SOAH DOCKET NO. 473-04-2459
PUC DOCKET NO. 29206

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY, FIRST CHOICE POWER, INC., AND TEXAS GENERATING COMPANY, L.P., TO FINALIZE STRANDED COSTS UNDER PURA § 39.262	§ § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

Direct Testimony and Exhibits of

Jeffry Pollock

On Behalf of

Texas Industrial Energy Consumers

March 2004
Project 8148

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

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Affidavit of Jeffry Pollock

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am a consultant with Brubaker & Associates, Inc., 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by the Texas Industrial Energy Consumers to testify in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibit JP-1 through JP-5, which has been prepared in written form for introduction into evidence in Public Utility Commission of Texas Docket No. 29206.

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 26th day of March 2004.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2008

Notary Public

My Commission expires on February 26, 2008.

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Direct Testimony of Jeffry Pollock

INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 1215 Fern Ridge Parkway, Suite 208; St. Louis, MO 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and am employed by BAI (Brubaker & Associates, Inc.).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments including energy procurement and regulatory matters in both the United States and several Canadian provinces. I have participated in regulatory matters before this Commission since 1977. This includes rulemaking projects and rate cases conducted before, during and after the implementation of S.B. 7. More details are provided in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Texas Industrial Energy Consumers (TIEC). The TIEC participants operate significant electricity consuming facilities in Texas-New Mexico Power Company's (TNMP) service territory. Thus, they have a substantial interest in the outcome of this proceeding.

Q WHAT SUBJECTS DO YOU ADDRESS IN YOUR TESTIMONY?

A I shall address various policy issues relevant to TNMP's proposed True-Up application. In addition, I shall:

- Introduce the other witnesses testifying on behalf of TIEC;
- Summarize TNMP's true-up request and TIEC's recommendations;
- Provide a historical context of the issues to be decided in this proceeding and discuss the standards of review in determining the amount of the required true-up.
- Assess TNMP's compliance with these standards; and
- Quantify the impact of TIEC's recommendations.

The fact that I am not addressing other issues should not be interpreted as an endorsement of TNMP's proposals in this proceeding.

Witness Introduction

Q ARE OTHER WITNESSES SPONSORING TESTIMONY ON BEHALF OF TIEC IN THIS PROCEEDING?

A Yes. Ms. Kathryn E. Iverson and Mr. Steve Weyel are also sponsoring testimony on behalf of the TIEC. Ms. Iverson's testimony:

- Provides a chronology of the TNP One sale;
- Quantifies the results of other asset sales that are reasonably comparable to TNP One;

- Quantifies the adjustment to book value for the allowable cost of land; and
- Quantifies the impact of TNMP's conduct regarding its fuel contract on the value of TNP One.

Mr. Weyel's testimony addresses:

- What constitutes a proper competitive offering and whether TNMP's sale process was properly competitive;
- The commercially reasonable practices for selling a generation asset and whether TNMP used commercially reasonable means to sell TNP One;
- Whether TNMP adequately protected and enhanced the value of TNP One in its conduct and in the timing of the sale of TNP One; and
- The impact of TNMP's failure to use commercially reasonable means to sell TNP One.

Summary

Q WHAT TRUE-UP AMOUNT ARE THE APPLICANTS SEEKING IN THIS PROCEEDING?

A The Applicants – TNMP, First Choice Power, Inc. (FCP) and Texas Generating Company, L.P. (TGC) – are seeking to recover a $357 million true-up amount. The table on page 5 summarizes the components of the Applicants' true-up request.

Q HAVE THE APPLICANTS DEMONSTRATED THAT THEY ARE ENTITLED TO A $357 MILLION TRUE-UP?

A No. Several adjustments to the Applicants' request are necessary in order to satisfy the standards of review in this proceeding. First, the Commission has already properly found that TNMP cannot true-up power cost projections under PURA § 39.262(d)(2) or PUC Subst. R. § 25.263.[1] As a result, the Commission's decision

[1] PUC Docket No. 29206, Supplemental Preliminary Order dated March 3, 2004, page 6.

Summary of True-Up Request
($Millions)

Description	Amount
Recoverable Stranded Costs	$ 307.57
Mitigation Adjustments	$ -
Final Fuel Balance (including interest)	$ (41.08)
True-Up of Capacity Auction Proceeds	$ 106.57
Retail Clawback	$ (15.93)
Regulatory Assets	$ -
Total TNMP Request	$ 357.14
Less: Eliminate Capacity Auction True-Up	$ (106.57)
Pending Amount	$ 250.56

eliminates $106 million of the Applicants' $357 million request. As discussed below, TIEC recommends adjustments to net book value totaling between $155 and $233 million and a $1.03 million reduction in the fuel balance.

Absent these adjustments, TNMP will over-recover its net, verifiable, nonmitigable stranded costs in violation of PURA § 39.262(h) and PUC Subst. R. § 25.263(a)(2). Further, stranded costs should only include costs that are eligible for recovery under normal ratemaking practices, and my understanding is that PURA does not allow for the recovery of costs that were mitigable.

For example, the Commission has previously found that TNMP had imprudently managed its lignite fuel contract. TNMP's imprudent decision to decline a certain 11% reduction in its fuel contract was a failure to mitigate its stranded costs. This failure had a profound impact on the sale price of TNP One and, as discussed later, increased the Applicants' stranded cost recovery by $30 million. Further, TNMP included $10.7 million of investment in land in quantifying the book value of TNP One despite the fact that the Commission had previously allowed only $5.0 million of this investment to be included as invested capital for ratemaking purposes. This $5.7

million of excluded investment would be recovered as stranded costs in this proceeding. Thus, the impact of any imprudent or mitigable costs must be quantified to prevent over-recovery.

Further, as Mr. Weyel testifies, the sale of TNP One was not the result of a properly competitive offering required under PURA § 39.262(h)(1), and TNMP did not pursue commercially reasonable means to reduce its potential stranded costs as required by PURA § 39.252(d) and PUC Subst. R. § 25.263(e)(4). As Mr. Weyel concludes, no reasonable entity would have sold TNP One during June of 2002. TNMP's decision to sell the plant at that time constituted a failure to properly mitigate its stranded costs.

Finally, a $1.03 million adjustment is necessary to give effect to the $15.7 million disallowance approved in Docket No. 27576. Specifically, the disallowance should have been spread evenly throughout the reconciliation period. This comports with past PUC practice. TNMP, by contrast, quantified the final fuel balance as though the disallowance occurred after the reconciliation period. As a result, TNMP overstated the amount of interest in the final fuel balance.

STANDARDS OF REVIEW

Q WHAT IS THE PURPOSE OF THIS PROCEEDING?

A The primary purpose of the True-Up proceeding is to quantify and reconcile the amount of generation-related stranded costs and other claims made by the former investor-owned electric utility. The Legislature defined stranded costs as:

> The positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, and the above market purchase power costs, and any deferred debit related to a utility's discontinuance of the Application of Statement of Financial Accounting Standards No. 71 ("Accounting for the Effects of Certain Types or Regulation") for generation related assets if required.[2]

Q IS QUANTIFYING STRANDED COST MERELY AN EXERCISE IN MATH?

A No. The determination of generation-related stranded cost is not merely the mathematical difference between the net book value and the market value of a utility's generation assets. PURA requires that stranded costs be *net*, *verifiable* and *nonmitigable*.[3]

Net stranded costs take into account all of a utility's generation assets. Certain assets may have a book value above the market value (i.e., stranded costs), while others may have a market value in excess of book value (i.e., stranded benefits). Further, any other capital contributed by customers that is no longer needed by the utility to fulfill its financial obligations (i.e., accumulated deferred income taxes) should also be netted. Thus, quantifying stranded costs requires netting both above-market and below-market generation-related assets.

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[2]PURA § 39.251(7) and PUC Subst. R. § 25.5(124); the term "stranded cost" has been used more broadly in other contexts.
[3]PURA § 39.252(a)

Verifiable means that a utility must support any stranded cost claim. This includes documentation supporting the net book value of its generation assets and demonstrating that the market value was determined in compliance with PURA.

Nonmitigable means that the utility must demonstrate that it could not have reasonably avoided or reduced the costs in question. At a minimum, the standard requires the utility to demonstrate that it has taken commercially reasonable steps to minimize stranded costs. In summary, a utility must take all reasonable steps to protect and enhance the value of its generation assets.

Q CAN ANY IMPRUDENT COSTS INCURRED BY A FORMER INTEGRATED ELECTRIC UTILITY BE CONSIDERED IN DETERMINING THAT UTILITY'S STRANDED COSTS?

