reduced approximately one-half cent per kwh from its current level, to 2.17264 cents per kwh. It should be emphasized that the space heating energy charge differential would be based on the summer rate, not the winter rate (6.420958 - 2.17264 = 4.247958 cents per kwh).

Mr. Rudolph's second option is to establish a simple winter tail-block that would apply to all residential customers. Such a proposal contains only two energy charges. The higher would apply to all summer usage and all winter usage below 550 kwh. The lower energy charge would apply to all winter usage over 550 kwh. The difference between the two charges would be 2.5 cents per kwh.

b. Analysis of the Parties' Proposals. The examiners agree with Dr. Johnson and Mr. Mentrup that the Company has not proven up the appropriateness of a space heating rate. Space heating load factors are consistently lower than regular residential service load factors, which indicates that space heating customers are not more efficient users of electricity. (Staff Ex. 34 at 16; City Ex. 57 at 72-73.) As Dr. Johnson points out, during the winter months space heating customers may in fact cause needle peaks on very cold days, which can strain capacity (due to units being down for scheduled maintenance). Further, the examiners do not agree with Mr. Meyhew that the space heating and water heating services are necessarily similar in usage, and that the per kwh cost to serve the space heating class is identical to that of the water heating class. The load data show that the two classes have many differing load characteristics, even during the off-peak winter months. In sum, there is no cost study of space heating customers; the only load data available are from New Mexico customers, and even they do not support the Company's assertions. Absent more comprehensive data, the examiners must conclude that the space heating rate is neither load justified or cost based.

Dr. Johnson characterizes the space heating rate as an attempt to compete with gas utilities for space heating customers, and notes that the examiners in Docket No. 5700 reached just such a conclusion. The examiners in this docket agree, for the reasons set out by Dr. Johnson. (City Ex. 57 at 68-70.) In Docket No. 5700 the examiners recommended the gradual reduction of the discount in order to avoid undue hardship on the customers who have committed to electric space heating in reliance on the Company's past promotional rates (Docket No. 5700, Examiner's Report at 123), and the Commission adopted that recommendation. In light of the conclusions made in the preceeding paragraph, the examiners believe that any attempts to increase the size of the discount, or to expand the kwh usage to which it applies, should be rejected. Indeed, dropping the cutover point (here, to 550 kwh) is exactly what should not be done. The Commission decided in Docket No. 5700 that elimination of the space heating rider was appropriate, but should be done over a period of time so as not to unduly impact current customers. Reducing the cutover point will simply increase reliance on a rate that needs to be eliminated, and make that elimination more difficult. Thus, the examiners reject the Company's proposal to reduce the switchover point, and would note in passing that all of the testimony as to whether the 550 kwh cutover point would help one bedroom apartment dwellers as opposed to three bedroom apartment dwellers or home owners is irrelevant. The examiners must also reject Mr. Rudolph's second option, as it incorporates the 550 kwh winter switchover point. While that is not to say that a reduced tail-block price for all customers is not appropriate, the examiners believe that the switchover point should be based upon further cost information, and not be based upon the Company's space heating rate customer usage study. The examiners wish to stress that they recommend rejection of the second option not because a winter tail block option is inappropriate per se, but because there is no cost or load data to support the 550 kwh switchover level.

As between Dr. Johnson's recommendation and Mr. Rudolph's first option, the examiners prefer Mr. Rudolph's seasonal rate proposal. EPEC is a summer peaking utility, with two shoulder months and a clear off-peak period, though that off-peak period does not involve an enormous drop in peak demand. Marginal costs are higher in the summer than other periods of the year, and thus a seasonal rate will send a more accurate price signal as respects seasonal cost responsibility. Mr. Rudolph notes that his proposal has two disadvantages. The first is that a seasonal rate may cause some customer dissatisfaction, in that electric bills will not be as stable over the course of a year. Such dissatisfaction is to be expected, but should not be viewed as a negative. Higher prices may cause dissatisfaction, but it is only through such dissatisfaction that usage characteristics can be changed. In any event, the Commission has approved a number of seasonal rates, some a simple winter/summer differential, some a reduced winter tail-block such as that contained in Mr. Rudolph's second option. (Staff Ex. 34, Schedule XI.) The second disadvantage set out by Mr. Rudolph is that this option maintains a space heating rider tail-block that is not available to all classes. The examiners believe it is appropriate to continue in the direction set in Docket No. 5700 and maintain the existance of the space heating rider, but reduce the discount. In either the next rate case or the one after that, the space heating rider can be eliminated altogether, or be replaced by a winter tail-block that is available to all customers, as in Mr. Rudolph's second option. The examiners would note in this regard that while the amount of the discount is over 2 cents per kwh, because that discount is subtracted from the summer rate, the difference between the winter rate and the space heating rate tail-block is smaller (1.673 cents per kwh).

c. <u>Examiners' Recommendations</u>. The examiners recommend the adoption of the rate design proposal set out in Mr. Rudolph's first option. Because the examiners have reached different revenue, cost allocation and rate design conclusions, the exact kwh charges vary from those recommended. The recommended residential energy charges are 7.201588 cents per kwh during the summer, 6.701588 cents per kwh during the winter, and 5.028588 cents per kwh for kwh in excess of 800 for space heating rider customers.

3. Water Heating

The water heating rider is available to customers who meet the requirements set out in the tariff. Water heating riders are also available to general service and small commercial customers who meet the same requirements. Qualifying water heating usage is separately metered, and the rates apply only to that usage. The rider consists of a customer charge and an energy charge. The Company proposes to decrease the monthly customer charge from $1.50 to $1.00, and to set a per kwh charge that will be identical for all water heating customers, regardless of which rate schedule they take service under. Based on its revenue requirement, cost allocation, and revenue distribution proposals, the Company's proposed energy rate is 4.241 cents per kwh for all kwh.

Dr. Johnson recommends that the customer charge be reduced as proposed, but that the discount for the energy portion of the rate be reduced from the current level of 2.673 cents per kwh (the current residential energy charge is 5.118 cents per kwh, while the water heating rate is 2.445 cents per kwh) to 2.5 cents per kwh. Dr. Johnson finds, based on the load data, some justification for the discount to the water heating customers, but based on the City's cost of service study, finds that discount to be beyond the level justified by the reduced costs to serve those customers. Thus the minor reduction in the level of the discount.

Mr. Mentrup testified only as to the customer charge portion of the rider, and supported the Company's proposal to decrease the charge.

Regarding the customer charge, because all water heating rider customers from all classes are separately metered and grouped into one rate class, there is cost of service data available for them, unlike for the space heating customers. Thus, the customer charge should be based upon the customer related costs incurred to serve that class. Those costs should be calculated as set out earlier for the residential class customer charge, and then rounded up to the nearest 50 cents. Doing so puts the customer charge at the Company's proposed level of $1.00 per month.

As to the energy charge, the examiners agree with the Company that the size of the differential (it is not a "discount", as Dr. Johnson names it: a discount implies a rate below cost, while the energy charge will recover all of the non-customer related costs assigned to the Rate 21 class) vis-a-vis the energy charge for that customer's basic rate schedule is irrelevant. The water heating customers, as a group, are a separate rate class, with their own assigned revenue requirement. That group should not be further broken down in an attempt to allocate costs to the residential water heating customers as opposed to the small commericial water heating customers and the general service water heating customers. They are one rate class, and should have identical rates. If that produces varying differentials, so be it. To tie the water heating rate to the energy charge for residential customers or small commercial customers makes no more sense than setting the residential rate based on what the small commercial rate is. They are independent rate classes, and it is to be expected that the differentials will vary from class to class. The appropriate rate for all water heating customers is thus 3.384958 cents per kwh.

B. Rate 02--Small Commercial

The Company has proposed that the small commercial class be segregated from the general service class. The small commercial class used to have its own rate, but then was merged with the general service class. EPEC, based on load data, recommends the class be reconstituted, and limited to customers whose demand does not exceed 15 KW. The rates will consist of a customer charge and an energy charge, but no demand charge. The Company proposes a $13.50 per month customer charge, and a 9.244 cents per kwh energy charge. The Company also proposes both a space heating rider and a water heating rider. None of the parties oppose the reinstitution of the small commercial class under a separate rate schedule.

1. Customer Charge

The customer charge should be calculated in the manner set out above for the residential class customer charge, resulting in a charge of $5.50 per month.

2. Space Heating

Unlike the residential class, space heating equipment for small commercial ratepayers is separately metered, and the reduced space heating charge applies to the separately metered kwh consumed during the November through April billing months. As with the residential space heating rate, the energy charge proposed by the Company is equal to that calculated for the water heating class. The current space heating rider for the general service class includes a provision that limits its applicability to existing former Rate Schedule 02, Space Heating Installations, as of January 5, 1979. The Company proposes to delete that restriction. The Company did not put on any testimony as to the deletion as part of its direct case. In his rebuttal testimony, Mr. Mayhew testified that the proposed deletion can provide benefits in smoothing out EPEC's seasonal load curve by increasing sales during the winter.

Dr. Johnson and Mr. Mentrup both testified that removing the restriction on the availability of the space heating rider was not justified by the Company. The examiners agree. As discussed above, when dealing with the residential space heating rider, the examiners believe that the Company has failed to justify the existance of any space heating rider. As before, the Company is attempting to go in the opposite direction by making the rider available to more customers, and increasing the discount provided. It may be that the Company's proposals will be beneficial to the system, but absent any load data and cost studies, the examiners believe that the space heating riders should continue to be phased out. The examiners thus recommend that the space heating rider limitation detailed above remain in effect.

As to the discount to be provided under the rider for those customers who qualify, the examiners agree with Dr. Johnson and Mr. Mentrup that the energy charge discount should be reduced from its current level of 4.363 cents per kwh (based on current Schedule 24 rates for 0-3000 kwh usage). Mr. Mentrup recommends a decrease of half a cent per kwh, while Dr. Johnson proposes a decrease of 1.363 cents per kwh. The two proposals set a range of reasonableness, and the exact point chosen within that range must of necessity be based on judgment. The examiners believe that Mr. Mentrup's reduction will not eliminate the class quickly enough, while Dr. Johnson's is too large, considering the increase in the kwh rate that is being caused by the separation of this class from the general service class. The examiners conclude that the reduction should be about in the middle of the two proposals, and thus recommend that the space heating rider energy charge be set at a level 3.5 cents per kwh lower than the energy charge for Rate 02.

3. Water Heating

The appropriate water heating rates have already been discussed earlier, in the section dealing with the residential class water heating rider.

C. Rate 24--General Service

Many of the issues dealing with the general service rates have already been decided. The customer charge should be set in the manner described for the residential class customer charge, which produces a monthly charge of $13.00. The water heating rider rates will be identical to those for the residential and small commercial water heating rider rates. As for the space heating rider, it will continue to be offered, but the restriction that it be available only to former Rate 02 Space Heating Installations as of January 5, 1979, will remain in force. It should be noted that the examiners originally considered deleting the rider for this class, but Mr. Mayhew's testimony is that there could be some former small commercial customers who have a qualifying space heating installation that are now general service customers. Thus, until there is clear testimony that no Rate 24 customers are eligible for the rider, it is appropriate to continue its availability. As for the appropriate rate, determining a discount level is difficult because of the fact that Rate 24 customers are demand metered, and thus have much lower energy charges than do residential and small commercial customers. In light of that fact, the examiners believe it would be appropriate to simply utilize the small commercial class space heating rider rate.

The major issue concerning this rate schedule is the relative increases of the KW and kwh charges. Mr. Mayhew testified that the Company relied upon the results of its cost of service study to determine the overall revenue requirement for this class, but then shifted approximately 20 percent of the demand responsibility to the energy charge by reducing the demand charge by 20 percent and adding the corresponding revenues to the amount of revenues to be recovered by the energy charge. This shift of demand costs was done to recognize the differing load characteristics of the customers, in that the shifting of costs increases the energy charge and thus allows some leveling of rates as between high load factor and low load factor customers. Despite this shift, Dr. Johnson testified that the increase in the KW charge was still too high (100 percent, based on EPEC's original proposal), compared both to the Company's proposed overall base rate revenue increase for the class as a whole (66.21 percent, based on original data), and as compared to the kwh increase for the class (7.76 percent on average, based on original data). Dr. Johnson bases his view upon his class cost of service study, which puts much more emphasis on energy than on demand, and upon an allegation that even the portion of production plant allocated based on average demand is recovered through the energy charge. Dr. Johnson's recommendation is that the KW charge and kwh charge should go up an equal amount.

The examiners disagree with Dr. Johnson. The examiners have already rejected his production plant cost allocation proposals and thus must reject his argument that the cost allocation methodology used by the Company puts too little emphasis on energy. As to recovery of production plant through the demand charge, that is entirely appropriate. The focus of rate design is not on demand versus energy, but on variable costs versus fixed costs. The demand charge is designed to recover costs that are fixed. The energy charge is designed to recover variable costs, with the exception of reconcilable fuel costs. Fixed costs are recovered through the demand charge because if they are recovered through the energy charge, a decrease in consumption caused by mild weather would result in the Company failing to recover those costs. Capacity costs--production plant--are fixed costs and thus should be recovered through the demand charge. As Mr. Mayhew testified on rebuttal, the requested revenue increase in this docket is caused primarily by Palo Verde, and thus it is only logical that the increase will be recovered primarily through the demand charge.

As to the Company's proposed 20 percent shift in costs to be recovered through the demand charge to the energy charge, the examiners find such a shift to be appropriate. The shift will provide some levelization of costs, thus recognizing the heterogeneity of the load characteristics of the customers in the class. The examiners therefore recommend that the Company's proposal be adopted, although the recommended demand and energy charges will of course vary from those proposed by the Company.

D. Economic Recovery Rider

The Economic Recovery Rider (ERR) is available to three rate schedules: 15 (Phelps-Dodge), 29 (ASARCO), and 30 (Border Steel). These three customers are all in the ferrous or nonferrous metals industries, and represent three of the largest customers on EPEC's system. The ERR provides for a 15 percent discount on the monthly KW charge if the customer's highest maximum demand during the month occurred during off-peak hours.

1. Continuation of the ERR

The Company originally did not propose continuation of the ERR, disingenuously arguing that because none of the customers had been able to take advantage of the rate, there was no need for its continuation. Of course, the reason why none of the customers had availed themselves of the ERR was that the Company had appealed the Commission's Order in Docket No. 6350, where the ERR was first approved, and had prevented the implementation of the tariffs resulting from that docket. The ERR has been in effect since April 8, 1987, and all three eligible customers have availed themselves of its provisions. Through July 31, 1987, the discounts provided totalled $193,946.

Both ASARCO and Border Steel presented witnesses testifying in favor of continuation of the ERR. Witnesses for both parties also put on evidence describing the continued economic plights of their respective clients. (ASARCO Ex. 3 at 13-28; Border Steel Ex. 1; Border Steel Ex. 2 at 5-9.) Mr. Shaw, testifying on behalf of ASARCO, also recommended that the discount be increased to 25 percent. On rebuttal, Mr. Mayhew again testified that the ERR should not be continued, because the Company had originally proposed it in order to help cushion the blow of an anticipated rate increase, when in fact the Commission decreased the Company's rates in Docket No. 6350. The ERR has thus been a far greater benefit to the three qualifying customers than the Company intended, with those customers seeing declining rates. Mr. Mayhew then testified that the Company could agree to continuation of the ERR only if: (1) EPEC receives some form of rate relief in this docket; (2) the ERR is modified to require customers to agree to remain on the system in order to receive the benefits of the ERR; and (3) the revenue discount is offset by increasing the rates of the other customers.

In Docket No. 6350 the Commission reversed the recommendations of the examiners and implemented the ERR, justifying it by finding that the evidence demonstrated:

> (1) The utility system and the general body of ratepayers are benefitted by maintaining the existing industrial load; (2) that such load is in serious danger of substantially shrinking or disappearing altogether; (3) that unusually high industrial electric rates are a major economic factor which elevates this possibility of serious load loss; and (4) that approval of the ERR would increase the probability that this needed industrial load will continue operating on the utility's system.

The examiners find that each of the above elements still currently exists, and thus recommend that the ERR be continued. While EPEC may have proposed the ERR anticipating a rate increase that did not materialize, the examiners are recommending herein a substantial base rate increase. Were the Commission in this docket to grant only a neglible increase, or none at all, the examiners would agree that the ERR should be eliminated. But based upon the examiners' recommendations, an increase is warranted, and the purpose of the ERR will be fulfilled.

The examiners do not believe that any changes to the ERR are warranted. The ERR was adopted as an experimental rider, and the experiment has been in effect for only a relatively short period of time. An increase in the discount to 25 percent is not warranted, as there is no evidence that the ferrous and nonferrous metals industries are in any worse shape than they were at the time Docket No. 6350 was decided. As to requiring the customers to agree to remain on the system, the examiners do not believe that such a requirement should be imposed at this time. While such a requirement could help, it could also be counter-productive. The companies may not be willing (or able, in their view) to enter into such a commitment. They thus would not receive the discount, and the lack of one could be enough to cause the plants to be shut down, the very thing the ERR is attempting to prevent. The examiners believe that the ERR should be implemented for at least some time, and the situation reviewed, before any such requirement is imposed.

Regarding the revenue shortfall associated with the ERR, the examiners are frankly disappointed at the lack of evidence or argument in brief on this issue. The issue was expressly reserved in Docket No. 6350 for the next rate case, but there is a dearth of evidence in this record. The examiners thus recommend that the issue again be reserved for EPEC's next general rate case, with the uncollected revenues deferred until that time.

In the alternative, in the event the Commission feels that the ERR should not be continued without some resolution of this issue, the examiners would recommend that the shortfall ultimately be borne by all ratepayers and by the Company. The evidence in the record is that all parties are benefitted by the ERR. The customers able to take advantage of it obviously reap the benefits in lower electric rates, and thus an improved ability to compete. The other ratepayers also benefit, in that with the continued industrial load, fixed costs are spread among a larger customer base, thus keeping the cost to other ratepayers down. Indeed, it is fear of the "death spiral", in which the loss of several large loads increases the per unit costs to other ratepayers, resulting in more ratepayers leaving the system, which in turn increases the rates to the remaining customers on the system, and so on, that was the impetus for the ERR in the first place. The Company also benefits from continuance of industrial loads and avoidance of a possible death spiral, as Mr. Mayhew admitted on cross-examination. (Tr. at 8629-8630.) As everyone involved reaps some benefit, everyone involved should contribute towards the shortfall. It being almost impossible to quantify the benefits associated with the ERR, the examiners believe that an even split would be appropriate. Thus, the Company should be assigned one-third of the shortfall in revenues, which it would presumably write off as a loss. The one-third assigned to the customers taking advantage of the ERR should be deferred, to be recovered in the future (the examiners anticipate that the deferred amounts would be included in rate base and allowed to earn a return). The same procedure would apply to the one-third of the shortfall in revenues assigned to all other ratepayers.

As to when those deferred amounts should be recovered, the examiners would recommend that the recovery not begin before the ERR is lifted, but in no event later than five years from now. The ERR is a short-term mechanism which should not remain in effect for an extended period of time, and it is only equitable that the Company be allowed to begin recovering the shortfall not written off in the not too distant future. As to the length of time over which the shortfall should be recovered, the examiners leave that issue for a later date, as the amount of the shortfall would likely have a major bearing on the time period chosen.

2. Application of the ERR to Ft. Bliss

Ft. Bliss proposes that the ERR be extended to include Rate 31. The Company does not oppose extension of the ERR to Ft. Bliss if the Stipulation is adopted, no doubt because under the terms of the Stipulation, EPEC is made whole as regards the revenue shortfall created by the ERR. The examiners would anticipate that, should their alternate recommendation be adopted, either in this docket or at a later point in time, the Company would be opposed to extending the ERR to Ft. Bliss.

DOD witness Patwardhan, noting that Company witnesses in Docket No. 6350 had testified that it was important to maintain operations in the Company's service area in order to stimulate the economy and keep the employment level up, testified that Ft. Bliss is EPEC's largest single customer, and that maintenance of a stable and growing operation at Ft. Bliss would be in the best interests of the Company. He also testified that the ERR would provide an incentive for Ft. Bliss, whose load follows that of the system as a whole and thus could not currently take advantage of the ERR, to try to shift its peak load to an off-peak period, or at least increase its off-peak loads such that its peak would no longer be during the on-peak period. Mr. Patwardhan testified that such a shift in load would be advantageous to the Company, as it would provide greater diversity between Ft. Bliss and the system as a whole.

The examiners recommend that the ERR not be extended to Ft. Bliss. First and foremost, the ERR was put into effect in order to meet the needs of EPEC's large <u>industrial</u> customers. The Order in Docket 6350 applies explicitly to industrial customers only. As Mr. Patwardhan recognizes, Ft. Bliss and a company such as ASARCO are different types of entities providing different services (Tr. at 8118). Second, while the examiners do not doubt that Ft. Bliss provides a large economic benefit to the El Paso area, there is no evidence that Ft. Bliss is likely to reduce operations or be closed down completely anytime in the forseeable future. While the DOD does take economic factors into consideration, and while there is some possibility that Ft. Bliss could someday begin self-generation, there is no evidence in the record that indicates that Ft. Bliss is likely to begin self-generation in the near future. Third, as to Mr. Patwardhan's load shifting argument, load shifting was not the purpose of the ERR. While an individual customer must peak off the system peak to garner the discount, the primary purpose of the ERR is not one of load management, but load retention. In any event, Ft. Bliss' tariff already includes a time of day provision, so extension of the ERR is not necessary in order to provide Ft. Bliss with an incentive to shift its load off-peak. Finally, the examiners would note that there is no evidence in the record as to what type of economic impact would occur if Ft. Bliss was offered the ERR, and was able to shift its load to an off-peak period (Tr. at 8111-8114). The examiners are hesitant to extend the an experimental rider to another customer when the record offers absolutely no evidence as to what the resultant impact will be. In sum, the examiners conclude that the ERR should not be extended to include Ft. Bliss.

E. <u>Rate 31--Ft. Bliss</u>

In addition to its request to have the provisions of the ERR extended to it, Ft. Bliss also seeks the removal of the ratchet contained in its rate schedule. The Company has a number of rate schedules that contain a minimum demand provision, or "ratchet." The ratchet provision applicable to Ft. Bliss operates such that, for billing purposes, the minimum level of demand for any month is never less than 75 percent of the highest peak demand established during the May through October billing months (utilizing the most recent 12 month period) or the minimum contract demand capacity, whichever is greater. Ft. Bliss' peak demand is almost triple that of its minimum contract demand, and thus the ratchet provision establishes the minimum monthly demand for billing purposes.

On direct Mr. Mayhew testified that ratchets provide a measure of protection to the Company and its ratepayers from customers who peak in the summer months but whose winter demands vary widely. The ratchet operates to send appropriate price signals to customers within a specific class that have widely varying demand patterns, and tends to promote equity within the class. Mr. Patwardhan testified that ratchets can send inappropriate price signals, by causing the total price per kwh in the winter to exceed the total price per kwh at peak usage, and may not have any affect on customers who have consistently low KW loads over time. He also testified that the intraclass equity argument is irrelevant for single customer classes, and that for such classes other pricing schemes would be more appropriate than a ratchet provision. Finally, Mr. Patwardhan notes that because EPEC does not have an unusually high difference between its summer and winter monthly peaks, a ratchet serves no purpose.

On rebuttal, Mr. Mayhew testified that the ratchet serves to protect the other ratepayers from a significant change in Ft. Bliss' load requirements. The Company has made significant investments in facilities in order to meet the demand placed on the system by Ft. Bliss. A dramatic decrease in demand would result in the cost responsibility for those facilities being shifted to other customers. The ratchet provision will, for a period of at least 12 months, help lessen the impact of the loss of load.

The examiners believe that both parties have valid points. For single customer classes, the intraclass equity arguments are irrelevant. Indeed, a ratchet provision can result in the Company overrecovering its demand costs. But Mr. Patwardhan did not present any testimony as to whether the ratcheted demand level had in fact ever been applied and utilized for billing purposes. The examiners agree with the Company that the ratchet provision will help lessen the impact on other ratepayers should there be a significant drop in load, but they also recognize that such protection could be achieved through means other than a ratchet. An alternate mechanism could be designed that would apply only in the event of a significant drop in load, rather than be applicable at all times, as is the ratchet. Thus, the ratchet could be replaced with a more narrowly drawn provision. No such clause was presented because the DOD simply recommended elimination of the ratchet, while the Company simply recommended it not be removed. Absent a more narrowly drawn clause, and absent any evidence by the DOD that there has ever been a month when the ratched demand level has been billed in place of the lower actual demand level, the examiners believe it reasonable to maintain all ratchets in place.

F. Rating Period Selection Option

The current on-peak period for EPEC is from 10:00 a.m. to 8:00 p.m. weekdays, Mountain Standard Time. The off-peak period consists of the remaining hours in the week. The Company proposes to include a rating period selection option for Rate Schedules 15 (Electrolytic Refining), 29 (Transmission Voltage Service), 30 (Electric Furnace), and 31 (Military Reservation). The rating period selection option would allow a customer, with the approval of the Company, to change the 10 hour on-peak period by two hours in either direction. A customer could thus change his on-peak period to, for example, 8:00 a.m. to 6:00 p.m. weekdays. The ratepayer would be limited to two changes during any twelve month period. Mr. Mayhew testified that the purpose behind the option is to allow a customer some latitude in matching his operating hours to that of EPEC's off-peak rating period.

While there is no testimony in opposition to the option, the examiners nonetheless recommend it be rejected. While the purpose behind the option may be reasonable--to recognize that large industrial customers operate plants in shifts--in practice the option is not a good load management tool. By altering his on-peak billing period, a customer could shift load that is currently defined as being on-peak to off-peak, which could result in lower bills. But does such a shift really reduce the Company's costs? It is important to note that the customer is not actually shifting his demand to off-peak periods, he is simply redefining what is deemed to be on-peak. The examiners do not believe it is appropriate to allow a customer to possibly reduce his rates by redefining what the rating periods are. Without any evidence as to what the possible revenue impact will be, or that there will be no impact, the examiners do not believe it would be reasonable to approve the Rating Period Selection Option, and thus they recommend it be rejected for all four rate schedules.

G. Rate 41--City and County Service

The TSA argue that state agencies should be allowed to take service under Rate 41. This special rate for city and county services was originally created in exhange for granting the Company a franchise within the city limits of the various cities, mainly the City of El Paso. Rate 41 customers have usage characteristics very similar to those of the Rate 24 (General Service) customers (Tr. at 8846), but the rates for Rate 41 are lower than those for Rate 24. The TSA argues that it provides services similar to those provided by other levels of government, and thus there is no basis for differentiating between the two.

The examiners in general agree with the TSA's arguments, but do not recommend adoption of the TSA's request. There appears to be no rationale for a separate rate class for city and county customers other than that was the quid pro quo for receiving a franchise from the City. There apparently is no reason for differentiating city and county customers from other general service customers based on usage. Nor is there any dispute that the city and county provide services not dissimilar from those provided by the TSA. However, there is no evidence that the TSA, which are members of the general service class, have load charateristics similar to the city and county Rate 41 customers. Before adding the TSA to Rate 41, the examiners believe that it is necessary to have that data, to ensure that such a step will not greatly change the load characteristics of either the Rate 24 or 41 rate classes.

The examiners thus recommend that EPEC be required to undertake the necessary studies so that during EPEC's next general rate case the load and usage characteristics of the TSA, as a group, can be compared to the load and usage characteristics of both Rate Classes 24 and 41. The examiners would also note that, rather than move the TSA from Rate Schedule 24 to Rate Schedule 41, the Commission should also consider in the next general rate case whether it would not be just as reasonable to simply eliminate Rate Schedule 41, rather than expand the number of customers who take service under that schedule.

H. Miscellaneous Service Charges

The Company proposes to increase the charge for returned checks and bank drafts, currently $8.00, to $12.00. The Company also proposes to begin offering same-day service for customers who request overtime service for new service, non-pay reconnects and "no light" service calls. Currently, the Company only performs same-day connections, or connections after hours, if there is a life threatening medical emergency or the customer was cut off in error. The applicable premium-overtime charge for such services will be $60.00, as compared to the normal charge of $15.00.

Mr. Rudolph takes issue with both of the Company's proposals. As to the returned check charge, Mr. Rudolph testified that $12.00 represents an extreme increase incompatible with rate moderation objectives, and is high relative to other major electric utilities in the state. He also reviewed the Company's cost-estimate and found it to be based upon a faulty assumption as to the amount of time it takes the Company to process returned checks. Concerning the premium-overtime charge, Mr. Rudolph testified that the Company had not adequately explained the assumptions that: (1) it would always have to pay double-time wages, as opposed to time and a half; and (2) that there would be no grouping of service requests, but that each request would require a separate service trip. Mr. Rudolph recommended that the returned check charge remain at $8.00, and that the premium-overtime charge be set at $35.00.

The examiners recommend adoption of Mr. Rudolph's returned check proposal. The examiners do agree with the Company that for items such as this, the magnitude of the increase is irrelevant if it is cost justified. They also agree that what other utilities charge is irrelevant. But they agree with Mr. Rudolph that the Company's cost justification is inaccurate, because it assumes a returned check processing time that is approximately double what the evidence supports. The examiners would also note that while Mr. Mayhew rebutted the first two criticisms raised by Mr. Rudolph, he did not address the claim that the cost study was inaccurate in his rebuttal testimony at all. While the examiners suspect an increase might be warranted, until such time as the Company can provide an accurate cost estimate, the returned check charge should remain at $8.00.

As to the premium-overtime charge, the examiners believe that neither recommendation is well supported by the evidence. Mr. Rudolph's criticisms were rebutted by Mr. Mayhew on rebuttal, but only with the barest of evidence. But Mr. Rudolph failed to provide any support for his proposal of $35.00. If these new services are to be provided, some charge must be approved. Both witnesses agree that the charge should be higher than the normal charge. The examiners reluctantly recommend that the Company's proposed $60.00 charge be adopted, and would further recommend that this issue be revisited in the next general rate case, by which time it is hoped that there will be some actual cost data available.

I. Miscellaneous Rate Design Issues

1. Line Loss Factors

DOD witness Patwardhan recommended that the line loss factors used to calculate the fixed fuel factor charges be disaggregated for transmission level customers. Normally, line loss factors are calculated for transmission, primary and secondary voltage levels. Ft. Bliss has lower line loss factors than do the other transmission level customers, and thus would like its fuel factor to reflect that difference. The Company did not oppose such a request, as it already possesses individualized line loss data for its major transmission level customers. Based on the Company's data (EPEC Ex. 131, Tab 15), the examiners have calculated the line loss factors, and the voltage level to base factors, as follows:

Customer	Line Loss Factor	Voltage Level To Base Factor
Secondary	1.11295	1.01288
Primary	1.07674	0.97992
Phelps-Dodge	1.05762	0.96252
Border Steel	1.04802	0.95378
ASARCO	1.04802	0.95378
Ft. Bliss	1.03758	0.94428

The resultant fixed fuel factors recommended by the examiners are set out on Schedule VIII.

2. Interruptible Rates

EPEC currently has no interruptible rate rider or schedule. Interruptible rates are usually offered to large industrial customers, and provide that, at the request of the utility, the customer must interrupt or shed a specific amount of load within a specified time frame. In the cost allocation process, production plant costs associated with providing service to the interruptible class are not allocated to that class, because the service can be interrupted by the utility at any time, and thus the utility does not have to incur fixed production costs to enable it to provide firm reliable service to that customer. Border Steel witness Goff suggested that the Commission consider adopting interruptible rates in lieu of EPEC constructing its next generating unit and/or contracting for a long-term firm power supply. In light of the examiners' conclusions regarding Palo Verde, institution of an interruptible rate any time in the near future is somewhat akin to closing the barn door after the horses have all run out, and would in fact likely be detrimental to the system as a whole. It should be noted that Mr. Goff did not suggest that interruptible rates be instituted at any specific point in time, but desires only a signal from this Commission that at some time in the future it will be willing to provide interruptible rates. There is little evidence in the record as to the desirability of interruptible rates, and even ordering EPEC to study the matter is probably a bit premature at this point. But the examiners believe that at some point in the future an interruptible rate may be beneficial both to the Company and its industrial ratepayers, and do not doubt that the Commission will consider the desirability of an interruptible rate at that time.

XVII. Service Rules and Regulations

A. Line Extension Charge

EPEC's Line Extension Policy is found in Section 3 of the Company's tariff. Under EPEC's current tariffs, persons who request the Company to extend service into a new area are required to enter into an agreement for a term of four years that guarantees and secures payment to the Company of an amount equal to the cost of the extension plus applicable interest charges. At the end of the four year period the revenues generated are compared to the cost of the extension, and if the revenues have not equalled the costs, interest charges will be computed on the difference, with such interest charge to be based upon the overall cost of capital to the Company at the time of the construction of the extension. The issue to be decided is whether the interest rate should be set at a level that includes taxes and other government fees associated with equity capital, as the Company argues, or exclusive of taxes, as the City contends. The different interpretations produce significantly different interest rates: 18.09 percent versus 11.95 percent, using Docket No. 6350 cost of capital figures.

The Company argues that the interest charge is but a return, and thus should reflect what would be received on a normal plant investment in rate base. Return on rate base is set based on after tax dollars, and the overall revenue requirement is set on that basis. Dr. Johnson argues that, as to guarantees already in place, ambiguities should be resolved against the party that wrote the language (the Company), and the interest rate should be exclusive of taxes. As to what interpretation would be reasonable in the future, Dr. Johnson notes that facilities are generally depreciated over more than four years, and thus the four year time period serves only as a rule of thumb test as to whether or not there will be a sufficient stream of revenues that can be anticipated from the new line. If not, the developer or customer is required to help subsidize the line. Because it is possible that revenues will in fact be sufficient over time to ensure cost recovery, even if they were low during the first four years and the Company applied the provisions of the guarantee, Dr. Johnson argues that the interest rate should not include taxes, to help prevent overburdening the developer or individual customer. In his view, the provision provides ample protection to the Company at the lower interest rate.

As Dr. Johnson testified, the current language is vague, and either interpretation could be inferred. The examiners agree with Dr. Johnson as to guarantees currently in place. The language used does not clearly express what the Company now contends it was meant to express. Use of the phrase "cost of capital" does not necessarily or even usually imply that the cost will be computed after taxes. Thus, for guarantees made prior to the effective date of the line extension policy tariffs resulting from this docket, the interest charge should be exclusive of taxes.

Going forward, the examiners agree with the Company. It is appropriate to compute the interest charge on an after tax basis. The interest charge is in effect a return to the investor, and the only way the investor will get his full return is to take into account the effect of taxes on the Company's revenues. While it is true that the facilities in question do last longer than four years, and thus a shortfall in the first four years does not necessarily indicate the Company will not recover its costs over the long-term, the examiners would prefer to err on the side of the Company, and thus on the side of the other ratepayers. It may occur that the developer will be slightly "overburdened", but that is preferable to the Company not recouping its costs. It should also be noted that contributions in aid of construction are deducted from rate base, preventing a double recovery by the Company.