A No. The policy behind stranded cost recovery is to provide the utility an opportunity to recover costs that would have been recovered in rates but for the change from a regulated to a competitive environment. Therefore, only costs that the Commission has found to have been prudently incurred for ratemaking purposes are eligible for stranded cost recovery.

Q WHAT OTHER FINDINGS MUST BE MADE IN THE TRUE-UP PROCEEDING?

A In addition to reconciling generation-related stranded costs, the True-Up proceeding will determine whether an electric utility is entitled to recover additional monies related to:

- The Final Fuel Balance;
- Capacity Auction True-Up;
- True-up of Price-to-Beat revenues; and

- To account for any amount of regulatory assets that have not been included in either a transition charge (TC) or a competition transition charge (CTC).

As previously stated, the Capacity Auction True-Up is no longer an issue in this proceeding as a result of the Commission's March 3, 2004 Order. TNMP is not seeking to recover any generation-related regulatory assets.

Q WHY IS IT NECESSARY TO RECONCILE THE AMOUNT OF STRANDED COSTS IN THE TRUE-UP PROCEEDING?

A In accordance with PURA § 39.201(h), stranded costs were initially estimated using the ECOM (Excess Cost Over Market) model in each utility's Unbundled Cost of Service (UCOS) proceeding. The ECOM model was the tool developed by the Commission and relied upon by the Legislature to initially estimate a utility's estimated stranded costs. The estimated stranded costs were to be used as a basis for setting CTCs when customer choice began on January 1, 2002.

Q WHAT WERE THE RESULTS OF USING THE ECOM MODEL IN TNMP'S UCOS PROCEEDING?

A The Commission found that TNMP would have negative $500,000 of ECOM.[4] Consequently, because TNMP had negative ECOM, the Commission found that it was not necessary to implement a CTC on January 1, 2002.

Q HOW ARE A UTILITY'S ACTUAL STRANDED COSTS TO BE QUANTIFIED?

A Under PURA, stranded costs were to be finally determined using a market valuation rather than an administrative model. This comports with the requirements that:

[4]Docket No. 22349, Order at Page 57.

> An electric utility is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service.[5]

And:

> An electric utility, together with its affiliated retail electric provider and its affiliated transmission and distribution utility, may not be permitted to overrecover stranded costs through the procedures established by this section or through the application of the measures provided by the other sections of this chapter.[6]

Thus, the stranded cost estimate derived in the UCOS proceedings would be reviewed and, if necessary, adjusted to reflect a final, actual valuation in the True-Up proceeding.[7] Further, the final actual valuation would be based on the value the assets would have if properly bought and sold in a bona fide, third-party transaction(s) on the open market under PURA § 39.262(h),[8] subject to any adjustments to book value necessary to ensure that the utility's conduct satisfied the statutory standards.

Q HOW CAN THE MARKET VALUE OF THE UTILITY'S GENERATION ASSETS BE DETERMINED?

A There are four possible methods allowed in PURA § 39.262(h). These methods are:

1. Sale of assets;
2. Stock valuation method;
3. Partial stock valuation method; and
4. Exchange of assets method.

[5]PURA § 39.252(a)
[6]PURA § 39.262(a)
[7]PURA § 39.201(l)
[8]PURA § 39.251(4)

In addition, for certain nuclear assets, the market value would be determined using the ECOM method.[9]

Q WHICH METHOD HAS TNMP CHOSEN FOR DETERMINING THE MARKET VALUE OF ITS GENERATION ASSETS?

A TNMP has chosen the sale of assets method.

Q WHAT ARE THE STANDARDS OF REVIEW APPLICABLE TO TNMP'S USE OF THE SALE OF ASSETS METHOD?

A Both PURA and the Commission's Substantive Rules state that an electric utility or its affiliate power generation company (APGC) that sells some or all of its generation assets after December 31, 1999 must do so in a proper bona fide, third-party transaction under a competitive offering.[10] This is consistent with the requirements that stranded costs are reflective of all of the utility's generation assets (i.e., *netting)*, are *verifiable*, and have been mitigated.

Q WHAT OTHER STANDARDS MUST THE APPLICANTS COMPLY WITH IN DETERMINING ITS STRANDED COST?

A First, the Applicants must demonstrate that they have properly mitigated their stranded costs. This requires, at a minimum, demonstrating that the utility has pursued commercially reasonable means to reduce (or mitigate) potential stranded costs, which includes but is not limited to: (1) good faith attempts to renegotiate above-cost fuel and purchase power contracts, or (2) the exercise of normal business

[9]PURA § 39.262(i)
[10]PURA § 39.262(h)(1) and PUC Subst. R. § 25.263(f)(1)(A)

practices to protect the value of its assets.[11] The policy objective is to ensure that the utility's conduct is examined to ensure that it recovers only *nonmitigable* stranded costs.

Second, as previously stated, the Applicants cannot over-recover their *net, verifiable* and *nonmitigable* stranded costs.

Q IF IT WERE DEMONSTRATED THAT THE APPLICANTS FAILED TO PURSUE COMMERCIALLY REASONABLE MEANS TO MITIGATE STRANDED COSTS, THEN WHAT ARE THE CONSEQUENCES?

A In the event that the Commission finds that the Applicants failed to pursue commercially reasonable means to reduce its potential stranded costs or exercise normal business practices to protect the value of its assets, then it may reduce the net book value of the APGC's generating assets or take other measures it deems appropriate in the True-Up proceeding.[12]

Q WHAT ACTION SHOULD BE TAKEN BY THE COMMISSION IF IT WERE DEMONSTRATED THAT A UTILITY'S STRANDED COSTS WERE AFFECTED BY COSTS THAT HAD BEEN PREVIOUSLY DISALLOWED FROM RATES?

A The Commission should adjust net book value to remove any imprudent or other disallowed costs as determined in prior regulatory proceedings. This is consistent with the fundamental premise of stranded cost recovery. The premise is that a utility is entitled to recover only those costs that it would have been allowed to recover through normal ratemaking practice. Allowing imprudent or disallowed costs to be

[11]PURA § 39.252(d) and PUC Subst. R. § 25.263(e)(4)
[12]PUC Subst. R. § 25.263(e)(4)

included in or influence the determination of stranded costs would unjustly reward a utility for those actions previously found not to be in the public interest.

Further, any disallowed costs could have been avoided or mitigated. Thus, removing disallowed costs (or the effects of disallowed costs) from book value is also mandated by the requirement that the stranded costs to be recovered are only those that are nonmitigable.

TNMP'S COMPLIANCE WITH THE STANDARDS OF REVIEW

Q WAS THE SALE OF TNP ONE MADE THROUGH A PROPERLY COMPETITIVE OFFERING?

A No. As described in the testimonies of Ms. Iverson and Mr. Weyel, the sale process was not properly competitive and was not designed to protect and enhance the value of TNP One. There was no competition for many months before the sale of TNP One. This is demonstrated in Exhibit KI-1. As can be seen, by December 20, 2001 all of the original six final bidders[13] had been eliminated from the process. By the end of March 2002, none of the alternative bidders, but one, remained in the process. That sole bidder was Sempra Energy Resources (Sempra). Sempra was the only bidder with whom TNMP seriously negotiated a power sales agreement (PSA). According to Mr. Weyel, negotiating with only one bidder cannot be characterized as a properly competitive offering.

Q ARE THERE OTHER INDICATIONS THAT THE SALE OF TNP ONE WAS NOT MADE THROUGH A COMPETITIVE OFFERING?

A Mr. Weyel cites several examples in his testimony. First, not all bidders were treated the same. For example, TNMP initially advised bidders to submit proposals on the assumption there would not be an "off-take" agreement for some or all of the output of TNP One. However, later in the process, after several bidders had dropped out, TNMP gave the bidders the option to submit proposals assuming an off-take

[13]The initial six final bidders were: FPL Energy (dropped out after first round), Mirant (dropped out December 20, 2001), NRG (notified by TNMP November 11, 2001 that it was not a finalist), WPS (also notified by TNMP November 11, 2001 that it was not a finalist), Orion (dropped out August 9, 2001) and Dynegy/Kiewit (notified TNMP August 28, 2001 that it was not submitting a final bid).

agreement. A process cannot be competitive if the rules and procedures are constantly changing.

Mr. Weyel also cited many other aspects of TNMP's process that resulted in the sale not occurring through a proper competitive offering, such as:

- Ensuring that the auction process is serious.
- Pre-qualifying interested buyers to ensure they are financially capable of purchasing the assets being offered.
- Establishing enforceable penalties for withdrawal of bids.
- Avoiding conflicts of interest.

Q WAS TNMP'S PROCESS DESIGNED AND CARRIED OUT IN A MANNER THAT PROTECTED AND ENHANCED THE VALUE OF TNP ONE?

A No. Mr. Weyel has determined that TNMP's process was inconsistent with the pursuit of commercially reasonable means to reduce potential stranded costs. He cites several examples whereby TNMP did not exercise normal business practices to protect the value of TNP One.

For example, TNMP's financial advisor was not the principal and controlling point of contact as is normally the case in sales of generation assets. Various TNMP personnel, as well as personnel from Constellation Energy Group (CEG), were actively involved in the sale process. In short, no one appeared to be consistently in charge of the process. Mr. Weyel indicates that normal business practice is to retain an investment banker to be the principal and sole contact between the seller and potential buyers. Only under this type of arrangement can the communications to buyers be strictly monitored and assured of consistency.

Further, according to Mr. Weyel, TNMP's process was not conducive to maximizing the value of the assets being sold. He describes how a different process, such as the simultaneous ascending auction, would have maximized revenues, thereby protecting and enhancing the value of TNP One.

Mr. Weyel also cites the fact that the sale process was not completed in a timely manner. Referring to Exhibit KI-1, the entire bid process lasted 26 months – 11 months to prepare the bid package, 7 months to receive and analyze four rounds of non-binding bids, another 4 months during which time all but one bidder dropped out, and 4 months to negotiate and sign the agreement. During this time, serious interest in TNP One waned due to dramatic changes in the market (e.g., declining natural gas prices and wholesale market prices for electricity, the loss of the arbitration with Walnut Creek Mining Company (WCMC), geo-political events (September 11), and further collateral damage resulting from the collapse of Enron, and the subsequent liquidity crisis in both debt and equity markets for generation assets).

These changing market conditions are discussed by Mr. Chambers, on behalf of TNMP, and by Mr. Weyel.[14]

Q HOW DID CHANGING MARKET CONDITIONS AFFECT THE BIDDING FOR TNP ONE?

A This can be seen by comparing the first and second round of bids. The first round of bids was received in July 2001. Bidders were willing to pay up to $275 million for TNP One. The second round of bids was received in late August. These bids ranged from $67 million to $162 million. The latter bids were contingent on several factors such as a reduction in lignite fuel prices in the pending WCMC arbitration, and the

[14]Direct Testimony of Jack V. Chambers, pages 8 and 9.

completion of a separate agreement (often referred to as an "off take agreement") between the buyer of TNP One and a TNMP subsidiary for the output of TNP One.

Half of the finalists from the first round did not submit bids in the second round. One of these non-bidders was Dynegy. In declining to bid, Dynegy cited four reasons:

(1) Forward gas and power prices had decreased significantly in response to general economic slowdown and aggressive expansion of new combined cycle (CC) generation, resulting in projected high reserve margins and reduced market heat rates;

(2) Inability to achieve synergies with Kiewit and awareness that TNMP did not prevail in its arbitration of the lignite price;

(3) Subsequent evaluation, which showed that a 300 MW expansion is uneconomic; and

(4) Its conclusion that gas-fired CC investment would be uneconomic based on current ERCOT market outlook.[15]

Consequently, TNMP was aware of the marked change in the market by late August 2001.

Q COULD TNMP HAVE COMPLETED THE SALE PROCESS BEFORE THE DECLINE IN WHOLESALE PRICES HAD OCCURRED?

A Yes. Ms. Iverson indicates that the initial plans to sell TNP One commenced as early as May 25, 2000. Management subsequently delayed the process to target a sale in the first quarter of 2002. According to Mr. Weyel, had TNMP exercised normal business practice, it would have completed the sale of TNP One in three to four months.

[15] TNMP TU 00541 and 00542

Q **DID THE COLLAPSE OF ENRON AFFECT THE BIDDING FOR TNP ONE?**

A Yes. Enron's collapse triggered a dramatic decline in the equity value and credit ratings of many of the key players in the competitive power industry. This included several of the original high bidders for TNP One.

Furthermore, only a month after the public announcement of Enron's bankruptcy, utility analysts recognized the impact:

> The year 2001 saw a dramatic slow down in the sale of utility-owned generation assets. ...concerns about credit status in the power industry and more general unease about the economic outlook have also contributed to the slowdown. ... Aside from regulation, concerns related to the demise of Enron Corp. are also likely slow the pace of new sales, S&P's Cortwright said. The prospect of warmer weather, economic slowdown and the resultant lower power sales had already made the power industry jittery. Enron's collapse exacerbated this by raising questions about the viability of off-balance sheet financing and concerns about liquidity and credit quality.[16]

Thus, it was common industry knowledge that interest in generation asset sales was down, and particularly that interest in TNP One had collapsed, with the sole exception of one bidder – Sempra.

Q **WAS SELLING TNP ONE IN JUNE OF 2002 CONSISTENT WITH PROTECTING AND ENHANCING ITS VALUE?**

A No. By the end of 2001, it became clear that TNMP was selling TNP One in a collapsed market. The collapse of the market is documented by Mr. Weyel.

[16]TNMP TU 02201 – 02202 (*Electric Utility Week*, January 7, 2002)

Q WERE MARKET CONDITIONS IN EARLY 2002 CONDUCIVE TO SELLING GENERATING ASSETS?

A No. Mr. Weyel documents the market conditions at that time, which were not conducive to selling generation assets.

Q WERE THERE OTHER INDICATIONS THAT MARKET CONDITIONS DURING THE FIRST HALF OF 2002 WERE NOT CONDUCIVE TO SALES OF GENERATION ASSETS?

A Yes. PEPCO Holdings Inc. (PHI) cancelled a power plant auction, which it had initiated in 2002 for 740 MW of fossil generation in New Jersey and Pennsylvania.[17] The reason cited for canceling the asset sale was that the bids received were not as high as the company would have liked. PHI was quoted as saying that it may hold a new auction in the future if the market improves.[18] Further, this was the second cancellation of a plant sale in 2002. Earlier, NRG had cancelled a purchase of plants from Atlantic City Electric Company (ACE) citing, among others things, declining market prices.

In summary, the market for selling generating assets had collapsed. It was not reasonable for TNMP to have sold its most valuable asset, TNP One, in this market. As Mr. Weyel explains, it is not normal business practice nor is it commercially reasonable to sell an asset in this environment absent financial distress. As such, TNMP failed to protect and enhance the value of TNP One.

[17]McGraw-Hill Companies, Inc., *Electric Utility Week*, January 20, 2003, pages 27-28.
[18]Id.

Q WAS TNMP UNDER A LEGISLATIVE MANDATE TO SELL TNP ONE BY A DATE CERTAIN?

A No. There was no obligation either in PURA or in the Commission's Substantive Rule mandating a sale of TNP One by a date certain. All that PURA requires is that an electric utility may sell generating assets at any time after December 31, 1999. In fact, at least one utility – AEP Texas Central Company (TCC) – is just now nearing the completion of the sale of its generation assets.

Q TNMP WITNESS CHAMBERS CLAIMS THAT GENERATION ASSET SALES HAD TO BE COMPLETED BEFORE JANUARY 2004. WAS THERE ANY MANDATE TO COMPLETE THE SALE OF GENERATION ASSETS BY JANUARY 2004?

A No. There is no such mandate in either PURA or the Commission's Substantive Rules that a utility must complete the sale of assets on or before January 2004. In any event, the True-Up proceeding would not have begun until after January 10, 2004, at a schedule and under procedures to be determined by the Commission.[19] Further, even if the Commission had scheduled a true-up proceeding on January 10, 2004, it was not a foregone conclusion that TNMP's True-Up proceeding would have been scheduled first.

[19]PUC Subst. R. § 29.263(c)

Q HOW DID THE COMMISSION DETERMINE THE SCHEDULE OF THE VARIOUS TRUE-UP PROCEEDINGS?

A Last March, the Commission proposed an amendment to Subst. R. § 25.263 to establish the true-up filing schedule required by PURA § 39.262(c).[20] The proposed schedule would have required TNMP to file a true-up proceeding on March 31, 2004.

Q HOW WAS THE RULEMAKING RESOLVED?

A At the request of TIEC and other parties, the Commission agreed to postpone CenterPoint Energy's True-Up filing from January 14 to March 31. In the process, TNMP's True-Up filing was moved to January 14.

Q COULD TNMP HAVE REQUESTED A LATER FILING DATE IN THE RULEMAKING?