B. Hold Harmless Clause

EPEC's tariff requires the customer to indemnify the Company against any loss it might incur as a result of EPEC equipment located on the customer's premises. This is regardless of how such damage may arise; whether negligence was involved, and if so, who was negligent; and regardless of the size of the loss. Such hold harmless or limitation of liability clauses have traditionally been a part of utility tariffs. The TSA argue that, as to the State, they are illegal and unenforceable. In their brief, the TSA argue that such a clause constitutes a lending of credit, could subject the governmental entity to unlimited liability, and requires the payment of attorney's fees. The TSA then cite several court cases holding that any debt created must be satisfied out of current revenues, that a governmental body can not be subject to unlimited liability, and that the state does not pay attorney's fees unless specifically authorized by statute. The TSA seeks a conclusion of law providing that the hold harmless clause does not apply to the State. The examiners agree with the TSA's arguments, and would note that the Company did not address this issue in its reply brief. An appropriate conclusion of law will be included.

C. Customer Complaint Tracking

Staff witness Paul G. Irish testified concerning the Company's tracking of customer complaints. On clarifying examination, it finally became clear that what Mr. Irish proposes is that, for complaints that are referred to the Company from this Commission, the Company be required to keep all records and documentation relating to that complaint. For all other complaints, the Company should keep track of the total number of complaints and categorize them as to type, regardless of whether those complaints come directly from the customer, via the City Attorney's Office, from some other agency, or elsewhere. Such information should be kept for at least two years. The examiners believe that such a proposal is reasonable, and is the minimum required of the Company by P.U.C. SUBST. R. 23.41(b)(4). The Company's policy of defining "complaints" as only those complaints forwarded by the Commission is not a reasonable view or a rational interpretation of that Substantive Rule. Indeed, it could be argued that the Company is required by that rule also to record the date of the complaint, the name of the complainant, and the final disposition of the complaint for <u>all</u> complaints, not just ones forwarded by the Commission. If, however, Mr. Irish believes that only total numbers and categorization are sufficient, that is all that the examiners recommend be required.

D. Final Billing Refund Statement

Since 1980, the Commission has required the Company to keep records of kwh consumption and KW demand, as well as the applicable Palo Verde related CWIP revenue factors, on a customer-by-customer basis. This allows for the derivation of the revenues received from each customer that are related to the inclusion of CWIP in rate base. The Commission has also required the Company to give a final billing refund statement to all customers leaving the system stating that, should any portion of Palo Verde be decertificated or sold, the customer may be entitled to a refund with interest of monies paid to EPEC, and thus the customer should keep the Company advised of his mailing address. The Company deleted these tariff provisions without any testimony on the issue. The City has disputed that deletion, but its witnesses also did not address the issue in testimony. In their briefs and reply briefs, the two parties argue as to whether or not it is necessary to continue with these provisions.

The examiners are of the opinion that the arguments of the parties are not a sufficient basis on which to decide the issue. Without testimony as to the effect of a sale-leaseback on the CWIP related revenues paid with respect to Palo Verde Unit 3, the examiners cannot decide the issue. Because the Company failed to meet its burden of explaining why the provisions can properly be deleted, the examiners recommend that those tariff provisions (which are unnumbered, but appear between Sections 2 and 3 in the current tariff) remain in effect.

E. Tariff Revisions Recommended by Mr. Irish

Mr. Irish put forward 12 numbered recommendations setting out revisions to the Company's proposed tariff. The Company took no issue with Recommendation Nos. 2 and 7 through 11. The examiners have reviewed those recommendations, and concur in their adoption. The recommendations at issue will be detailed below.

1. Recommendation No. 1

The provision in question (Section No. 1, Sheet No. 25, Page 2) reads as follows:

> If the customer's payment of the delinquent bill is received at a Company business office during normal business hours and customer desires reconnection on same day or after business hours, or on Saturdays, Sundays and holidays, and Company calls out a serviceman, than an additional charge will be made per the premium overtime rate.

Mr. Irish recommends deletion of the phrase "on same day or" in order to allow for same day reconnections at the standard charge if it would not inconvenience the Company. On cross-examination Mr. Irish also voiced a concern that persons who pay extra for same day service may bump those who do not pay extra from being connecting in a timely manner.

As explained by Mr. Keyes on rebuttal, crews do not change their work schedule once they leave in the morning, except for emergency trouble reports, and thus same day service requests will not delay normal connections. The examiners agree with the Company that Mr. Irish's proposal will make the tariff unclear, such that it could easily be read to mean that same day reconnects will be made without any additional charge as a matter of course. The examiners recommend that the Company's proposed language be adopted.

2. Recommendation Nos. 3 and 12

These provisions (Section No. 2, Sheet No. 1, Page 2 and Section No. 3, Sheet No. 4, Page 2) deal with the definition of a "permanent" customer. Mr. Irish recommended revisions, and on rebuttal Mr. Keyes revised those revisions. Mr. Keyes' language is very similar to that of Mr. Irish, except that it defines a permanent customer/installation in part by requiring that the installation be "used or occupied on a full time basis." The examiners do not believe full-time occupancy is a necessary prerequisite to being a permanent customer, and thus recommend approval of the language proposed by Mr. Irish.

3. Recommendation No. 4

This provision (Section No. 2, Sheet No. 1, Page 6) concerns meter installations and replacement. Mr. Irish recommends addition of the following language: "When possible, the customer will be notified of a meter change so that customer verification of meter readings can be accomplished." This proposal is designed to reduce a customer's suspicions, especially if there is a pending billing dispute. Customers often feel that the Company removes the meter at a time when the customer is not home, so that it will be difficult for the customer to dispute the final meter reading because the customer was unable to verify that final reading at the time of removal. Mr. Keyes' rebuttal testimony contains proposed language that simply requires the Company to leave a notice informing the customer that the meter has been changed. This proposal will not eliminate the problem, in that the customer still will not be able to check the meter reading at the time the meter is removed. The examiners recommend that Mr. Irish's proposal be adopted, with one modification. The words "in advance" should be added after "notified" in order to make it clear that advance notice is what is contemplated by that tariff provision.

4. Recommendation Nos. 5 and 6

These provisions (Section No. 2, Sheet No. 1, Page 13) concern deposits, and the issue raised is whether it will be the Company or the customer that will estimate, for purposes of setting the deposit amount, the annual usage of that customer. The Commission has, for some period of time, adopted the position put forward by Mr. Irish in this docket. However, the Commission recently changed its position, and in the West Texas Utilities rate case (Docket No. 7510) determined that the utility ought to be the party that estimates usage.

The examiners believe that the recent West Texas Utilities decision is the better reasoned approach. As Mr. Keyes notes, a deposit is only required when a customer cannot establish a satisfactory credit rating. A letter of credit history from a previous utility, production of generally accepted credit cards, or credit reference letters establish statisfactory credit. A letter of guarantee by another person also eliminates the need for a cash deposit. A customer unable to meet such requirements either has a poor or nonexistant credit history. Customers in general are not likely to be as accurate in their estimations: the tariff provides no guidelines for assisting the customer in making his estimation, while the Company is intimately familiar with usage characteristics for its service area. Further, while the Company can increase the amount of the deposit required, it is limited in its ability to do so: actual usage must be three times the estimated usage, and the current usage must exceed $150 per month and 150 percent of the current deposit. For a utility that is currently writing off approximately $100,000 per month in bad debt, the examiners prefer not to let "a poor credit risk customer [to] 'guess' at the amount of the deposit" to be provided (EPEC Ex. 133, Tab 3 at 4), and thus recommend rejection of Mr. Irish's proposed language.

F. EPEC's Failure to Notate Changes

P.U.C. SUBST. R. 23.24(e) requires proposed tariff sheets to contain notations in the right-hand margin indicating each change made on the sheet. Seven different notations are provided for in that rule. The rule also requires that each notation include a vertical line which clearly shows the exact number of lines being changed. Paragraph (g) of that rule provides that any tariff filed with the Commission and found not to be in compliance with all of the paragraphs of that rule shall be so marked as rejected and returned to the utility with a brief explanation of the reasons for rejection.

The proposed tariff filed by EPEC on April 6, 1987, did not notate all of the proposed changes in the tariff. The revised proposed tariff filed on October 7, 1987, likewise did not notate all of the proposed changes. On rebuttal Mr. Mayhew sponsored another revised proposed tariff, but even that proposed tariff did not have notations for all of the proposed changes. In its brief, the City argues that some of the changes would impact the Company's revenues. For that reason, and because the Company did not notate all of the changes even on rebuttal, the City recommends rejection of all of EPEC's proposed changes in the rules of service. In response, the Company argues that the rule does not require the Company to identify the revenue effect of its proposed changes, but only identify the changes. The Company notes that all of the changes have now been identified and the proposed tariffs are now in compliance with the Substantive Rules. The Company also argues that under the rule tariffs that are not in compliance are rejected, with an explanation why, and the utility impliedly may amend the tariffs and resubmit them for approval.

The sentences that are fatal to the Company's position are found in the Company's brief, although the examiners obviously view them differently than does the Company:

> Apparently, the Company and Staff reviews failed to recognize these few changes. Staff Witness Paul Irish testified that he had reviewed all of the Company's tariffs and he apparently also failed to pick up these changes. [TR 8172]

(Applicant's Brief [Phase III - Rate Design], p. 26.) It is exactly because a person reviewing a tariff for proposed changes is likely to miss some of them if they are not in some way identified that the Commission requires all changes to be notated. A party should not have to do a line by line analysis of the current tariff to the proposed tariff to ensure that he has located all of the proposed changes. As to EPEC's argument that all of the changes are now notated, that misses the point. They were not notated until rebuttal testimony, when the other parties, including the staff, had already testified. What if Mr. Irish had wanted to testify concerning one of the changes that had not been notated? It would have been too late: by the time the change was identified, Mr. Irish had already testified. For the same reason, the Company's argument that it has simply revised rejected tariffs and refiled them must fail. Normally, if tariffs are refiled, they are once again subject to review, objection and testimony. That was not the case here.

Were there only one or two changes that had not been notated, and had they had no possible negative ratepayer impact, the examiners would recommend approval of the changes and let EPEC escape with an admonishment. But that is not the situation here. Over 22 changes were not notated. Some will impact the amount of monies paid by customers or applicants to the Company. The Company should not be permitted to implement tariff changes that it only identified at the end of the hearing, where those changes could have a possible negative impact on the Company's ratepayers. The examiners have reviewed each of the changes that were not notated and not addressed by the testimony of any witness, and where it appears that the change may have a negative impact on customers or applicants, they recommend the change be rejected. The examiners' recommendations are summarized below:

Section 2

Sheet 1, p. 4	Approve	Sheet 1, p. 16	Reject
Sheet 1, p. 5	Reject	Sheet 1, p. 20	Approve
Sheet 1, p. 10	Approve	Sheet 1, p. 21	Approve
Sheet 1, p. 14	Approve	Sheet 5, p. 1	Approve
Sheet 1, p. 15	Approve	Sheet 5, p. 2	Approve

Section 3

Sheet 2, p. 4	Approve	Sheet 5, p. 8	Reject
Sheet 4, p. 3	Reject/Approve*	Sheet 5, p. 9	Reject
Sheet 5, p. 1	Approve	Sheet 5, p. 10	Reject
Sheet 5, p. 3	Approve	Sheet 5, p. 11	Reject
Sheet 5, p. 6	Reject	Sheet 5, p. 12	Reject
Sheet 5, p. 7	Reject/Approve**	Sheet 5, pp. 13-16	Approve

* - Reject change to Paragraph M; approve change to Paragraph N
** - Reject change to Paragraph 1(a)(1); approve change to Paragraph 1(a)(2)

The examiners do not believe it necessary to go through and list the subject matter of each of the changes that they recommend be rejected (which include, among others, provision of meter enclosures and underground service extension policies), although they would note that Section 2, Sheet 1, p. 16 constitutes the late payment penalty for commercial customers. They would also note that while Section 3, Sheet 5, pp. 13-16 were not notated, they have been approved because they are obviously new pages.

XVIII. Reconciliation

The frankest discussion of the reconciliation of the Company's fuel expense must start with the declaration that the record on this issue is inadequate to the task. P.U.C. SUBST. R. 23.23(b)(2)(H) requires that final reconciliation of fuel costs shall be made at the time of the utility's general rate case or reconciliation proceeding. The examiners read this rule as requiring that a final reconciliation be made in this docket, and believe that achieving a final reconciliation would be particularly compelling in light of the fact that there was no final reconciliation in EPEC's last rate case, Docket No. 6350. The section in the Examiner's Report in that docket dealing with reconciliation is actually a discussion of the proper calculation of the cumulative over/underrecovery balances from March 1984 through July 1985 and of the various alternatives for making refunds to customers.

Nevertheless, in its direct case, the Company's entire proposal for final reconciliation in this docket consists of a single page (Schedule G-3) showing fuel cost over/underrecoveries for the eighteen months August 1985 through January 1987, during which there have apparently been at least three overrecovery refund projects. The staff's recommendations were based on a reconciliation period from March 1984 through May 1987. The Commission's final Order in Project No. 7758 stated that the issue of reconciliation of fuel cost over/underrecoveries for the months of December 1986 through August 1987 and interest thereon through November 30, 1987, is removed from Docket No. 7460. Even if the record permitted reconciliation, it would be extremely difficult to know what period of time the reconciliation should cover.

There was no testimony from the Company specifically addressing reconciliation of fuel expense. Staff witnesses Kaplan and Griffey offered exhaustively detailed analyses of the Company's fuel procurement and management; theirs was an admirably thorough review. Still, the witnesses' conclusions on some issues were not quantified, and on those their final recommendations were simply to adopt the Company's proposed costs for calculating the fixed fuel factor, and to fight this issue again in the next rate case.

Neither the Company nor the staff briefed fuel issues, not even the legality, under Rule 23.23(b)(2)(H), of postponing the reconciliation instead of pursuing it in this docket.

It is discouraging to consider recommending that reconciliation be postponed. This Company has gone nearly four years without a final reconciliation of fuel expenses. It is tempting to suggest that the Commission use the over/underrecovery balance presented by the Company and order reconciliation for the months August 1985 through November 1986, but that would be merely a superficial compliance with the technical requirements of Rule 23.23(b)(2)(H), an inadequate observance of the spirit of the Rule and its underlying policy, and a serious disservice to the ratepayers and the Company. Despite the mandate of Rule 23.23(b)(2)(H) and the close scrutiny of the staff witnesses, the record on reconciliation simply fails. The Commission staff undertook the monumental task of performing a painstaking review and candid appraisal of the Company's fuel management practices; that they were unable to complete this work does not justify discarding it.

This report recommends that, as general counsel and EPEC have agreed, final reconciliation should not be had in this docket. However, unlike general counsel and the Company, this report questions the wisdom of including reconciliation in EPEC's next rate case, for two reasons. First, this utility needs a final reconciliation of fuel expense, and the sooner it is begun, the sooner it will be finished. Second, it is clear that the issues raised in a reconciliation of nearly four years' worth of fuel expenses are enormous and require a great deal of time and attention from the staff and the intervenors. Combining that review with a rate case, particularly one involving as many new and thorny problems as this, proved to be more than the participants could manage. There is no reason to believe that the next rate case for EPEC will be any easier, and there are some reasons to think it could be more difficult.

Thus, it is with great reluctance, but equally great conviction, that the examiners recommend isolating the final reconciliation of fuel expense for EPEC from any rate case. Further, in this instance, the examiners believe that it is appropriate, because it would expedite final reconciliation, for the Commission in its final order in this docket to sever the reconciliation issues and institute a separate reconciliation proceeding for the period March 1984 through August 1987.

XIX. Stipulation

A. Introduction

As noted much earlier in this Report, a Stipulation signed by some but not all of the parties to this proceeding was filed on October 22, 1987. The Stipulation is attached hereto as Examiners' Exhibit C. Signatories to the Stipulation include the Company, ASARCO, W. Silver, Phelps-Dodge, Border Steel, and the Commission's general counsel. The DOD generally supports the Stipulation, but because it does not agree with the resolution of the ERR issues in the Stipulation, the DOD is not a signatory to it. Three parties that did not sign the Stipulation (Providence Memorial Hospital, United Steelworkers of America, and Ms. Rosie Wallin) have not been active participants in these proceedings. The Stipulation is actively opposed by the TSA, OPC, and, in particular, the City. Because not all parties are signatories to the Stipulation, the hearing on the merits was not abbreviated. Instead, a fourth hearing phase was added, dealing solely with the Stipulation. That phase of the hearing lasted not quite three days.

A final judgment based upon a settlement agreement can be entered only if all the parties consent, or if each provision of the Stipulation is supported by substantial evidence and the Commission is persuaded that it is reasonable and in the public interest. The examiners note that the parties have presented the Stipulation as an integrated whole. As is common with negotiated settlements, the final document is the result of give and take by all of the signatories to it. In Paragraph 20 of the Stipulation, the parties to it indicate that they do not necessarily agree to or concur with any specific methodology, finding, or conlusion reached therein. Paragraph 19 provides that if the Stipulation is not adopted in its entirety, then it shall have no force or effect, and the signatories will not be bound by it. Thus the examiners approached the Stipulation with the viewpoint that if it could not be adopted in its entirety, it should not be considered at all.

The examiners first considered the provisions of the Stipulation, and determined that there were several major portions of the Stipulation that they felt were either unreasonable or not supported by the evidence. Because there are ambiguities or problems concerning several of the major provisions in the Stipulation, and particularly because there is not substantial evidence to support some of the provisions, the examiners determined that they could not find the Stipulation to be in the public interest and recommend its adoption.

Hence it was necessary to address the matters to be decided in this docket as contested issues. Since the Stipulation must be considered as a whole, it would be inequitable and inappropriate to compare the provisions in the Stipulation to the positions the parties took on those issues during the hearing on the merits. With the exception of several prudence issues concerning Palo Verde, the examiners have reached the recommendations set out in this Report without further consideration of the terms of the Stipulation. Set forth below are only some of the major provisions of the Stipulation that they cannot recommend be adopted, even as part of a Stipulation.

B. Discussion of Selected Provisions

1. Paragraph 1

The Report recommends a much larger exclusion of the investment in Palo Verde than is provided for in the Stipulation. The examiners have excluded $151 million from Unit 1, as opposed to $50 million from Unit 1 and $10 million from Unit 3 under the Stipulation. A second important difference is that the Stipulation purports to "settle all issues relating to decisional prudence on Palo Verde Units 1, 2, and 3." Considering that the Company has a variety of techniques for making it appear that, even including Unit 3, it will have a negative net reserve in every year of its forecast except for 1991 and 1992, and that most of these techniques would probably be perfectly acceptable if there were no prudence issues involved, adopting the Stipulation would have ramifications in future rate increases and future building cycles far beyond anything indicated in the bottom line in this case.

2. Paragraph 4

The examiners have determined that the Company has only proved a need for an increase in base rate revenues of $30,124,691, as compared to the stipulated increase of $48,066,859.

3. Paragraph 7

The examiners have determined that the Company's reconcilable known and reasonably predictable fuel expenses are $51,952,710, which produces a Texas system fuel factor undifferentiated for line losses of 1.6587 cents per kwh, as compared to the higher stipulated fuel factor of 1.691 cents per kwh.

4. Paragraph 8(c)

There is no evidence to support a finding that costs on Palo Verde Unit 3 cannot be excluded because of the construction period of the Arizona Interconnection Project. While there is testimony that the Stipulation as a whole is reasonable, there is no basic underlying evidence to support this finding.

5. Paragraph 10

This paragraph of the Stipulation provides for the Company to refund, with interest, the amount of monies collected during the court ordered stay of Docket No. 6350 above the rates authorized by this Commission in that docket. While the examiners dislike preventing the refund of overcollections, it is clear that this Commission has no jurisdiction over any aspect of Docket No. 6350. The appeal of Docket No. 6350, including the question of refunds, is pending before the district court. That court has not issued any orders, nor have the parties to that proceeding presented the court with a settlement of all issues, or even an agreement as to the refund of overcollections. Further, it is unclear whether all of the parties to the appeal in district court are signatories to the Stipulation. In sum, this Commission should not attempt to usurp the power of the district court.

6. Paragraph 11

This paragraph sets performance standards for Palo Verde. The examiners have no objection to the implementation of performance standards in general, but do find some of the specifics of this proposal to be unreasonable. First, there is no specific evidence in the record directly addressing and supporting the various performance "bands" to be applied. While there is testimony that similar (but not identical) standards have been imposed in other jurisdictions, and while there is testimony explaining the various bands, that does not constitute sufficient evidence to support the precise delineations and penalties/incentives that have been included in the Stipulation.

Second, the provision for determining the first annual capacity factor is biased in favor of the Company. In general, the capacity factor is determined utilizing a start-of-fuel-reload to start-of-fuel-reload time period. Thus, at least one down period for reloading fuel is factored in. But for the first "annual" capacity factor, the time period is from the effective date of the rates approved in this docket to the start of the next fuel reload. Unit 1 was due to come back on line sometime in January of 1988. The rates approved in this docket will go into effect approximately two months later. Thus, there will be no fuel reload period included. (Tr. at 9120-9212.) If the Company is correct, and Palo Verde only has a forced outage rate of 10 percent, then the capacity factor for Palo Verde will be 90 percent. The lack of a fuel load during the first "annual" performance period skews the capacity factor calculation upward, resulting in undeserved incentive payments.

Third, the penalty/incentive provisions themselves are skewed. At first glance, they appear equally weighted (the incentive payment for a capacity factor 5 percent above the dead zone of 60 to 75 percent will equal the penalty for a capacity factor 5 percent below the dead zone), but in practice they will not operate that way. Utilizing the assumptions and analysis of Dr. Anderson (OPC Ex. 2 at 12-14), an 80 percent capacity factor during one period results in an incentive payment of $911,886, while a capacity factor of 55 percent in the second period results in a refund of $825,192. As Dr. Johnson notes, summing the two periods produces a capacity factor of 67.5 percent, exactly in the middle of the dead zone, but the Company would still receive an additional $86,694. As long as the incremental cost of energy is less than the average cost, the standards remain biased in the Company's favor.

Finally, the Stipulation provides for the "automatic reconsideration" of the Company's last general rate case if the capacity factor is less than 35 percent on either Unit 1 or Unit 2. The Company's witness could not say whether a full general rate case would be required or not. (Tr. at 9117-9119.) Thus, the party with the responsibility for filing something does not know what the Stipulation requires it to file. Mr. Reilley testified that the reconsideration would involve more than fuel, and would likely extend to possible removal of plant from rate base or disallowance of lease payments. (Tr. at 9172.) If a full rate case is required, then that rate case would be in addition to the yearly rate cases contemplated by the Stipulation. The Commission could thus face two, and perhaps three, general rate cases all within about one year's time frame. Such a result would obviously be a drain on the resources of all the parties involved, and would increase rate case expenses substantially.

7. Paragraph 12

Among other provisions, this paragraph provides for EPEC to "flow-through to the ratepayers any monies recovered from the Combustion Engineering ("CE") litigation in excess of $28 million." This language is unclear and ambiguous in several respects. First, it is not clear whether it is the recovery of $28 million by <u>EPEC</u> that would trigger the "flow-through", or whether it is the recovery of $28 million by <u>ANNP</u> as a whole that would trigger the "flow-through. To the extent this provision ever provides any benefit to the ratepayers, the provision is obviously worth a lot more to them if it is triggered by the recovery of $28 million by ANPP as a whole.

Second, it is not set forth in the Stipulation what is meant by "flow-through." There are different ways to flow through a sum of money to the ratepayers. It is not clear whether the signatory parties intend that the method be left open, or whether they consider "flow-through" to be a term that denotes a specific, but undisclosed, methodology.

The examiners also find Paragraph 12 to be objectionable in that it appears to provide for a double recovery by EPEC of construction costs in the amount of $28 million (or $4.424 million, depending on how the ambiguity is resolved), as the $28 million is not specifically set out in the Stipulation as being part of the $60 million disallowance. By comparison, the examiners' recommendations in this docket would enable the parties to explore further the amount of recovery EPEC can reasonably expect based on its contractual claims, as this was not an issue squarely presented in this docket. In addition, the examiners' recommendations would make it clear that the Company has a duty to ratepayers to try to collect on those claims. These are construction costs that are being paid for by the public; a partial reimbursement by CE is not a bonus that the Company is entitled to keep for its own use absent an order or agreement requiring the Company to flow through only certain "excess" amounts. Any recovery by EPEC from CE is already due the ratepayers; this provision of the Stipulation does not give the ratepayers something, but on the contrary, it takes something away from them.

The examiners also object to Paragraph 12 becasue there is no basis in the evidence for awarding the Company either the first $28 million or the first $4.424 million that may be collected from CE. The numbers would appear to be essentially arbitrary. Although staff witness Jacobs, in a critique of Mr. Hubbard's estimate of $170 million in delay costs for EPEC alone, reduced this $170 million figure to $28 million by considering that ratepayers had the use of their money longer as a result of project delay, there is no necessary connection between this calculation of increased costs to the ratepayers caused by the delay and any amount that EPEC or ANPP stands to receive in <u>contractual</u> damages from CE.

Finally, as stated earlier, it is unclear why, if the $28 million figure represents increased costs to the ratepayers caused by the delay, that money is being given to EPEC. The examiners would note that if the $28 million does represent part of the $60 million disallowance provided for in the Stipulation, the stipulated disallowance could eventually turn out to be much less than $60 million; it could be only half that amount.

8. Paragraphs 13 and 14

The rate design provisions of the Stipulation differ in many respects from those recommended by the examiners. The customer charges are much higher than recommended under the examiners' proposed methodology. The Stipulation also adopts a summer/winter differential and eliminates the space heating rider discount for the residential class (Rudolph Option 2). There is no evidence to support the 550 kwh cutover for winter reduced rate tail-block: the 550 kwh figure is based on the Company's space heating rider proposal, not a seasonal rate. There is no evidence indicating that the switchover level for a space heating rider is the appropriate switchover level for a reduced winter tail-block. Likewise, there is no evidence to support a $9.00 returned check charge, an amount not testified to by any witness.

C. Conclusion

It is with reluctance that the examiners must recommend that the Stipulation not be adopted. It is the policy of this Commission to support the attempts of parties to resolve contested dockets by negotiation, and stipulations are in general looked upon favorably. In this instance, however, the Stipulation has not been signed by all of the parties to the docket. Thus, because certain key provisions in the Stipulation are either ambiguous or not supported by the evidence, and because the Stipulation was presented as an integrated whole, the examiners feel that they have no choice but to recommend that it not be adopted.

D. Rulings on Proposed Findings of Fact

On January 23, 1988, the signatory parties to the Stipulation filed joint proposed findings of fact and conclusion of law. Section 16(b) of the APA provides that: "If, in accordance with agency rules, a party submitted proposed findings of fact, the decision shall include a ruling on each proposed finding." This Commission has not adopted any rules regarding the submission of proposed findings of fact, and thus it is not clear that they need be ruled on. However, the examiners believe the conservative approach would be to rule on each proposed finding in any event. No ruling on the one proposed conclusion of law is necessary under the APA.

The following proposed findings of fact should be rejected as they are not reasonably supported by a preponderance of the evidence: 1, 2, 3, 5, 6, 7, 9, 10, 11, 16, 17, 18, 19, 20, 21, 22 and 23.

The following proposed findings of fact, while accurate factual statements, should be rejected as they are either unnecessary to support the recommendations of the examiners, or are duplicative of findings that the examiners have proposed: 4, 8, 12, 13, 14, 15, 24, 25, 26, 27 and 28.

XX. Findings of Fact and Conclusions of Law

The report recommends that the Commission adopt the following findings of fact and conclusions of law. The schedules referred to in the findings and conclusions are attached to the Proposed Order for purposes of this report. If the findings and conclusions are adopted by the Commission, the schedules referred to will be those attached to the final Order.

A. Findings of Fact

1. El Paso Electric Company (EPEC or the Company) filed this request for a change in rates in all unincorporated areas in Texas in which it serves on April 6, 1987.

2. As amended, the proposed change was a base rate increase of $76,476,924 over adjusted non-fuel revenues for the test year ended September 30, 1986. The Company also sought a decrease in fuel revenues of $12,199,878. All Texas customers are affected by the proposed change.

3. The effective date of the Company's proposed rate change is June 24, 1987; implementation of rates beyond the effective date was suspended for the statutory period of 150 days until November 17, 1987. Because there were 68 days of actual hearing in this case, the suspension period is extended for 106 days until March 6, 1988.

4. The Company also filed identical requests for rate increases with the municipalities retaining original jurisdiction over electric utility rates. The ratemaking ordinances of those municipalities (the City of El Paso and the Towns of Clint, Socorro, Vinton, Anthony, and Van Horn) were timely appealed to the Commission and the appeals are consolidated with this environs docket.

5. On October 31, 1986, EPEC filed an application reporting the sale and leaseback in August 1986 of 73.5 percent of its ownership of Unit 2 of the Palo Verde Nuclear Generating Station (PVNGS) and related common facilities; this filing was assigned Docket No. 7172. It was amended on August 13, 1987, when EPEC reported the sale and leaseback in December 1986 of the remaining 26.5 percent of its ownership interest in Unit 2 and common facilities. Docket No. 7172 was consolidated with the rate case on October 27, 1987.

6. A stipulation signed by fewer than all the parties to this docket was filed on October 22, 1987.

7. EPEC published notice of its requested rate increase four times in newspapers of general circulation in each county in which it serves, and provided notice of its filing to the appropriate office of each affected municipality simultaneously with its filing at the Commission.

8. The Company gave notice of its filing in Docket No. 7172 by publishing, once each week for two consecutive weeks in newspapers of general circulation in each county in which EPEC serves, notice of the sale and leaseback transaction, as ordered in that docket.

9. In the <u>Long-Term Peak Demand and Capacity Resource Forecast for Texas 1986</u>, the Commission recognized the unique characteristics of EPEC's service territory, and permitted the Company until the end of 1988 to gather the data needed to make accurate projections of the kW peak demand reductions and kWh savings, and the costs and benefits of specific conservation and load management activities and programs.

10. EPEC provided testimony about its energy efficiency plan and the extent to which the goals have been reached, insofar as that was possible. The Company also indicated the status of all energy efficiency programs and studies, and documented the costs and, insofar as was possible, benefits.

11. Overall, EPEC has improved its performance in the area of conservation and load management since its last rate case.

12. Because of limited residential consumption and demand, the opportunity for significant savings in that customer class is negligible, and the change in emphasis in EPEC's conservation and load management programs from residential to commercial and industrial appears justified.

13. Even though some load management programs legitimately promote increased sales, the Company must carefully plan and thoroughly justify such programs to insure their compliance with the load shape objectives recognized by this Commission.

14. EPEC's High Efficiency Appliance Program promotes the indiscriminate consumption of electricity, does not further energy efficiency goals, and cannot be justified on any basis.

15. The Commission must consider a utility's conservation and energy efficiency activities in fixing a return on invested capital, regardless of the source of funding for programs promoting increased sales.

16. EPEC's Energy Efficiency Plan to be filed December 31, 1989, will include the data it will have collected by year-end 1988. That Energy Efficiency Plan must comply in every respect with the Commission's requirements for evaluating costs and benefits of conservation and load management programs.

17. The Commission should exclude from the Company's cost of service $131,345 (Texas), representing the costs of the discontinued Water Heater Program ($2,133) and the High Efficiency Appliance Information and Demonstration Program, calculated as set forth in Section V.A. of the Examiners' Report.

18. EPEC's conservation and load management practices do not warrant a downward adjustment of $400,000 (5 basis points) to EPEC's overall return.

19. In August 1985, the Touche Ross Management Audit of EPEC was issued. The audit reviewed the areas of executive management and organization, system planning and design, engineering and construction, fuels management, power supply, transmission and distribution, financial management, customer service and public relations, corporate support services, human resource management, and Franklin Land & Resources; and it made 187 recommendations.

20. EPEC approved 157 of the recommendations, excepted to 29, and rejected one.

21. The Commission staff found EPEC had adequately addressed the audit recommendations in implementation plans submitted in November 1985.

22. Despite cash problems beginning in 1985, EPEC has implemented between 108 and 117 of the 187 audit recommendations.

23. The Company notified the Commission staff in March 1986 of plans to suspend all implementation activities requiring cash outlays, regardless of potential savings, because of the Company's cash flow difficulties.

24. Not all audit implementation activities ceased in March 1986, but only those requiring cash expenditures.

25. Implementation of audit recommendations requiring cash outlays resumed following the cash infusion brought about by the sale/leaseback of PVNGS Unit 2.

26. There are a number of factors which can make the calculation of cost and benefits inaccurate, including the passage of time and the fact that initial estimates can later prove to be wrong.

27. EPEC performed its own analysis of the costs and benefits of implementing the Touche Ross audit recommendations; the Company did not agree with Touche Ross on all its cost/benefit analyses, and did not rely on those in the audit in making decisions and plans for implementing audit recommendations.

28. The staff's use of Touche Ross's estimate of benefits which would result from five audit recommendations, which staff believes are incomplete, as a surrogate for calculating a management penalty for EPEC's failure to implement

more of the audit recommendations is inappropriate. Four of the five audit recommendations are either complete or the Company is currently engaged in the process of implementing them. The estimated benefit for the fifth (reduction of the time lag between bill generation/receipt and termination of service on unpaid accounts) which has not be implemented was predicated on a reduction (from 28 to 25 days) which cannot legally be implemented.

29. The relationship between EPEC and its subsidiary PasoTex was not examined in depth and there is no analysis in this record of whether or how the Touche Ross audit recommendations regarding Franklin Land & Resources apply to PasoTex.

30. There is no evidence in this record on how the Touche Ross management audit recommendations were to be implemented, whether there was a specific or implicit timetable or deadline for implementation, or whether the Company had the option of deviating from the recommendations.

31. Given the facts in this record, it is unfair to penalize EPEC for not implementing audit recommendations because of its cash problems when the staff had been given notice of the delay and the reasons for it and had itself never notified EPEC of agreement or disagreement with the delay in implementation.

32. The facts in this record do not justify imposition of the management penalty recommended by the staff and supported by the City of El Paso.

33. EPEC should update all implementation plans and cost/benefit analyses no later than the next quarterly filing following the final order in this docket.

34. In the future, the quality of EPEC's management will be determined, in part, on its achievements in implementing the Touche Ross management audit recommendations.

35. In 1972, Arizona Public Service Company (APS) and Salt River Project formed the Arizona Nuclear Power Project (ANPP) and became its steering committee.

36. APS was designated project manager and operating agent.

37. In 1972 or 1973 the ANPP steering committee invited other utilities to participate in ANPP.

38. Of the utilities which were contacted to participate in ANPP, EPEC, Public Service of New Mexico (PNM), and Tucson Gas and Electric Company joined the project.

39. Although APS and Salt River Project had originally intended to construct a 600 to 1200 MW nuclear plant, ANPP, after it gained additional participants, ultimately settled on a plan to construct three identical 1,270 MW units at the Palo Verde site in Arizona.

40. While the 1,270 MW unit size was slightly larger than had originally been contemplated by APS and Salt River Project, it was smaller than the unit size that would have been dictated by the capacity requests being made by the ANPP participants as a whole.

41. To accommodate all of the capacity requests that were initially made by the participants, the generating units would have needed to be rated at 1,550 MWs each.

42. The Nuclear Regulatory Commission (NRC) limits the thermal core power of nuclear units in such a way that a 1,300 MW unit is approximately the maximum that can be licensed.

43. In March of 1972, APS hired a very experienced project director.

44. ANPP selected an appropriate organization structure for the project which included a single engineer-constructor.

45. ANPP hired Bechtel to be the engineer constructor at Palo Verde.

46. Hiring Bechtel was a prudent choice.

47. At 1,270 MW each, the Palo Verde units are the largest in the United States.

48. The next largest nuclear units in the United States after Palo Verde are on the order of 1,100 MW.

49. The size of the units at Palo Verde may, to a large extent, have dictated the choice of Combustion Engineering (CE) as the nuclear steam supply system (NSSS) vendor.