A Yes. The Commission proposed a September 3, 2004 filing date for TCC. Notably, TCC is the only other utility using the sale of assets method. In proposing the filing date for TCC, the Commission stated that:

> This relatively late filing date is essentially based upon AEP Central's specific circumstances – that is, this date reflects the fact that AEP Central has not yet definitely determined whether the market valuation of its generation assets will occur by the sale of the assets or by the issuance of stock pursuant to a stock valuation or partial stock valuation methodology.[21]

Thus, the proposed filing date recognized that under either method, TCC would require approximately 18 months to complete a market valuation of its generation assets. The 18-month period reflects that TCC is selling multiple generation assets, including a nuclear plant, as compared to TNMP's single coal plant sale.

[20]PUC Project No. 27401

[21]Public Utility Commission of Texas, Project No. 27401, Proposal For Publication of an Amendment to § 25.263 As Approved at the March 21, 2003 Open Meeting, page 3.

Like TCC, TNMP could have asked the Commission for a later filing date to accommodate a commercially reasonable sale of TNP One.

Q **DID TNMP FILE ANY COMMENTS IN THIS RULEMAKING PROCEEDING?**

A No.

Q **IF TNMP HAD TAKEN TNP ONE OFF THE MARKET IN 2002, COULD THE UNIT HAVE BEEN SOLD AT A HIGHER PRICE?**

A Yes. Mr. Weyel explains what TNP One would have sold for had TNP taken reasonable steps to protect and enhance the value of TNP One. His analysis is bourne out by the fact that TNP One is an extremely valuable asset for the reasons listed below, and therefore should command a premium price in the market:

1. It is a solid fuel resource located in a power region (i.e., ERCOT) where natural gas is the marginal fuel.
2. Both Units 1 and 2 have operated at very high capacity factors (over 80% in most years and increasing to 90% to 95% in 2002).
3. The plant is located in the North Congestion Zone.
4. TNP One is the cleanest coal-fired generating plant in Texas.[22]

Q **WHAT IS THE SIGNIFICANCE OF THE FACT THAT TNP ONE IS A SOLID FUEL RESOURCE IN ERCOT?**

A Market clearing prices in ERCOT are set primarily by natural gas generation. The close relationship between market clearing prices and natural gas prices is shown in Exhibit JP-1. This exhibit compares balancing energy prices in the North Congestion

[22] http://www.sempraenergyresources.com/Pages/Projects/Twin_Oaks/Twin_Oaks.aspx

Zone as published by ERCOT to the daily closing at the Houston Ship Channel daily natural gas prices as published in Platts' *Gas Daily*.

Thus, electricity market prices rise and fall with changes in natural gas prices. Solid fuel resources have lower and more stable fuel costs than do natural gas units. This means that TNP One can earn higher margins during periods of high market (natural gas) prices. The more stable cost structure means lower market risk. All other things being equal, higher operating margins and lower market risk support a higher asset value for TNP One.

Q DID TNMP BELIEVE THAT INCREASING GAS PRICES WAS ADVANTAGEOUS TO THE VALUE OF TNP ONE?

A Yes, the Company certainly did. For example, as shown in Exhibit KI-1, in late December 2000, the Company found that "at gas prices of at least $6 and that over the long run, TNP One will be worth more than book value."[23] Furthermore, in negotiations with Sempra in the spring of 2002, TNMP claimed that the increasing gas market enhances the price Sempra should be willing to pay for the asset.[24]

Q HOW DOES THE CAPACITY FACTOR OF TNP ONE COMPARE WITH OTHER COAL/LIGNITE ASSETS THAT WERE SOLD?

A An analysis of the capacity factors is provided in Exhibit JP-2. For the three years before its sale, TNP One operated at an average capacity factor of 83%. Other coal-fired resources operated at capacity factors ranging from 32% to 85% in the three years before the sale. As can be seen, only one other plant operated better than TNP One before it was sold.

[23]TNMP TU 02590
[24]TNMP TU 09809 and 09811

Q WHAT IS THE SIGNIFICANCE OF THE FACT THAT TNP ONE HAS OPERATED AT HIGHER CAPACITY FACTORS THAN OTHER COAL UNITS THAT HAVE BEEN SOLD?

A TNP One has a higher operating leverage than similar assets that have operated at a lower capacity factor. Thus, the fixed costs associated with the ownership, operation and maintenance of TNP One can be spread over a larger sales base. The higher operating leverage, coupled with its lower operating costs (relative to natural gas resources), further enhances the value of TNP One.

Q WHAT IS THE SIGNIFICANCE OF TNP ONE'S LOCATION IN THE NORTH CONGESTION ZONE?

A The North Zone has experienced higher market clearing prices than any of the other zones. This is shown in Exhibit JP-3. The capacity margins are also lower in the North Zone. This is shown in Exhibit JP-4. In a competitive wholesale market, the lower the capacity margin the higher the price.

Q DID TNMP BELIEVE THAT THE LOCATION OF TNP ONE IN THE NORTH ZONE WAS ADVANTAGEOUS?

A Yes. Mr. Chambers discusses this development in his testimony.[25] He cited the movement of TNP One from the South to the North Congestion Zone (which became effective on January 1, 2002) as a factor that would increase the value of the plant's output. This is because of the higher market prices in the North Zone. All other things being equal, this should increase the bids for TNP One.

[25] Direct Testimony of Jack V. Chambers, page 6.

Q IS THERE COMPELLING EVIDENCE THAT TNMP WOULD HAVE REALIZED A HIGHER MARKET VALUE OF TNP ONE IF IT HAD NOT SOLD THE PLANT IN 2002?

A Yes. Four coal-fired plants have been sold since the sale of TNP One. As shown in Exhibit KI-2, all of these plants were sold at much higher prices than TNP One. Especially noteworthy is the Oklaunion coal plant recently sold. This asset would be the most comparable to TNP One since Oklaunion is located in ERCOT. According to the press releases, Oklaunion sold for $792/kW. This compares to only $400/kW for TNP One. Thus, Oklaunion sold at a premium to TNP One of $118 million.[26]

Q ARE THERE OTHER EXAMPLES DEMONSTRATING THAT TNMP DID NOT PURSUE COMMERCIALLY REASONABLE MEANS TO PROTECT AND ENHANCE THE VALUE OF TNP ONE?

A Yes. In her testimony, Ms. Iverson discusses the impact of the arbitration between TNMP and WCMC. TNMP had an opportunity to realize an 11% reduction in the cost of fuel for TNP One. However, TNMP elected instead to submit the contract to arbitration. The bidders were aware of the arbitration. In fact, as Ms. Iverson demonstrates, several bidders qualified their bids depending on the outcome of the arbitration. As Ms. Iverson concludes, by failing to accept the guaranteed 11% reduction in fuel prices, the value of TNP One was reduced by $30 million.

[26] TNP One has a total rated capacity of 300 megawatts.

Q WAS IT REASONABLE FOR BIDDERS TO LOWER THEIR ASKING PRICES IN RESPONSE TO THE ARBITRATION DECISION?

A Yes. The value of an asset is determined by the net present value of future operating margins; that is, revenues minus cash operating expenses. Fuel is the largest single operating expense associated with a generating asset. Thus, changes in the projected cost of fuel can significantly affect future operating margins and, thus, the bid prices for a generating asset like TNP One.

Q HAS THE COMMISSION PREVIOUSLY RULED ON TNMP'S MANAGEMENT OF ITS LIGNITE FUEL CONTRACT?

A Yes. The Commission found that TNMP's conduct was imprudent. Specifically, the Commission disallowed $5.7 million of TNMP's lignite fuel expense.[27]

Q SHOULD THE COMMISSION REDUCE TNMP'S NET BOOK VALUE TO REFLECT THE EFFECTS OF TNMP'S FAILURE TO ACCEPT THE GUARANTEED 11% REDUCTION?

A Yes. As stated previously, a utility is not entitled to recover as stranded costs any costs (or the effect of any costs) that would not have otherwise been allowed in regulated rates. The Commission found that TNMP was imprudent in its conduct surrounding the contract with WCMC, and it disallowed $5.7 million of lignite fuel costs. The PFD quoted the position of one intervenor that WCMC's final offer to lower lignite costs by around $100 million over the life of the agreement presented a

[27]Application of Texas-New Mexico Power Company for Final Reconciliation of Fuel Costs Under PUC Subst. R. § 25.236(g); Finding of Fact 53, Conclusion of Law 17 and 18, and Proposal For Decision, page 3.

rare "win-win-win" situation.[28] This was especially apropos given that this was the last price redetermination TNMP could use to lower stranded costs.

By forgoing the opportunity for an 11% reduction in a key operating cost, TNMP reduced the market value of TNP One, thereby increasing TNMP's stranded cost claim. Such conduct was unreasonable and inconsistent with TNMP's duty to mitigate its stranded costs. Absent an adjustment to book value, TNMP's customers would pay higher rates, and TNMP would be rewarded for its unreasonable and imprudent conduct. Therefore, the Commission must reduce net book value to reflect the impact of TNMP's conduct, which Ms. Iverson has quantified to be $30 million.

Q WAS THERE ANY FURTHER COLLATERAL DAMAGE BECAUSE OF THE WCMC ARBITRATION?

A Yes. The arbitration occurred during the period June 2001 through the end of August 2001. This period coincided with the first and second rounds of bidding in the TNP One sale, which took place in July and August 2001. Because it was in arbitration with TNMP, none of the bidders was able to negotiate directly with WCMC during the all-important due-diligence period. Had the bidders been able to negotiate with WCMC, it is possible that they would have realized some reduction in TNP One fuel costs. This would have allowed the six finalists to submit higher bids and would have resulted in enhancing the value of TNP One.

[28] Id at page 16.

Q ARE THERE ANY OTHER COSTS THAT TNMP IS SEEKING TO RECOVER IN THIS PROCEEDING THAT WERE NOT ALLOWED IN RATES?

A Yes. Ms. Iverson has determined that TNMP is seeking to recover $5.7 million of investment in TNP One that was disallowed in a prior rate case.

Q IS THIS DISALLOWED INVESTMENT PROPERLY RECOVERABLE?

A No. Because this investment was never included in invested capital, it was never reflected in TNMP's base rates. Consequently, TNMP should have had no expectation of recovering this investment as stranded costs in this proceeding. To do otherwise would be tantamount to reversing over a decade of regulatory policy, and it would force customers to now pay for costs that were never allowed in rates.

This result would not comport with the policy objective behind stranded cost recovery. Stranded costs are only those costs that were previously determined to have been prudently incurred and which are also net, verifiable and mitigable. The disallowed investment was imprudent. Further, TNMP has had every opportunity to monetize the value of this imprudent investment, and, consequently, it was mitigable.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE REASONABLENESS OF APPLICANTS' CLAIMS FOR STRANDED COST RECOVERY.

A The Applicants have not complied with PURA § 39.252(d), § 39.262(a), and § 39.262(h)(1). Therefore, an adjustment should be made to the net book value of TNMP's generation assets as required under PUC Subst. R. § 25.263(e)(4).

QUANTIFICATION OF TIEC RECOMMENDATIONS

Adjustments to Net Book Value

Q WHAT ADJUSTMENTS SHOULD BE MADE TO THE NET BOOK VALUE?

A There should be at least three adjustments. The first adjustment is to recognize that the sale of TNP One was not the result of a proper competitive offering required under PURA § 39.262(h)(1) and TNMP did not mitigate its stranded costs. It did not pursue commercially reasonable means and exercise normal business practices to reduce its potential stranded costs as required by PURA § 39.252(d) and PUC Subst. R. § 25.263(e)(4).

The second adjustment is to recognize the Commission's prior determinations that certain TNP One investment was imprudent and has never been included in rates, and that TNMP had imprudently managed its lignite fuel contract. This adjustment is necessary for two reasons. First, stranded costs should only include costs (and the effects of costs) that are eligible for recovery under normal ratemaking practices. Accordingly, the impact of any imprudent or disallowed costs must be quantified to prevent over-recovery. Second, the higher fuel costs were avoidable. Similarly, TNMP has had plenty of time to monetize the value of the disallowed land investment. Thus, both costs were mitigable.

Finally, the third adjustment removes the fees charged by Laurel Hill Capital Partners, LP in determining the net value received from the sale of TNP One.

Q HOW DID YOU QUANTIFY THE FIRST ADJUSTMENT?

A Mr. Weyel testifies that had TNMP acted in a commercially reasonable manner, and exercised normal business practice, TNMP would have pulled TNP One from the collapsed market in 2002 and renewed efforts to sell the plant after market conditions improved. Had TNMP opted to delay the sale of TNP One a mere six months, as Mr. Weyel testified, TNMP could have sold TNP One for at least $255 million. Moreover, had TNMP further delayed the sales process until December of 2003, as improving market conditions suggested was commercially reasonable to do, TNMP could have sold TNP One for as much as $316 million. Accordingly, if TNMP had behaved in a commercially reasonable manner, TNMP could have realized at least an additional $135 million to $196 million in the sale of TNP One.

Alternatively, TNMP should have realized a value at least comparable to the sale price of TCC's share of the Oklaunion plant. According to Ms. Iverson, had Applicants sold TNP One at the same price as TCC's sale price of Oklaunion, they would have realized an additional $118 million.

Q IS OKLAUNION A REASONABLE BENCHMARK TO TNP ONE?

A Yes. Both plants are located in ERCOT. None of the other coal plants that have been sold on a stand-alone basis was located in ERCOT. Thus, both plants compete in the same markets. If anything, Oklaunion is a conservative benchmark to compare with TNP One. This is because TNP One is located in the North Congestion Zone, while Oklaunion is located in the West Zone. In addition, the North Congestion Zone generally experiences higher market prices than the West Zone (Exhibit JP-3), and it has a lower capacity margin (Exhibit JP-4). Further, TNP One has operated at a much higher capacity factor than Oklaunion (Exhibit JP-2). These factors make TNP One is a more valuable resource than Oklaunion.

Q **PLEASE SUMMARIZE THE FIRST ADJUSTMENT.**

A In summary, book value should be reduced by between $118 million and $196 million to recognize that TNMP failed to sell the asset through a competitive offering and use all commercially reasonable means of mitigating stranded costs, and used poor judgment in selling TNP One in a collapsed market.

Q **HOW IS THE SECOND ADJUSTMENT QUANTIFIED?**

A Ms. Iverson has determined that the impact of TNMP's imprudent conduct in managing its fuel contract was $30 million. Similarly, she has determined that $5.7 million of the investment in land associated with TNP One was never included as invested capital for ratemaking purposes. Consistent with the standards of review described earlier in my testimony, book value should be reduced by $35.7 million.

Q **HOW DID YOU QUANTIFY THE THIRD ADJUSTMENT?**

A According to TNMP's Schedule IV-A-1, the fees paid to Laurel Hill Capital Partners, LP (LHCP) were $1.275 million. These fees, along with other transaction costs, were deducted from the total sales proceeds to derive the net value realized from the sale of TNP One. As Mr. Weyel explains, TNMP's selection of LHCP was not commercially reasonable because it could not properly perform the role of an independent financial advisor due to LHCP's conflict of interest and lack of experience in the sale of generating assets. As a result, the auction process was not conducted properly and effectively.

Based on Mr. Weyel's conclusions, LHCP's fees should not be included in determining the net value realized.

Q **SHOULD ANY OTHER ADJUSTMENTS BE MADE TO NET BOOK VALUE?**

A TIEC is not specifically proposing additional adjustments to book value. However, it is plausible that other adjustments would be appropriate to ensure that TNMP does not over-recover its net, verifiable and nonmitigable stranded costs.

Q **PLEASE EXPLAIN.**

A Consistent with normal ratemaking practices, customers have provided capital to support future obligations. To the extent that these obligations no longer exist because of the asset sale, then such customer-supplied capital should offset net book value.

For example, customers were required to provide capital to support future tax obligations. This is because although rates were set assuming straight-line depreciation for determining income tax expense, TNMP actually incurred lower income taxes because it used accelerated depreciation for reporting its income to the IRS. The difference between tax and book depreciation is recognized for ratemaking purposes as accumulated deferred income taxes (ADFIT). Because it is capital supplied by customers, ADFIT is deducted from rate base when rates are set. If these taxes are forgiven because the plant was sold, then any remaining ADFIT should be used to offset the net book value of the plant. Other similar offsets may be required.

Fuel Balance

Q **TNMP CLAIMS THAT THE FINAL FUEL BALANCE IS AN OVER-RECOVERY OF $41.1 MILLION. DO YOU AGREE WITH TNMP'S ANALYSIS?**

A No. TNMP's analysis assumed that the $15.7 million disallowance approved in TNMP's final fuel reconciliation (Docket No. 27576) occurred after the reconciliation period, which was from January 1, 2000 through December 31, 2001. However, the costs that were disallowed by the Commission were incurred during the entire reconciliation period. For this reason, it is appropriate to assume that the lower eligible fuel cost would have been incurred throughout the reconciliation period.