50. The CE System 80 NSSS, which is what ANPP ordered for the project, was the largest NSSS designed for use in the United States at the time that it was ordered.

51. The CE System 80 is a larger, somewhat modified version of a proven design.

52. Size alone makes the CE System 80 NSSS a first-of-kind design.

53. At the time that ANPP ordered the System 80, there were three other utilities before it who had also ordered it.

54. If those utilities had moved ahead with their projects on schedule, ANPP would not have been the first to install and test the System 80 in an actual nuclear plant.

55. At the time that ANPP ordered the System 80, it could reasonably have expected that there would be extensive design reviews and testing over the years at ANPP and other projects to work out minor defects in the system.

56. There is no evidence that an NSSS on the scale of the System 80 exceeds the physical limits of an NSSS.

57. It was reasonable for ANPP to have gone ahead with a System 80.

58. In terms of its qualifications and level of professionalism, CE would have appeared to be equal to the task of supplying an NSSS on the scale of the System 80.

59. ANPP's selection of CE was reasonable.

60. At the time that ANPP selected Combustion Engineering as the NSSS vendor, CE did not manufacture reactor coolant pumps.

61. CE conducted a bid selection process with regard to choosing a reactor coolant pump vendor and prepared a list of potential vendors for review by ANPP and Bechtel.

62. Of the potential vendors, Klein, Schanzlin, and Becker (KSB) of West Germany was judged to be the best reactor coolant pump vendor for the project.

63. Subsequent to KSB's being chosen as the reactor coolant system (RCS) pump vendor, CE and KSB formed a joint venture to manufacture RCS pumps for the CE System 80 NSSS.

64. ANPP's choice of KSB to supply the RCS pumps was reasonable.

65. At the time that ANPP selected CE as the NSSS vendor, CE did not manufacture low pressure safety injection (LPSI) pumps.

66. CE conducted the bid selection process for the LPSI pump vendors.

67. ANPP ultimately decided upon a pump/motor combination utilizing an Ingersoll Rand pump and a Westinghouse motor.

68. ANPP's choice of LPSI pump vendor was reasonable.

69. Although the KSB pump design for the RCS required very little modification for the CE System 80, it did require some, and was therefore a first-of-kind pump.

70. In 1978, before the KSB pump was installed at Palo Verde, it was put through a 500-hour demonstration test under plant operating conditions with 30 stop-start cycles.

71. When the pumps were subsequently taken apart and examined, stress corrosion was found in the diffuser cap screws.

72. KSB manufactured cap screws using different materials in order to correct the problem that had been observed at the time of the 500 hour demonstration test.

73. Subsequent to the 500-hour demonstration test, KSB tested the pump with the new cap screws at approximately 150 percent of design flow for 50 hours.

74. The cap screws showed no damage after the 50-hour test.

75. Following the 50-hour test, the next indication that there were problems with the RCS came at the time of the hot functional test at Palo Verde Unit I in July 1983.

76. Following the hot functional test at Palo Verde Unit I in July 1983, the diffuser cap screws on the RCS showed stress damage.

77. Beginning in 1983, ANPP experienced problems with the LPSI pumps.

78. The problems with the LPSI pumps were stress-related.

79. The problems with the LPSI pumps appear to have been corrected.

80. The problems with the RCS have been corrected to some extent, but there may still be some cracking in the pump shafts.

81. To the extent that there is cracking in the pump shafts, ANPP has temporarily solved this problem by changing out pump shafts during refueling and maintenance activities at Palo Verde Unit 1.

82. ANPP has replaced all of the pump shafts in the RCS at Palo Verde Unit I.

83. ANPP has litigation pending against CE as the result of the equipment failures involving the RCS and the LPSI pumps.

84. The litigation against CE is a claim for contractual damages for breach of warranty.

85. There is no evidence in this docket that the RCS and LPSI failures at Palo Verde Unit I were the result of anyone's negligence or mismanagement.

86. Overall, APS, ANPP, and Bechtel managed the project in a prudent and efficient manner.

87. ANPP experienced problems in the early phases of start-up, but it had corrected these problems by 1984.

88. The overall costs for Palo Verde on a per kilowatt basis are reasonable.

89. The overall construction costs of Palo Verde are reasonable considering that there would have been some increase in costs attributable to the RCS and LPSI failures.

90. ANPP secured water rights for Palo Verde from City of Phoenix, consisting of rights to sewage effluent.

91. ANPP constructed a pipeline in three sections running from the sewage treatment plant in City of Phoenix to Palo Verde.

92. The first section of the effluent pipeline leading to Palo Verde is seven miles long. It runs from the 91st Avenue Sewage Plant to the Buckeye Station and has a capacity of 170,000 acre/feet per year.

93. The second section of the effluent pipeline leading to Palo Verde is 23.5 miles long. It runs from the Buckeye Station to the Hassayampa River Pumping Station and has a capacity of 140,000 acre/feet.

94. The third section of the effluent pipeline leading to Palo Verde is 8.5 miles long. It runs from the Hassayampa River Pumping Station to Palo Verde and has a capacity of 105,000 acre/feet per year.

95. The effluent pipeline was sized to accomplish several goals. One was to carry 30,000 acre/feet of sewage effluent for the Buckeye Irrigation Company from the 91st Avenue Sewage Plant to the Buckeye Station in exchange for a right-of-way for the pipeline from the 91st Avenue Sewage Plant to the Hassayampa River. The pipeline was also sized to provide for diurnal fluctuation in the volume of effluent and serve as a reservoir for additional amounts of water in the event of a shut-down at the 91st Avenue Sewage Plant or an emergency at Palo Verde.

96. The effluent pipeline leading to Palo Verde is a facility which is entirely used and useful in providing service.

97. FERC accounting rules dictate that 100 percent of the cost of the effluent pipeline leading to Palo Verde be assigned to Palo Verde Unit I.

98. Leaving aside the issue of whether all of EPEC's 15.8 percent participation in Palo Verde is used and useful, just and reasonable rates may be set based upon full inclusion of EPEC's share of Palo Verde construction costs, less any costs which are reimbursed by Combustion Engineering.

99. ANPP has substantial outstanding claims against Combustion Engineering in connection with the RCS and LPSI failures at Palo Verde, as well as other miscellaneous claims.

100. In the event that ANPP is reimbursed by Combustion Engineering for any of the claims outstanding against Combustion Engineering, or in the event that ANPP abandons a valid claim or compromises or settles a claim in a manner contrary to the public interest, rates as set in this docket (No. 7460) may no longer be just and reasonable, as actual construction costs for Palo Verde will be overstated unless some adjustment to plant in service is made.

101. In reaching its decision to participate in Palo Verde at some level, it would have been reasonable for EPEC to have considered the factors set out in Section VII.C.1 of this report and relied on information developed by the ANPP steering committee.

102. On the basis of the information indicated in the preceeding finding of fact, it would have been reasonable for EPEC to conclude that it should participate in some portion of the Palo Verde project.

103. None of the factors designated in the two preceding findings of fact would, without more, have indicated the level at which EPEC should participate.

104. With regard to level of participation in Palo Verde, EPEC's decision-making and planning processes were seriously deficient.

105. EPEC originally intended to commit to a 684 MW share of PVNGS.

106. Although EPEC originally requested a 684 MW share of PVNGS, its share was ultimately reduced to 600 MW as a result of a pro rata reduction in the shares requested by the ANPP participants at the time the final decisions were made regarding the number and size of the units to be built at Palo Verde.

107. At some point in 1972, EPEC had Stone & Webster, EPEC's consultants, make a financial analysis of a plan involving an investment in a large nuclear construction program, bearing an unknown relationship to the specific decisions to request 684 MW of PVNGS and to commit to 600 MW.

108. The financial analysis made by Stone & Webster in 1972 was designed to represent a "most likely" scenario.

109. In 1972 and 1973 nuclear costs estimates were very uncertain, but knowledgeable observers expected them to go up as unpredictable safety and environmental requirements were established, and as the utility industry gained experience with plants that were not built under turnkey contracts with reactor vendors, as they had been in the 1960s.

110. Considering the uncertainty about nuclear costs at the time that EPEC was making its initial decision to request 684 MW of Palo Verde and commit to 600 MW, it would have been far more useful for Stone & Webster to have produced a "worst case" scenario for a project as much like financing the share in PVNGS that was contemplated as possible, as opposed to a "most likely" scenario involving a hypothetical project bearing only a general relationship to the specific investment that was being contemplated.

111. EPEC's decision-making and planning processes in 1972 and 1973 were deficient in that EPEC gave inadequate consideration to alternatives to a 684 MW (reduced to a 600 MW) level of participation in PVNGS.

112. EPEC has provided, as an example of the kind of study on which it relied in making its decision to participate in 600 MW of Palo Verde, a three-page document prepared in 1975, whose ultimate conclusion was no more definitive than that "nuclear generation of the size of PVNGS is ... in no way inferior to other sources." (Report, Docket No. 6350, page 23.)

113. Despite dramatically deteriorated load growth after the Arab Oil Embargo of 1973, EPEC has never taken the initiative to readjust or fine tune its Palo Verde commitment except in response to regulatory and short-term financial concerns.

114. EPEC, which had no financial planning department as such at the time that the decision to participate in PVNGS was made, has a history of relatively limited sensitivity analysis in contingency planning to anticipate the impact of alternative series of events.

115. EPEC was weak in the area of sensitivity analysis and contingency planning at the time it made its initial decisions with regard to PVNGS and may not have conducted any sensitivity analysis or contingency planning at all.

116. In making its initial decision with regard to PVNGS, EPEC utilized no studies that integrated financial feasibility with other strategic concerns.

117. Although, at the time that it made its initial decision with regard to PVNGS, EPEC possessed plenty of generic studies from various time periods discussing the relative economics of nuclear energy versus coal, these studies taken alone or in conjunction should have led to at least one very high caliber study of the specific alternatives available to EPEC.

118. There is no evidence in the record that, at the time that it made its initial decisions with regard to PVNGS, EPEC possessed detailed knowledge and understanding of coal and uranium availability in the 1980s, which one of the studies it purported to have relied on indicated was essential.

119. There is no evidence that, at the time that EPEC made its initial decisions with regard to Palo Verde, it made the kind of study recommended in the 1971 Steering Committee and Task Force reports cited by EPEC in support of its decision.

120. There is no evidence that EPEC ever considered the impact on the public, under the largest-single-hazard-plus-five-percent of peak method of calculating reserve margin, of investing in 200 MW shares in three units as opposed to 150 MW shares in four units, or any other alternative.

121. EPEC uses the largest-single-hazard-plus-five-percent method of calculating reserve margin.

122. EPEC does not require more than a twenty percent reserve margin to ensure system reliability.

123. In making the Palo Verde commitment on the basis of inadequate study, EPEC subjected the company and its ratepayers to substantial and unreasonable financial risks.

124. EPEC has failed to prove that its initial decision to commit to 600 MW of Palo Verde was prudent or in the public interest at the time that it made the initial commitment.

125. As a result of the Palo Verde commitment, EPEC has more than 300 MW of excess capacity on its system through at least the year 1997 or beyond. This finding is based on the discussion of loads and resources in Section VII.D of this report.

126. EPEC's investment in Palo Verde represents an investment in excess capacity which can only be charged to ratepayers by techniques designed to make more of a questionable investment appear used and useful to the detriment of ratepayers.

127. If more than 300 of the 400 MW involved in EPEC's share of Palo Verde Units 1 and 2 are recognized in rate base as being used and useful to provide service to the public for purposes of earning a return, rates set upon this basis would be unjust and unreasonable.

128. EPEC's sale/leaseback of its share of PVNGS Unit 2 and related common facilities resulted in a gain over the book value of the transferred assets.

129. The lease payment EPEC must make is based on the total sales price; however, only the portion related to the book value of Unit 2 and related common facilities will be included in the cost of service on which rates are based.

130. The Company's sale/leaseback of PVNGS Unit 2 and related common facilities was essentially a financing arrangement.

131. EPEC's proposed "book break-even" calculation of the portion of the lease payment to be included in cost of service is reasonable, as it has the effect of lowering the initial cost of PVNGS Unit 2 for the ratepayers, as compared to traditional ratemaking plant in service/rate base methodology.

132. Although the lease payments in the later years of the lease would be greater than would be the cost of PVNGS Unit 2 and related common facilities included in rate base under traditional ratemaking treatment, the advantage of the lease is that the payment stream is fairly level for the life of the lease.

133. The ratemaking treatment of PVNGS Unit 2 and related common facilities under the lease is equitable because it spreads the burden more evenly across generations of ratepayers than would traditional rate base treatment.

134. The "book break-even" methodology is the fairest way of including costs for PVNGS Unit 2 in rates, since the ratepayers do not pay for more in rates than they would have had EPEC sold this asset at book value.

135. EPEC bears no greater operational risks or costs under the lease than it would have had as an owner of PVNGS Unit 2 and related common facilities.

136. The lease includes, at the end of its term, an option for EPEC to repurchase the facilities at fair market value or to continue leasing at one-half the rentals. This option is reasonable because it permits EPEC to choose a course of action which is beneficial for the ratepayers and the Company based on the circumstances at the end of the lease, but it is not reasonable to require EPEC to choose that course of action now.

137. Considering all aspects of the transactions, the sale/leaseback is in the public interest, and will not unreasonably affect rates or services to the ratepayers.

138. EPEC reported the sale/leaseback transactions within a reasonable period of time following their completion.

139. The Company's proposed accounting entries for the sale/leaseback are reasonable and should be approved.

140. In accord with other recommendations regarding PVNGS, EPEC should be allowed to recover 75 percent of the "book break-even" lease payment and of the deferred lease payments in its cost of service, as well as transaction expenses, calculated as set forth in Section XI.B.9. of the report.

141. Any future request by EPEC that ratepayers make up any earnings shortfall (from EPEC's unregulated subsidiaries' investments of the gain portion of the sale/leaseback proceeds from which the gain portion of the lease obligation is

to be met) should be subjected to the most intense scrutiny; should be treated as rate base deductions if granted; and in fact should be denied, absent the imminent collapse of the Company or other extraordinary and compelling circumstances.

142. The Company's total non-PVNGS used and useful plant in service amount is $443,804,358.

143. For the reasons discussed in Section VIII of this report, it is reasonable to include all the PVNGS common facilities in plant in service (subject to the exclusion under the used and useful analysis), as requested by EPEC, rather than allocating a portion of it to PVNGS Unit 3 as recommended by the staff and the City of El Paso.

144. The preponderance of the evidence establishes the reasonableness of excluding a portion of PVNGS Unit 1 and common facilities from plant in service. This amount should be calculated by excluding 25 percent of the cash and gross AFUDC components of the plant in service amounts for PVNGS Unit 1 and common facilities.

145. The preponderance of the evidence supports the allocation of all PVNGS Unit 2-related AFUDC credits to PVNGS Unit 1.

146. The preponderance of the evidence supports inclusion of all PVNGS transmission and general plant in service, as requested by EPEC.

147. The preponderance of the evidence establishes a total amount for used and useful plant in service as shown on Schedule IV of the order.

148. The adjustment to accumulated depreciation recommended by the City of El Paso should be rejected because it conflicts with the goal of matching revenues, expenses, and investments for the test year as adjusted for known and measurable changes.

149. The preponderance of the evidence supports accumulated depreciation adjusted in accord with the reasoning underlying the recommended changes in plant balances for PVNGS Unit 1 and common facilities.

150. The recommended accumulated depreciation is that shown on Schedule IV of the order.

151. In accord with the Company's amendment to its request, no nuclear fuel in process should be included in plant in service.

152. As discussed in Section IX of the report, the preponderance of the evidence establishes the net plant in service amount shown on Schedule IV of the order.

153. The Company's request for $17,543,127 of construction work in progress in invested capital was not supported by a preponderance of evidence demonstrating that inclusion of CWIP is necessary for EPEC's financial integrity.

154. EPEC's request for $83,215 for coal inventory should be denied for the reasons set forth in Section IX.F.1. of the report.

155. The adjustment to materials and supplies recommended by the staff should be adopted for the reasons set forth in Section IX.F.2. of the report.

156. The staff's adjustment to prepayments is supported by a preponderance of the evidence and should be adopted, as discussed in Section IX.F.3. of the report and shown on Schedule IV of the order.

157. The lead-lag study performed by the Company is a fully-developed study, and includes depreciation, amortization, deferred taxes, return, cost of money, and cash allowances.

158. EPEC's lead-lag study produced a cash working capital allowance in excess of that which would result from use of the formula in the Commission's substantive rules.

159. The staff's lead-lag study also included some non-cash items, and resulted in a cash working capital allowance in excess of that which would

result from use of the formula in the Commission's substantive rules.

160. The City's adjustments to the Company's lead-lag study had the effect of excluding non-cash items.

161. All three lead-lag studies included interest on long-term debt and preferred stock dividends.

162. For the reasons set forth in Section IX.F.4. of the report, the City's proposed cash working capital allowance should be adopted.

163. EPEC has a cash working capital allowance requirement as shown on Schedule IV of the order.

164. As discussed in Sections VII.E. and XI.B.8. of this report, the preponderance of the evidence supports inclusion in rate base of the unamortized deferred carrying costs for PVNGS plant (Units 1 and 2 and common facilities) and PVNGS O&M expense in an amount shown on Schedule IV of the order.

165. The preponderance of the evidence does not support the City's proposed adjustments to accumulated deferred federal income tax.

166. The preponderance of the evidence supports an adjustment to accumulated deferred federal income tax consistent with the recommendations regarding the amount of PVNGS plant to be included in rate base. The adjustment and recommended amount are shown on Schedule IV of the order.

167. The amounts shown on Schedule IV of the order for pre-1971 investment tax credits, injuries and damages reserve, customer deposits, customer advances for construction, and other deferred credits are supported by a preponderance of the evidence and should be adopted.

168. The appropriate method for determining the rate of return for EPEC is to determine the weighted average cost of capital.

169. EPEC's cost of equity is properly determined by the company-specific DCF analyses performed by the witnesses for the staff, the DOD, and the City of El Paso, and the comparable company DCF analyses performed by the witnesses for the staff and the City.

170. The preponderance of the evidence establishes that a reasonable cost of equity for EPEC is 12.75 percent.

171. For the reasons given in Section X.A. of the report, the appropriate capital structure for EPEC to be used in determining its overall return is that proposed by the Company.

172. The appropriate capital structure, cost of capital by classes, and weighted average cost of capital for EPEC are set forth in Section X.E. of the report.

173. A cost of equity of 12.75 percent and an overall rate of return of 10.8016 percent will permit EPEC a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

174. The preponderance of the evidence establishes that the Company has a total revenue requirement with components as set forth in Schedule I of the order.

175. In accord with the discussion at Sections VII.E. and XI.A. of the report, the preponderance of the evidence establishes that, for the purpose of setting fuel factors, EPEC has fuel and purchased power expenses as follows:

Fuel	
Reconcilable	$62,323,361
Non-reconcilable	308,539
Fuel Sub-total	$62,631,900

Purchased power	
Reconcilable	$15,407,300
Non-reconcilable	4,188,125
Purchased Power Sub-total	$19,595,425
Total Fuel/Purchased Power	$82,227,300

176. In accordance with the discussion at Sections VII.E. and XI.B. of the report, the preponderance of the evidence establishes an operations and maintenance expense for EPEC with components as shown in Schedule II of the order.

177. The preponderance of the evidence supports approval of the uncontested items of O&M expense requested by EPEC.

178. The unrebutted adjustments recommended by the staff and the City to Accounts 567, 923, 580, 582, 593, 594, 596, 585, and 565, summarized in Sections XI.B.13. and 14. of the report, should be adopted for the reasons stated therein.

179. For the reasons set forth in Section XI.B.1., the Company's payroll expense ratio is 88.57 percent.

180. The staff's adjustments to EPEC's expense for salaries and wages are supported by a preponderance of the evidence and should be adopted, as discussed in Section XI.B.1. of the report.

181. As set forth in Section XI.B.2., the preponderance of the evidence supports the staff's adjustments to the 401-k plan expense, pension expense, employee insurance expense, LESOP expense, and other employee benefits.

182. The preponderance of the evidence supports the City's adjustment to remove all TRASOP expense from employee benefits expense, as discussed in Section XI.B.2.e. of the report.

183. For the reasons set forth in Section XI.B.3. of the report, the preponderance of the evidence establishes the reasonableness of the recommended expense for advertising, contributions and dues.

184. Payroll is properly excludable from regulatory commission expense, for the reasons set forth in Section XI.B.4.a. of the report.

185. The preponderance of the evidence supports the City's recommendation to exclude all requested expenses for the ANPP prudence audit, for the reasons given in Section XI.B.4.b. of the report.

186. Because the expenses the Company incurred for the prudence phase of this docket are not known and measurable, they should not be included in the cost of service in this docket. However, EPEC should continue to record its prudence phase hearing expenses in FERC Account 186, Miscellaneous Deferred Debits, so that the costs recorded in this account can be reviewed in the Company's next rate case.

187. The preponderance of the evidence establishes City rate case expenses of $1,005,355.

188. The preponderance of the evidence supports approval of the uncontested items of regulatory commission expense requested by EPEC.

189. The preponderance of the evidence supports approval of the Company's adjustments removing all expense for Rio Grande Units 3, 4, and 5 and in the "Other O&M" category.

190. The preponderance of the evidence establishes the reasonableness of the Palo Verde O&M expense requested by the Company; that amount should be included as shown on Schedule II of the order.

191. The preponderance of the evidence, summarized in Section XI.B.8. of the report, establishes that EPEC should be permitted to defer the operating and carrying costs on PVNGS Units 1 (including common facilities) and 2 from the in-service date of each unit to the date the rates set in this docket become effective.

192. The preponderance of the evidence establishes that EPEC's proposed deferral balances, based on both actual expenses and estimates through October 1987, should be used in this docket and "trued-up" to actual booked amounts in the Company's next rate case.

193. For the reasons stated in Section XI.B.8. of the report, the staff's proposal to reclassify the balance of deferred displaced nuclear fuel credits to the regular fuel over/underrecovery upon implementation of the rates set in this docket and to refund those amounts as any other fuel overrecovery should not be adopted.

194. In accord with the reasons set forth in the discussion of used and useful plant in Section VII.D. and the discussion of PVNGS Unit 2 deferrals in Section XI.B.9.b. of the report, 75 percent of the "book break-even" lease payment for PVNGS Unit 2 should be included in O&M expense, and 75 percent of the deferred "book break-even" lease payments should be included in the deferrals for Unit 2.

195. The preponderance of the evidence supports the City's recommended exclusion of the fees and expenses of the Chrysler Capital Corporation from the sale/leaseback transaction expense, as discussed in Section XI.B.9.c. of the report.

196. The preponderance of the evidence supports the transaction expense recommended in Section XI.B.9.c. of the report and shown on Schedule II of the order.

197. The preponderance of the evidence establishes property insurance expense recommended in Section XI.B.10. of the report and shown on Schedule II of the order.

198. The staff's recommended injuries and damages expense was established by a preponderance of the evidence, summarized in Section XI.B.11. of the report and shown on Schedule II of the order.

199. The energy efficiency expense adjustment recommended by staff (noted in Section XI.B.12. of the report) was established by a preponderance of the evidence summarized in Section V. of the report.

200. The staff's recommended adjustment for wheeling expense (noted in Section XI.B.13. of the report) was established by a preponderance of the evidence, summarized in Section XI.A.6. of the report.

201. The preponderance of the evidence, discussed in Section XI.B.16. of the report, establishes the reasonableness of calculating uncollectible expense using the staff's uncollectible rate and the revenue requirement shown on Schedule I of the order. The amount of the uncollectible expense is shown on Schedule II of the order.

202. The preponderance of the evidence, summarized in Section XI.C. of the report, establishes the reasonableness of the Company's decommissioning study.

203. The Company's election of the DECON alternative as the basis for estimating the cost of decommissioning is reasonable, for the reasons set forth in Section XI.C. of the report.

204. Use of the DECON decommissioning alternative to estimate the cost of decommissioning does not commit the PVNGS participants to a specific course of action following final plant shutdown.

205. The reasonableness of the cost estimate in EPEC's decommissioning study, including a 25 percent contingency, was established by the preponderance of the evidence.

206. The purpose of the contingency is not to try to predict now which events will or will not occur, but to state examples of the ways and reasons current estimates can fall short of the actual cost of decommissioning.

207. The cost of decommissioning PVNGS should be borne by those ratepayers who benefit from the nuclear plant.

208. Changing the payment stream for funding the decommissioning reserves does not threaten the sufficiency or the availability of the reserves.

209. The decommissioning study, inflation rate, yields on the trust's investments, etc., should be reviewed periodically and adjusted if necessary.

210. An inflation-adjusted payment stream insures generational equity in funding the cost of decommissioning.

211. The preponderance of the evidence establishes the reasonableness of calculating the amount to be included in the cost of service using the staff's recommended four percent inflation rate and eight percent after-tax yield.

212. The preponderance of the evidence, summarized in Sections VII.E.5. and XI.D. of the report, establishes the reasonableness of the depreciation expense shown on Schedule I of the order.

213. The amortization expense, shown on Schedule I of the order, is supported by the preponderance of the evidence, summarized in Section XI.E. of the report.

214. The reasonable and necessary interest on the $3,298,721 of customer deposits held by EPEC is $197,923, calculated at the statutory interest rate of six percent, as recommended by the City.

215. The preponderance of the evidence, summarized in Section XI.G. of the report, establishes that EPEC incurs taxes other than income taxes with components as set forth in Schedule III of the order.

216. The preponderance of the evidence supports the reasonableness of EPEC's requested deferred property and payroll tax amount, based on estimates through November 1987, and of EPEC's continued booking of such expenses in FERC Account 186 from November 1987 until rates set in this docket go into effect. These deferred expenses should then be "trued-up" in EPEC's next rate case.

217. The preponderance of the evidence, discussed in Seciton XI.I., supports the staff's methodology in calculating federal income tax expense for EPEC, shown on Schedule V of the order.

218. The preponderance of the evidence, summarized in Section XI.I. of the report, supports EPEC's recovery of deferred tax deficiencies arising from past flow-through of tax benefits, calculated as recommended by the staff.

219. The preponderance of the evidence does not support an adjustment to reflect consolidated tax savings.

220. The preponderance of the evidence, summarized in Section XII.A. of the report, establishes the reasonableness of the customer growth and loss of load adjustments proposed by the Company and supported by the staff. These adjustments should be used in the calculation of non-fuel revenues.

221. The City's proposed annualization adjustment unfairly adjusts only Texas sales and revenues and not Texas costs, and should not be adopted.

222. The City's proposed unbilled revenues adjustment is not supported by a preponderance of the evidence.

223. The "miscellaneous and other revenue" amounts proposed by the Company are reasonable and should be adopted.

224. The staff's short-term forecast of electric sales should be used for the calculation of fuel and purchased power revenues.

225. For the reasons stated in Section XIII.B.of the Report, it is reasonable to allocate Accounts 502, 505, 510, 512, 513 and 514 at the jurisdictional level utilizing the allocators proposed by the Company.

226. For the reasons stated in Section XIII.B. of the Report, it is reasonable to allocate Accounts 925.2, 926.2 and 930.2 at the jurisdictional level utilizing a 12 CP demand allocator.

227. It is reasonable to allocate LESOP dividends and excess deferred taxes as the jurisdictional level utilizing the allocators recommended by Dr. Kol, for the reasons set out in Section XIII.B. of the Report.

228. For the reasons stated in Section XIII.C.1. of the Report, and subparagraphs thereof, it is reasonable to utilize the A&E-4CP methodology to allocate EPEC's production plant, including Palo Verde, between EPEC's Texas retail customer classes.

229. For the reasons stated in Section XIII.C. of the Report, it is reasonable to utilize the A&E-4CP methodology to allocate EPEC's transmission plant between EPEC's retail customer classes.

230. For the reasons set out in Section XIII.C.3. of the Report, it is reasonable to functionalize Account 364 on a 74.9 percent primary/25.1 percent secondary basis, and functionalize Account 366 on a 30.5 percent primary/69.5 percent secondary basis.

231. For the reasons stated in Section XIII.C.3. of the Report, it is reasonable to use EPEC's distribution plant allocators, with the exception of Accounts 364 through 367, which should be allocated on a 60 percent demand/20 percent customer/20 percent energy basis, and Account 368, which should be allocated on a 70 percent demand/15 percent customer/15 percent energy basis.

232. It is reasonable to allocate intangible plant using the general plant allocator, as set out in Section XIII.C.4. of the Report

233. For the reasons stated in Section XIII.C.5. of the Report, it is reasonable to allocate uncollectible expense on the basis of operating revenues.

234. For the reasons set out in Section XIII.C.6. of the Report, it is reasonable to directly assign 30 percent of City rate case expenses to ratepayers residing within the City's corporate limits, to be recovered via a direct surcharge, and to allocate the remaining 70 percent utilizing a customer allocator.

235. For the reasons stated in Section XIII.C.7. of the Report, it is reasonable to calculate the PVD in the manner set out by W. Silver witness Stanley at pages 26 and 27 of his testimony (W. Silver Ex. 1).

236. For the reasons set out in Section XV.A. of the Report, it is reasonable to have EPEC's rates reflect the full revenue requirement to which it has proven it is entitled to, and implementation of a rate moderation plan is not necessary.

237. Any revenue distribution guidelines adopted by the Commission should be designed to move all classes toward a unity relative rate of return.

238. The base rate revenue distribution guidelines set out in Section XV.B. of the Report are reasonable and appropriate for use in this docket, for the reasons set out therein, and should be adopted.

239. For the reasons set out in Section XVI.A.1. of the Report, it is reasonable for customer charges for the Residential, Small Commercial, Water Heating and General Service rate classes to be calculated in the manner set out in that Section.

240. There is no evidence to support a reduced winter tail block switchover point of 550 kwh.

241. For the reasons stated in Section XVI.A.2. of the Report, it is reasonable to implement the type of seasonal (summer/winter) rate differential for the Residential class recommended by Mr. Rudolph in his Option No. 2.

242. The space heating riders should continue to be phased out by reducing the space heating rider energy charge discounts, for the reasons set out in Section XVI.A.2. of the Report.

243. For the reasons stated in Section XVI.A.2. of the Report, it is reasonable to reduce the Residential class space heating rider discount to 2.173 cents per kwh.

244. The energy charge should be the same for all Water Heating (Rate 21) customers, for the reasons set out in Section XVI.A.2. of the Report.

245. The load data supports the reinstitution of a Small Commercial rate class.

246. Consistent with the finding that all space heating riders should continue to be phased out, it is reasonable to keep the provision that limits the Small Commercial and General Service space heating riders to existing former Rate Schedule 02, Space Heating Installations, as of January 5, 1979.

247. For the reasons set out in Section XVI.B. of the Report, it is reasonable to reduce the Small Commercial class space heating rider discount to 3.5 cents per kwh.

248. It is appropriate to recover production plant related costs through a demand charge, even if such costs are allocated in part based on energy consumption, for the reasons set out in Section XVI.C. of the Report.

249. For the reasons stated in Section XVI.C. of the Report, the Company's proposed 20 percent shift in costs to be recovered through the demand charge to the energy charge for the General Service and Large Power rate classes is reasonable.

250. The utility system and the general body of ratepayers are benefitted by maintaining the existing industrial load.

251. Such industrial load is in serious danger of substantially shrinking or disappearing altogether.

252. Unusually high electric rates are a major economic factor which elevates the possibility of serious industrial customer load loss.

253. Approval of the ERR increases the probability that this needed industrial load will continue operating on the Company's system.

254. Based upon the four preceding findings of fact, it is reasonable to continue the ERR as an experimental rider.

255. For the reasons set out in Section XVI.D.1. of the Report, the provisions of the ERR chould not be changed.

256. There is not sufficient evidence upn which to base a decision on the issue of how the revenue shortfall resulting from the ERR should be recovered. Thus it is reasonable to reserve this issue until the next general rate case, with the revenue shortfall to be deferred until that time.

257. For the reasons set out in Section XVI.D.2. of the Report, the ERR should not be made available to Rate Class 31--Military Reservation (Ft. Bliss).

258. For the reasons set out in Section XVI.E. of the Report, it is reasonable to maintain all ratchet provisions in effect.

259. The rating period selection option is not a reasonable provision, for the reasons set out in Section XVI.F. of the Report, and thus it should be rejected.

260. Texas state agencies should not be allowed to take service under the City and County Service rate (Rate 41), for the reasons set out in Section XVI.G. of the Report.

261. The cost study done by the Company to support an increase in the returned check/bank draft charge is inaccurate, and thus it is reasonable to maintain the current charge of $8.00.

262. For the reasons set out in Section XVI.H. of the Report, it is reasonable to set the premium-overtime charge at $60.00 for purposes of this docket only.

263. For the reasons set out in Section XVI.J.1. of the Report, it is reasonable to split the transmission level line loss factor into separate line loss factors for each major customer that receives service at transmission level

voltage. The resultant line loss and voltage level to base factors for use in setting the fixed fuel factors are set out in that Section.

264. For the reasons set out in Section XVII.A. of the Report, the interest rate charge for line extension guarantees entered into prior to the effective date of the line extension policy tariffs resulting from this docket should be at the appropriate before tax cost of capital, while the interest rate for line extension guarantees entered into after that date should be at the appropriate after tax cost of capital.

265. For the reasons set out therein, it is reasonable to require the Company to track complaints in the manner set out in Section XVII.C. of the Report.

266. The Company has failed to present any evidence showing why it should be allowed to delete the Revenues Related to Construction Work in Progress Costs for the Palo Verde Nuclear Generating Station and the Final Billing Refund Statement tariff sheets, and thus those sheets should remain in force.

267. For the reasons stated in Section XVII.F. of the Report, the revisions to the Company's proposed tariff recommended by Mr. Irish are reasonable and should be adopted, except for the revisions contained in his Recommendation Nos. 1, 5 and 12, which are not reasonable and should be rejected.

268. It is reasonable to reject all tariff changes which might be detrimental to customers or applicants that were not notated prior to the Company's rate design rebuttal testimony, for the reasons set out in Section XVII.F. of the Report.

269. Except as indicated above, all of the Company's proposed service rules and regulations and line extension policy tariff sheets are reasonable and should be approved.

270. The evidence in this record is insufficient for reaching a final reconciliation of EPEC's fuel expense.

271. Reconciliation of EPEC's fuel expense should be for the period March 1984 through August 1987.

272. Final reconciliation of EPEC's fuel expense for March 1984 through August 1987 should be severed from this docket and a separate reconciliation docket instituted for EPEC.

273. For the reasons set forth in Section XIX. of the report, the Stipulation contains provisions which are not reasonably supported by a preponderance of the evidence in this record.

274. As discussed in Section XIX. of the report, the Stipulation contains provisions which are ambiguous.

275. The signatories to the Stipulation proposed findings of fact and one conclusion of law to be adopted. For the reasons set forth in Section XIX.D. of the report, proposed findings of fact numbers 1 through 28 should not be adopted.

B. Conclusions of Law

1. EPEC is a public utility as defined in section 3(c)(1) of PURA and, as such, is subject to the Commission's jurisdiction and authority.

2. The Commission has jurisdiction over these consolidated dockets pursuant to sections 16, 17(d) and (e), 26, 37, 43, and 63 of PURA.

3. The rate filing package filed by EPEC meets the requirements of section 43(a) of PURA regarding the contents of a statement of intent.