Q **HOW SHOULD THE FINAL FUEL BALANCE HAVE BEEN DETERMINED?**

A The final fuel balance should have been determined by assuming that the $15.7 million disallowance was spread evenly during the reconciliation period. This is shown in Exhibit JP-5. As can be seen, the effect of spreading the $15.7 million disallowance throughout the reconciliation period would be to increase the fuel over-collection to $42.11 million, which is $1.03 million higher than TNMP's proposal.

Q **DOES THIS CONCLUDE YOUR TESTIMONY?**

A Yes.

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is PO Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and am employed by BAI (Brubaker & Associates, Inc.).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. BAI was formed in April 1995.

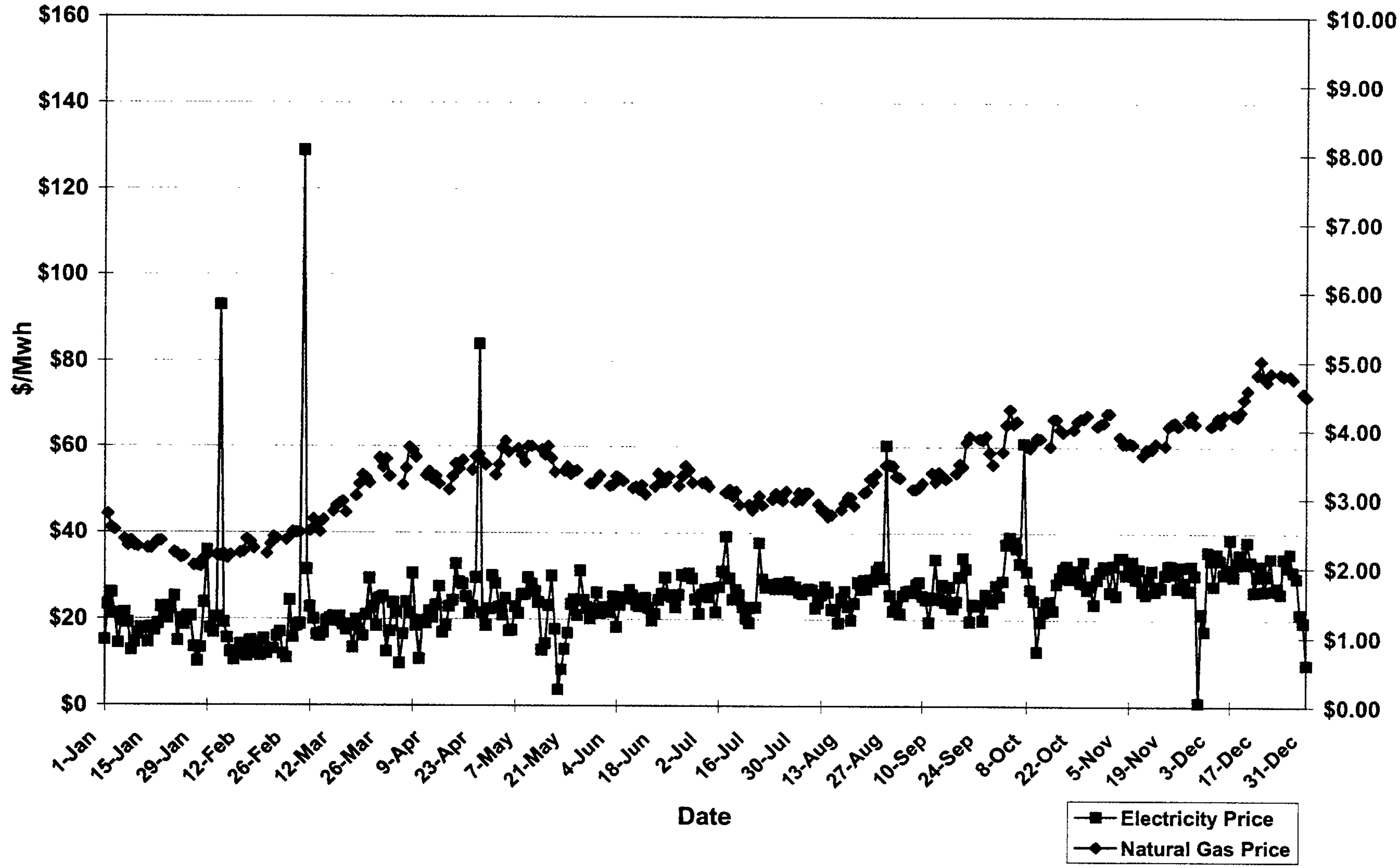
BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the procurement and management of utility and energy services in both regulated and competitive markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present timely seminars on electricity. In the last five years, BAI professionals have participated in numerous regulatory proceedings and in projects implementing customer choice in 40 states and Canada.

During my tenure at both DBA and BAI, I have also been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing request for proposals (RFPs), evaluating RFP responses and contract negotiation. I am also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

In addition to our main office in St. Louis, BAI also has branch offices in Denver, Colorado; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

COMPARISON BETWEEN ELECTRICITY AND NATURAL GAS PRICES
2002 NORTH ZONE MCPE VS. HOUSTON SHIP CHANNEL



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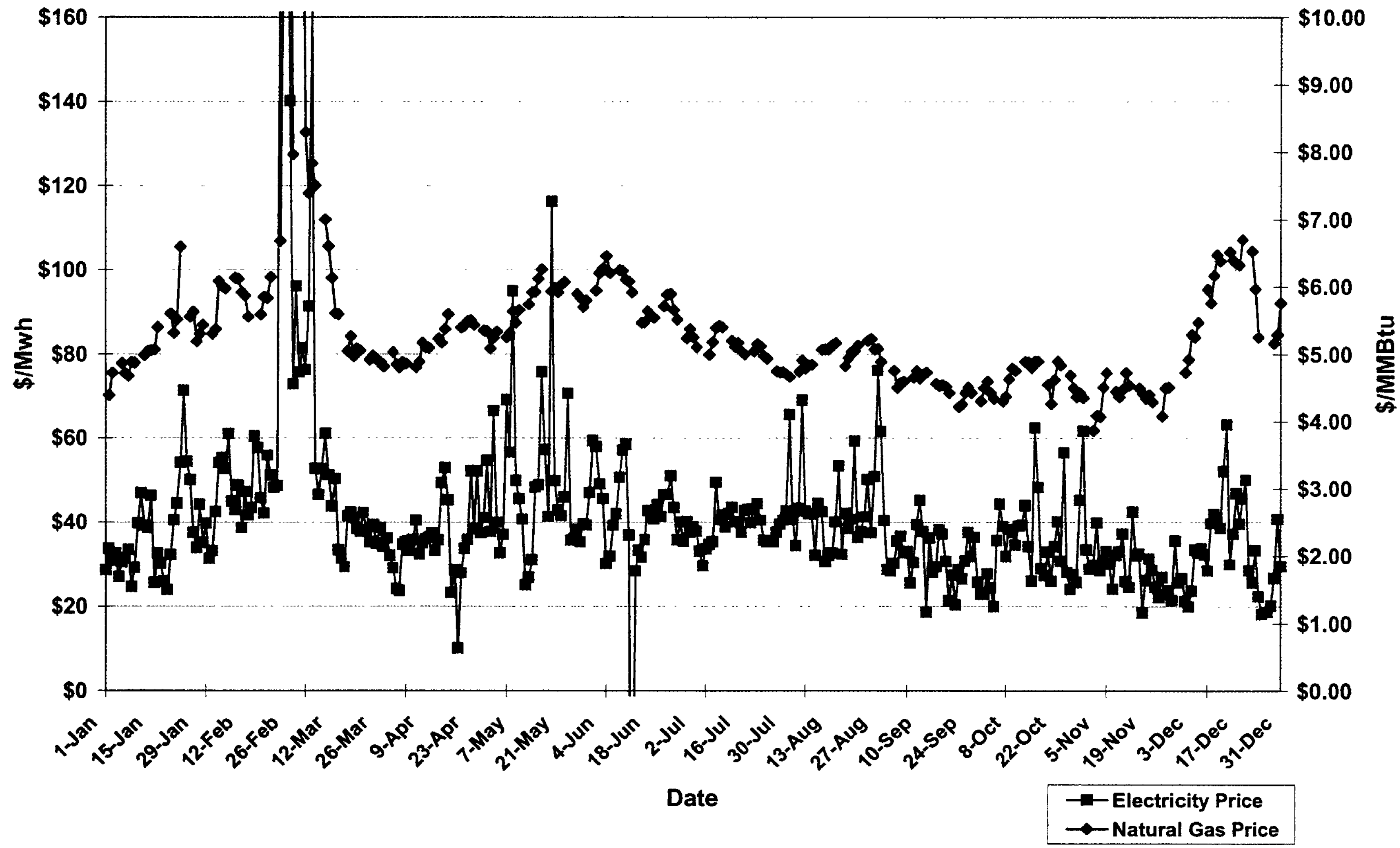
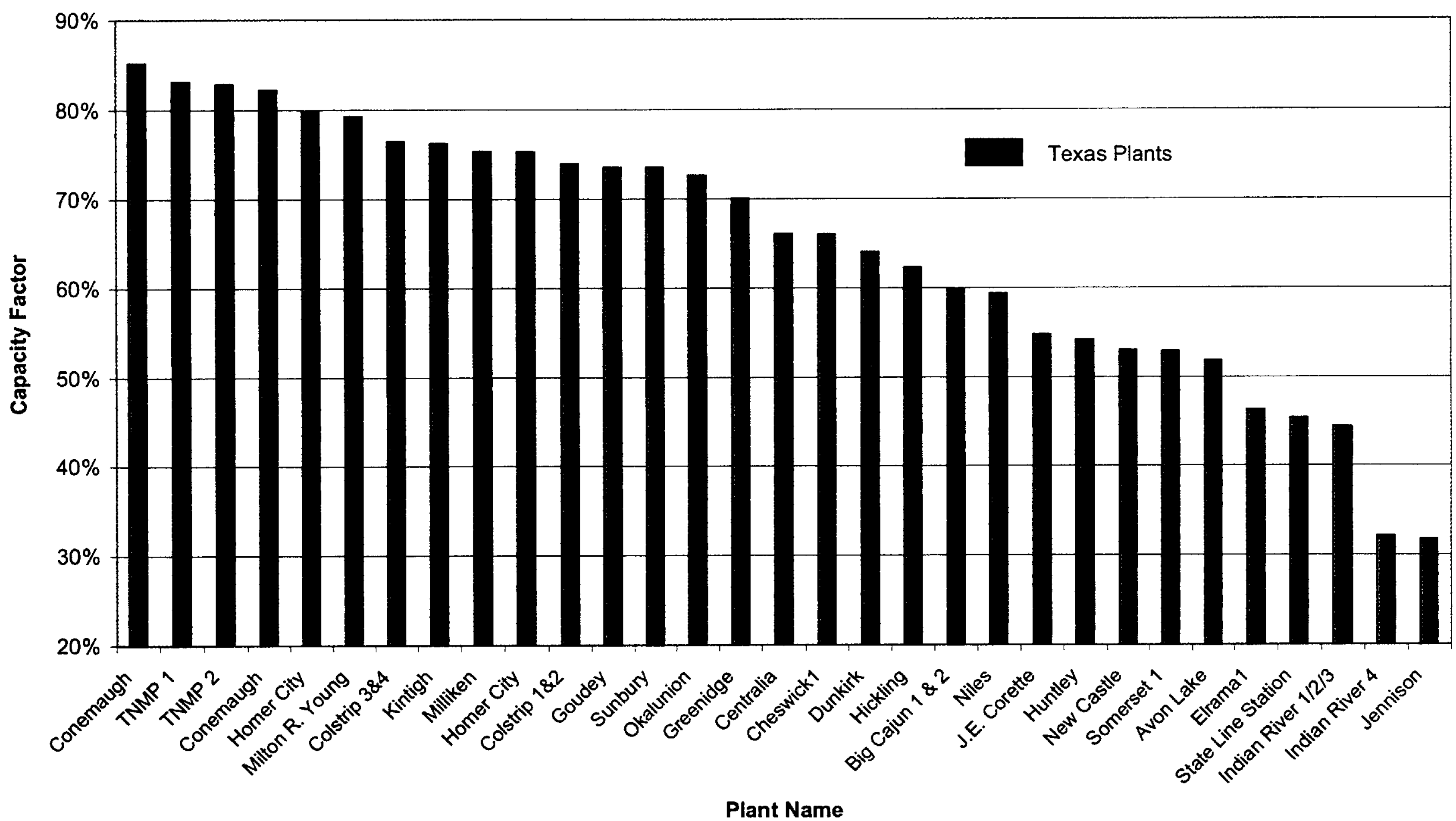


Exhibit JP-2

Average Capacity Factor of Coal-Fired Power Plants During the Three Years Prior to Being Sold



ERCOT

BALANCING ENERGY MARKET CLEARING PRICES (MCPE)
($/MWh)

Year	Month	Data	Total
2002	1	Average of North	$ 18.68
		Average of South	$ 9.81
		Average of West	$ 17.32
		Average of Houston	$ 16.83
	2	Average of North	$ 18.45
		Average of South	$ 11.98
		Average of West	$ 15.70
		Average of Houston	$ 17.09
	3	Average of North	$ 23.27
		Average of South	$ 22.36
		Average of West	$ 23.58
		Average of Houston	$ 22.89
	4	Average of North	$ 25.07
		Average of South	$ 18.62
		Average of West	$ 15.60
		Average of Houston	$ 21.90
	5	Average of North	$ 21.37
		Average of South	$ 20.80
		Average of West	$ 21.23
		Average of Houston	$ 21.83
	6	Average of North	$ 24.70
		Average of South	$ 22.31
		Average of West	$ 24.83
		Average of Houston	$ 25.41
	7	Average of North	$ 26.94
		Average of South	$ 24.14
		Average of West	$ 27.42
		Average of Houston	$ 26.65
	8	Average of North	$ 26.74
		Average of South	$ 25.24
		Average of West	$ 26.54
		Average of Houston	$ 26.44
	9	Average of North	$ 25.91
		Average of South	$ 24.62
		Average of West	$ 26.11
		Average of Houston	$ 26.93
	10	Average of North	$ 29.96
		Average of South	$ 29.60
		Average of West	$ 29.49
		Average of Houston	$ 30.09
	11	Average of North	$ 28.24
		Average of South	$ 28.25
		Average of West	$ 28.50
		Average of Houston	$ 28.24
	12	Average of North	$ 30.37
		Average of South	$ 30.24
		Average of West	$ 30.37
		Average of Houston	$ 30.30
2002 Average of North			$ 25.02
2002 Average of South			$ 22.40
2002 Average of West			$ 23.96
2002 Average of Houston			$ 24.60

ERCOT

BALANCING ENERGY MARKET CLEARING PRICES (MCPE)
($/MWh)

Year	Month	Data	Total
2003	1	Average of North	$ 37.05
		Average of South	$ 36.76
		Average of West	$ 37.02
		Average of Houston	$ 37.21
	2	Average of North	$ 78.16
		Average of South	$ 77.76
		Average of West	$ 78.14
		Average of Houston	$ 77.99
	3	Average of North	$ 51.53
		Average of South	$ 45.51
		Average of West	$ 50.04
		Average of Houston	$ 50.69
	4	Average of North	$ 36.45
		Average of South	$ 34.05
		Average of West	$ 36.23
		Average of Houston	$ 37.00
	5	Average of North	$ 49.22
		Average of South	$ 46.56
		Average of West	$ 49.04
		Average of Houston	$ 48.97
	6	Average of North	$ 39.20
		Average of South	$ 38.95
		Average of West	$ 39.19
		Average of Houston	$ 39.08
	7	Average of North	$ 39.05
		Average of South	$ 36.75
		Average of West	$ 38.94
		Average of Houston	$ 37.93
	8	Average of North	$ 43.88
		Average of South	$ 39.46
		Average of West	$ 43.46
		Average of Houston	$ 42.76
	9	Average of North	$ 30.84
		Average of South	$ 30.63
		Average of West	$ 30.83
		Average of Houston	$ 30.90
	10	Average of North	$ 35.99
		Average of South	$ 35.35
		Average of West	$ 35.92
		Average of Houston	$ 36.54
	11	Average of North	$ 29.07
		Average of South	$ 29.00
		Average of West	$ 29.07
		Average of Houston	$ 29.05
	12	Average of North	$ 33.36
		Average of South	$ 33.33
		Average of West	$ 33.34
		Average of Houston	$ 33.38
2003 Average of North			$ 41.77
2003 Average of South			$ 40.11
2003 Average of West			$ 41.56
2003 Average of Houston			$ 41.58
Total Average of North			$ 33.40
Total Average of South			$ 31.26
Total Average of West			$ 32.76
Total Average of Houston			$ 33.09

ERCOT

2003 Capacity Margins By Congestion Zone

Line	Congestion Zone	Resources (MW)	2003 Actual Coincident Demand (MW)	Capacity Margin
		(1)	(2)	(3)
1	**Houston**	20,244	14,991	**26%**
2	**North**	32,691	25,755	**21%**
3	**South**	23,862	15,251	**36%**
4	**West**	6,408	3,941	**39%**
5	**ERCOT System Peak**	83,205	59,938	**28%**