4. The operation of the proposed rate schedule was suspended in accord with section 43(d) of PURA.

5. EPEC has substantially complied with the notice requirements of P.U.C. PROC. R. 21.22(b)(1) regarding notice of the proposed change in rates, and with

the examiner's order, issued pursuant to P.U.C. PROC. R. 21.25, regarding notice of the sale and leaseback of PVNGS Unit 2.

6. EPEC has substantially complied with the requirements for energy efficiency plans set forth in P.U.C. SUBST. R. 23.22.

7. Pursuant to Section 38 of the PURA, where a utility submits insufficient evidence of prudence in committing to participate in new generating capacity, and the inclusion of such capacity in plant-in-service will result in substantial excess capacity, it is appropriate for the Commission to consider resources and discount loads, over the utility's objection, to the extent that they have been added to or substracted from a utility's system in order to make more of such an investment appear used and useful.

8. Pursuant to Section 38 of the PURA, where a utility presents insufficient evidence that it gave adequate consideration to the public interest in committing to participate in new generating capacity, and the inclusion of such capacity in plant-in- service would result in substantial excess capacity, it is appropriate for the Commission to count such capacity last in determining which of the utility's available capacity is used and useful to provide service to the public.

9. Pursuant to Section 38 of the PURA, where the utility has failed to prove that its initial decision to invest in new generating capacity was prudent and in the public interest, the Commission may discount firm, off-system sales to the extent that they would make more of such an investment appear used and useful.

10. In appropriate circumstances, the Commission may allow a utility to recover expenses associated with plant that is not used and useful in rendering service to the public.

11. It is appropriate to consider the financial integrity of the utility along with other factors in deciding whether to allow expenses associated with plant that is not used and useful in rendering service to the public.

12. Where a utility's investment in the generating capacity of a plant has been deemed not used and useful because there is excess capacity on its system, and other, cheaper capacity is available, but the plant continues to be operated, there are circumstances in which it is appropriate to allow expenses associated with such capacity.

13. In deciding whether to allow expenses associated with capacity that has been deemed not used and useful, the Commission may consider the practical problems associated with disallowing such expenses, particularly where there are offsetting benefits to ratepayers in allowing such expenses to be recovered.

14. A utility has a duty to ratepayers to pursue valid claims against suppliers in connection with the construction of generating facilities to the extent that the cost of those facilities may be, or has been, included in rate base, and to call such claims to the Commission's attention to the extent that they may be, or have been, reimbursed by third parties subsequent to the inclusion of those costs in rate base.

15. Where there is no showing that a utility or its agents are at fault in causing additional costs to be incurred on a construction project, it is inappropriate to exclude such costs under a theory that they are not used and useful.

16. Pursuant to Sections 35(a) and 38 of the PURA, where the overall cost of construction of a new generating facility appears to be reasonable under the circumstances, and it appears that the utility and its agents were prudent and efficient overall in constructing the facility, there should be no disallowance of construction costs to the extent that they were actually incurred and have not been reimbursed by parties against whom the utility has a claim for damages.

17. Pursuant to PURA sections 38, 39, and 41, EPEC should be authorized to defer the carrying costs and operational expenses for PVNGS Unit 1 and common facilities from March 1986 until March 1988 and for PVNGS Unit 2 from September

1986 until March 1988, capitalize the deferred amounts, and amortize those deferrals as recommended in Section XI.B.8. of the report.

18. As required by PURA section 41(a), the net plant component of EPEC's invested capital set froth in Schedule IV of the order is based upon the original cost of property used by and useful to EPEC in providing electric utility service.

19. The methods and rates of depreciation implicit in Schedules I and IV of the order are proper and adequate and have been uniformly and consistently applied, in accord with Section 27(b) of PURA.

20. To the extent included in invested capital, EPEC's generation, transmission, and distribution facilities are safe, adequate, efficient, and reasonable, as required by PURA section 35(a).

21. The overall rate of return and component rates of return recommended in Section X.E. of the report substantially comply with P.U.C. SUBST. R. 23.21(c)(1).

22. Taking into consideration EPEC's quality of management, quality of service, effort to conserve energy and resources, and efficiency of operations, the return set forth in Schedule I of the order constitutes a reasonable return on EPEC's invested capital used and useful in rendering service to the public, in accord with PURA section 39(b).

23. The return set forth in Schedule I of the order will permit EPEC a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses, as required by section 39(a) of PURA.

24. The expenses set forth in Schedule I of the order substantially comply with P.U.C. SUBST. R. 23.21(b).

25. EPEC substantially complied with PURA section 63 in reporting the sale and leaseback of PVNGS Unit 2 and related common facilities within a reasonable time following completion of the transactions.

26. EPEC's sale and leaseback of PVNGS Unit 2 and related common facilities is in the public interest, and will not unreasonably affect rates or service, within the meaning and intent of PURA section 63.

27. EPEC has met the burden of proof imposed by section 40 of PURA to show that rates producing the total Texas retail revenue set forth in Schedule VI of the order are just and reasonable.

28. The rate and rate design resulting from the rate class revenue requirements in Schedule VII of the Order are just and reasonable and are not unreasonably preferential, prejudicial, or discriminatory within the meaning of PURA Section 38.

29. As required by Section 45 of PURA, the rate design and rates resulting from the recommendations herein do not grant an unreasonable preference or advantage to any customer within a classification, subject any customer within a classification to an unreasonable prejudice or disadvantage, or establish unreasonable differences as to rates or service between localities or between classes of service.

30. The rates approved by the Commission in this case are to be effective only for customers in areas within the Commission's original jurisdiction and in the municipalities from which appeals were consolidated with this proceeding.

31. The hold harmless clause in the Company's tariff is inapplicable to the State.

32. The rates resulting from the revenue deficiency and rate design provisions in Schedules VI through VIII of the Order are just and reasonable and otherwise comply with the ratemaking mandates of PURA Article VI, and should be approved.

33. In accord with section 16(b) of the Administrative Procedure and Texas Register Act, Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1987), the

proposed findings of fact submitted by the signatories to the stipulation should not be adopted. APA section 16(b) does not require a ruling on the one proposed conclusion of law.

33. The Stipulation as a whole is not a reasonable resolution of the contested issues in this docket, is not in the public interest, and should not be adopted.

Respectfully submitted,

Mary Ross McDonald
Mary Ross McDonald
Administrative Law Judge

Cornelia M. Adams
Cornelia M. Adams
Hearings Examiner

Howard V. Fisher
Howard V. Fisher
Administrative Law Judge

APPROVED on this the 29th of January 1988.

Phillip A. Holder
Phillip A. Holder
Director of Hearings

ENDNOTES

[1]The nature of the protest was that the Commission lacked jurisdiction over out-of-state facilities for purposes of granting or denying certification.

[2]Even though it is cast in an either/or form, this language would seem really to amount to a finding that EPEC was entitled to a certificate under both sections 53 and 54. Arguably, the "grandfather" factor might have played a part in the section 54 grant. In any event, this order was subsequently reversed and set aside by the district court.

[3]This grandfather certificate for facilities "existing or under construction" as of September 1, 1975, would have covered the entire 15.8 percent share in the three units. The Participation Agreement committing EPEC to its 15.8 percent share had been signed on August 23, 1973. EPEC had expended some funds on the project as is recited in the report; as for actual construction, however, the NRC (Nuclear Regulatory Commission) did not issue the project a construction permit until May of 1976, and the first structural concrete was not poured at PVNGS Unit 1 until November of 1976.

[4]Specifically, the Commission found that purchasing power from the Salt River Project was "the most feasible alternative to Copper Station." Although this language certainly suggests that there are degrees of feasibility, and thus drawbacks to different options, it nonetheless conveys the idea that purchasing power from the Salt River Project was feasible.

[5]On the record in this docket (No. 7460), the Company contended, without actual demonstration, that if staff's 1978 forecast had only been translated into logarithmic form, it would have substantially agreed with the Company's forecast. Without investigation, staff was not able to confirm or deny.

[6]The source of the commercial operation dates that would have been forecast by ANPP at the time is Volume 1 of Attachment B to the Direct Testimony of Mr. Richard B. Hubbard. (City Ex. No. 48A at 27 and 30.)

[7]"Native system" peak is line item 1.1 of EPEC's 1987 loads and resources forecast which is substantially set out at the beginning of Section VII.D.1. of this report. It represents peak consumption by the ratepayers on the system; it would not include off-system sales.

[8]Hopefully, the ability to make off-system sales was not intended as an independent ground of justification for adding capacity that, when added to existing capacity, would result in a situation of oversupply. While in a situation of excess capacity it is probably better, assuming coverage of variable costs, to make off-system sales than not, it would be inappropriate to justify the addition of excess capacity on grounds that off-system sales would benefit ratepayers. Off-system sales do not necessarily recoup the full cost associated with the new capacity and, when they do not, ratepayers make up the difference.

[9]The report in Docket No. 1981 states that system peak for 1978 was 695 MW whereas the record in this docket (No. 7460) reflects that the total system peak for 1978 was 690 MW. The reason for this discrepancy is not known. One may also note that no figures are available in the record that would reflect native system peak as opposed to total system peak prior to 1986. Native system peak is a subset of total system peak. One of the major items that is included in total system peak, but not in native system peak, is firm, off-system sales.

[10]Curiously, the appeals court in City of El Paso v. P.U.C., 609 S.W.2d 574, 577 (Tex. Civ. App.--1980, no writ) considered that, by granting the capital transition allowance, the Commission "had, in effect, required that the company reduce its percentage of participation in the plant. . . ." Apparently, this "requirement" has never been understood as an "order" of the Commission, the fines and penalties for the violation of which would be sizeable considering EPEC's opposition, between 1978 and 1981, to reducing its participation. See Section 72(a) of the PURA.

[11]The directive to "continually look for alternatives to the Palo Verde Project" at page 5 of the report was not expressly included in the order. Similarly, the directive to "keep the lines of communication open to potential buyers," which, due to its open-endedness, could arguably have been satisfied by keeping the phone bill paid, was also not expressly included in the order.

[12]Interestingly, at page 5 of the report in paragraph 4, the examiner in Docket No. 1981 notes the following:

> Neither the staff nor the City recommended that EPEC be required to sell any or all of its interest in Palo Verde.

[13]Fear of rate shock, *i.e.*, fear that the need for higher rates would lead to reduced profits because of a drop-off in demand - which would affect the utility even in the absence of regulation - could also provide an incentive for a utility to try to remove its more expensive plant from rate base; a rate moderation plan would, of course, also be a way of dealing with rate shock considerations.

[14]Specifically, the settlement of the parties, dated August 24, 1983, provided:

> [A]lthough the Company. . . is continuing its efforts to sell a portion of Palo Verde, there are no parties currently available to purchase any of EPE's ownership interest. . .

[15]This statement might be somewhat disquieting to ratepayers considering that the capacity which has been contracted to TNP and IID will "revert" to EPEC in the not-so-distant future unless EPEC extends the terms of the contracts or enters into new ones. Depending on the way in which load grows over the years, if new generating resources are added to make up for a temporary shortfall in resources, EPEC may then be facing a situation of "surplus" capacity when the capacity dedicated to off-system sales "reverts," *i.e.*, comes out from under contract. If, at that time, EPEC enters into additional long-term, firm-capacity, off-system contracts to dispose of this power, an entire cycle will have been completed. In essence, EPEC would be designing and building a system to meet the needs of firm-capacity, off-system purchasers as well as those of its native system ratepayers. Thus, it would be designing and buildng a somewhat larger system than it would otherwise; and, far from

"benefitting" from these off-system sales, native system ratepayers would be the ones to make up any difference between the cost of the latest capacity addition and the off-system sales price.

[16]Interestingly, despite the holding on burden of proof, no one appears to have argued that *no* Palo Verde CWIP should have been allowed without some finding of prudence and efficiency. Such an application of the holding would, of course, have made the holding appear to produce a very harsh result. Insofar as the production of harsh results may lead to a rethinking of the underlying doctrine, it is perphaps this that has doomed this argument to obscurity as far as being urged by intervenors. Moreover, a utility that attempted to use the argument to effect a rethinking would obviously be playing with fire as it might in consequence lose even its partial allowance.

It may be noted that the examiner in Docket No. 6350, the El Paso rate case subsequent to Docket No. 5700, mentions that the possibility exists that the Commission could have declared a complete disallowance of CWIP based on the apparent failure of the utility to prove that its undertaking was prudent, but, based on the fact that Docket No. 5700 is precedent, he does not recommend this approach. (See Report, Docket No. 6350, at page 38.)

The undersigned examiner does not intend these remarks as disparagement of Docket No. 5700's method of determining a CWIP allowance. Quantifying prudence (or imprudence), except on an all-or-nothing basis where the utility attempts, but fails, to prove that no less than one hundred percent participation was prudent, is a devilish business. The approach taken in Docket No. 5700 has the very strong recommendation that it is workable and mediates between the competing interests.

[17]All other things are not quite equal. The differences are, first, that in 1978, Palo Verde Unit 1 was due on line in 1982, with Palo Verde Unit 2, and probably Unit 3 as well, to follow in 1984, whereas by 1984, the Palo Verde units were apparently all due on line by the end of 1987. Thus, in 1978, all three units were probably not due on line until the sixth year of the forecast, whereas by 1984, all three units were due on line as early as the fourth year of the forecast. Secondly, oil and gas prices were very high and generally expected to rise back in 1978, whereas, by 1984, the price of oil and gas had fallen dramatically. Thus, independence from "expensive" oil and gas, which was an important consideration back in 1978, has very much faded from view in the ensuing period.

[18]EPEC uses the "largest-single-hazard-plus-five-percent" method to calculate reserve margin. Largest-single-hazard refers to the hazard that EPEC's largest generating unit, or largest share in a unit, will suddenly go out of service outside the context of scheduled maintenance. The five percent which is added to the largest-single-hazard is five percent of total system peak.

[19]It appears that not all of the Newman capacity would have been in existence in 1972. Nonetheless, EPEC President and Chief Executive Officer Evern Wall discusses planned additions to the Newman Station in such a way as to indicate that additions made after 1972 were already planned in the 1972 time period. (EPEC Ex. No. 1, Vol. 1, Tab 1 at 15.)

[20]EPEC stated "Losses to Others" and "ANPP Start-up" as separate line items whereas Commission staff appears to have lumped them together.

[21]This date would, however, appear to have been somewhat convenient for Docket No. 6350 purposes both in terms of including the return and expenses associated with these units in revenue requirement and excluding their capacity for purposes of calculating any disallowance of Palo Verde CWIP under the Docket No. 5700 approach.

[22]Base-loaded units are those which, typically because of high fixed costs and low variable costs, it is most economical to keep running at full capacity all the time except, obviously, for scheduled maintenance. The object is to spread the fixed costs over as many hours and as many kilowatts as possible, because whenever the unit is down or operating at less than full capacity, this means fewer kilowatt hour sales over which to spread those costs.

[23]EPEC's method of calculating reserve margin is the largest-single-hazard-plus-five-percent method. This is one of the three methods recommended

by the Western Systems Coordinating Council (WSCC) and, according to EPEC, results in the lowest reserve margin of the three. Nonetheless, this Commission has in the past used a 20 percent reserve margin for EPEC, and there does not appear to be any legal impediment to EPEC's using the reserve margin recommended by this Commission instead of that recommended by the WSCC.

[24]The report in Docket No. 5700 indicated that section 41(c)(3)(D) is a basis for excluding from invested capital expenditures representing imprudent or inefficient management of construction. Section 41(c)(3)(D) provides that unreasonable or unnecessary expenditures shall be disallowed. Within the structure of section 41, however, section 41(c)(3)(D) addresses operating expenses rather than invested capital.

[25]All of the projects for which the CE System 80 has been ordered have been cancelled except for Palo Verde. There is no evidence that the cancellations had anything to do with the System 80. ANPP did not know until approximately 1981 that it would be the first to test the System 80 in an operating plant. (Tr. at 3712-3713.)

APPENDIX F

PARTICIPATION CHRONOLOGY

August 23, 1973	-	Arizona Public Service Co.	29.1%
		Salt River Project	29.1%
		Tucson Gas & Electric Co.	15.8%
		Public Service Co. of New Mexico	10.2%
		El Paso Electric Co.	15.8%
January 1, 1974	-	Arizona Public Service Co.	28.1*
		Salt River Project	28.1*
		Tucson Gas & Electric Co.	15.4*
		Public Service Co. of New Mexico	10.2%
		El Paso Electric Co.	15.8%
		*Arizona Electric Power Corp.	2.4%*
August 28, 1975	-	Arizona Public Service Company	28.1%
		Salt River Project	28.1%
		*Southern California Edison Co.	15.4%
		Public Service Co. of New Mexico	10.2%
		El Paso Electric Co.	15.8%
		Arizona Electric Power Corp.	2.4%
July 22, 1976	-	Arizona Public Service Co.	29.1%*
		Salt River Project	29.1%*
		Southern California Edison Co.	15.8%*
		Public Service Co. of New Mexico	10.2%
		El Paso Electric Co.	15.8%

* Change in owner and/or participation level.

PARTICIPATION CHRONOLOGY (Continued)

September 10, 1982 -	Arizona Public Service Co.	________	29.1%
	Salt River Project	________	23.19%*
	Southern California Edison Co.	________	15.8%
	Public Service Co. of New Mexico	________	10.2%
	El Paso Electric Co.	________	15.8%
	*Southern California Public Power Authority	________	5.91%*
January 29, 1986 -	Arizona Public Service Company	________	29.1%
	Salt River Project	________	17.49%*
	Southern California Edison Co.	________	15.8%
	Public Service Co. of New Mexico	________	10.2%
	El Paso Electric Co.	________	15.8%
	Southern California Public Power Authority	________	5.91%
	*Los Angeles Dept. of Water & Power 1/	________	5.7%*

1/ On August 18, 1977, Salt River and LADWP entered into a complex sale and exchange agreement that served to reduce SRP's short-term over capacity while providing it with a substantially improved cash flow. Part 1 of this transaction involved the immediate sale of 30 percent of SRP's interest in the Coronado Coal Plant, which was scheduled for commercial operation in 1979, to LADWP. Part 2 involved the exchange at the time of commercial operation, of SRP's 5.7 percent interest in ANPP for LADWP's interest in Coronado. The exchange was contingent upon PVNGS Unit 1 commercial operation. A 15-year market value recapture provision can be exercised by SRP in 2001 to effect a repurchase of their 5.7 percent interest in PVNGS.

EXAMINERS' EXHIBIT B

A+E-4CP allocation, for each class, is as follows:

$$\frac{\text{class average demand}}{\text{total average demand}} \times \text{system load factor}$$

$$+ \frac{\text{class excess demand}}{\text{total excess demand}} \times (1 - \text{system load factor})$$

SCENARIO NO. 1

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	50	100	50	50
Class 2	10-40	50	20	40
System		77.78	70	90

Allocation:

Class 1: .7143 x 77.78% = 55.56
0 x 22.22% = 0
55.56% x 108 MW = 60 MW

Class 2: .2857 x 77.78% = 22.22
1.00 x 22.22% = 22.22
44.44% x 108 MW = 48 MW

SCENARIO NO. 2

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	50	100	50	50
Class 2	10-40	40	16	40
System		73.33	66	90

Allocation:

Class 1: .7576 x 73.33% = 55.55
0 x 22.22% = 0
55.55% x 108 MW = 60 MW

Class 2: .2424 x 73.33% = 17.78
1.00 x 26.67% = 26.67
44.45% x 108 MW = 48 MW

SCENARIO NO. 3

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	30-50	70	35	50
Class 2	10-40	40	16	40
System		56.67	51	90

Allocation:

Class 1: .6863 x 56.67% = 38.89
.3846 x 43.33% = 16.66
55.55% x 108 MW = 60 MW

Class 2: .3137 x 56.67% = 17.78
.6154 x 43.33% = 26.67
44.45% x 108 MW = 48 MW

SCENARIO NO. 4

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	30-50	70	35	50
Class 2	10-40	40	16	30
System		63.75	51	80

Allocation:

Class 1: .6863 x 63.75% = 43.75
.5172 x 36.25% = 18.75
62.50% x 96 MW = 60 MW

Class 2: .3137 x 63.75% = 20.00
.4828 x 36.25% = 17.50
37.50% x 96 MW = 36 MW

SCENARIO NO. 5

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	30-50	70	35	35
Class 2	10-40	40	16	40
System		68.00	51	75

Allocation:

Class 1: .6863 x 68.00% = 46.67
0 x 32.00% = 0
46.67% x 90 MW = 42 MW

Class 2: .3137 x 68.00% = 21.33
1.00 x 32.00% = 32.00
53.33% x 90 MW = 48 MW

SCENARIO NO. 6

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	30-50	70	35	45
Class 2	10-40	40	16	20
System		78.46	51	65

Allocation:

Class 1: .6863 x 78.46% = 53.85
.7143 x 21.54% = 15.39
69.24% x 78 MW = 54 MW

Class 2: .3137 x 78.46% = 24.61
.2857 x 21.54% = 6.15
30.76% x 78 MW = 24 MW

SCENARIO NO. 7

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	30-50	70	35	35
Class 2	10-40	40	16	35
System		72.86	51	70

Allocation:

Class 1: .6863 x 72.86% = 50.00
0 x 27.14% = 0
50.00% x 84 MW = 42 MW

Class 2: .3137 x 72.86% = 22.86
1.00 x 27.14% = 27.14
50.00% x 84 MW = 42 MW

SCENARIO NO. 8

	Demand Range (MW)	Load Factor (%)	Ave. Load (MW)	Demand at System Peak (MW)
Class 1	30-50	70	35	30
Class 2	10-40	40	16	40
System		72.86	51	70

Allocation:

Class 1: .6863 x 72.86% = 50.00
0* x 27.14% = 0
50.00% x 84 MW = 42 MW

Class 2: .3137 x 72.86% = 22.86
1.00* x 27.14% = 27.14
50.00% x 84 MW = 42 MW

*For Class 1, would be - .2632, for a total allocation of 42.86% (36 MW), were negative excesses not set equal to 0.

For Class 2, would be 1.2632, for a total allocation of 57.14% (48 MW), were negative excesses not set equal to 0.

EXAMINERS' EXHIBIT C

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BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

IN THE MATTER OF THE APPLICATION)
OF THE EL PASO ELECTRIC COMPANY)
FOR AUTHORITY TO CHANGE RATES) DOCKET 7460

STIPULATION

In consideration of the mutual agreements and covenants herein contained, the undersigned parties stipulate and agree as follows:

1. El Paso Electric Company (the "Company" or "EPE") will remove from rate base the sum of $60 million on a total Company basis ($50 million will be assigned to Palo Verde Unit 1 and $10 million to Palo Verde Unit 3). The Texas jurisdictional effect of this removal shall be established based on the jurisdictional allocators in this case and shall remain constant throughout the life of the affected units. Except as specifically provided in Paragraph 8, this disallowance will settle (a) all issues relating to decisional prudence on Palo Verde Units 1, 2 and 3 ("decisional prudence" specifically includes any decisions, acts or omissions relating to the Company's decision to become or to remain a 15.8% participant in the Arizona Nuclear Power Project, occurring prior to the date on which this Stipulation is executed, including but in no way limited to the prudence of the Company's load forecasting methodologies and practices); (b) all issues relating to construction prudence on Palo Verde Units 1 and 2, whether resulting from decisions, acts or omissions of El Paso Electric Company, Arizona Public Service Company or any other person, firm or corporation ("construction prudence" includes all issues relating to or arising out of the licensing, construction or startup of the units in question); and (c) those issues

relating to construction prudence on Unit 3 resulting directly from the construction of Units 1 and 2, limited to those matters delineated on the attached Exhibit A. Specific issues to remain "open" on Palo Verde especially as to Unit 3 are set forth in Paragraph 8.

2. On a Texas jurisdictional basis, the ratio of the tax basis of Palo Verde Unit 1 and Unit 3 to the book basis of each unit prior to the write-off adjustment set forth in Paragraph 1 will be calculated. The write-off amount ($50 million for Unit 1, $10 million for Unit 3) will be multiplied by the ratio to produce the equivalent reduction to the jurisdictional tax basis for the respective units. The adjusted tax basis will be used in all Texas rate cases for the calculation of tax depreciation on these units.

3. The parties agree they will support the Company's pending "in-service" application on Unit 2 in Docket 7280.

4. The Company will receive a base rate increase in this Docket for its Texas jurisdiction, before the effect of the rate moderation deferral is taken into account, in the amount of $48,066,859. Exhibit B provides the calculation of the revenue requirement and rate base. The basis for determining this amount is set forth on Page 1 of 3 of Exhibit B.

   The reallocation of all Unit 2 Contra-AFUDC to Unit 1 (including the impact on deferrals as noted in Exhibit B (2) (c)) will not be contested in future cases. The rate base treatment of accumulated deferred income taxes ("ADFIT") relating to future tax depreciation associated with the disallowance shall remain an open issue to be addressed in the Company's next rate case, except as discussed in Paragraph 2. Further, if the treatment of ADFIT in the next rate case results in a lower Texas revenue requirement, the Company agrees that the "overcollection" during the first year of the rate moderation plan ("RMP") will be flowed back to the ratepayers in the revenue requirement for the second RMP year. The amount of this "overcollection" will be calculated as if the treatment of ADFIT used in the next rate case had been used in the calculation of the revenue requirement in this Docket 7460.

5. This non-fuel base rate increase shall be phased-in consistent with the requirements under the "Statement of Accounting Standards No. 92" (FASB 92) dated August 1987. This phase-in or RMP is for the costs associated with Palo Verde Units 1 and 2 which have been approved by the Public Utility Commission of Texas ("PUCT") for rate-making purposes in Docket No. 7460. Throughout the term of this agreement, the costs to be deferred shall be derived by subtracting:

    A. EPE's Texas jurisdictional non-fuel base revenue requirement to be charged to customers under the RMP, from

    B. EPE's total Texas jurisdictional non-fuel base revenue requirements prior to rate moderation.

EPE shall initiate recovery of the deferred costs by filing annually a formal application with the PUCT. The application shall be accompanied by a rate filing package as prescribed under the PUCT's then current Procedural and/or Substantive Rules. Both EPE's total Texas jurisdictional revenues and cost of service shall be determined in accordance with the then current rules and practices of the PUCT. Said determination shall include Findings of Fact and Conclusions of Law with respect to the appropriate Texas jurisdictional revenues, cost of service, the amount of costs to be deferred and the accumulated deferrals. The agreed-upon Texas jurisdictional revenues and cost of service for the test year ended September 30, 1986 and as projected for each year of the phase-in is shown in Exhibit C. The projected deferrals could be different each year depending on other factors, such as actual sales, cost-of-service items other than those related to Docket No. 7460, the cost of capital, the method selected to calculate, accrue and book the deferrals, etc.

a. Rate increases beginning with the Final Order in Docket No. 7460 shall be as follows:

(i) The total Texas retail non-fuel base revenue increase shall be 13.74%. Net of fuel this equates to approximately 4%.

(ii) Not sooner than one year after the increase in Docket No. 7460 becomes effective, non-fuel base revenues shall increase by an additional 4%.

(iii) Not sooner than one year after the second increase, non-fuel base revenues shall again increase by 3.5%.

(iv) Not sooner than one year after the third increase, non-fuel base revenues shall again increase by 3.5%.

(v) Notwithstanding Paragraphs 5(a)(ii)-(iv), if a smaller increase would allow complete amortization of the deferrals within one year, the Company will request only the amount of increase needed to support that level of amortization.

(vi) Thereafter, and until the earlier of either (A) the tenth anniversary of the Final Order in Docket No. 7460 or (B) the year in which the cost-of-service deferrals approved in Docket No. 7460 are projected to reach zero, non-fuel base rates shall not be increased except pursuant to Paragraph 5(b) below. Upon the occurrence of condition (B), EPE shall notify the Commission and the parties hereto. Upon a finding by the

PUCT that the deferral balance has reached zero, the RMP shall be terminated.

b. This RMP provides that the cost-of-service deferrals approved in Docket No. 7460 shall be scheduled for recovery on or before the tenth anniversary date of the Final Order in said Docket. In the event projections indicate that these deferrals will not be fully recovered by the tenth anniversary date of the Final Order, then EPE shall be permitted to adjust non-fuel base revenues after the fourth increase specified in Paragraph 5(a)(iv) above. As with the other increases permitted under the phase-in, EPE shall adhere to the procedural requirements specified in this paragraph.

c. The cost-of-service deferrals approved for rate-making purposes shall be deferred from month to month for the succeeding twelve-month period on a gross of tax basis at EPE's prevailing AFUDC rate with corresponding deferred tax reserves in Account 186 and the necessary subaccounts. The balance of cost-of-service deferrals will not be included in rate base. However, recovery of all capitalized return is allowed over the life of the RMP.

d. Any rate increase relating to Palo Verde Unit 3 is not prohibited by this RMP, but would be in addition to it.

e. It is the parties' intention that this phase-in plan continue to be in full compliance with FASB 92 or its successor. The parties recognize that FASB 92 could be amended and/or clarified from time to time. In either event, the parties shall readdress the terms of this Stipulation to reflect such amendments or clarifications.

f. For purposes of determining the cost-of-service deferrals for the first year of this phase-in, the parties have agreed to flow back the unprotected portion of the excess accumulated deferred income taxes resulting from a change in the tax rate under the 1986 Tax Reform Act and the deferred income taxes associated with Palo Verde-related ABFUDC over the remaining life of the corresponding assets. The parties shall address whether these accumulated deferred income taxes should be flowed back at an accelerated rate in EPE's next adjudicated proceeding. In any event, the rate-making treatment of these accumulated deferred taxes shall be consistent with the flow back used for financial reporting purposes.

6. Current Texas average non-fuel base rates are agreed to be $0.05014/KWh. This would be the starting point for any increases.

7. The parties agree to a new Texas system fuel factor of $0.01691/KWh. The Fixed Fuel Factors due to different voltage levels of service are agreed to be:

   Transmission Voltage $0.01610/KWh

   (Individual Transmission customers fixed fuel factors will vary slightly.)

   Primary Voltage $0.01657/KWh

   Secondary Voltage $0.01713/KWh

   All fuel-related costs shall remain subject to reconciliation, including the appropriate regulatory rate-making treatment to be afforded the Company's involvement in the Palo Verde Uranium Venture.

8. The parties agree to the following with regard to the status of Palo Verde Unit 3 and issues to remain open on Palo Verde:

   a. The parties agree Palo Verde Unit 3 does not meet the Commission's current in-service criteria as set forth in PUCT Substantive Rule 23.21(c)(2)(E) and will remain under construction until completion of the Arizona Interconnection Project ("AIP").

b. Without waiving their legal positions on the issues set forth in Paragraph 8(f) below, the parties agree that if a Certificate of Convenience and Necessity is required for AIP by the Public Utility Regulatory Act in Texas, they will not oppose the granting of such CCN.

c. The parties understand the current construction schedule contemplates completion of AIP by December 31, 1989. The parties agree that costs on Palo Verde Unit 3 cannot be excluded because of the construction period of AIP, unless AIP remains uncompleted on or after June 30, 1991, but could be challenged as being unreasonably high for other reasons--e.g., O&M during the "construction" period was unreasonably high, or that Unit 3 is not used and useful for reasons unrelated to AIP.

d. Based on Paragraphs 8(a) and 8(c), the Company agrees not to file a case to recover Palo Verde Unit 3 in rates based on a test year ending earlier than December 31, 1989, in exchange for which the parties agree to support a request by the Company for an accounting order if needed to preserve the Company's opportunity to seek and obtain recovery of all costs associated with Unit 3.

e. Because Unit 3 is under construction as set forth in Paragraph 8(a), the following accounting treatment will continue until Unit 3 is found to be in-service by the Public Utility Commission of Texas:

   (1) Deferral of all items of costs which would be expensed such as property taxes, operating expenses and maintenance expenses with offset for any fuel displacement credits.

   (2) Capitalization of AFUDC.

(3) Fuel savings from operation of Unit 3 shall not be considered as reconcilable fuel expense for any of the period preceding the date when Unit 3 rates are effective.

f. The only issues remaining open on the Palo Verde plant are:

(1) The appropriate application of the "used and useful" test. The parties understand and agree that the resolution of the decisional prudence issues in this Docket cannot be used as evidence in a Unit 3 case except to demonstrate that such issues have been resolved.

(2) Does excess capacity actually exist on EPE's system with regard to Unit 3? (In addition, excess capacity issues relating to Units 1 and 2 may be raised once the phase-in plan described in Paragraph 5 is concluded, but not before.)

(3) Where the prudence of a utility's forecasting and decisional processes leading to the construction of plant is not at issue, is it permissible to exclude such plant from rate base as excess capacity on the theory that it is not used and useful in providing utility service?

(4) If so, how should excess capacity be treated for regulatory and accounting purposes? For example, is deregulation an appropriate regulatory alternative? If so, on what terms should deregulation be implemented?

(5) The reasonableness of Unit 3 O&M expenses.

(6) The reasonableness of Unit 3 construction costs (except any costs directly related to the construction or startup of Units 1 and 2 as delineated in Exhibit A).

9. The Company will accept the Staff's decommissioning funding plan provided it is approved by the IRS as a tax qualified plan. If it is not, then the parties agree to support in the next rate case the Company's decommissioning funding plan as filed in Docket 7460. The contingency percentage shall be 10% as noted in the Staff's testimony in Docket 7460.

10. The Company agrees to refund the amount collected during the court ordered stay of Docket 6350, together with interest accruing since the stated effective date of the tariffs approved under the Commission's Final Order in said docket, and calculated at the postjudgment interest rate prescribed by the Texas Consumer Credit Commissioner, pursuant to Section 2 of TEX. REV. CIV. STAT. ANN. art. 5069-1.05, for each month since the stated effective date of said tariffs. The Company agrees that the tariff for Schedule No. 15, Phelps Dodge, reflecting the Interconnection Agreement with EPE, will be utilized for calculating the refund to Phelps Dodge during the period the tariff under the Interconnection Agreement was in effect. In calculating said refunds, the Company also agrees to apply the Economic Recovery Rider ("ERR") approved in Docket No. 6350 to Border Steel and ASARCO back to the stated effective date of the tariffs approved under the Docket No. 6350 order, thus resolving any dispute which might exist between them and the Company as to the adequacy and effectiveness of Border Steel's and ASARCO's requests to take service under the ERR during the period between said tariffs' stated effective date and the date on which the Company finally implemented the ERR on a prospective basis following dissolution of the court-ordered stay of the Commission's order in Docket No. 6350. The interclass allocation of this refund is to be made based on the difference between the class-based revenues recovered under the Docket

No. 5700 tariffs and the revenues which would have been recovered had the Docket No. 6350 tariffs been in effect. The intraclass refund shall be accomplished and refunded using the same method the Commission currently uses in fuel refund proceedings under the Commission's Substantive Rules. The issues to remain open and be decided by the Company's appeal are as follows:

a. Dismissal of In-Service case.

b. Construction Work in Progress issues.

    (1) Financial integrity considerations.

    (2) Prudence considerations.

    (3) $1 Adjustment to CWIP.

c. Energy Efficiency Plan issues.

d. Appropriate level of return on equity.

e. Adjustments to capital structure and related investment tax credit issues.

f. Customer growth adjustment methodology.

g. Appropriate depreciation rates for Rio Grande Units 3, 4 and 5.

h. Recommendations regarding Franklin Land & Resources.

i. Protest of language relating to excess capacity.

j. Removal of New Mexico Project amortization.

k. Disallowance of Staff depreciation add-back.

l. Use of effects of consolidated tax return.

m. Adjustment to tax expense for deductions disallowed.

n. Propriety of unbilled revenues adjustment.

o. Level of cash working capital in rate base.

p. Treatment of interest deduction on nuclear fuel trust.

q. Exclusion of trade association dues.

r. Exclusion of charitable contributions.

s. Proper amortization of management audit.

11. That for the period beginning with the effective date of the rates in Docket No. 7460 and ending when the RMP described in Paragraph 5 herein is terminated, the following performance standards shall be applied to Palo Verde Unit 1 and Unit 2:

a. A "dead band" will be established at an annual capacity factor (CF) of 60-75%. (The first "annual" capacity factor will be calculated for each unit utilizing the period from the effective date of the new rates in Docket No. 7460 to the start of the first fuel reload. For the remainder of the phase-in period, each succeeding "annual" capacity factor will be calculated for each unit utilizing the period from the beginning of a fuel reload to the start of the next fuel reload, which is currently estimated to be approximately 18 months. "Annual" capacity factor shall be calculated by taking the total period in question divided by the actual number of months times 12.):

(1) CF's between 50-60% will result in EPE being penalized by an amount equal to one-half the additional fuel costs incurred, using as a proxy for such costs EPE's weighted average fuel and purchase power costs (other than Four Corners, Palo Verde and SPS capacity).

(2) CF's between 75-85% will result in EPE being rewarded by an amount equal to one-half the additional fuel costs avoided, using as a proxy for such costs EPE's weighted average fuel and purchase power costs (other than Four Corners, Palo Verde and SPS capacity).

(3) CF's below 50% will result in EPE being penalized by an amount equal to the additional fuel costs incurred, using the proxy established hereinabove.

(4) CF's greater than 85% will result in EPE being rewarded by an amount equal to the additional fuel costs avoided, using the proxy established hereinabove.

b. An annual CF of less than 35% on either Palo Verde Unit 1 or Unit 2, as shown in EPE's filings described in the following paragraph, shall trigger an automatic reconsideration of EPE's most recent general rate case to determine whether the then current rate-making treatment of the Unit(s) in question is appropriate in accordance with procedures as prescribed by the Commission. The prescribed performance penalty will be applied pending the outcome of such reconsideration, unless the Commission orders otherwise.

c. Within thirty (30) days of the beginning of a fuel reload of any unit, EPE will file with the Commission and all parties a report with supporting work papers to substantiate the value of the costs incurred or avoided that resulted from the level of each Unit's performance during the previous period. That filing will be subject to challenge within sixty (60) days of receipt of the Company's notice by the filing of written notice with the Commission. The costs incurred or avoided will then be booked (and accrue interest at EPE's overall cost of capital as determined in the Company's last general rate case) and reconciled in the fuel factor in accordance with the Commission's rules.

d. Claims by EPE for special relief due to a force majeure event shall trigger an automatic hearing with notice to every party in EPE's last general rate proceeding and shall not affect the imposition of any penalty pending the outcome of said hearing, unless the Commission orders otherwise.

e. EPE may not claim the existence of a force majeure event when the effect of that claim would be to increase the amount of a reward or to produce a reward, as described in Paragraph 11(a) above, when such would not otherwise exist.

12. The Company will flow-through to the ratepayers any monies recovered from the Combustion Engineering ("CE") litigation in excess of $28 million. The Company will bear the expense of pursuing its lawsuit against CE. However, to the extent the Company's recovery from CE exceeds $28 million, the Company will be proportionately reimbursed for litigation expenses directly related to its lawsuit against CE. Recovery by the Company of CE litigation expenses will be based upon the ratio of the recovery in excess of $28 million to the total recovery.

13. The parties agree that the Company's revenue requirement for Docket No. 7460 shall be distributed to and recovered from the various customer classes in accordance with the class cost of service methodology filed by the Company in this Docket, as revised, incorporating those Staff cost allocation adjustments listed in Exhibit D and subject to the agreed upon class revenue requirements as shown on the attached Exhibit E.

14. For the purposes of this Docket No. 7460 only, and except as provided in Subparagraphs 14(a) through 14(f) below, the parties agree to implementation of the individual rate structures proposed by the Company in its Rate Filing Package, as adjusted to recognize the reduced revenue requirements agreed to by the parties herein.

a. Customer Charges for the following schedules shall be:

(i)	Schedule No. 01	Residential Service	$ 6.50 per month
(ii)	Schedule No. 02	Commercial Service (Proposed)	$12.00 per month
(iii)	Schedule No. 24	General Service	$20.00 per month

b. Schedule No. 1, Residential Service charges per KWH shall be as follows:

(i) An identical first-block energy charge in the peak and off-peak period.

(ii) The establishment of an above-550 KWH tail block for both Rate 01 (Residential Service) and Rate 05 (Residential Space Heating Service) customers during the November through April billing period.

(iii) The establishment of a $0.0250 per KWH price differential between blocks during the November through April billing period.

c. Schedule No. 2, Commercial Service (Proposed).

The Space Heating Rider as it currently exists in Schedule No. 24, General Service, is to be maintained in its present form for the proposed Schedule No. 02.

The space heating restrictions and price differentials as presently exist under this rider shall be maintained in the rider for this rate.

d. Schedule No. 99, Miscellaneous Service Charges.

(i) The premium overtime charge shall be $35.00 for New Service, Non-Pay Reconnect and "No Light" Service Call charges.

(ii) The Returned Check or Bank Draft charge shall be $9.00.

e. Under the Primary Voltage Discount Clause for Schedule Nos. 24, General Service; 25, Large Power; and 45, (Proposed) Supplementary

Power Service for Cogeneration and Small Power Production, the transformer discount shall for this rate case alone be increased to $0.30 per kilowatt of adjusted kilowatt demand.

f. As a part of the rate moderation plan embodied in this Stipulation, the parties agree that the ERR shall continue to be available for those classes and at the demand charge discount level approved by the Commission in Docket No. 6350 through the end of the initial four-year phase-in period for the base rate increases agreed to in Paragraph 5. Thereafter, the continuation of the ERR shall be subject to reevaluation in light of then prevailing economic circumstances and such other factors as the Commission shall deem relevant at the time. The parties further agree that the United States Department of Defense ("DOD") may present for decision by the Examiner and the Commission its contention that the availability of the ERR should be extended to include Rate Schedule 31 (Fort Bliss). It is agreed that any revenue shortfall resulting from application of the ERR shall be recovered in future rates through the deferrals as established in Paragraph 5.

15. EPE in its next general rate filing will provide testimony and support for the use of a "minimum size" allocation methodology for Distribution Plant.

16. EPE agrees that in its next general rate filing it will provide testimony and documentation in support of a new study that it will have conducted prior to such rate filing in regard to the separation of Distribution Plant investment between primary and secondary voltages.

17. In exchange for the voluntary withdrawal of the prefiled direct testimony of ASARCO's Phase II (PVNGS) witnesses, Michael K. Moore, Dr. Donald A.

Murry and Dr. William E. Avera, EPE, by its execution of this Stipulation, hereby reduces and limits its request for a revenue increase in this Docket No. 7460 to that level which is consistent with this Stipulation. The parties to this Stipulation agree that the prefiled direct testimony of all other witnesses sponsored by the signatory parties, except as heretofore ruled upon by the Examiners to the contrary, shall be tendered for admission into the evidentiary record in this Docket without objection by any such party. The signatory parties further agree to waive authentication of such testimony, and to forego cross-examination of such other witnesses, except to the extent that each signatory party in its discretion deems cross-examination necessary in response to or in anticipation of cross-examination by any party to this Docket No. 7460 who is not also a party to this Stipulation and agreement.

18. It is specifically agreed between the Company and those parties to this Stipulation who are not regulatory authorities or governmental bodies that, in the event the Company seeks regulatory, judicial, or other legal authorization to depart from the terms hereof in a manner which would increase the rate path set forth in Paragraph 5 other than as prescribed therein, then in such event, the issues referenced in Paragraph 1 relating to decisional prudence and construction prudence shall be subject to reopening and redetermination in a future docket upon petition to the Commission by any party, including the Commission Staff, to this Stipulation.

19. The undersigned believe this Stipulation, if adopted by the Commission, represents a fair, just and reasonable solution to the issues being resolved. Moreover, this Stipulation will serve the purpose of moderating the rates of El Paso Electric Company in the Texas

jurisdiction. This Stipulation reflects settlement discussions and if this Stipulation is not adopted in its entirety by the Public Utility Commission of Texas, then it shall have no force or effect and the statements and/or positions taken herein by any of the undersigned parties shall not be admissible in any proceeding before any regulatory body or Court.

20. It is recognized and agreed by the parties to this Stipulation that by filing this Stipulation no party necessarily expresses agreement to or concurrence with any specific methodology, finding, or conclusion expressed herein, and that such Stipulation is made and filed solely in connection with compromise settlement of Docket No. 7460 subject to the specific approval by the Commission of the matters herein stipulated and agreed to between them.

Executed this 22nd day of October, 1987.

EL PASO ELECTRIC COMPANY

By: David N. Wiggs Jr.

ASARCO Incorporated

By: J. Alan Holman

W. SILVER, INC., et al.

By: Alton Hall

PHELPS-DODGE REFINING CORPORATION

By: [signature]

DEPARTMENT OF DEFENSE

By: * See attached letter

TEXAS STATE AGENCIES

By: ______________________________

BORDER STEEL ROLLING MILLS &
EL PASO IRON & METAL

By: ______________________________

COMMISSION GENERAL COUNSEL

By: ______________________________
Assistant General Counsel

OFFICE OF PUBLIC COUNSEL

By: ______________________________

CITY OF EL PASO

By: ______________________________

PROVIDENCE MEMORIAL HOSPITAL

By: ______________________________

UNITED STEELWORKERS OF AMERICA

By: ______________________________

ROSIE WALLIN

By: ______________________________

EXHIBIT A

1. Reactor Coolant Pumps (RCP), i.e.,

   a. problems with the diffuser/casing cap screws and diffuser/suction pipe cap screws;

   b. problems associated with the cavitation damage to the diffuser-vane upper-inlet tips of all four RCP's;

   c. problems resulting from broken impellers in the RCP's.

2. Control Element Assembly (CEA) shroud, i.e.,

   a. cracks at or near welds in the shroud tubes, or at the attachment of CEA extension-shaft-guides to webs, or between shroud-tube and web;

   b. crack in the base metal of a web;

   c. wear marks or sizing of shroud;

   d. ductile break in a web.

3. Safety-Injection-Nozzle Thermal Liner, i.e.,

   a. problems resulting from dislodged thermal liners.

4. Resistance Temperature-Detector Thermowells, i.e.,

   a. bent or broken thermowells.

5. Low-Pressure Safety-Injection Pumps (LPSI), i.e.,

   a. failures to restart.

6. Any issue or problem discovered during hot functional testing on Unit 1 and subsequently corrected on Units 2 and 3.

7. Issues relating to sizing or construction of the pipeline supplying effluent to the plant.

EXHIBIT B

ADJUSTMENTS TO STAFF REVENUE REQUIREMENT

The base rate increase amount of $48,066,859 incorporates the following:

1. Staff's recommended rate of return on equity 13.0%, adjusted to 12.72% for penalties quantified in Staff testimony (as supplemented). The allowed overall rate of return is 10.56%.

2. The Company's requested rate base and cost of service as adjusted in the Staff testimony (including errata/corrections), except as follows:

   a. Recalculation of property insurance expense (with Palo Verde CWIP removed from the ratio used to derive such expense).

   b. Recovery of all deferred expenses for Palo Verde Units 1 and 2, to be included in rate base and amortized over the lives of the respective plants. For purposes of this docket, the Company's estimates of deferrals through the month of October were utilized. Reevaluation of the total deferral amounts will occur at the time of the next rate case in order to include actual data through the end of the deferral period with necessary adjustments. The adjustment of the deferral balance for the effects of the $50 million disallowance related to Palo Verde Units 1 and 2 shall remain an open issue for future rate cases. Nuclear fuel displacement credits will not be refunded, but will be included with the deferrals as an offset to the amount to be recovered.

   c. Assignment of all Palo Verde Unit 2 Contra-AFUDC to Palo Verde Unit 1. The balance of deferred expenses for Palo Verde Units 1 and 2 will not be adjusted to reflect this reallocation of Contra-AFUDC.

   d. Reassignment of all Commons to Palo Verde Unit 1. If Unit 3 is sold, other than a sale/leaseback transaction, an appropriate adjustment to rate base will be made to remove the Palo Verde Unit 3 Commons from rate base. "Commons" means the common facilities at the Palo Verde Nuclear Generating Station, the Palo Verde Switchyard and the Palo Verde 500 KV Transmission System facilities.

   e. Treatment of accumulated deferred income taxes related to the disallowance. (See specific discussion of this issue in Paragraph 4.)

EL PASO ELECTRIC COMPANY
SCHEDULE P(B) - JURISDICTIONAL ADJUSTED COST OF SERVICE STUDY - DOCKET 7460 SETTLEMENT
FOR THE TEST YEAR ENDED SEPTEMBER 30, 1986
REVENUE REQUIREMENT

		TOTAL COMPANY	TEXAS	OTHER
ANNUALIZED OPERATING REVENUES	35C	310,562,693	201,893,699	108,668,994
COST TO SERVE				
FUEL	40C	62,878,400	42,025,934	20,852,466
PURCHASE POWER	45C	19,595,400	12,918,158	6,677,242
OPERATING EXPENSES				
OPERATION & MAINTENANCE	50C	143,322,660	95,419,085	47,903,575
INTEREST ON CUSTOMER DEPOSITS	55I	187,384	141,906	45,478
DEPRECIATION & AMORTIZATION	60C	28,544,698	18,251,653	10,293,045
DECOMMISSIONING	65C	635,076	405,638	229,438
TAXES OTHER THAN FEDERAL INC TAXES	75C	25,450,533	18,903,177	6,547,356
STATE INCOME TAX	85C	299,453	175,356	124,097
FEDERAL INCOME TAXES	120C	18,656,364	11,581,250	7,075,113
RETURN	125C	79,816,985	50,138,401	29,678,584
TOTAL REVENUE REQUIREMENT	135C	379,386,952	249,960,558	129,426,395
OTHER REVENUE	140C	1,588,533	1,182,074	406,459
BASE RATE REVENUE REQUIREMENT	145C	377,798,419	248,778,484	129,019,936
NON-FUEL / BASE REVENUE INCREASE	150C	68,824,259	48,066,859	20,757,401
CURRRENT FUEL / OPERATING REVENUES	151C	331,954,173	214,099,209	117,854,964
TOTAL REVENUE INCREASE	152C	47,432,779	35,861,349	11,571,431

EXHIBIT B
ADJUSTMENTS TO STAFF REVENUE REQUIREMENT

EXHIBIT B

ADJUSTMENTS TO STAFF REVENUE REQUIREMENT

EL PASO ELECTRIC COMPANY
SCHEDULE P(B) - JURISDICTIONAL ADJUSTED COST OF SERVICE STUDY - DOCKET 7460 SETTLEMENT
FOR THE TEST YEAR ENDED SEPTEMBER 30, 1986
RATE BASE

		TOTAL COMPANY	TEXAS	OTHER
PLANT IN SERVICE	160C	943,135,847	567,467,328	375,668,519
ACCUMULATED DEPRECIATION & AMORT	165C	(144,405,347)	(95,857,033)	(48,548,314)
NET PLANT IN SERVICE	170C	798,730,500	471,610,295	327,120,205
WORKING CAPITAL	190C	15,599,672	11,304,585	4,295,087
CONSTRUCTION WORK IN PROGRESS				
DEFERRED CARRYING COST	348I	35,353,461	35,353,461	0
CAPITALIZATION OF O & M	193I	39,150,114	39,150,114	0
DEDUCTIONS				
ACCUMULATED DEFERRED F I T	342C	(126,308,194)	(78,492,315)	(47,815,879)
INJURIES & DAMAGES RESERVE	330C	(100,000)	(71,873)	(28,127)
CUSTOMER ADVANCES FOR CONSTR	335I	(1,027,911)	(143,701)	(884,210)
CUSTOMER DEPOSITS	340I	(3,298,721)	(2,498,121)	(800,600)
UNAMORTIZED PRE 1971 ITC	345C	(651,847)	(392,204)	(259,643)
OTHER DEFERRED CREDIT - COPPER 1	347C	(1,604,411)	(1,024,774)	(579,637)
TOTAL RATE BASE	356C	755,842,663	474,795,468	281,047,196
REQUESTED RATE OF RETURN	365C	.10560	.10560	.10560
RETURN ON RATE BASE	370C	79,816,985	50,138,401	29,678,584

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Base Scenario as submitted October 13. 1987
PV3 Common to PV1-- 50/10 Disallowance--Constant Rate of Return--4%, 4%, 3.5%, 3.5% increases
Accum Deferral-Return on Previous Years Deferral plus a Return on 1/2 Current Years Incr. Deferral

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

EXHIBIT C

JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

Line No.	Description	1987 Total Company	1987 Texas	1988 Total Company	1988 Texas	1989 Total Company	1989 Texas
	Current Operating Revenues						
128	Base	233,102,252	150,094,000	281,600,952	180,034,235	301,210,421	193,083,942
129	Fuel	97,124,482	62,823,055	83,133,018	53,334,315	88,450,930	56,397,197
130	Other / IID Deferrals	3,174,543	1,021,177	8,999,125	1,062,024	7,061,810	1,104,505
131	Wheeling	252,000	160,958	252,000	158,659	252,000	157,832
132	Total Revenues	333,653,277	214,099,270	373,985,096	234,589,233	396,975,161	250,743,476
	Revenue Requirement						
133	Operation & Maintenance	224,706,071	150,401,762	237,956,165	155,075,224	242,555,707	157,371,000
134	Interest on Customer Deposits	187,384	141,986	187,384	141,986	187,384	141,986
135	Depreciation & Amortization	29,245,629	18,657,291	31,931,575	19,750,967	35.048.006	20,470,192
136	Taxes Other Than FIT	26,256.002	18,087,040	32,355,538	23,137,615	33,019,652	23,582,160
137	Federal Income Taxes	19,995,307	11,581,250	23,051,770	13,069,863	22,675,079	12.838,400
138	State Income Tax	277,955	137,313	507,873	286,029	501.467	282,115
139	Return on Rate Base	76,285,097	50,074,049	82,788,567	46,767,018	81,685,274	46,041,938
140	Deferred Debit (REFUDC Amortization)	0	0	2,240,949	0	2,272,977	0
141	AD/ADFIT	0	0	-375,019	0	-380,378	0
142	Total Revenue Requirement	376,954,244	249,960,619	410,644,804	258,228,622	417,485,167	260,727,793
143	Base Revenue Requirement	373,527,701	248,778,404	401,393,679	257,007,939	410,171,350	259,465,456
144	Non Fuel Base Revenue Requirement	297,794,701	198,160,939	316,144,979	202,310,962	322,755,350	203,730,404
145	Required Revenue Increase	43,300,967	35,861,349	36,659,700	23,639,309	20,510,006	9,984,317
146	Non Fuel Base Increase	64,553,541	48,066,859	34,544,026	22,204,727	21,544,936	10,646,462
	Settlement Proposal						
147	Total Settlement Increase with Fuel	5,995,006	8,563,971	11,042,792	8,556,031	7,591,900	6,095,793
148	Increase Deferral	37,305,002	27,297,370	20,651,410	10,117,060	17,949,670	8,920,176
149	Accumulated Deferral Related to REFUDC			-39,930	0	-177,990	0
150	Accumulated Deferral	41,245,010	28,738,543	70,214,460	47,652,729	87,996,015	56,770,200
151	Net Accumulated Deferral	41,245,010	28,738,543	70,214,460	47,652,729	87,996,015	56,770,200
152	Settlement Total Revenues	339,648,363	222,663,241	385,027,000	243,145,264	404,567,149	256,839,260
153	Settlement Base-Sales Revenues	336,221,820	221,481,106	375,776,763	241,924,501	397,253,339	255,576,931
154	Settlement Non-Fuel Base-Sales Revenues	260,488,820	170,863,561	290,528,063	187,235,604	309,837,339	199,841,000
155	Settlement Non Fuel Revenue Increase	27,306,560	20,769,401	8,927,111	7,201,369	8,626,917	6,757,938
	Unit Rates						
156	Total	0.07396	0.07398	0.07514	0.07669	0.07655	0.07857
157	Non-Fuel Base Sales	0.05730	0.05707	0.05809	0.05936	0.05970	0.06143
158	Fuel	0.01666	0.01691	0.01705	0.01734	0.01684	0.01713
15[illegible]	[illegible]H Sales at Meter	4.546,213	2,993,712	[illegible]	3.154,392	[illegible]565	3.252.920

1192

, 1987
PV3 Common to ... urn—4%, 4%, 3.5%, 3.5% increases
Accum Deferral-Return on Previous Years Deferral plus a return on 1/2 Current Years Incr. Deferral

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

Line No.	Description	1990 Total Company	1990 Texas	1991 Total Company	1991 Texas	1992 Total Company	1992 Texas
	Current Operating Revenues						
128	Base	319,049,725	205,267,109	337,414,799	219,139,500	354,891,624	224,847,256
129	Fuel	90,474,176	57,248,125	95,868,824	60,087,492	108,590,720	67,000,103
130	Other / IID Deferrals	6,002,682	1,148,685	4,705,829	1,194,633	3,679,291	1,242,418
131	Wheeling	277,200	172,963	304,920	189,125	335,412	207,417
132	Total Revenues	415,803,784	263,836,882	438,294,373	280,610,749	467,497,046	293,297,193
	Revenue Requirement						
133	Operation & Maintenance	250,959,407	162,132,066	265,548,873	170,473,753	276,635,697	176,217,086
134	Interest on Customer Deposits	187,304	141,986	187,304	141,986	187,304	141,986
135	Depreciation & Amortization	37,565,451	21,999,912	38,108,389	22,242,045	38,509,641	22,456,924
136	Taxes Other Than FIT	34,241,222	24,444,196	33,820,922	24,098,054	34,379,048	24,543,733
137	Federal Income Taxes	23,529,474	13,340,147	22,330,196	12,535,954	21,035,707	11,723,893
138	State Income Tax	515,997	291,095	495,602	277,229	473,586	263,407
139	Return on Rate Base	84,289,170	47,658,091	80,521,897	45,114,802	76,455,536	42,562,885
140	Deferred Debit (AEFUDC Amortization)	2,300,323	0	2,337,296	0	2,347,185	0
141	AD/ADFIT	-304,955	0	-391,142	0	-392,797	0
142	Total Revenue Requirement	433,283,472	270,007,412	442,959,417	274,883,823	449,630,991	277,909,834
143	Base Revenue Requirement	426,923,590	268,685,764	437,948,668	273,500,066	445,616,200	276,460,000
144	Non Fuel Base Revenue Requirement	334,857,590	210,432,116	333,761,568	208,200,763	334,283,100	207,766,204
145	Required Revenue Increase	17,399,600	6,170,530	4,665,044	-5,726,926	-17,866,056	-15,387,359
146	Non Fuel Base Increase	15,807,865	5,165,007	-3,653,232	-10,938,738	-20,608,435	-17,000,972
	Settlement Proposal						
147	Total Settlement Increase with Fuel	8,776,172	8,109,071	8,318,276	5,211,011	2,742,300	1,693,613
148	Increase Deferral	14,610,786	3,975,069	2,761,790	-4,523,715	-14,671,072	-11,143,609
149	Accumulated Deferral Related to AEFUDC	-304,146	0	-532,833	0	-835,160	0
150	Accumulated Deferral	103,751,040	60,754,069	107,947,223	56,230,353	93,702,717	45,006,744
151	Net Accumulated Deferral	103,751,040	60,754,069	107,947,223	56,230,353	93,702,717	45,006,744
152	Settlement Total Revenues	424,579,956	272,026,754	446,612,649	285,822,561	470,239,426	294,990,806
153	Settlement Base-Sales Revenues	418,300,074	270,705,105	441,601,099	284,438,003	466,224,724	293,540,971
154	Settlement Non-Fuel Base-Sales Revenues	326,234,074	212,451,458	337,414,799	219,139,500	354,891,624	224,847,256
155	Settlement Non Fuel Revenue Increase	7,184,349	7,184,349	0	0	0	0
	Unit Rates						
156	Total	0.07786	0.08102	0.07891	0.08253	0.07986	0.08301
157	Non-Fuel Base Sales	0.06072	0.06358	0.06029	0.06358	0.06079	0.06358
158	Fuel	0.01714	0.01743	0.01862	0.01895	0.01907	0.01943
159	MWH Sales at Meter	5,372,660	3,341,225	5,596,391	3,446,412	5,838,053	3,536,178

EXHIBIT C
JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

1193

Base Scenario as submitted October 13, 1987
PV3 Common to PV1— 50/10 Disallowance—Constant Rate of Return—4%, 4%, 3.5%, 3.5% increases
Accum Deferral-Return on Previous Years Deferral plus a Return on 1/2 Current Years Incr. Deferral

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

EXHIBIT C
JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

Line No.	Description	1993 Total Company	1993 Texas	1994 Total Company	1994 Texas	1995 Total Company	1995 Texas
	Current Operating Revenues						
128	Base	369,537,911	232,574,592	377,248,976	239,788,227	386,477,094	246,574,444
129	Fuel	116,875,206	71,054,516	133,189,983	81,223,610	151,666,000	92,879,800
130	Other / IID Deferrals	2,311,316	1,292,115	937,849	1,343,799	-306,957	1,397,551
131	Wheeling	368,953	229,394	405,849	252,876	446,433	280,443
132	Total Revenues	489,093,387	305,150,617	511,782,576	322,608,511	538,283,379	341,132,319
	Revenue Requirement						
133	Operation & Maintenance	301,529,491	190,940,522	323,658,729	205,095,596	334,305,061	212,855,684
134	Interest on Customer Deposits	187,384	141,986	187,384	141,986	187,384	141,986
135	Depreciation & Amortization	39,158,970	23,039,356	41,561,304	24,628,966	42,254,832	25,335,891
136	Taxes Other Than FIT	34,933,056	25,164,067	36,208,000	26,237,860	36,437,812	26,626,640
137	Federal Income Taxes	19,897,386	11,179,837	20,005,816	11,328,907	18,706,285	18,775,079
138	State Income Tax	454,230	254,872	456,074	258,051	433,975	249,576
139	Return on Rate Base	72,879,749	40,918,001	73,220,357	41,444,001	69,138,161	39,788,003
140	Deferred Debit (AEFUDC Amortization)	2,359,627	0	2,362,600	0	0	0
141	AB/ABFIT	-394,879	0	-395,377	0	-399,685	0
142	Total Revenue Requirement	471,005,014	291,638,640	497,264,967	309,135,287	501,063,826	315,773,578
143	Base Revenue Requirement	468,324,745	290,117,132	495,921,270	307,538,612	500,924,350	314,095,504
144	Non Fuel Base Revenue Requirement	338,745,045	211,337,001	347,809,770	217,214,971	345,103,050	218,671,475
145	Required Revenue Increase	-18,088,373	-13,511,976	-14,517,609	-13,473,224	-37,219,553	-25,358,741
146	Non Fuel Base Increase	-30,792,067	-21,237,591	-29,439,206	-22,573,256	-41,374,045	-27,902,969
	Settlement Proposal						
147	Total Settlement Increase with Fuel	12,703,694	7,725,615	14,921,597	9,100,032	4,154,492	2,544,229
148	Increase Deferral	-26,031,357	-16,476,002	-26,418,291	-19,552,341	-40,417,661	-26,946,506
149	Accumulated Deferral Related to AEFUDC	-1,179,761	0	-1,530,032	0	-1,530,032	0
150	Accumulated Deferral	67,757,750	20,609,062	41,674,146	9,057,521	1,256,405	-17,009,064
151	Net Accumulated Deferral	67,757,750	20,609,062	41,674,146	9,057,521	1,256,405	-17,009,064
152	Settlement Total Revenues	501,797,001	312,876,231	526,704,173	331,708,543	542,437,071	343,676,548
153	Settlement Base-Sales Revenues	499,116,811	311,354,723	525,360,476	330,111,069	542,298,394	341,998,553
154	Settlement Non-Fuel Base-Sales Revenues	369,537,911	232,574,592	377,248,976	239,788,227	386,477,094	246,574,444
155	Settlement Non Fuel Revenue Increase	0	0	0	0	0	0
	Unit Rates						
156	Total	0.08137	0.08512	0.08334	0.08754	0.08403	0.08819
157	Non-Fuel Base Sales	0.06024	0.06358	0.05984	0.06358	0.05989	0.06358
158	Fuel	0.02112	0.02154	0.02349	0.02395	0.02415	0.02461
155	MWH Sales at Meter	6,134,182	3,657,706	6,304,026	3,771,155	6,453,501	3,877,882

EXHIBIT C

JURISDICTIONAL COST OF SERVICE

FORECAST OF RATE PATH

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY — 1996

Line No.	Description	Total Company	Texas
	Current Operating Revenues		
128	Base	396,341,405	253,972,539
129	Fuel	159.725,205	98,287,165
130	Other / IID Deferrals	-3,816,995	1,453,453
131	Wheeling	491,077	310,012
132	Total Revenues	552,740,691	354,023,169
	Revenue Requirement		
133	Operation & Maintenance	361,351,422	230,778,939
134	Interest on Customer Deposits	187,304	141,906
135	Depreciation & Amortization	45,920,670	27,829,819
136	Taxes Other Than FIT	38,425,014	28,289,638
137	Federal Income Taxes	19,615,188	11,490,365
138	State Income Tax	449.431	262,693
139	Return on Rate Base	71,993,204	42,121,055
140	Deferred Debit (AEFUDC Amortization)	0	0
141	RB/RDFIT	-401,791	0
142	Total Revenue Requirement	537,541,403	340,914,415
143	Base Revenue Requirement	540,867,321	339,150,950
144	Non Fuel Base Revenue Requirement	372,194,721	235,357,961
145	Required Revenue Increase	-15,199,288	-13,108,753
146	Non Fuel Base Increase	-24,146,684	-18,614,578
	Settlement Proposal		
147	Total Settlement Increase with Fuel	8,947,395	5,505,024
148	Increase Deferral	-24,146,684	-18,614,578
149	Accumulated Deferral Related to AEFUDC	-1,530,032	0
150	Accumulated Deferral	-22,090,199	-36,503,642
151	Net Accumulated Deferral	-22,090,199	-36,503,642
152	Settlement Total Revenues	561,680,087	359,528,993
153	Settlement Base-Sales Revenues	565,014,005	357,765,528
154	Settlement Non-Fuel Base-Sales Revenues	396,341,405	253,972,539
155	Settlement Non Fuel Revenue Increase	0	0
	Unit Rates		
156	Total	0.08544	0.08957
157	Non-Fuel Base Sales	0.05993	0.06358
158	Fuel	0.02551	0.02599
159	KWH Sales at Meter	6,613,215	3,994,232

EXHIBIT D

STAFF ALLOCATION ADJUSTMENTS TO THE

COMPANY'S CLASS COST OF SERVICE

C.O.S. Line No.	FERC Account	EPEC Allocation Allocator	EPEC Allocation C.O.S. Line	Staff Allocation Allocator	Staff Allocation C.O.S. Line
Jurisdictional					
610	512	Energy	4020	Demand/Energy	3930/4020
615	513	Energy	4020	Demand/Energy	3930/4020
1119	928-Other	Labor	4545	Base Sales	385
1234 (Adj)	928-Other	Labor	4545	Base Sales	385
1232	925-P.V.	Labor	4545	Demand	3930
1243	926-P.V.	Labor	4545	Demand	3930
Class					
1232	925-P.V.	Labor	4545	Demand	3930
1243	926-P.V.	Labor	4545	Demand	3930
1267	930.2-P.V.	Labor	4545	Demand	3930
1250	904	Spec. Sales	4612	Class Sales	4470

EXHIBIT E

CLASS REVENUE REQUIREMENTS

EL PASO ELECTRIC COMPANY
TOTAL REVENUE REQUIREMENTS BY RATE CLASSIFICATION
FOR THE TEST YEAR ENDED SEPTEMBER 30, 1986
Moderated Proportional Increase

Line No.	Description (1.3)	Annualized Base	Proposed Base	Base Revenue Increase Percent	Base Increase Amount	Proposed Moderated Base	Base Revenue Increase Percent	Base Increase Amount	Total Increase Amount	Total Increase Percent	Relative Base Inc Percent	Relative Total Inc Percent
1	Residential Service 01	$53,551,972	$66,948,230	25.02%	$13,396,258	$59,484,926	11.08%	5,932,954	$2,570,560	3.63%	0.80	0.90
2	Small Commercial 02	11,511,162	13,604,949	18.19%	2,093,787	12,446,254	8.12%	935,092	340,189	2.33%	0.59	0.58
3	Municipal Street Lighting 08	1,657,860	2,075,605	25.20%	417,745	1,842,842	11.16%	184,982	87,685	4.06%	0.81	1.01
4	El Paso Municipal Pumping 11	4,984,311	6,759,773	35.62%	1,775,462	5,765,388	15.67%	781,077	311,221	4.20%	1.13	1.05
5	Electrolytic Refining 15	2,456,566	2,701,998	9.99%	245,432	2,568,923	4.57%	112,357	-198,073	-4.88%	0.33	-1.22
6	Off-Peak Water Heating 21	1,360,136	1,863,841	37.03%	503,705	1,580,597	16.28%	221,461	36,187	1.56%	1.18	0.39
7	Irrigation Service 22	36,344	44,892	23.52%	8,548	40,135	10.43%	3,791	1,716	3.65%	0.75	0.91
8	General Service 24	37,883,680	53,545,581	41.34%	15,661,901	44,692,936	17.97%	6,809,256	3,565,598	6.53%	1.30	1.63
9	Large Power Service 25	19,385,991	25,664,262	32.39%	6,278,271	22,152,352	14.27%	2,766,361	835,098	2.85%	1.08	0.71
10	Private Security Light 28	693,507	837,892	20.82%	144,385	757,741	9.26%	64,234	40,262	4.98%	0.67	1.23
11	Transmission Voltage 29	2,017,473	2,785,263	38.06%	767,790	2,354,904	16.73%	337,431	3,387	0.09%	1.21	0.02
12	Electric Furnace 30	2,837,690	4,784,303	68.60%	1,946,613	3,347,740	17.97%	510,050	134,412	2.82%	1.30	0.70
13	Military Reservation 31	4,757,464	6,720,051	41.25%	1,962,587	5,612,576	17.97%	855,112	326,936	4.21%	1.30	1.05
14	Cotton Gin Service 34	96,592	163,437	69.20%	66,845	113,954	17.97%	17,362	6,046	3.92%	1.30	0.97
15	City County Service 41	6,683,872	9,400,456	40.64%	2,716,584	7,876,638	17.85%	1,192,766	484,229	4.69%	1.29	1.17
16	Municipal Pumping 54	179,459	243,298	35.57%	63,839	207,544	15.65%	28,085	11,415	4.30%	1.13	1.07
17	Subtotal	150,094,079	198,143,831	32.01%	48,049,752	170,846,449	13.83%	20,752,370	8,546,860	4.01%	1.00	1.00
18	Other	1,182,074	1,199,182		17,108	1,199,182		17,108	17,108			
19	Total	$151,276,153	$199,343,013	31.77%	$48,066,860	$172,045,631	13.73%	$20,769,478	$8,563,968	4.00%		

DEPARTMENT OF THE ARMY
OFFICE OF THE JUDGE ADVOCATE GENERAL
NASSIF BUILDING · 5611 COLUMBIA PIKE
FALLS CHURCH, VIRGINIA 22041-5013
20 October 1987

REPLY TO
ATTENTION OF
Regulatory Law Office
U 3490

SUBJECT: El Paso Electric Company, Texas PUC Docket No. 7460

Ms. Lisa Groomes
Filing Clerk
Public Utility Commission of Texas
7800 Shoal Creek Boulevard, Suite 450N
Austin, TX 78757

Dear Ms. Groomes:

A draft Stipulation of settlement was circulated to the parties by Mr. David H. Wiggs, Jr., counsel for the El Paso Electric Company, under a cover memorandum dated October 16, 1987. Recognizing that the Company, Commission Staff and other parties have made a significant effort to reconcile issues, it appears advisable to make a statement regarding the Stipulation. This letter is comment on behalf of the consumer interest of the intervenor, United States Department of Defense and other affected Executive Agencies (hereinafter "DOD"), regarding the proposed Stipulation.

The terms and conditions of the proposed Stipulation reflect compromise normally found in settlement proposals. As to paragraphs: 1,2,3,4,5,6,7, 8,9,11,12,15,16,17,18, and 19, DOD takes no position on the specific terms, but does not object to the net affect of these provisions for purposes of resolving the case. Paragraph 13 and related Exhibit E of the proposed Stipulation have the support of DOD. Counsel for El Paso Electric Company advised DOD of a possible slight modification of Exhibit 13, which has been received by TELEX this day. It changes the"total increase amount"for Fort Bliss (Rate 31) from $ 311,541 to $316,936. Given the overall merits of the proposed Stipulation, DOD makes no objection to that amended Exhibit E. If there are significant other modifications to Exhibit E or other items, DOD reserves the right to comment further and amend its position.

As to paragraph 14, signatories are required to <u>agree</u> to a provision (14 (f)) which affords some transmission voltage cusmtomers a preferential tariff treatment (not based on costs of service) that is not afforded to all transmission voltage customers. Fort Bliss, (Rate 31) is the rate schedule that does not receive the benefit of the "ERR" tariff provision under the Stipulation, which gratuitously gives DOD the right to present its case to the PUC, DOD cannot <u>agree</u> to a Stipulation which on its face discriminates against a tax-payer supported transmission voltage customer like Fort Bliss in the favor of other private entities. Paragraph 10 of the Stipulation involves an enhanced "retroactive" application of the "ERR" tariff provision which DOD questions in Paragraph 14 (f). Thus, while DOD is generally supportive of the proposed Stipulation, DOD cannot be a signatory party. Copies of this letter are being sent to all parties in accord with the Certificate of Service.

Sincerely,

David A. McCormick

DAVID A. McCORMICK
Attorney

CERTIFICATE OF SERVICE

I hereby certify that I have caused a copy of the foregoing letter to be sent by first class, postage prepaid U.S. Mail to the following addressees:

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Nanette Williams
Assistant City Attorney
Two Civic Center Plaza
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Dated this 20th day of October 1987 at Fairfax County, Virginia.

David A. McCormick
DAVID A. McCORMICK

DOCKET NOS. 7460 & 7172

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § § §	PUBLIC UTILITY COMMISSION
APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVIEW OF THE SALE AND LEASEBACK OF PALO VERDE NUCLEAR GENERATING STATION UNIT NO. 2	§ § § § §	OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that statutory notice of the above-styled applications was provided to the public and to interested persons and said applications were processed in accordance with Applicable Statutes and Commission rules. An Examiner's Report containing Findings of Fact and Conclusions of Law was submitted.

1. On October 22, 1987, the Company, the General Counsel, and intervenors, ASARCO Incorporated, Phelps-Dodge Refining Corporation, Border Steel Rolling Mills, Inc., and W. Silver, Inc. et al signed and filed with the Commission a Stipulation addressing all issues in this Docket. The United States Department of Defense, also an intervenor in the case, filed a letter with the Commission stating it could not sign, but did not oppose the Stipulation. The Stipulation was not signed by the City of El Paso, the Office of Public Utility Counsel or the Texas State Agencies.

On March 22, 1988, the signatory parties to the Stipulation filed an Amended and Restated Stipulation, incorporating further concessions made by the Company in briefs and oral argument before the Commission. A copy of this document is attached as Appendix A to this Order.

On March 22, 1988, the Company agreed to further modification of the Amended and Restated Stipulation, as follows:

(a) The Company agreed that the entire $60 million disallowance provided for in the Amended and Restated Stipulation shall be assigned to Palo Verde Unit 1 and removed from rate base in this docket.

[1] (b) The Company agreed that issues of decisional prudence arising after the effective date of the Commission's order in Docket No. 1981 shall not be resolved in this docket insofar as such decisional prudence may affect the regulatory treatment of Palo Verde Unit 3, but rather shall remain open issues in future proceedings. All issues of decisional prudence arising prior to the effective date of the Commission's order in this docket shall be resolved as to the regulatory treatment of Palo Verde Units 1 and 2. "Decisional prudence" specifically includes any decisions, acts, or omissions relating to the Company's decision to become or to remain a 15.8% participant in the Arizona Nuclear Power Project, including but not limited to the prudence of the Company's load forecasting methodologies and practices.

(c) In the event of a disallowance of all or a portion of Palo Verde Unit 3, the Company agreed that the Commission may consider what treatment, if any, of common facilities would be appropriate, in conformance with Statement of Financial Accounting Standards No. 92 (FASB 92).

[2] 2. As modified by the Company at the open meeting on March 22, 1988, the Amended and Restated Stipulation provides for a Texas base rate increase in this Docket of $45,694,691, to be phased-in pursuant to the rate moderation plan in Paragraph 5 of the Amended and Restated Stipulation.

[3] 3. It is the policy of this Commission to encourage the settlement of proceedings before this Commission, for the following reasons:

(a) Settlements usually reduce the expense to ratepayers and taxpayers of resolving the issues presented;

(b) Settlements usually conserve the resources of the Commission available for ratemaking;

(c) Settlements allow the parties to the settlement to avoid the risk that a litigated resolution to the issues may produce results that are unacceptable to such parties; and

(d) Settlements promote peaceful relations among the parties.

[4] 4. Even where some parties to a proceeding do not agree to a stipulated result, it is reasonable to adopt such a stipulation if:

(a) The parties opposing the stipulation have notice that the stipulation may be considered by the Commission and an opportunity to be heard on their reasons for opposing the stipulation;

(b) The matters contained in the stipulation are supported by a preponderance of the credible evidence in the case;

(c) The stipulation is in accordance with applicable law;

(d) The stipulation results in just and reasonable rates; and

(e) The results of the stipulation are in the public interest, including the interest of those customers represented by parties opposing the stipulation.

5. Pursuant to the Findings of Fact and Conclusions of Law set forth below, the Commission finds the Amended and Restated Stipulation, as modified, is a reasonable basis for resolution of the issues in this case and that adoption of the Amended and Restated Stipulation, as modified, as the basis of the Commission's Order in this proceeding is in the public interest. Modified Exhibits to the Amended and Restated Stipulation have been attached to this Order to reflect the modifications agreed to by the Company at the March 22, 1988 open meeting.

6. The above-styled applications of El Paso Electric Company are hereby GRANTED in part and DENIED in part, as reflected in the terms of this Order and the attached Findings of Fact and Conclusions of Law, which are adopted and substituted for those in the Examiner's Report. The Examiner's Report is adopted only to the extent it is not inconsistent with the specific Findings of Fact and Conclusions of Law adopted by this Order. The Examiners' Report and the Findings of Fact and Conclusions of Law contained therein, pertaining to the prudence of El Paso Electric Company's participation in Palo Verde are expressly repudiated.

[2] 7. The Company shall receive a base rate revenue increase of $45,694,691, of which $20,769,479 shall be immediately incorporated into the Company's rates and $24,925,212 shall be deferred for Later recovery pursuant to the rate moderation plan in the Amended and Restated Stipulation.

8. The Company shall maintain records tracking the effect of the ERR approved in this case. The issue of who should bear the burden of any resulting underrecovery shall be addressed in the Company's next general rate case.

9. The Company shall file revised rate schedules in accordance with the rates and guidelines set out in this Order sufficient to generate revenues not greater than those prescribed in this Order no later than twenty (20) days from the date of this Order. The Company shall also file any other pages of its tariff that are being revised pursuant to this docket. The revised tariff sheets shall be filed in four (4) copies of the Commission filing clerk and shall comply with the requirements of P.U.C. SUBST. R. 23.24. The Company shall serve a copy of its revised tariff on all parties of record at the same time that it is filed with the Commission. The parties shall have ten (10) days from the date of filing to present their written objections to the revised tariff, if any, to the Commission staff for its review and consideration. The Commission staff shall have twenty (20) days from the date of the filing of the revised tariff to review it for approval or rejection. The tariff shall be deemed to be approved and shall become effective upon the expiration of twenty (20) days after filing

or sooner upon notification by the examiner. In the event of rejection, the Company shall be notified by the examiner, with a copy sent to all parties, and it shall have ten (10) additional days to file another revised tariff, with the same procedures then to be repeated.

10. The revised and approved rates shall be charged only for service rendered in areas over which this Commission was exercising its original or appellate jurisdiction as of the adjournment of the hearing on the merits herein, and said rates may be charged only for service rendered after the tariff approval date. Should the tariff approval date fall within the Company's billing period, the Company shall be authorized to prorate each customer's bill to reflect that customer's customer charge, demand charge, and daily energy consumption at the appropriate new rates.

11. This Order is deemed effective on the date of signing. Approval of the revised tariff filed in compliance with this Order shall be deemed to be final on the date of its effectiveness either by operation of this Order or by notification by the examiner, whichever occurs first.

[5] 12. The issue whether the Company's sale and leaseback transactions relating to Palo Verde Unit 2 are in the public interest is reserved for decision in the Company's next rate case.

13. The issue of reconciliation of EPEC's fuel expense for the period August 1985 through October 1987 is severed from this docket.

14. The Company shall perform a revised minimum system distribution plant study, and present the results in its next general rate case filing.

15. The Company shall perform the appropriate studies, so that during the Company's next general rate case, the load and usage characteristics at the state agencies, as a group, including any state universities and colleges, can be compared to the load and usage characteristics of both Rate Classes 24 and 41.

16. The issue as to the reasonableness of the Company's and the Cities' rate case expense incurred in the prosecution of this case is severed from this docket.

17. All motions, applications, and requests for entry of specific Findings of Fact and Conclusions of Law and any other requests for relief, general or specific, if not expressly granted herein are denied for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 30th day of March, 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Dennis L. Thomas
DENNIS L. THOMAS

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: Marta Greytok
MARTA GREYTOK

ATTEST:

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

DOCKET NO. 7460

IN THE MATTER OF THE APPLICATION	§	PUBLIC UTILITY COMMISSION
OF THE EL PASO ELECTRIC COMPANY	§	
FOR AUTHORITY TO CHANGE RATES	§	OF TEXAS

AMENDED AND RESTATED STIPULATION

In consideration of the mutual agreements and covenants herein contained, the undersigned parties stipulate and agree as follows:

1. El Paso Electric Company (the "Company" or "EPE") will remove from rate base the sum of $60 million on a total Company basis ($50 million will be assigned to Palo Verde Unit 1 and $10 million to Palo Verde Unit 3).

[1] a. The Texas jurisdictional effect of this removal shall be established based on the jurisdictional allocators in this case and shall remain constant throughout the life of the affected units. Except as specifically provided in Paragraph 8, this disallowance will settle (a) all issues relating to decisional prudence on Palo Verde Units 1, 2 and 3 ("decisional prudence" specifically includes any decisions, acts or omissions relating to the Company's decision to become or to remain a 15.8% participant in the Arizona Nuclear Power Project, occurring prior to the date on which this Amended and Restated Stipulation is executed, including but in no way limited to the prudence of the Company's load forecasting methodologies and practices); (b) all issues relating to construction prudence on Palo Verde Units 1 and 2, whether resulting from decisions, acts or omissions of El Paso Electric Company, Arizona Public Service Company

or any other person, firm or corporation ("construction prudence" includes all issues relating to or arising out of the licensing, construction or startup of the units in question); and (c) those issues relating to construction prudence on Unit 3 resulting directly from the construction of Units 1 and 2, limited to those matters delineated on the attached Exhibit A. Specific issues to remain "open" on Palo Verde especially as to Unit 3 are set forth in Paragraph 8.

b. The Company agrees that in the event it sells or otherwise deregulates Palo Verde Unit 3 (other than through a sale-leaseback), the $10 million disallowance assigned to Unit 3 will be applied against Unit 1, and the Company hereby waives any claim of retroactive ratemaking relating to such application.

c. The Company further agrees that if the Company sells a portion of its Palo Verde participation (other than in connection with a sale-leaseback), the Commission may reconsider the cost levels at which Units 1 and 2 are included in the Company's rates. The Company hereby waives any claim of retroactive ratemaking relating to such reconsideration.

2. On a Texas jurisdictional basis, the ratio of the tax basis of Palo Verde Unit 1 and Unit 3 to the book basis of each unit prior to the write-off adjustment set forth in Paragraph 1 will be calculated. The write-off amount ($50 million for Unit 1, $10 million for Unit 3) will be multiplied by the ratio to produce the equivalent reduction to the jurisdictional tax basis for the respective units. The adjusted tax basis will be used in all Texas rate cases for the calculation of tax depreciation on these units.

3. The parties agree they will support the Company's pending "in-service" application on Unit 2 in Docket 7280.

4. The Company will receive a base rate increase in this Docket for its Texas jurisdiction, before the effect of the rate moderation deferral is taken into account, in the amount of $4~~8~~6,846,316. Exhibit B provides the calculation of the revenue requirement and rate base. The basis for determining this amount is set forth on Page 1 of 3 of Exhibit B. The reallocation of all Unit 2 Contra-AFUDC to Unit 1 (including the impact on deferrals as noted in Exhibit B (2) (c)) will not be contested in future
[6] cases. The rate base treatment of accumulated deferred income taxes ("ADFIT") relating to future tax depreciation associated with the disallowance shall remain an open issue to be addressed in the Company's next rate case, except as discussed in Paragraph 2. Further, if the treatment of ADFIT in the next rate case results in a lower Texas revenue requirement, the Company agrees that the "overcollection" during the first year of the rate moderation plan ("RMP") will be flowed back to the ratepayers in the revenue requirement for the second RMP year. The amount of this "overcollection" will be calculated as if the treatment of ADFIT used in the next rate case had been used in the calculation of the revenue requirement in this Docket No. 7460.

[2],[6] 5. This non-fuel base rate increase shall be phased-in consistent with the requirements under the "Statement of Accounting Standards No. 92" (FASB 92) dated August 1987. This phase-in or RMP is for the costs associated with Palo Verde Units 1 and 2 which have been approved by the Public Utility Commission of Texas ("PUCT") for ratemaking purposes in Docket No. 7460. Throughout the term of this agreement, the costs to be deferred shall be derived by subtracting:

A. EPE's Texas jurisdictional non-fuel base revenue requirement to be charged to customers under the RMP, from

B. EPE's total Texas jurisdictional non-fuel base revenue requirements prior to rate moderation.

EPE shall initiate recovery of the deferred costs by filing annually a formal application with the PUCT. The application shall be accompanied by a rate filing package as prescribed under the PUCT's then current Procedural and/or Substantive Rules. Both EPE's total Texas jurisdictional revenues and cost of service shall be determined in accordance with the then current rules and practices of the PUCT. Said determination shall include Findings of Fact and Conclusions of Law with respect to the appropriate Texas jurisdictional revenues, cost of service, the amount of costs to be deferred and the accumulated deferrals. The agreed-upon Texas jurisdictional revenues and cost of service for the test year ended September 30, 1986 and as projected for each year of the phase-in is shown in Exhibit C. The projected deferrals could be different each year depending on other factors, such as actual sales, cost-of-service items other than those related to Docket No. 7460, the cost of capital, the method selected to calculate, accrue and book the deferrals, etc.

a. Rate increases beginning with the Final Order in Docket No. 7460 shall be as follows:

(i) The total Texas retail non-fuel base revenue increase shall be 13.74%. Net of fuel this equates to approximately 4%.

(ii) Not sooner than one year after the increase in Docket No. 7460 becomes effective, non-fuel base revenues shall increase by an additional 4%.

(iii) **Not sooner than one year after the second increase, non-fuel base revenues shall again increase by 3.5%.**

(iv) Not sooner than one year after the third increase, non-fuel base revenues shall again increase by 3.5%.

(v) Notwithstanding Paragraphs 5(a)(ii)-(iv), if a smaller increase would allow complete amortization of the deferrals within one year, the Company will request only the amount of increase needed to support that level of amortization.

(vi) Thereafter, and until the earlier of either (A) the tenth anniversary of the Final Order in Docket No. 7460 or (B) the year in which the cost-of-service deferrals approved in Docket No. 7460 are projected to reach zero, non-fuel base rates shall not be increased except pursuant to Paragraph 5(b) below. Upon the occurrence of condition (B), EPE shall notify the Commission and the parties hereto. Upon a finding by the PUCT that the deferral balance has reached zero, the RMP shall be terminated.

b. This RMP provides that the cost-of-service deferrals approved in Docket No. 7460 shall be scheduled for recovery on or before the tenth anniversary date of the Final Order in said Docket. In the event projections indicate that these deferrals will not be fully recovered by the tenth anniversary date of the Final Order, then EPE shall be permitted to adjust non-fuel base revenues after the fourth increase specified in Paragraph 5(a)(iv) above. As with the other increases permitted under the phase-in, EPE shall adhere to the procedural requirements specified in this paragraph.

c. The cost-of-service deferrals approved for ratemaking purposes shall be deferred from month to month for the succeeding twelve-month period on a gross of tax basis at EPE's prevailing AFUDC rate with corresponding deferred tax reserves in Account 186 and the necessary subaccounts. The balance of cost-of-service deferrals will not be included in rate base. However, recovery of all capitalized return is allowed over the life of the RMP.

d. Any rate increase relating to Palo Verde Unit 3 is not prohibited by this RMP, but would be in addition to it.

e. It is the parties' intention that this phase-in plan continue to be in full compliance with FASB 92 or its successor. The parties recognize that FASB 92 could be amended and/or clarified from time to time. In either event, the parties shall readdress the terms of this Amended and Restated Stipulation to reflect such amendments or clarifications.

f. For purposes of determining the cost-of-service deferrals for the first year of this phase-in, the parties have agreed to flow back the unprotected portion of the excess accumulated deferred income taxes resulting from a change in the tax rate under the 1986 Tax Reform Act and the deferred income taxes associated with Palo Verde-related ABFUDC over the remaining life of the corresponding assets. The parties shall address whether these accumulated deferred income taxes should be flowed back at an accelerated rate in EPE's next adjudicated proceeding. In any event, the ratemaking treatment of these accumulated deferred taxes shall be consistent with the flow back used for financial reporting purposes.

6. Current Texas average non-fuel base rates are agreed to be $0.05014/KWh. This would be the starting point for any increases.

[7] 7. The parties agree to a new Texas system fuel factor of $0.016587/KWh. The Fixed Fuel Factors due to different voltage levels of service are agreed to be:

Primary Voltage	$0.016254/KWh
Secondary Voltage	$0.016801/KWh
Fort Bliss	$0.015663/KWh
Border Steel	$0.015821/KWh
ASARCO	$0.015821/KWh
Phelps-Dodge	$0.015965/KWh

All fuel-related costs shall remain subject to reconciliation, including the appropriate regulatory ratemaking treatment to be afforded the Company's involvement in the Palo Verde Uranium Venture.

8. [8] The parties agree to the following with regard to the status of Palo Verde Unit 3 and issues to remain open on Palo Verde:

a. The parties agree Palo Verde Unit 3 does not meet the Commission's current in-service criteria as set forth in PUCT Substantive Rule 23.21(c)(2)(E) and will remain under construction until completion of the Arizona Interconnection Project ("AIP").

b. Without waiving their legal positions on the issues set forth in Paragraph 8(f) below, the parties agree that if a Certificate of Convenience and Necessity is required for AIP by the Public Utility Regulatory Act in Texas, they will not oppose the granting of such CCN.

c. **Based on Paragraph 8(a), the Company agrees not to file a case to recover Palo Verde Unit 3 in rates based on a test year ending earlier than December 31, 1989, in exchange for which the parties** agree to support a request by the Company for an accounting order if needed to preserve the Company's opportunity to seek and obtain recovery of all costs associated with Unit 3.

d. Because Unit 3 is under construction as set forth in Paragraph 8(a), the following accounting treatment will continue until Unit 3 is found to be in-service by the Public Utility Commission of Texas:

(1) Deferral of all items of costs which would be expensed such as property taxes, operating expenses and maintenance expenses with offset for any fuel displacement credits.

(2) Capitalization of AFUDC.

(3) Fuel savings from operation of Unit 3 shall not be considered as reconcilable fuel expense for any of the period preceding the date when Unit 3 rates are effective.

[9] e. The only issues remaining open on the Palo Verde plant arising under either the prudence or "used and useful" standards are:

(1) The appropriate application of the "used and useful" test. The parties understand and agree that the resolution of the decisional prudence issues in this Docket cannot be used as evidence in a Unit 3 case except to demonstrate that such issues have been resolved.

(2) Does excess capacity actually exist on EPE's system with regard to Unit 3? (In addition, excess capacity issues relating to Units 1 and 2 may be raised once the phase-in plan described in Paragraph 5 is concluded, but not before.)

(3) Where the prudence of a utility's forecasting and decisional processes leading to the construction of plant is not at issue, is it permissible to exclude such plant from rate base as excess capacity on the theory that it is not used and useful in providing utility service?

(4) If so, how should excess capacity be treated for regulatory and accounting purposes? For example, is deregulation an appropriate regulatory alternative? If so, on what terms should deregulation be implemented?

(5) The reasonableness of Unit 3 O&M expenses.

(6) The reasonableness of Unit 3 construction costs (except any costs directly related to the construction or startup of Units 1 and 2 as delineated in Exhibit A).

[10] 9. The Company will accept the Staff's decommissioning funding plan provided it is approved by the IRS as a tax qualified plan. If it is not, then the parties agree to support in the next rate case the Company's decommissioning funding plan as filed in Docket 7460. In either event, the decommissioning fund shall be held in an irrevocable trust. The contingency percentage shall be 10% as noted in the Staff's testimony in Docket 7460.

10. The Company agrees to refund the amount collected during the court-ordered stay of Docket 6350 to the extent that such amount exceeded the revenues which would have been recovered had the Commission-ordered tariffs in Docket 6350 been in effect, together with interest accruing since the stated effective date of the tariffs approved under the Commission's Final Order in said docket, and calculated at the postjudgment interest rate

prescribed by the Texas Consumer Credit Commissioner, pursuant to Section 2 of TEX. REV. CIV. STAT. ANN. art. 5069-1.05, for each month since the stated effective date of said tariffs.

11. A proceeding shall be instituted by EPE to establish performance standards to be applied to Palo Verde Unit 1 and Unit 2. The performance standards established by the Commission in said proceeding shall apply to the period beginning with the effective date of the rates ordered in Docket No. 7460 and ending when the RMP described in Paragraph 5 herein is terminated. The Company agrees to waive any reward to which it may be entitled if the initial period to which performance standards are applied does not include a fuel load. The Company further agrees not to request performance standards more favorable to its interests than those contained in the Stipulation dated October 22, 1987, and previously executed by the signatory parties in this Docket No. 7460.

12. The Company will present to the Commission for expedited consideration, any proposed settlement of its litigation with Combustion Engineering (CE). The Company agrees that any monies recovered from CE, through either judgment or settlement, will be held by the Company for appropriate distribution as ordered by the Commission.

13. The parties agree that the Company's revenue requirement for Docket No. 7460 shall be distributed to and recovered from the various customer classes in accordance with the class cost of service methodology filed by the Company in this Docket, as revised, incorporating those Staff cost allocation adjustments listed in Exhibit D and subject to the agreed upon class base revenue requirements as shown on the attached Exhibit E.

14. For the purposes of this Docket No. 7460 only, and except as provided in Subparagraphs 14(a) through 14(f) below, the parties agree to implementation of the individual rate structures proposed by the Company in its Rate Filing Package, as adjusted to recognize the reduced revenue requirements agreed to by the parties herein.

a. Customer Charges for the following schedules shall be:

(i)	Schedule No. 01	Residential Service	\$ 4.00 per month
(ii)	Schedule No. 02	Commercial Service (Proposed)	\$ 5.50 per month
(iii)	Schedule No. 24	General Service	\$13.00 per month

b. Schedule No. 01, Residential Service charges per KWh shall be as follows:

(i) The establishment of a summer/winter first-block energy charge with the summer charge being \$0.005/KWh higher than the winter charge.

(ii) The current tail block of 800 KWh (Residential Space Heating Service) customers during the November through April billing period shall remain unchanged from the current tariff.

(iii) The price differential for Residential Space Heating Service shall be \$0.01673/KWh between blocks during the November through April billing period.

c. Schedule No. 02, Commercial Service (Proposed).

The Space Heating Rider as it currently exists in Schedule No. 24, General Service, is to be maintained in its present form for the proposed Schedule No. 02.

The space heating restrictions and price differentials as presently exist under this rider shall be maintained in the rider for this rate.

d. Schedule No. 99, Miscellaneous Service Charges.

(i) The premium overtime charge shall be $35.00 for New Service, Non-Pay Reconnect and "No Light" Service Call charges.

(ii) The Returned Check or Bank Draft charge shall be $8.00.

e. Under the Primary Voltage Discount Clause for Schedule Nos. 24, General Service; 25, Large Power; and 45, (Proposed) Supplementary Power Service for Cogeneration and Small Power Production, the transformer discount shall for this rate case alone be increased to $0.30 per kilowatt of adjusted kilowatt demand.

[11] f. As a part of the rate moderation plan embodied in this Stipulation, the Parties agree that the ERR shall continue to be available for those classes and at the demand charge discount level approved by the Commission in Docket No. 6350 through the end of the initial four-year phase-in Period for the base rate increases agreed to in Paragraph 5. Thereafter, the continuation of the ERR shall be subject to reevaluation in light of then prevailing economic circumstances and such other factors as the Commission shall deem relevant at the time. It is agreed that the disposition and allocation of any revenue shortfall resulting from application of the ERR shall be resolved in EPE's next general rate filing with this Commission.

15. EPE in its next general rate filing will provide testimony and support for the use of a "minimum size" allocation methodology for Distribution Plant.

16. EPE agrees that in its next general rate filing it will provide testimony and documentation in support of a new study that it will have conducted prior to such rate filing in regard to the separation of Distribution Plant investment between primary and secondary voltages.

17. In exchange for the voluntary withdrawal of the prefiled direct testimony of ASARCO's Phase II (PVNGS) witnesses, Michael K. Moore, Dr. Donald A. Murry and Dr. William E. Avera, EPE, by its execution of this Amended and Restated Stipulation, hereby reduces and limits its request for a revenue increase in this Docket No. 7460 to that level which is consistent with this Amended and Restated Stipulation. The parties to this Amended and Restated Stipulation agree that the prefiled direct testimony of all other witnesses sponsored by the signatory parties, except as heretofore ruled upon by the Examiners to the contrary, shall be tendered for admission into the evidentiary record in this Docket without objection by any such party. The signatory parties further agree to waive authentication of such testimony, and to forego cross examination of such other witnesses, except to the extent that each signatory party in its discretion deems cross-examination necessary in response to or in anticipation of cross-examination by any party to this Docket No. 7460 who is not also a party to this Stipulation and agreement.

18. It is specifically agreed between the Company and those parties to this Amended and Restated Stipulation who are not regulatory authorities or governmental bodies that, in the event the Company seeks regulatory, judicial, or other legal authorization to depart from the terms hereof in a manner which would increase the rate path set forth in Paragraph 5 other than as prescribed therein, then in such event, the issues referenced in
[1] Paragraph 1 relating to decisional prudence and construction prudence shall be subject to reopening and redetermination in a future docket upon petition to the Commission by any party, including the Commission Staff, to this Amended and Restated Stipulation.

19. The undersigned believe this Amended and Restated Stipulation, if adopted by the Commission, represents a fair, just and reasonable solution to the issues being resolved. Moreover, this Amended and Restated Stipulation will serve the purpose of moderating the rates of El Paso Electric Company in the Texas jurisdiction. This Amended and Restated Stipulation reflects settlement discussions and if this Stipulation is not adopted in its entirety by the Public Utility Commission of Texas, then it shall have no force or effect and the statements and/or positions taken herein by any of the undersigned parties shall not be admissible in any proceeding before any regulatory body or Court.

20. It is recognized and agreed by the parties to this Amended and Restated Stipulation that by filing this Stipulation no party necessarily expresses agreement to or concurrence with any specific methodology, finding, or conclusion expressed herein, and that such Stipulation is made and filed solely in connection with compromise settlement of Docket No. 7460 subject to the specific approval by the Commission of the matters herein stipulated and agreed to between them.

Executed this 22nd day of March, 1988.

EL PASO ELECTRIC COMPANY

By: Michael D. McGhee

COMMISSION GENERAL COUNSEL

By: [signature]

ASARCO Incorporated

By: J. Alan Holman

W. SILVER, INC., et al.

By: Marianne Carroll

PHELPS-DODGE REFINING CORPORATION

By: [illegible]

BORDER STEEL ROLLING MILLS &
EL PASO IRON & METAL

By: C. Michael [illegible]

2702E

EXHIBIT A

1. Reactor Coolant Pumps (RCP), i.e.,

    a. problems with the diffuser/casing cap screws and diffuser/suction pipe cap screws;

    b. problems associated with the cavitation damage to the diffuser-vane upper-inlet tips of all four RCP's;

    c. problems resulting from broken impellers in the RCP's.

2. Control Element Assembly (CEA) shroud, i.e.,

    a. cracks at or near welds in the shroud tubes, or at the attachment of CEA extension-shaft-guides to webs, or between shroud-tube and web;

    b. crack in the base metal of a web;

    c. wear marks or sizing of shroud;

    d. ductile break in a web.

3. Safety-Injection-Nozzle Thermal Liner, i.e.,

    a. problems resulting from dislodged thermal liners.

4. Resistance Temperature-Detector Thermowells, i.e.,

    a. bent or broken thermowells.

5. Low-Pressure Safety-Injection Pumps (LPSI), i.e.,

    a. failures to restart.

6. Any issue or problem discovered during hot functional testing on Unit 1 and subsequently corrected on Units 2 and 3.

7. Issues relating to sizing or construction of the pipeline supplying effluent to the plant.

MODIFIED

EXHIBIT B

ADJUSTMENTS TO STAFF REVENUE REQUIREMENT

The base rate increase amount of $45,694,691 incorporates the following:

1. Staff's recommended rate of return on equity 13.0%, adjusted to 12.72% for penalties quantified in Staff testimony (as supplemented). The allowed overall rate of return is 10.56%.

2. The Company's requested rate base and cost of service as adjusted in the Staff testimony (including errata/corrections), except as follows:

   a. Recalculations of property insurance expense (with Palo Verde CWIP removed from the ratio used to derive such expense).

   b. Recovery of all deferred expenses for Palo Verde Units 1 and 2, to be included in rate base and amortized over the lives of the respective plants. For purposes of this docket, the Company's estimates of deferrals through the month of October were utilized. Reevaluation of the total deferral amounts will occur at the time of the next rate case in order to include actual data through the end of the deferral period with necessary adjustments. The adjustment of the deferral balance for the effects of the $50 million disallowance related to Palo Verde Units 1 and 2 shall remain credits will not be refunded, but will be included with the deferrals as an offset to the amount to be recovered.

   c. Assignment of all Palo Verde Unit 2 Contra-AFUDC to Palo Verde Unit 1. The balance of deferred expenses for Palo Verde Units 1 and 2 will not be adjusted to reflect this reallocation of Contra-AFUDC.

   d. Reassignment of all Commons to Palo Verde Unit 1. If Unit 3 is sold, other than a sale/leaseback transaction, an appropriate adjustment to rate base will be made to remove the Palo Verde Unit 3 Commons from rate base. "Commons" means the common facilities at the Palo Verde Nuclear Generating Station, the Palo Verde Switchyard and the Palo Verde 500 KV Transmission System facilities.

   e. Treatment of accumulated deferred income taxes related to the disallowance. (See specific discussion of this issue in Paragraph 4.)

EL PASO ELECTRIC COMPANY
SCHEDULE P(B) - JURISDICTIONAL ADJUSTED COST OF SERVICE STUDY - DOCKET 7460 SETTLEMENT
FOR THE TEST YEAR ENDED SEPTEMBER 30, 1986
REVENUE REQUIREMENT

		TOTAL COMPANY	TEXAS	OTHER
ANNUALIZED OPERATING REVENUES	35C	310,562,693	201,893,699	108,668,994
COST TO SERVE				
FUEL	40C	62,564,900	41,816,401	20,748,499
PURCHASE POWER	45C	19,595,400	12,918,158	6,677,242
OPERATING EXPENSES				
OPERATION & MAINTENANCE	50C	142,118,677	94,427,743	47,690,934
INTEREST ON CUSTOMER DEPOSITS	55I	187,384	141,906	45,478
DEPRECIATION & AMORTIZATION	60C	28,025,267	17,323,007	10,702,260
DECOMMISSIONING	65C	635,076	405,638	229,438
TAXES OTHER THAN FEDERAL INC TAXES	75C	26,443,305	19,543,933	6,899,372
STATE INCOME TAX	85C	281,017	164,056	116,960
FEDERAL INCOME TAXES	120C	18,353,591	11,395,296	6,958,295
RETURN	125C	78,735,036	49,452,252	29,282,784
TOTAL REVENUE REQUIREMENT	135C	376,939,652	247,588,389	129,351,263
OTHER REVENUE	140C	1,588,533	1,182,074	406,459
BASE RATE REVENUE REQUIREMENT	145C	375,351,119	246,406,316	128,944,804
NON-FUEL / BASE REVENUE INCREASE	150C	66,376,959	45,694,691	20,682,269
CURRRENT FUEL / OPERATING REVENUES	151C	331,954,173	214,099,209	117,854,964
TOTAL REVENUE INCREASE	152C	44,985,479	33,489,181	11,496,299

MODIFIED
EXHIBIT B
ADJUSTMENTS TO STAFF REVENUE REQUIREMENT

EL PASO ELECTRIC COMPANY
SCHEDULE P(B) - JURISDICTIONAL ADJUSTED COST OF SERVICE STUDY - DOCKET 7460 SETTLEMENT
FOR THE TEST YEAR ENDED SEPTEMBER 30, 1986
RATE BASE

		TOTAL COMPANY	TEXAS	OTHER
PLANT IN SERVICE	160C	933,135,847	561,080,098	372,055,749
ACCUMULATED DEPRECIATION & AMORT	165C	(144,405,347)	(95,857,033)	(48,548,314)
NET PLANT IN SERVICE	170C	788,730,500	465,223,065	323,507,435
WORKING CAPITAL	190C	15,353,938	11,193,844	4,160,094
CONSTRUCTION WORK IN PROGRESS				
DEFERRED CARRYING COST	348I	35,353,461	35,353,461	0
CAPITALIZATION OF O & M	193I	39,150,114	39,150,114	0
DEDUCTIONS				
ACCUMULATED DEFERRED F I T	342C	(126,308,194)	(78,492,231)	(47,815,963)
INJURIES & DAMAGES RESERVE	330C	(100,000)	(71,873)	(28,127)
CUSTOMER ADVANCES FOR CONSTR	335I	(1,027,911)	(143,701)	(884,210)
CUSTOMER DEPOSITS	340I	(3,298,721)	(2,498,121)	(800,600)
UNAMORTIZED PRE 1971 ITC	345C	(651,847)	(391,945)	(259,902)
OTHER DEFERRED CREDIT - COPPER 1	347C	(1,604,411)	(1,024,774)	(579,637)
TOTAL RATE BASE	355C	745,596,929	468,297,839	277,299,090
REQUESTED RATE OF RETURN	365C	.10560	.10560	.10560
RETURN ON RATE BASE	370C	78,735,036	49,452,252	29,282,784

MODIFIED
EXHIBIT B
ADJUSTMENTS TO STAFF REVENUE REQUIREMENTS

1225

MODIFIED
EXHIBIT C
JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

Line No.	Description	1987 Total Company	1987 Texas	1988 Total Company	1988 Texas	1989 Total Company	1989 Texas
	Current Operating Revenues						
128	Base	233.102.252	150.096.080	281.600.952	180.034.235	301.218.421	193.085.942
129	Fuel	97.124.402	62.023.055	83.133.818	53.334.315	88.450.930	56.397.197
130	Other / IID Deferrals	3.174.543	1.021.177	8.999.125	1.062.024	7.061.810	1.104.505
131	Wheeling	252.000	160.958	252.000	158.659	252.000	157.832
132	Total Revenues	333.653.277	214.099.270	373.985.096	234.589.233	396.975.161	250.743.476
	Revenue Requirement						
133	Operation & Maintenance	222.630.570	148.406.261	237.956.165	155.075.224	242.555.706	157.371.880
134	Interest on Customer Deposits	187.384	141.906	187.384	141.906	187.384	141.906
135	Depreciation & Amortization	29.079.377	18.581.358	31.681.575	19.593.567	34.798.086	20.313.613
136	Taxes Other Than FIT	26.700.199	19.389.756	32.163.327	23.001.106	32.832.406	23.449.779
137	Federal Income Taxes	19.807.082	11.515.221	22.737.879	12.079.683	22.369.582	12.454.405
138	State Income Tax	267.001	128.408	502.535	282.705	496.272	278.983
139	Return on Rate Base	75.256.165	49.425.541	81.882.544	46.161.561	80.645.621	45.454.581
140	Deferred Debit (AEFUDC Amortization)	0	0	2.240.949	0	2.272.977	0
141	AB/ADFIT	0	0	-375.019	0	-380.370	0
14.	Total Revenue Requirement	373.927.777	247.580.451	408.897.339	257.135.753	415.777.576	259.466.188
143	Base Revenue Requirement	370.501.234	246.406.316	399.646.215	255.915.070	408.463.766	258.403.851
144	Non Fuel Base Revenue Requirement	294.768.234	195.708.771	314.397.515	201.226.093	321.847.766	202.648.799
145	Required Revenue Increase	40.274.500	33.489.181	34.912.244	22.546.520	18.802.415	8.922.712
146	Non Fuel Base Increase	61.527.074	45.694.691	32.796.562	21.191.050	19.837.344	9.584.857
	Settlement Proposal						
147	Total Settlement Increase with Fuel	5.995.086	8.563.971	11.042.792	8.556.831	7.591.980	6.095.793
148	Increase Deferral	34.279.414	24.925.210	23.869.451	13.990.480	11.210.427	2.826.920
149	Accumulated Deferral Related to AEFUDC			-52.673	0	-203.599	0
150	Accumulated Deferral	37.898.970	26.241.137	64.857.038	43.741.054	80.429.384	51.335.839
151	Net Accumulated Deferral	37.898.970	26.241.137	64.857.038	43.741.054	80.429.384	51.335.839
152	Settlement Total Revenues	339.648.363	222.663.241	385.027.888	243.145.264	404.567.149	256.839.240
153	Settlement Base-Sales Revenues	336.221.820	221.481.106	375.776.763	241.924.581	397.253.339	255.576.931
154	Settlement Non-Fuel Base-Sales Revenues	260.408.820	170.863.561	290.528.863	187.235.684	309.837.339	199.841.888
155	Settlement Non Fuel Revenue Increase	27.384.560	20.769.481	8.927.111	7.201.369	8.626.917	6.757.938
	Unit Rates						
156	Total	0.07396	0.07398	0.07514	0.07669	0.07655	0.07857
157	Non-Fuel Base Sales	0.05730	0.05707	0.05809	0.05936	0.05970	0.06143
158	Fuel	0.01666	0.01691	0.01705	0.01734	0.01684	0.01713
159	MWH Sales at Meter	4.546.213	2.993.712	5.000.917	3.154.392	5.189.545	3.252.920

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

Line No.	Description	1990 Total Company	1990 Texas	1991 Total Company	1991 Texas	1992 Total Company	1992 Texas
	Current Operating Revenues						
128	Base	319.049.725	205.267.109	337.414.799	219.139.500	354.091.624	224.047.256
129	Fuel	90.474.176	57.240.125	95.068.024	60.087.492	108.590.720	67.000.103
130	Other / IID Deferrals	6.002.602	1.148.605	4.705.029	1.194.633	3.679.291	1.242.418
131	Wheeling	277.200	172.963	304.920	189.125	335.412	207.417
132	Total Revenues	415.803.704	263.836.802	438.294.373	280.610.749	467.497.046	293.297.193
	Revenue Requirement						
133	Operation & Maintenance	250.959.407	162.132.066	265.548.872	170.673.753	276.635.696	176.217.006
134	Interest on Customer Deposits	187.304	141.906	187.304	141.906	187.304	141.906
135	Depreciation & Amortization	37.315.451	21.843.921	37.058.389	22.006.905	38.259.641	22.382.325
136	Taxes Other Than FIT	34.058.925	24.316.051	33.643.626	23.973.969	34.206.675	24.423.264
137	Federal Income Taxes	23.232.371	13.161.064	22.041.408	12.364.044	20.755.394	11.557.726
138	State Income Tax	510.944	287.992	490.692	274.237	468.021	260.516
139	Return on Rate Base	83.355.886	47.091.670	79.614.904	44.560.756	75.576.995	42.035.025
140	Deferred Debit (AEFUDC Amortization)	2.300.323	0	2.337.296	0	2.347.105	0
141	AB/ADFIT	-384.955	0	-391.142	0	-392.797	0
142	Total Revenue Requirement	431.535.737	268.975.468	441.331.591	273.093.650	448.042.994	276.937.840
143	Base Revenue Requirement	425.255.055	267.653.820	436.320.041	272.499.095	444.028.292	275.400.013
144	Non Fuel Base Revenue Requirement	333.189.055	209.400.172	332.133.741	207.200.590	332.695.192	206.794.297
145	Required Revenue Increase	15.731.953	5.138.506	3.037.218	-6.727.099	-19.454.052	-16.359.346
146	Non Fuel Base Increase	14.140.129	4.133.063	-5.281.058	-11.938.911	-22.196.432	-18.052.958
	Settlement Proposal						
147	Total Settlement Increase with Fuel	8.776.172	8.189.871	8.318.276	5.211.011	2.742.388	1.693.613
148	Increase Deferral	6.955.780	-3.051.206	-5.281.058	-11.938.911	-22.196.432	-18.052.958
149	Accumulated Deferral Related to AEFUDC	-341.950	0	-503.294	0	-898.303	0
150	Accumulated Deferral	93.876.970	53.705.105	95.667.208	47.436.916	78.953.929	34.392.022
151	Net Accumulated Deferral	93.876.970	53.705.105	95.667.208	47.436.916	78.953.929	34.392.022
152	Settlement Total Revenues	424.579.956	272.026.754	446.612.649	285.822.561	470.239.426	294.990.006
153	Settlement Base-Sales Revenues	418.300.076	270.705.105	441.601.099	284.438.803	466.224.724	293.540.971
154	Settlement Non-Fuel Base-Sales Revenues	326.234.076	212.451.458	337.414.799	219.139.500	354.091.624	224.047.256
155	Settlement Non Fuel Revenue Increase	7.104.349	7.104.349	0	0	0	0
	Unit Rates						
156	Total	0.07786	0.08102	0.07891	0.08253	0.07906	0.08301
157	Non-Fuel Base Sales	0.06072	0.06358	0.06029	0.06358	0.06079	0.06358
158	Fuel	0.01714	0.01745	0.01862	0.01895	0.01907	0.01943
159	MWH Sales at Meter	5.372.660	3.341.229	5.596.391	3.446.412	5.830.058	3.536.170

MODIFIED
EXHIBIT C
JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

Line No.	Description	1993 Total Company	1993 Texas	1994 Total Company	1994 Texas	1995 Total Company	1995 Texas
	Current Operating Revenues						
128	Base	369.537.911	232.574.592	377.248.976	239.788.227	386.477.094	246.574.444
129	Fuel	116.075.206	71.054.516	133.109.903	81.223.618	151.666.888	92.879.888
130	Other / IID Deferrals	2.311.316	1.292.115	937.849	1.343.799	-386.957	1.397.551
131	Wheeling	368.953	229.394	405.849	252.876	446.433	288.443
132	Total Revenues	489.093.387	305.150.617	511.782.576	322.688.511	538.283.379	341.132.319
	Revenue Requirement						
133	Operation & Maintenance	301.529.490	190.940.521	323.658.728	205.095.596	334.385.861	212.855.686
134	Interest on Customer Deposits	187.384	141.906	187.384	141.906	187.384	141.906
135	Depreciation & Amortization	38.900.978	22.003.920	41.311.304	24.473.196	42.004.832	25.170.044
136	Taxes Other Than FIT	34.765.142	25.046.160	36.044.063	26.123.216	36.270.034	26.516.211
137	Federal Income Taxes	19.625.460	11.017.660	19.742.292	11.171.329	18.451.156	18.620.959
138	State Income Tax	449.686	252.052	451.593	255.316	429.636	246.984
139	Return on Rate Base	72.025.576	40.403.100	72.392.555	40.966.082	68.336.720	39.380.073
140	Deferred Debit (AEFUDC Amortization)	2.359.627	0	2.362.600	0	0	0
141	AB/ADFIT	-394.079	0	-395.377	0	-399.605	0
142	Total Revenue Requirement	469.456.385	290.405.319	495.755.962	308.204.640	499.593.947	314.058.581
143	Base Revenue Requirement	466.776.116	289.163.811	494.412.244	306.687.966	499.454.471	313.180.506
144	Non Fuel Base Revenue Requirement	337.197.216	218.383.680	346.300.744	216.204.324	343.633.171	217.756.477
145	Required Revenue Increase	-19.637.002	-14.465.297	-16.026.635	-14.408.071	-38.689.432	-26.273.738
146	Non Fuel Base Increase	-32.340.696	-22.190.912	-30.948.231	-23.503.903	-42.043.923	-28.017.967
	Settlement Proposal						
147	Total Settlement Increase with Fuel	12.703.694	7.725.615	14.921.597	9.180.082	4.154.492	2.844.229
148	Increase Deferral	-32.340.696	-22.190.912	-30.948.232	-23.503.903	-42.043.923	-28.017.967
149	Accumulated Deferral Related to AEFUDC	-1.255.521	0	-1.617.742	0	-1.617.742	0
150	Accumulated Deferral	50.220.409	15.833.440	21.240.907	-5.990.602	-21.594.937	-34.016.569
151	Net Accumulated Deferral	50.220.409	15.833.440	21.240.907	-5.990.602	-21.594.937	-34.016.569
152	Settlement Total Revenues	501.797.081	312.876.231	526.704.173	331.788.543	542.437.071	343.676.548
153	Settlement Base-Sales Revenues	499.116.011	311.354.723	525.360.476	330.111.069	542.298.394	341.990.553
154	Settlement Non-Fuel Base-Sales Revenues	369.537.911	232.574.592	377.248.976	239.788.227	386.477.094	246.574.444
155	Settlement Non Fuel Revenue Increase	0	0	0	0	0	0
	Unit Rates						
156	Total	0.08137	0.08512	0.08334	0.08754	0.08405	0.08819
157	Non-Fuel Base Sales	0.06024	0.06358	0.05984	0.06358	0.05989	0.06358
158	Fuel	0.02112	0.02154	0.02349	0.02395	0.02415	0.02461
159	MWH Sales at Meter	6.134.182	3.657.706	6.304.026	3.771.155	6.453.501	3.877.002

MODIFIED
EXHIBIT C
JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

EL PASO ELECTRIC COMPANY
JURISDICTIONAL COST OF SERVICE STUDY
FOR THE FORECASTED YEARS 1987-1996

SUMMARY

1996

Line No.	Description	Total Company	Texas
	Current Operating Revenues		
128	Base	396.341.405	253.972.539
129	Fuel	159.725.205	90.287.165
130	Other / IID Deferrals	-3.816.995	1.453.453
131	Wheeling	491.077	310.012
132	Total Revenues	552.740.691	354.023.169
	Revenue Requirement		
133	Operation & Maintenance	361.351.421	230.770.930
134	Interest on Customer Deposits	187.304	141.906
135	Depreciation & Amortization	45.670.678	27.671.996
136	Taxes Other Than FIT	38.271.345	20.100.251
137	Federal Income Taxes	19.360.454	11.340.297
138	State Income Tax	445.235	260.098
139	Return on Rate Base	71.210.221	41.645.747
140	Deferred Debit (AEFUDC Amortization)	0	0
141	AD/ADFIT	-401.791	0
142	Total Revenue Requirement	536.110.940	340.019.233
143	Base Revenue Requirement	539.436.059	330.255.760
144	Non Fuel Base Revenue Requirement	370.764.259	234.462.778
145	Required Revenue Increase	-16.629.751	-14.003.936
146	Non Fuel Base Increase	-25.577.147	-19.509.760
	Settlement Proposal		
147	Total Settlement Increase with Fuel	8.947.395	5.505.024
148	Increase Deferral	-25.577.147	-19.509.760
149	Accumulated Deferral Related to AEFUDC	-1.617.742	0
150	Accumulated Deferral	-47.172.004	-54.326.329
151	Net Accumulated Deferral	-47.172.004	-54.326.329
152	Settlement Total Revenues	561.688.087	359.528.993
153	Settlement Base-Sales Revenues	565.014.005	357.765.520
154	Settlement Non-Fuel Base-Sales Revenues	396.341.405	253.972.539
155	Settlement Non Fuel Revenue Increase	0	0
	Unit Rates		
156	Total	0.08544	0.08957
157	Non-Fuel Base Sales	0.05993	0.06358
158	Fuel	0.02551	0.02599
159	MWH Sales at Meter	6.613.215	3.994.232

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MODIFIED
EXHIBIT C
JURISDICTIONAL COST OF SERVICE
FORECAST OF RATE PATH

EXHIBIT D

STAFF ALLOCATION ADJUSTMENTS TO THE COMPANY'S CLASS COST OF SERVICE

C.O.S. Line No.	FERC Account	EPEC Allocation Allocator	EPEC Allocation C.O.S. Line	Staff Allocation Allocator	Staff Allocation C.O.S. Line
Jurisdictional					
610	512	Energy	4020	Demand/Energy	3930/4020
615	513	Energy	4020	Demand/Energy	3930/4020
1119	928-Other	Labor	4545	Base Sales	385
1234 (Adj)	928-Other	Labor	4545	Base Sales	385
1232	925-P.V.	Labor	4545	Demand	3930
1243	926-P.V.	Labor	4545	Demand	3930
Class					
1232	925-P.V.	Labor	4545	Demand	3930
1243	926-P.V.	Labor	4545	Demand	3930
1267	930.2-P.V.	Labor	4545	Demand	3930
1250	904	Spec. Sales	4612	Class Sales	4470

EL PASO ELECTRIC COMPANY
TOTAL REVENUE REQUIREMENTS BY RATE CLASSIFICATION
FOR THE TEST YEAR ENDED SEPTEMBER 30, 1986
Moderated Proportional Increase

Line No	Description (1,3)		Annualized Base	Proposed Base	Base Revenue Increase Percent	Base Increase Amount	Proposed Moderated Base	Base Revenue Increase Percent	Base Increase Amount	Total Increase Amount	Total Increase Percent	Relative Base Incr Percent	Relative Total Inc Percent
1	Residential Service	01	53,551,972	66,146,729	23.52%	12,594,757	59,484,926	11.08%	5,932,954	2,306,609	3.26%	0.80	0.91
2	Small Commercial	02	11,511,162	13,442,071	16.77%	1,930,909	12,446,254	8.12%	935,092	293,491	2.01%	0.59	0.57
3	Municipal Str Lights	08	1,657,860	2,050,756	23.70%	392,896	1,842,842	11.16%	184,982	80,048	3.71%	0.81	1.04
4	EP Municipal Pumping	11	4,984,311	6,678,845	34.00%	1,694,534	5,765,388	15.67%	781,077	273,865	3.70%	1.13	1.04
5	Electrolytic Refining	15	2,456,566	2,669,650	8.67%	213,084	2,568,923	4.57%	112,357	-209,141	-5.16%	0.33	-1.45
6	Off-Peak Water Heat	21	1,360,136	1,841,527	35.39%	481,391	1,581,597	16.28%	221,461	21,644	0.94%	1.18	0.26
7	Irrigation Service	22	36,344	44,355	22.04%	8,011	40,135	10.43%	3,791	1,552	3.30%	0.75	0.93
8	General Service	24	37,883,680	52,904,536	39.65%	15,020,856	44,692,936	17.97%	6,809,256	3,310,958	6.07%	1.30	1.70
9	Large Power	25	19,385,991	25,357,011	30.80%	5,971,020	22,152,352	14.27%	2,766,361	681,800	2.32%	1.03	0.65
10	Private Security Light	28	693,507	827,861	19.37%	134,354	757,741	9.26%	64,234	38,381	4.70%	0.67	1.32
11	Transmission Voltage	29	2,017,473	2,751,918	36.40%	734,445	2,354,904	16.73%	337,431	-20,930	-0.56%	1.21	-0.16
12	Electric Furnace	30	2,837,690	4,727,026	66.58%	1,889,336	3,347,740	17.97%	510,050	107,068	2.24%	1.30	0.63
13	Military Reservation	31	4,757,464	6,639,599	39.56%	1,882,135	5,612,576	17.97%	855,112	255,826	3.40%	1.30	0.95
14	Cotton Gin Service	34	96,592	161,480	67.18%	64,888	113,954	17.97%	17,362	5,155	3.33%	1.30	0.93
15	City County Service	41	6,683,872	9,287,914	38.96%	2,604,042	7,876,638	17.85%	1,192,766	428,273	4.15%	1.29	1.16
16	Municipal Pumping	54	179,459	240,385	33.95%	60,926	207,544	15.65%	28,085	10,107	3.81%	1.13	1.07
17	Subtotal		150,094,079	195,771,662	30.43%	45,677,583	170,846,450	13.83%	20,752,371	7,584,706	3.56%	1.00	1.00
18	Other		1,182,074	1,199,182		17,108	1,199,182		17,108	17,108			
19	Total		151,276,153	196,970,844	30.21%	45,694,691	172,045,632	13.74%	20,769,479	7,601,814	3.55%		

CLASS REVENUE REQUIREMENTS

MODIFIED
EXHIBIT 8

1231

DEPARTMENT OF THE ARMY
OFFICE OF THE JUDGE ADVOCATE GENERAL
NASSIF BUILDING · 5611 COLUMBIA PIKE
FALLS CHURCH, VIRGINIA 22041-5013

20 October 1987

REPLY TO
ATTENTION OF
Regulatory Law Office
U 3490

SUBJECT: El Paso Electric Company, Texas PUC Docket No. 7460

Ms. Lisa Groomes
Filing Clerk
Public Utility Commission of Texas
7800 Shoal Creek Boulevard, Suite 450N
Austin, TX 78757

Dear Ms. Groomes:

A draft Stipulation of settlement was circulated to the parties by Mr. David H. Wiggs, Jr., counsel for the El Paso Electric Company, under a cover memorandum dated October 16, 1987. Recognizing that the Company, Commission Staff and other parties have made a significant effort to reconcile issues, it appears advisable to make a statement regarding the Stipulation. This letter is comment on behalf of the consumer interest of the intervenor, United States Department of Defense and other affected Executive Agencies (hereinafter "DOD"), regarding the proposed Stipulation.

The terms and conditions of the proposed Stipulation reflect compromise normally found in settlement proposals. As to paragraphs: 1,2,3,4,5,6,7, 8,9,11,12,15,16,17,18, and 19, DOD takes no position on the specific terms, but does not object to the net affect of these provisions for purposes of resolving the case. Paragraph 13 and related Exhibit E of the proposed Stipulation have the support of DOD. Counsel for El Paso Electric Company advised DOD of a possible slight modification of Exhibit 13, which has been received by TELEX this day. It changes the"total increase amount"for Fort Bliss (Rate 31) from $ 311,541 to $316,936. Given the overall merits of the proposed Stipulation, DOD makes no objection to that amended Exhibit E. If there are significant other modifications to Exhibit E or other items, DOD reserves the right to comment further and amend its position.

As to paragraph 14, signatories are required to agree to a provision (14 (f)) which affords some transmission voltage cusmtomers a preferential tariff treatment (not based on costs of service) that is not afforded to all transmission voltage customers. Fort Bliss, (Rate 31) is the rate schedule that does not receive the benefit of the "ERR" tariff provision under the Stipulation, which gratuitously gives DOD the right to present its case to the PUC. DOD cannot agree to a Stipulation which on its face discriminates against a tax-payer supported transmission voltage customer like Fort Bliss in the favor of other private entities. Paragraph 10 of the Stipulation involves an enhanced "retroactive" application of the "ERR" tariff provision which DOD questions in Paragraph 14 (f). Thus, while DOD is generally supportive of the proposed Stipulation, DOD cannot be a signatory party. Copies of this letter are being sent to all parties in accord with the Certificate of Service.

Sincerely,

David A. McCormick

DAVID A. McCORMICK
Attorney

DOCKET NO. 7460

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

FINDINGS OF FACT AND CONCLUSIONS OF LAW

FINDINGS OF FACT

1. El Paso Electric Company (EPEC or the Company) filed this request for a change in rates in all unincorporated areas in Texas in which it serves on April 6, 1987.

2. As amended, the proposed change was a base rate increase of $76,476,924 over adjusted non-fuel revenues for the test year ended September 30, 1986. The Company also sought a decrease in fuel revenues of $12,199,878. All Texas customers are affected by the proposed change.

3. The effective date of the Company's proposed rate change is July 19, 1987; implementation of rates beyond the effective date was suspended for the statutory period of 150 days until December 16, 1987. Because there were 68 days of actual hearing in this case, the suspension period is extended for 106 days until March 31, 1988.

4. The Company also filed identical requests for rate increases with the municipalities retaining original jurisdiction over electric utility rates. The ratemaking ordinances of those municipalities (the City of El Paso and the towns of Clint, Socorro, Vinton, Anthony, and Van Horn) were timely appealed to the Commission and the appeals are consolidated with this environs docket.

5. On October 31, 1986, EPEC filed an application reporting the sale and leaseback in August 1986 of 73.5 percent of its ownership of Unit 2 of the Palo Verde Nuclear Generating Station (PVNGS) and related common facilities; this filing was assigned Docket No. 7172. It was amended on August 13, 1987, when EPEC reported the sale and leaseback in December 1986 of the remaining 26.5 percent of its ownership interest in Unit 2 and common facilities. Docket No. 7172 was consolidated with the rate case on October 27, 1987.

6. A stipulation signed by fewer than all the parties to this docket was filed on October 22, 1987. In its Exceptions to the Examiners' Report, the Company indicated a willingness to make certain changes in the original stipulation. All parties had notice of, and an opportunity to be heard at the Final Order Hearing in this Docket, at which the Company was first to present oral argument. The Commissioners inquired during the Company's opening oral argument as to the Company's willingness to enter into an amended stipulation incorporating certain changes consisting primarily of those changes

offered in the Company's Exceptions to the Examiners' Report. All parties had an opportunity to be heard on the stipulation and the changes being suggested by the Commission. On March 22, 1988, an Amended and Restated Stipulation, which incorporated such changes, was signed and filed by the parties to the original stipulation.

At its open meeting of March 22, 1988, further concessions were made by the Company to the Amended and Restated Stipulation. Such concessions were as follows:

(a) The Company agreed that the entire $60 million disallowance provided for in the Amended and Restated Stipulation shall be assigned to Palo Verde Unit 1 and removed from rate base in this docket.

(b) The Company agreed that issues of decisional prudence arising after the effective date of the Commission's order in Docket No. 1981 shall not be resolved in this docket insofar as such decisional prudence may affect the regulatory treatment of Palo Verde Unit 3, but rather shall remain open issues in future proceedings. All issues of decisional prudence arising prior to the effective date of the Commission's order in this docket shall be resolved as to the regulatory treatment of Palo Verde Units 1 and 2. "Decisional prudence" specifically includes any decisions, acts, or omissions relating to the Company's decision to become or to remain a 15.8% participant in the Arizona Nuclear Power Project, including but not limited to the prudence of the Company's load forecasting methodologies and practices.

(c) In the event of a disallowance of all or a portion of Palo Verde Unit 3, the Company agreed that the Commission may consider what treatment, if any, of common facilities would be appropriate, in conformance with Statement of Financial Accounting Standards No. 92 (FASB 92).

7. EPEC published notice of its requested rate increase four times in newspapers of general circulation in each county in which it serves, and provided notice of its filing to the appropriate office of each affected municipality simultaneously with its filing at the Commission.

8. The Company gave notice of its filing in Docket No. 7172 by publishing, once each week for two consecutive weeks in newspapers of general circulation in each county in which EPEC serves, notice of the sale and leaseback transaction, as ordered in that docket.

9. In the <u>Long-Term Peak Demand and Capacity Resource Forecast for Texas 1986</u>, the Commission recognized the unique characteristics of EPEC's service territory, and permitted the Company until the end of 1988 to gather the data needed to make accurate projections of the kW peak demand reductions and kWh savings, and the costs and benefits of specific conservation and load management activities and programs.

10. EPEC provided testimony about its energy efficiency plan and the extent to which the goals have been reached, insofar as that was

possible. The Company also indicated the status of all energy efficiency programs and studies, and documented the costs and, insofar as was possible, benefits.

11. Overall, EPEC has improved its performance in the area of conservation and load management since its last rate case.

12. Because of limited residential consumption and demand, the opportunity for significant savings in that customer class is negligible, and the change in emphasis in EPEC's conservation and load management programs from residential to commercial and industrial appears justified.

13. Even though some load management programs legitimately promote increased sales, the Company must carefully plan and thoroughly justify such programs to insure their compliance with the load shape objectives recognized by this Commission.

14. EPEC's High Efficiency Appliance Program promotes the indiscriminate consumption of electricity, does not further energy efficiency goals, and cannot be justified on any basis.

15. The Commission must consider a utility's conservation and energy efficiency activities in fixing a return on invested capital, regardless of the source of funding for programs promoting increased sales.

16. EPEC's Energy Efficiency Plan to be filed December 31, 1989, will include the data it will have collected by year-end 1988. That Energy Efficiency Plan must comply in every respect with the Commission's requirements for evaluating costs and benefits of conservation and load management programs.

17. The Commission should exclude from the Company's cost of service $131,345 (Texas), representing the costs of the discontinued Water Heater Program ($2,133) and the High Efficiency Appliance Information and Demonstration Program, calculated as set forth in Section V.A. of the Examiners' Report.

18. The evidence regarding EPEC's conservation and load management practices supports a downward adjustment of $400,000 (5 basis points) to EPEC's overall return.

19. In August 1985, the Touche Ross Management Audit of EPEC was issued. The audit reviewed the areas of executive management and organization, system planning and design, engineering and construction, fuels management, power supply, transmission and distribution, financial management, customer service and public relations, corporate support services, human resource management, and Franklin Land & Resources; and it made 187 recommendations.

20. EPEC approved 157 of the recommendations, excepted to 29, and rejected one.

21. The Commission staff found EPEC had adequately addressed the audit recommendations in implementation plans submitted in November 1985.

22. Despite cash problems beginning in 1985, EPEC has implemented between 108 and 117 of the 187 audit recommendations.

23. The Company notified the Commission staff in March 1986 of plans to suspend all implementation activities requiring cash outlays, regardless of potential savings, because of the Company's cash flow difficulties.

24. Not all audit implementation activities ceased in March 1986, but only those requiring cash expenditures.

25. Implementation of audit recommendations requiring cash outlays resumed following the cash infusion brought about by the sale/leaseback of PVNGS Unit 2.

26. There are a number of factors which can make the calculation of cost and benefits inaccurate, including the passage of time and the fact that initial estimates can later prove to be wrong.

27. EPEC performed its own analysis of the costs and benefits of implementing the Touche Ross audit recommendations; the Company did not agree with Touche Ross on all its cost/benefit analyses, and did not rely on those in the audit in making decisions and plans for implementing audit recommendations.

28. The relationship between EPEC and its subsidiary PasoTex was not examined in depth and there is no analysis in this record of whether or how the Touche Ross audit recommendations regarding Franklin Land & Resources apply to PasoTex.

29. There is no evidence in this record on how the Touche Ross management audit recommendations were to be implemented, whether there was a specific or implicit timetable or deadline for implementation, or whether the Company had the option of deviating from the recommendations.

30. The facts in this record support imposition of the management penalty recommended by the staff and supported by the City of El Paso.

31. EPEC should update all implementation plans and cost/benefit analyses no later than the second quarterly filing following the final order in this docket.

32. In the future, the quality of EPEC's management will be determined, in part, on its achievements in implementing the Touche Ross management audit recommendations.

33. In 1972, Arizona Public Service Company (APS) and Salt River Project formed the Arizona Nuclear Power Project (ANPP) and became its steering committee.

34. APS was designated project manager and operating agent.

35. In 1972 or 1973 the ANPP steering committee invited other utilities to participate in ANPP.

36. Of the utilities which were contacted to participate in ANPP, EPEC, Public Service of New Mexico (PNM), and Tucson Gas and Electric Company joined the project.

37. Although APS and Salt River Project had originally intended to construct a 600 to 1200 MW nuclear plant, ANPP, after it gained additional participants, ultimately settled on a plan to construct three identical 1,270 MW units at the Palo Verde site in Arizona.

38. While the 1,270 MW unit size was slightly larger than had originally been contemplated by APS and Salt River Project, it was smaller than the unit size that would have been dictated by the capacity requests being made by the ANPP participants as a whole.

39. To accommodate all of the capacity requests that were initially made by the participants, the generating units would have needed to be rated at 1,550 MWs each.

40. The Nuclear Regulatory Commission (NRC) limits the thermal core power of nuclear units in such a way that a 1,300 MW unit is approximately the maximum that can be licensed.

41. In March of 1972, APS hired a very experienced project director.

42. ANPP selected an appropriate organization structure for the project which included a single engineer-constructor.

43. ANPP hired Bechtel to be the engineer constructor at Palo Verde.

44. Hiring Bechtel was a prudent choice.

45. At 1,270 MW each, the Palo Verde units are the largest in the United States.

46. The next largest nuclear units in the United States after Palo Verde are on the order of 1,100 MW.

47. The size of the units at Palo Verde may, to some extent, have dictated the choice of Combustion Engineering (CE) as the nuclear steam supply system (NSSS) vendor.

48. The CE System 80 NSSS, which is what ANPP ordered for the project, was the largest NSSS designed for use in the United States at the time that it was ordered.

49. The CE System 80 is a larger, somewhat modified version of a proven design.

50. Size alone makes the CE System 80 NSSS a first-of-kind design.

51. At the time that ANPP ordered the System 80, there were three other utilities before it who had also ordered it.

52. If those utilities had moved ahead with their projects on schedule, ANPP would not have been the first to install and test the System 80 in an actual nuclear plant.

53. At the time that ANPP ordered the System 80, it could reasonably have expected that there would be extensive design reviews and testing over the years at ANPP and other projects to work out minor defects in the system.

54. There is no evidence that an NSSS on the scale of the System 80 exceeds the physical limits of an NSSS.

55. It was reasonable for ANPP to have gone ahead with a System 80.

56. In terms of its qualifications and level of professionalism, CE would have appeared to be equal to the task of supplying an NSSS on the scale of the System 80.

57. ANPP's selection of CE was reasonable.

58. At the time that ANPP selected Combustion Engineering as the NSSS vendor, CE did not manufacture reactor coolant pumps.

59. CE conducted a bid selection process with regard to choosing a reactor coolant pump vendor and prepared a list of potential vendors for review by ANPP and Bechtel.

60. Of the potential vendors, Klein, Schanzlin, and Becker (KSB) of West Germany was judged to be the best reactor coolant pump vendor for the project.

61. Subsequent to KSB's being chosen as the reactor coolant system (RCS) pump vendor, CE and KSB formed a joint venture to manufacture RCS pumps for the CE System 80 NSSS.

62. ANPP's choice of KSB to supply the RCS pumps was reasonable.

63. At the time that ANPP selected CE as the NSSS vendor, CE did not manufacture low pressure safety injection (LPSI) pumps.

64. CE conducted the bid selection process for the LPSI pump vendors.

65. ANPP ultimately decided upon a pump/motor combination utilizing an Ingersoll Rand pump and a Westinghouse motor.

66. ANPP's choice of LPSI pump vendor was reasonable.

67. Although the KSB pump design for the RCS required very little modification for the CE System 80, it did require some, and was therefore a first-of-kind pump.

68. In 1978, before the KSB pump was installed at Palo Verde, it was put through a 500-hour demonstration test under plant operating conditions with 30 stop-start cycles.

69. When the pumps were subsequently taken apart and examined, stress corrosion was found in the diffuser cap screws, among other problems.

70. KSB manufactured cap screws using different materials in order to correct the problem that had been observed at the time of the 500 hour demonstration test.

71. Subsequent to the 500-hour demonstration test, KSB tested the pump with the new cap screws at approximately 150 percent of design flow for 50 hours.

72. The cap screws showed no damage after the 50-hour test.

73. Following the 50-hour test, the next indication that there were problems with the RCS came at the time of the hot functional test at Palo Verde Unit I in July 1983.

74. Following the hot functional test at Palo Verde Unit I in July 1983, the diffuser cap screws on the RCS showed stress damage, among other problems.

75. Beginning in 1983, ANPP experienced problems with the LPSI pumps.

76. The problems with the LPSI pumps were stress-related.

77. The problems with the LPSI pumps appear to have been corrected.

78. The problems with the RCS have been corrected to some extent, but there may still be some cracking in the pump shafts.

79. To the extent that there is cracking in the pump shafts, ANPP has temporarily solved this problem by changing out pump shafts during refueling and maintenance activities at Palo Verde Unit 1.

80. ANPP has replaced all of the pump shafts in the RCS at Palo Verde Unit I.

81. ANPP has litigation pending against CE as the result of the equipment failures involving the RCS and the LPSI pumps.

82. The litigation against CE is a claim for contractual damages for breach of warranty.

83. A preponderance of the evidence in this docket supports a disallowance of $28,000,000 of the cost of the Palo Verde plant due to delays in construction.

84. Overall, APS, ANPP, and Bechtel managed the project in a prudent and efficient manner. Although ANPP experienced problems in the early phases of start-up, it had corrected these problems by 1984.

85. ANPP secured water rights for Palo Verde from City of Phoenix, consisting of rights to sewage effluent.

86. ANPP constructed a pipeline in three sections running from the sewage treatment plant in City of Phoenix to Palo Verde.

87. The first section of the effluent pipeline leading to Palo Verde is seven miles long. It runs from the 91st Avenue Sewage Plant to the Buckeye Station and has a capacity of 170,000 acre/feet per year.

88. The second section of the effluent pipeline leading to Palo Verde is 23.5 miles long. It runs from the Buckeye Station to the Hassayampa River Pumping Station and has a capacity of 140,000 acre/feet.

89. The third section of the effluent pipeline leading to Palo Verde is 8.5 miles long. It runs from the Hassayampa River Pumping Station to Palo Verde and has a capacity of 105,000 acre/feet per year.

90. The effluent pipeline was sized to accomplish several goals. One was to carry 30,000 acre/feet of sewage effluent for the Buckeye Irrigation Company from the 91st Avenue Sewage Plant to the Buckeye Station in exchange for a right-of-way for the pipeline from the 91st Avenue Sewage Plant to the Hassayampa River. The pipeline was also sized to provide for diurnal fluctuation in the volume of effluent and serve as a reservoir for additional amounts of water in the event of a shut-down at the 91st Avenue Sewage Plant or an emergency at Palo Verde.

91. The effluent pipeline leading to Palo Verde is a facility which is entirely used and useful in providing service.

92. FERC accounting rules dictate that 100 percent of the cost of the effluent pipeline leading to Palo Verde be assigned to Palo Verde Unit I.

93. ANPP has substantial outstanding claims against Combustion Engineering in connection with the RCS and LPSI failures at Palo Verde, as well as other miscellaneous claims.

94. The Company will present to the Commission for expedited consideration any proposed settlement of its litigation with Combustion Engineering (CE). The Company agrees that any monies recovered from CE, through either judgment or settlement, will be held by the Company for appropriate distribution as ordered by the Commission.

95. EPEC originally intended to commit to a 684 MW share of PVNGS.

96. Although EPEC originally requested a 684 MW share of PVNGS, its share was ultimately reduced to 600 MW as a result of a pro rata reduction in the shares requested by the ANPP participants at the time the final decisions were made regarding the number and size of the units to be built at Palo Verde.

97. At some point in 1972, EPEC had Stone & Webster, EPEC's consultants, make a financial analysis of a plan involving an investment in a large nuclear construction program, bearing an unknown relationship to the specific decisions to request 684 MW of PVNGS and to commit to 600 MW.

98. EPE has a total invested capital of $745,596,929 on a total company basis as illustrated in Exhibit B (page 3 of 3) of the Amended and Restated Stipulation.

99. The Company and/or its representatives for whom it is responsible were not entirely prudent in their planning and management of the construction of Units 1 and 2 of the Palo Verde project.

100. Staff witness Jacobs presented a credible quantification of construction management imprudence related to ccsts of delay in the amount of $28 million.

101. The Company was not entirely prudent in its planning and management of its participation in the Palo Verde project.

102. There is evidence in the record of imprudence in the Company's continuing evaluation of the level of its participation in the Palo Verde Project. The parties to the Amended and Restated Stipulation have quantified The cost of such imprudence as $22 million as applied to Units 1 and 2. The Company has conceded an additional $10 million disallowance to be applied to PVNGS Units 1 and 2.

103. Quantification of the effects of imprudence requires the exercise of judgment based upon the evidence. In light of the evidence relating to prudence and the difficulties in quantification, the quantification

of decisional imprudence at $32 million for Units 1 and 2 is reasonable and appropriate.

104. The disallowance allocated to Units 1 and 2 is removed from the rate base amount related to Unit 1.

105. Based on the record in this case, EPEC has met its burden that the invested capital found in Finding of Fact No. 98 is currently used and useful in providing service to the public.

106. No decision is necessary on issues concerning the relationship between excess capacity and the application of the used and useful standard. The parties to the Amended and Restated Stipulation have agreed such issues should be reserved for consideration if and when additional generating capacity is requested for inclusion in rate base, when costs or expenses associated therewith are requested for inclusion in the Company's cost of service or in the proceeding establishing appropriate performance standards for Palo Verde Units 1 or 2 pursuant to paragraph 11 of the Amended and Restated Stipulation. The reservation of consideration of such issues in such future cases is reasonable in light of the record in this case and the following findings.

107. On the basis of Findings 108 through 119, the record in this case demonstrates that no present excess capacity exists on the EPEC

system. These findings are based upon the record in this case and relate to the Company's system including its interest in Palo Verde Units 1 and 2. These findings are not to be considered as precedents in any manner in cases involving the addition of future generating capacity to the system, including Palo Verde Unit 3, or in any reconsideration proceeding conducted pursuant to paragraph 11 of the Amended and Restated Stipulation.

108. The native system load forecast presented by Mr. Ramgopal on behalf of the Staff is reasonable. Mr. Ramgopal's forecast of EPEC's 1988 native system peak load is 829 MW.

109. For purposes of evaluating whether excess capacity exists on the EPEC system, the Commission should not include sales of 100 MW to the Imperial Irrigation District ("IID") in EPEC's load requirements.

110. The purpose of a reserve margin criterion is to insure that the utility can continue to provide service with adequate reliability at a reasonable cost.

111. The largest single hazard plus five percent ("LSH + 5") criterion for determining a reasonable reserve margin is used by EPEC and recommended by the Western Systems Coordinating Council, of which EPEC is a member.

112. Based on the evidence presented, use of the LSH + 5 criterion is reasonable for application to the EPEC system in this case.

113. Using the LSH + 5 criterion, EPEC should carry 258 MW of reserve capacity in 1988.

114. Based on the evidence presented, for purposes of determining EPEC's load requirements in this case, EPEC's commitment to provide up to 42.5 MW annually to the Public Service Company of New Mexico ("PNM") should not be considered a committed resource obligation. This commitment is contingent upon the operation of specific generating units on EPEC's system and no evidence was presented that PNM intended to utilize such capacity in the foreseeable future.

115. In forecasting utility load, contractual obligations for the utility to provide interruptible power should not be considered as required load. Likewise, in forecasting utility resources, contractual obligations for the utility to obtain purchased power on an interruptible basis should not be considered available capacity.

116. For purposes of resource planning, EPEC's contract to purchase power from SPS should not be included as available capacity, since the record in this case supports a finding that such power from SPS is interruptible.

117. EPEC's total load for 1988 using Mr. Ramgopal's forecast for native system peak load (Staff Exh. 22, Schedule PR-5), then adjusting to exclude EPEC's sales to the Imperial Irrigation District but to include its sales to TNP, is 908 MW. Adding a reserve margin based on the LSH + 5% criterion then brings EPEC's total peak capacity requirement to 1166 MW, which the Commission finds to be reasonable.

118. A reasonable analysis of EPEC's available capacity with Palo Verde Units 1 and 2 on-line and allowing for maintenance as it is currently scheduled, results in 1,200 MW of capacity available to meet system peak.

119. Using EPEC's resource capacity analysis and Staff's native system load forecast for the coming year, with the specific adjustments outlined above, the Commission finds that the Company's currently available capacity exceeds its capacity requirements (including an adequate reserve margin) by less than 3%. This is a reasonable net resources margin and should not be considered excess capacity in this case.

120. EPEC's sale/leaseback of its share of PVNGS Unit 2 and related common facilities resulted in a gain over the book value of the transferred assets.

121. The lease payment EPEC must make is based on the total sales price; however, only the portion related to the book value of Unit 2 and related common facilities will be included in the cost of service on which rates are based.

122. EPEC's proposed "book break-even" calculation of the portion of the lease payment may be included in cost of service in this instance, as it is not in excess of the amount that would result if calculated using the traditional ratemaking plant in service/rate base methodology.

123. The Company's total non-PVNGS used and useful plant in service amount is $443,804,358.

124. For the purposes of this docket, it is reasonable to include all the PVNGS common facilities in plant in service. EPEC has agreed that in the event of a disallowance or sale (other than a sale/leaseback) of PVNGS Unit 3, the Commission may revisit the issue of the level of common facilities to be included in Plant in service, in conformance with Statement of Financial Accounting Standards No. 92 (FASB 92).

125. The preponderance of the evidence supports the allocation of all PVNGS Unit 2-related AFUDC credits to PVNGS Unit 1.

126. The preponderance of the evidence supports inclusion of all PVNGS transmission and general plant in service, as requested by EPEC.

127. The preponderance of the evidence establishes a total amount for used and useful plant in service of $933,135,847.

128. The adjustment to accumulated depreciation recommended by the City of El Paso should be rejected because it conflicts with the goal of matching revenues, expenses, and investments for the test year as adjusted for known and measurable changes.

129. The preponderance of the evidence supports accumulated depreciation adjusted in accord with the reasoning underlying the changes in plant balances for PVNGS Unit 1 and common facilities.

130. The Company's accumulated depreciation is $144,405,347.

131. In accord with the Company's amendment to its request, no nuclear fuel in process should be included in plant in service.

132. The preponderance of the evidence establishes EPEC's net plant in service of $788,730,500.

133. The Company's request for $17,543,127 of construction work in progress in invested capital was not supported by a preponderance of evidence demonstrating that inclusion of CWIP is necessary for EPEC's financial integrity.

134. EPEC's request for $83,215 for coal inventory should be denied for the reasons set forth in the testimony of Staff witness Stan Kaplan.

135. The adjustment to materials and supplies recommended by the staff should be adopted for the reasons set forth in the testimony of Staff witness Candice Tye.

136. The staff's adjustment to prepayments is supported by a preponderance of the evidence and should be adopted, as discussed in the testimony of Staff witness Tye.

137. The lead-lag study performed by the Company is a fully-developed study, and includes depreciation, amortization, deferred taxes, return, cost of money, and cash allowances.

138. EPEC's lead-lag study produced a cash working capital allowance in excess of that which would result from use of the formula in the Commission's substantive rules.

139. The staff's lead-lag study also included some non-cash items, and resulted in a cash working capital allowance in excess of that which would result from use of the formula in the Commission's substantive rules.

140. The City's adjustments to the Company's lead-lag study had the effect of excluding non-cash items.

141. All three lead-lag studies included interest on long-term debt and preferred stock dividends.

142. For the reasons set forth in the testimony of Staff witness Tye, the Staff's proposed cash working capital allowance should be adopted.

143. EPEC has a cash working capital allowance requirement of $6,612,378.

144. The preponderance of the evidence supports inclusion in rate base of the unamortized deferred carrying costs for PVNGS plant (Units 1 and 2 and common facilities) and PVNGS O&M expense in the amount of $74,503,575.

145. The preponderance of the evidence does not support the City's proposed adjustments to accumulated deferred federal income tax.

146. The amounts requested by the Company for pre-1971 investment tax credits, injuries and damages reserve, customer deposits, customer advances for construction, and other deferred credits are supported by a preponderance of the evidence and should be adopted.

147. The appropriate method for determining the rate of return for EPEC is to determine the weighted average cost of capital.

148. EPEC's cost of equity is properly determined by the company-specific DCF analyses performed by the witnesses for the staff, the DOD, and the City of El Paso, and the comparable company DCF analyses performed by the witnesses for the staff and the City.

149. The preponderance of the evidence establishes that a reasonable cost of equity for EPEC is 13.0 percent, prior to reduction for the penalties imposed pursuant to Findings 18 and 30 above. Application of these penalties results in a reasonable equity rate of return for EPEC of 12.72 percent.

150. The appropriate capital structure for EPEC to be used in determining its overall return is that proposed by Staff witness Eugene Bradford.

151. A cost of equity of 12.72 percent and an overall rate of return of 10.56 percent will permit EPEC a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

152. The preponderance of the evidence establishes that the Company has a total revenue requirement with components as set forth in Exhibit B of the Amended and Restated Stipulation.

153. The preponderance of the evidence establishes that, for the purpose of setting fuel factors, EPEC has fuel and purchased power expenses as follows:

Fuel	
Reconcilable	$62,323,361
Non-reconcilable	308,539
Fuel Sub-total	$62,631,900
Purchased power	
Reconcilable	$15,407,300
Non-reconcilable	4,188,125
Purchased Power Sub-total	$19,595,425
Total Fuel/Purchased Power	$82,227,300

154. The preponderance of the evidence establishes an operations and maintenance expense for EPEC with components as shown in Exhibit B of the Amended and Restated Stipulation.

155. The preponderance of the evidence supports approval of the uncontested items of O&M expense requested by EPEC.

156. For the reasons set forth in the testimony of Staff witness Mark Young, the Company's payroll expense ratio is 88.04 percent.

157. The staff's adjustments to EPEC's expense for salaries and wages are supported by a preponderance of the evidence and should be adopted.

158. The preponderance of the evidence supports the staff's adjustments to the 401-k plan expense, pension expense, employee insurance expense, LESOP expense, and other employee benefits.

159. The preponderance of the evidence supports the Staff's adjustment to the TRASOP expense component of employee benefits expense, as discussed in the testimony of Staff witness Young.

160. The preponderance of the evidence establishes the reasonableness of the Company's expense for advertising, contributions and dues, as adjusted by Staff witness Young.

161. The preponderance of the evidence supports the City's recommendation to exclude all requested expenses for the ANPP prudence audit.

162. The preponderance of the evidence supports approval of the uncontested items of regulatory commission expense requested by EPEC.

163. The preponderance of the evidence supports approval of the Company's adjustments removing all expense for Rio Grande Units 3, 4, and 5 and in the "Other O&M" category.

164. The preponderance of the evidence establishes the reasonableness of the Palo Verde O&M expense requested by the Company; that amount is $29,621,000.

165. The preponderance of the evidence establishes that EPEC should be permitted to defer the operating and carrying costs on PVNGS Units 1 (including common facilities) and 2 from the in-service date of each unit to the date the rates set in this docket become effective.

166. The preponderance of the evidence establishes that EPEC's proposed deferral balances, based on both actual expenses and estimates through October 1987, should be used in this docket and "trued-up" to actual booked amounts in the Company's next rate case.

167. The staff's proposal to reclassify the balance of deferred displaced nuclear fuel credits to the regular fuel over/underrecovery upon implementation of the rates set in this docket and to refund those amounts as any other fuel overrecovery should not be adopted.

168. The preponderance of the evidence establishes a reasonable property insurance expense as described in Exhibit B of the Amended and Restated Stipulation.

169. The staff's recommended injuries and damages expense was established by a preponderance of the evidence.

170. The energy efficiency expense adjustment recommended by staff witness Nat Treadway was established by a preponderance of the evidence.

171. The staff's recommended adjustment for wheeling expense was established by a preponderance of the evidence.

172. The preponderance of the evidence establishes the reasonableness of calculating uncollectible expense using the staff's uncollectible rate.

173. The preponderance of the evidence establishes the reasonableness of the Company's decommissioning study.

174. The Company's election of the DECON alternative as the basis for estimating the cost of decommissioning is reasonable.

175. Use of the DECON decommissioning alternative to estimate the cost of decommissioning does not commit the PVNGS participants to a specific course of action following final plant shutdown.

176. EPEC's decommissioning study, if modified to include the Staff's 10 percent contingency, is reasonable and supported by the preponderance of the evidence.

177. The cost of decommissioning PVNGS should be borne by those ratepayers who benefit from the nuclear plant.

178. Changing the payment stream for funding the decommissioning reserves does not threaten the sufficiency or the availability of the reserves.

179. It is reasonable to require the Company's decommissioning fund to be held in an irrevocable trust.

180. An inflation-adjusted payment stream insures generational equity in funding the cost of decommissioning.

181. The preponderance of the evidence establishes the reasonableness of calculating the amount to be included in the cost of service using the staff's recommended four percent inflation rate and eight percent after-tax yield. The inflation adjusted payment stream shown on Attachment 1 to these findings is approved for funding EPEC's portion of the Palo Verde Units 1 and 2 decommissioning cost. The annual decommissioning expense to be included in cost of service in this docket is $635,070. EPEC's decommissioning funding will be adjusted in future dockets to match the approved funding schedule.

182. The preponderance of the evidence establishes the reasonableness of the depreciation expense amount shown on Exhibit B of the Amended and Restated Stipulation.

183. The amortization expense, shown on Exhibit B of the Amended and Restated Stipulation is supported by the preponderance of the evidence.

184. The preponderance of the evidence establishes that EPEC incurs taxes other than income taxes in the amount of $26,443,305.

185. The preponderance of the evidence supports the reasonableness of EPEC's requested deferred property and payroll tax amount, based on estimates through November 1987, and of EPEC's continued booking of such expenses in FERC Account 186 from November 1987 until rates set in this docket go into effect. These deferred expenses should then be "trued-up" in EPEC's next rate case.

186. The preponderance of the evidence supports the staff's methodology in calculating federal income tax expense for EPEC. This results in federal income tax expense of $18,353,591.

187. The preponderance of the evidence supports EPEC's recovery of deferred tax deficiencies arising from past flow-through of tax benefits, calculated as recommended by the staff.

188. The preponderance of the evidence establishes the reasonableness of the customer growth and loss of load adjustments proposed by the Company and supported by the staff. These adjustments should be used in the calculation of non-fuel revenues.

189. The City's proposed annualization adjustment unfairly adjusts only Texas sales and revenues, and not Texas costs, and should not be adopted.

190. The City's proposed unbilled revenues adjustment is not supported by a preponderance of the evidence.

191. The "miscellaneous and other revenue" amounts proposed by the Company are reasonable and should be adopted.

192. The staff's short-term forecast of electric sales should be used for the calculation of fuel and purchased power revenues.

193. It is reasonable to allocate Accounts 512, 513, 928-Other, 925-PV, 926-PV, 930.2-PV, and 904 at the jurisdictional and class levels as stated in Exhibit D of the Amended and Restated Stipulation.

194. It is reasonable to allocate LESOP dividends and excess deferred taxes as the jurisdictional level utilizing the allocators recommended by Staff witness Dr. Pheng Kol.

195. It is reasonable to utilize the A&E-4CP methodology to allocate EPEC's production plant, including Palo Verde, between EPEC's Texas retail customer classes, as supported by six of the seven witnesses who addressed this issue.

196. The preponderance of the evidence likewise supports utilizing the A&E-4CP methodology to allocate EPEC's transmission plant between EPEC's retail customer classes.

197. For purposes of this case, it is reasonable to use the Company's functionalization of Accounts 364 and 366 on a primary/secondary basis, and to use its distribution plant allocation methodology.

198. It is reasonable to allocate intangible plant using the general plant allocator, based upon the Staff's testimony.

199. It is reasonable to utilize the primary voltage discount in the manner set out in paragraph 14(e) of the Amended and Restated Stipulation.

200. EPEC has shown itself entitled to a base rate increase of $45,694,691, which does not include the rate case expenses which have been severed out for determination in a separate docket, Docket No. 8018, and as supported in modified Exhibit B of the Amended and Restated Stipulation. Due to the magnitude of this increase, a rate moderation plan is reasonable and necessary.

201. The Amended and Restated Stipulation proposed in this case presents a Rate Moderation Plan ("RMP") for recognition of Palo Verde Units 1 and 2 in rates.

202. This RMP covers a ten-year period and moderates the impact of the costs associated with inclusion of the Palo Verde units in rate base over that period.

203. The RMP smoothes the rate impact caused by recognition of large generating plants in rate base or in the utility's cost of service.

204. This ten-year period is a reasonable term for the RMP since it is the maximum period allowed for such plans under the statements of the Financial Accounting Standards Board, Section 92 (FASB 92), and allows for minimization of required rate increases while maximizing the utility's opportunity to recover its deferred costs.

205. The RMP agreed to in the Amended and Restated Stipulation is in compliance with FASB 92.

206. Any base rate revenue distribution guidelines adopted by the Commission should be designed to move all classes toward a unity relative rate of return.

207. The base rate revenue distribution guidelines set out in Exhibit E to the Amended and Restated Stipulation move all classes toward a unity relative rate of return and are therefore reasonable and appropriate for use in this docket.

208. For the reasons set out in Section XVI.A.1. of the Examiners' Report, it is reasonable for customer charges for the Residential, Small Commercial, Water Heating, and General Service rate classes to be calculated in the manner set out in that Section.

209. There is no evidence to support a reduced winter tail block switchover point of 550 kwh.

210. For the reasons stated in Section XVI.A.2. of the Examiners' Report, it is reasonable to implement the type of seasonal (summer/winter) rate differential for the Residential class recommended by Mr. Rudolph in his Option No. 2.

211. For the reasons stated in Section XVI.A.2. of the Examiners' Report, it is reasonable to reduce the Residential class space heating rider differential to 2.173 cents per kwh.

212. The energy charge should be the same for all Water Heating (Rate 21) customers, for the reasons set out in Section XVI.A.2. of the Examiners' Report.

213. The load data supports the reinstitution of a Small Commercial rate class.

214. It is reasonable to keep the provision that limits the Small Commercial and General Service space heating riders to existing former Rate Schedule 02, Space Heating Installations, as of January 5, 1979.

215. It is appropriate to recover production plant related costs through a demand charge, even if such costs are allocated in part based on energy consumption, for the reasons set out in Section XVI.C. of the Examiners' Report.

216. For the reasons stated in Section XVI.C. of the Examiners' Report, the Company's proposed 20 percent shift in costs to be recovered through the demand charge to the energy charge for the General Service and Large Power rate classes is reasonable.

217. The utility system and the general body of ratepayers are benefitted by maintaining EPEC's existing industrial load.

218. EPEC's industrial load is in serious danger of substantially shrinking or disappearing altogether.

219. Unusually high EPEC electric rates are a significant competitive disadvantage and a major economic factor which elevates the possibility of serious industrial customer load loss.

220. Continued approval of the ERR increases the probability that this needed industrial load will continue operating on the EPEC system.

221. Based upon the four preceding findings of fact, it is reasonable to continue the ERR.

222. For the reasons set out in Section XVI.D.1. of the Examiners' Report, the provisions of the ERR should not be changed.

223. There is not sufficient evidence upon which to base a decision on the issue of how the revenue shortfall resulting from the ERR should be recovered. Thus it is reasonable to reserve this issue until the next general rate case, with the revenue shortfall to be deferred until that time.

224. For the reasons set out in Section XVI.D.2. of the Examiners' Report, the ERR should not be made available to Rate Class 31--Military Reservation (Ft. Bliss).

225. For the reasons set out in Section XVI.E. of the Examiners' Report, it is reasonable to maintain all ratchet provisions in effect.

226. The rating period selection option is a reasonable provision as proposed by the Company, and should thus be adopted.

227. Texas state agencies should not be allowed to take service under the City and County Service rate (Rate 41), for the reasons set out in Section XVI.G. of the Examiners' Report.

228. The cost study done by the Company to support an increase in the returned check/bank draft charge is inaccurate, and thus it is reasonable to maintain the current charge of $8.00.

229. For the reasons set out in Staff's testimony, it is reasonable to set the premium-overtime charge at $35.00 for purposes of this docket.

230. For the reasons set out in Section XVI.J.1. of the Examiners' Report, it is reasonable to split the transmission level line loss factor into separate line loss factors for each major customer that receives service at transmission level voltage. The resultant line loss and voltage level to base factors for use in setting the fixed fuel factors are set out in that Section.

231. The interest rate charge for line extension guarantees, entered into both prior to and after the effective date of the line extension policy tariffs resulting from this docket, should be at the appropriate after-tax cost of capital.

232. For the reasons stated in Section XVII.F. of the Examiners' Report, the revisions to the Company's proposed tariff recommended by

Mr. Irish are reasonable and should be adopted, except for the revisions contained in his Recommendation Nos. 1, 5, and 12, which are not reasonable and should be rejected.

233. Except as indicated above, all of the Company's proposed service rules and regulations and line extension policy tariff sheets are reasonable and should be approved.

234. The evidence in this record is insufficient for reaching a final reconciliation of EPEC's fuel expense.

235. In recognition of the Commission's final order in Docket No. 7167, reconciliation of EPEC's fuel expense should be for the period August 1985 through October 1987.

236. Final reconciliation of EPEC's fuel expense for August 1985 through October 1987 should be severed from this docket.

237. The provisions of the Amended and Restated Stipulation are reasonable and supported by a preponderance of the credible evidence in this record and should be adopted.

ATTACHMENT 1

PUBLIC UTILITY COMMISSION OF TEXAS
El Paso Electric Co. - Docket 7460
Palo Verde Units 1 and 2
Decommissioning Funding Schedule

Year	Inflation Adjusted Payment Stream
1988	$635,076
1989	$660,479
1990	$686,898
1991	$714,374
1992	$742,949
1993	$772,667
1994	$803,574
1995	$835,717
1996	$869,145
1997	$903,911
1998	$940,068
1999	$977,670
2000	$1,016,777
2001	$1,057,448
2002	$1,099,746
2003	$1,143,736
2004	$1,189,485
2005	$1,237,065
2006	$1,286,547
2007	$1,338,009
2008	$1,391,530
2009	$1,447,191
2010	$1,505,079
2011	$1,565,282
2012	$1,627,893
2013	$1,693,009
2014	$1,760,729
2015	$1,831,158
2016	$1,904,405
2017	$1,980,581
2018	$2,059,804
2019	$2,142,196
2020	$2,227,884
2021	$2,316,999
2022	$2,409,679
2023	$2,506,066
2024	$2,606,309
2025	$2,710,561
2026	$2,818,984

CONCLUSIONS OF LAW

1. EPEC is a public utility as defined in section 3(c)(1) of PURA and, as such, is subject to the Commission's jurisdiction and authority.

2. The Commission has jurisdiction over these consolidated dockets pursuant to sections 16, 17(d) and (e), 26, 37, 43, and 63 of PURA.

3. The rate filing package filed by EPEC meets the requirements of section 43(a) of PURA regarding the contents of a statement of intent.

4. The operation of the proposed rate schedule was suspended in accord with section 43(d) of PURA.

5. EPEC has substantially complied with the notice requirements of P.U.C. PROC. R. 21.22(b)(1) regarding notice of the proposed change in rates, and with the examiner's order, issued pursuant to P.U.C. PROC. R. 21.25, regarding notice of the sale and leaseback of PVNGS Unit 2.

6. EPEC has substantially complied with the requirements for energy efficiency plans set forth in P.U.C. SUBST. R. 23.22.

7. In considering the proposed inclusion of new generating facilities in rate base, the Commission should consider not only the utility's initial decision to construct such a facility, but also its continuing evaluation of such a commitment.

8. The quantification of imprudence in Findings of Fact 100 and 102 resolves the issues of the prudence of EPEC's initial commitment and continuing evaluation of its participation in the Palo Verde Project for purposes of regulatory treatment of PVNGS Units 1 and 2, and, under the record in this case, represents a reasonable application of the requirement that utility investments and expenses be reasonably and prudently incurred.

9. A utility has a duty to ratepayers to pursue valid claims against suppliers in connection with the construction of generating facilities to the extent that the cost of those facilities may be, or has been, included in rate base, and to call such claims to the Commission's attention to the extent that they may be, or have been, reimbursed by third parties subsequent to the inclusion of those costs in rate base.

10. Pursuant to PURA sections 38, 39, and 41, EPEC should be authorized to defer the carrying costs and operational expenses for PVNGS Unit 1 and common facilities from March 1986 until March 1988 and for PVNGS Unit 2 from September 1986 until March 1988, capitalize the deferred amounts, and amortize those deferrals in accordance with the Amended and Restated Stipulation, as modified per Finding of Fact No. 6.

11. Under Sections 39 and 41 of PURA, the Commission may not include in a utility's rate base the value of facilities not used and useful in providing service to utility customers.

12. As required by PURA section 41(a), the net plant component of EPEC's invested capital set forth in the modified Exhibit B to the Amended and Restated Stipulation is based upon the original cost of property used by and useful to EPEC in providing electric utility service.

13. The methods and rates of depreciation implicit in the modified Exhibit B to the Amended and Restated Stipulation are proper and adequate and have been uniformly and consistently applied, in accord with Section 27(b) of PURA.

14. To the extent included in invested capital, EPEC's generation, transmission, and distribution facilities are safe, adequate, efficient, and reasonable, as required by PURA section 35(a).

15. The overall rate of return set forth in the Amended and Restated Stipulation substantially complies with P.U.C. SUBST. R. 23.21(c)(1).

16. Taking into consideration EPEC's quality of management, quality of service, effort to conserve energy and resources, and efficiency of operations, the return set forth in the modified Exhibit B to the

Amended and Restated Stipulation constitutes a reasonable return on EPEC's invested capital used and useful in rendering service to the public, in accord with PURA section 39(b).

17. The return set forth in the modified Exhibit B to the Amended and Restated Stipulation will permit EPEC a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses, as required by section 39(a) of PURA.

18. The expenses set forth in the modified Exhibit B to the Amended and Restated Stipulation substantially comply with P.U.C. SUBST. R. 23.21(b).

19. A final determination of the issue of whether the sale/leaseback of Palo Verde Unit 2 is in the public interest is specifically reserved for decision in a future proceeding.

20. EPEC has met the burden of proof imposed by section 40 of PURA to show that rates producing the total Texas retail revenue requirement set forth in the modified Exhibit B to the Amended and Restated Stipulation are just and reasonable.

21. The rate and rate design resulting from the rate class revenue requirements in the modified Exhibit E to the Amended and Restated Stipulation are just and reasonable and are not unreasonably preferential, prejudicial, or discriminatory within the meaning of PURA Section 38.

22. As required by Section 45 of PURA, the rate design and rates resulting from the findings and conclusions set forth herein do not grant an unreasonable preference or advantage to any customer within a classification, subject any customer within a classification to an unreasonable prejudice or disadvantage, or establish unreasonable differences as to rates or service between localities or between classes of service.

23. The rates approved by the Commission in this case are to be effective only for customers in areas within the Commission's original jurisdiction and in the municipalities from which appeals were consolidated with this proceeding.

24. The hold harmless clause in the Company's tariff is inapplicable to the State.

25. The rates resulting from the revenue deficiency and rate design provisions in the Amended and Restated Stipulation, as modified per Finding of Fact No. 6, are just and reasonable and otherwise comply with applicable law including the ratemaking mandates of PURA Article VI, and should therefore be approved.

26. In accord with section 16(b) of the Administrative Procedure and Texas Register Act, Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1987), the proposed findings of fact submitted by the signatories to the stipulation should be adopted.

27. The Commission may adopt a contested Stipulation if it finds the settlement is supported by the record and in the public interest.

28. The Amended and Restated Stipulation, as modified per Finding of Fact No. 6, represents a reasonable resolution of the contested issues in this docket, is supported in the record, is in the public interest, and should therefore be adopted, as the basis for the Commission's Order in this case.

29. Neither the finding of decisional imprudence nor its quantification as to Palo Verde Units 1 and 2 shall be precedent in any case involving the regulatory treatment of as to Palo Verde Unit 3. Rather, issues of decisional prudence arising after the effective date of the Commission's Order in Docket No. 1981 insofar as such decisional prudence may affect the regulatory treatment of Palo Verde Unit 3, shall remain open issues in future proceedings.

DOCKET NOS. 7460 AND 7172

RECEIVED

1988 MAY 11 AM 10: 45

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION
APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVIEW OF THE SALE AND LEASEBACK OF PALO VERDE NUCLEAR GENERATING STATION UNIT 2	§ § § § §	OF TEXAS

ORDER ON REHEARING

On March 30, 1988, the Commission signed a final order in these consolidated dockets. Motions for rehearing were subsequently timely filed by the City of El Paso, the Office of Public Utility Counsel, the Texas State Agencies, and the Department of Defense; replies to the motions for rehearing were filed by El Paso Electric Company, Border Steel Rolling Mills, Inc. and El Paso Iron & Metal Company, ASARCO, and the Commission's General Counsel. On May 4, 1988, in open meeting at its offices in Austin, Texas, the Commission considered the motions for rehearing and the replies to those motions. After deliberation of the issues raised in the motions for rehearing and replies, the Commission hereby GRANTS rehearing on the following points and orders the following relief:

1. Finding of Fact No. 164 is amended to add the words, "as adjusted by the staff," so that the finding reads as follows:

   164. The preponderance of the evidence establishes the reasonableness of the Palo Verde O&M expense requested by the Company as adjusted by the staff; that amount is $29,621,000.

2. Both Findings of Fact Nos. 144 and 165 are amended so as to refer to the discussion of the Examiners' Report of the evidence

supporting these findings. Finding of Fact No. 144 is amended to read as follows:

> 144. As discussed in the Examiners' Report, the preponderance of the evidence supports inclusion in rate base of the unamortized deferred carrying costs for PVNGS plant (Units 1 and 2 and common facilities) and PVNGS O&M expense in the amount of $74,503,575.

Finding of Fact No. 165 is amended to read as follows:

> 165. As discussed in the Examiners' Report, the preponderance of the evidence establishes that EPEC should be permitted to defer the operating and carrying costs on PVNGS Units 1 (including common facilities) and 2 from the in-service date of each unit to the date the rates set in this docket become effective.

3. In all other respects, the requests for relief contained in the motions for rehearing and the replies to those motions are hereby DENIED for lack of merit.

4. This Order hereby incorporates by reference as if set out in full all aspects of the Order of March 30, 1988, in these consolidated dockets, including all findings of fact and conclusions of

law made by the Commission in that Order, except as expressly amended by this Order.

SIGNED AT AUSTIN, TEXAS on this the 10th day of May 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Dennis L. Thomas
DENNIS L. THOMAS

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: Marta Greytok
MARTA GREYTOK

ATTEST:

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

DOCKET NOS. 7460 AND 7172

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION
APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVIEW OF THE SALE AND LEASEBACK OF PALO VERDE NUCLEAR GENERATING STATION UNIT 2	§ § § §	OF TEXAS

SECOND ORDER ON REHEARING

On May 10, 1988, the Commission signed an order on rehearing in these consolidated dockets. Second motions for rehearing were subsequently timely filed by the City of El Paso, the Office of Public Utility Counsel, and the Texas State Agencies. Replies to the second motions for rehearing were filed by ASARCO, Inc. and the Commission's General Counsel. On June 15, 1988, in open meeting at its offices in Austin, Texas, the Commission considered the second motions for rehearing and the replies to those motions.

The Commission hereby DENIES all second motions for rehearing. This Second Order on Rehearing hereby incorporates by reference as if set out in full all aspects of the Order of March 30, 1988, and the Order on Rehearing of May 10, 1988, in these consolidated dockets, including all findings of fact and conclusions of law made by the Commission in the Order of March 30, 1988, as amended by the Order on Rehearing of May 10, 1988.

SIGNED AT AUSTIN, TEXAS on this the 16th day of June 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: Marta Greytak
MARTA GREYTOK

ATTEST:
Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

MEMORANDUM DECISIONS

TELEPHONE

Southwestern Bell Telephone Company, Docket No. 8438. Application to amend Access Service tariff to restrict eligibility for WATS prorate credits dismissed by examiner's order on December 21, 1988, based on withdrawal of application.

GTE Southwest, Inc., Docket No. 7708. Amended Examiner's Report on remand adopted on January 4, 1989. Commission approved stipulated request for a good cause waiver of the requirements of P.U.C. SUBST. R. 23.68 to permit a special five year amortization of the December 31, 1987 net book value of GTE's embedded CPE resulting above-the-line lease revenues to partially fund the amortization.

Southwestern Bell Telephone Company, Docket No. 8140. Examiner's Report adopted on November 22, 1988. Application to eliminate Eight-Party Rural Exchange Service and Information Terminal Service granted.

Mustang Telephone Company, Docket No. 8141. Examiner's Report adopted on November 22, 1988. Request for approval of Tel-Assistance Service Plan granted.

ELECTRIC

Gulf States Utilities Company, Docket No. 8053. Examiner's Report adopted on November 23, 1988. Application for transmission line approved despite finding of possible adverse effects on aesthetics, community values, and the environment.