Sources: ERCOT: Report on the Capacity, Demand, and Reserves in the ERCOT Region, May 2003; ERCOT EIA-411 Report; ERCOT, New Projects Under Construction and Completed Projects; 2002 and 2003 ERCOT 15-minute Demand

TEXAS-NEW MEXICO POWER COMPANY
TOTAL TEXAS
FUEL OVER/(UNDER) RECOVERIES REFLECTING FINAL ORDER IN DOCKET NO. 27576
FOR THE PERIOD JANUARY 1, 2000 TO DECEMBER 31, 2002

LINE NO.	MON	YR	TOTAL RECONCILABLE FUEL COSTS ($)	ADJUSTMENT FOR DISALLOWED COSTS ($)	ADJUSTED ELIGIBLE MONTHLY FUEL COSTS ($)	FUEL FACTOR REVENUE ($)	ADJUSTED FUEL OVER/ (UNDER) RECOVERY ($)	ADJUSTED CUMULATIVE FUEL COST OVER/(UNDER) RECOVERY ($)	CUMULATIVE INTEREST ACCRUAL BALANCES ($)	CUMULATIVE OVER/(UNDER) FUEL COST AND INTEREST RECOVERY ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Beg. Balance								**(16,386,803)**	**(4,736,754)**	**(21,123,557)**
1	JAN	00	6,473,436	(654,082)	5,819,354	6,198,289	378,935	(16,007,868)	(4,824,160)	(20,832,028)
2	FEB	00	6,076,234	(654,082)	5,422,152	5,786,114	363,962	(15,643,906)	(4,910,360)	(20,554,266)
3	MAR	00	7,331,560	(654,082)	6,677,478	5,375,625	(1,301,853)	(16,945,760)	(4,995,411)	(21,941,170)
4	APR	00	5,579,415	(654,082)	4,925,333	5,932,791	1,007,458	(15,938,302)	(5,086,200)	(21,024,502)
5	MAY	00	10,830,208	(654,082)	10,176,126	6,244,751	(3,931,375)	(19,869,677)	(5,173,196)	(25,042,873)
6	JUN	00	12,663,277	(654,082)	12,009,195	8,553,185	(3,456,010)	(23,325,687)	(5,276,820)	(28,602,507)
7	JUL	00	12,807,711	(654,082)	12,153,629	10,825,478	(1,328,151)	(24,653,838)	(5,395,173)	(30,049,011)
8	AUG	00	15,072,765	(654,082)	14,418,683	10,614,982	(3,803,701)	(28,457,539)	(5,519,511)	(33,977,050)
9	SEP	00	13,870,560	(654,082)	13,216,478	14,029,868	813,390	(27,644,150)	(5,660,103)	(33,304,253)
10	OCT	00	8,517,853	(654,082)	7,863,771	9,660,371	1,796,600	(25,847,550)	(5,797,911)	(31,645,461)
11	NOV	00	7,194,383	(654,082)	6,540,301	8,680,893	2,140,592	(23,706,958)	(5,928,855)	(29,635,813)
12	DEC	00	8,891,541	(654,082)	8,237,459	8,994,749	757,290	(22,949,668)	(6,051,484)	(29,001,152)
13	JAN	01	9,042,782	(654,082)	8,388,700	11,902,088	3,513,388	(19,436,280)	(6,198,370)	(25,634,650)
14	FEB	01	7,502,000	(654,082)	6,847,918	12,078,563	5,230,645	(14,205,635)	(6,328,205)	(20,533,841)
15	MAR	01	7,906,182	(654,082)	7,252,100	10,416,616	3,164,516	(11,041,120)	(6,432,206)	(17,473,325)
16	APR	01	7,988,775	(654,082)	7,334,693	11,639,312	4,304,619	(6,736,501)	(6,520,705)	(13,257,206)
17	MAY	01	10,901,575	(654,082)	10,247,493	11,890,003	1,642,510	(5,093,991)	(6,587,851)	(11,681,842)
18	JUN	01	14,098,451	(654,082)	13,444,369	18,105,890	4,661,521	(432,470)	(6,647,018)	(7,079,488)
19	JUL	01	15,408,225	(654,082)	14,754,143	20,458,967	5,704,824	5,272,354	(6,682,874)	(1,410,520)
20	AUG	01	14,713,562	(654,082)	14,059,480	22,371,790	8,312,310	13,584,664	(6,690,018)	6,894,646
21	SEP	01	16,770,860	(654,082)	16,116,778	19,644,303	3,527,525	17,112,189	(6,655,098)	10,457,091
22	OCT	01	7,760,705	(654,082)	7,106,623	15,464,443	8,357,820	25,470,008	(6,602,134)	18,867,874
23	NOV	01	8,514,882	(654,082)	7,860,800	13,696,045	5,835,245	31,305,253	(6,506,572)	24,798,681
24	DEC	01	11,531,671	(654,082)	10,877,589	13,241,821	2,364,232	33,669,485	(6,380,971)	27,288,514
25	JAN	02	3,105,615		3,105,615	12,559,470	9,453,855	43,123,340	(6,283,095)	36,840,245
26	FEB	02	(942,236)		(942,236)	(953)	941,283	44,064,623	(6,283,095)	37,781,528
27	MAR	02	(29,524)		(29,524)	4,038	33,562	44,098,185	(6,283,095)	37,815,090
28	APR	02	(1,170,516)		(1,170,516)	(136)	1,170,380	45,268,565	(6,283,095)	38,985,470
29	MAY	02	185,110		185,110	582	(184,528)	45,084,037	(6,283,095)	38,800,942
30	JUN	02	66		66	410	344	45,084,381	(6,283,095)	38,801,286
31	JUL	02	-		-	242	242	45,084,623	(6,283,095)	38,801,528
32	AUG	02	-		-	310	310	45,084,933	(6,283,095)	38,801,838
33	SEP	02	436,838		436,838	(839)	(437,677)	44,647,256	(6,283,095)	38,364,161
34	OCT	02	(369,648)		(369,648)	(175)	369,473	45,016,729	(6,283,095)	38,733,634
35	NOV	02	(845,677)		(845,677)	(478)	845,199	45,861,928	(6,283,095)	39,578,833
36	DEC	02	(4,659)		(4,659)	137	4,796	45,866,724	(6,283,095)	39,583,629
37	TOTAL RECON PERIOD		247,813,982	(15,697,964)	232,116,018	294,369,545	62,253,527	45,866,724	(6,283,095)	**39,583,629**

TEXAS-NEW MEXICO POWER COMPANY

TOTAL TEXAS

FUEL OVER/(UNDER) RECOVERIES REFLECTING FINAL ORDER IN DOCKET NO. 27576

FOR THE PERIOD JANUARY 1, 2000 TO DECEMBER 31, 2002

				INTEREST CALCULATION		
LINE NO.	MON	YR	CUMULATIVE OVER/(UNDER) FUEL COST AND INTEREST RECOVERY ($)	APPROVED ANNUAL INTEREST RATE	EFFECTIVE INTEREST FACTOR FOR ANNUAL COMPOUNDING	INTEREST ON PREVIOUS MONTH'S OVER/(UNDER) FUEL RECOVERY AND INTEREST BALANCE ($)
	(k)	(l)	(m)	(n)	(o)	(p)
Beg. Balance			**(21,123,557)**			
1	JAN	00	(20,832,028)	5.08%	0.00413785	($87,406)
2	FEB	00	(20,554,266)	5.08%	0.00413785	(86,200)
3	MAR	00	(21,941,170)	5.08%	0.00413785	(85,051)
4	APR	00	(21,024,502)	5.08%	0.00413785	(90,789)
5	MAY	00	(25,042,873)	5.08%	0.00413785	(86,996)
6	JUN	00	(28,602,507)	5.08%	0.00413785	(103,624)
7	JUL	00	(30,049,011)	5.08%	0.00413785	(118,353)
8	AUG	00	(33,977,050)	5.08%	0.00413785	(124,338)
9	SEP	00	(33,304,253)	5.08%	0.00413785	(140,592)
10	OCT	00	(31,645,461)	5.08%	0.00413785	(137,808)
11	NOV	00	(29,635,813)	5.08%	0.00413785	(130,944)
12	DEC	00	(29,001,152)	5.08%	0.00413785	(122,629)
13	JAN	01	(25,634,650)	6.25%	0.00506483	(146,886)
14	FEB	01	(20,533,841)	6.25%	0.00506483	(129,835)
15	MAR	01	(17,473,325)	6.25%	0.00506483	(104,001)
16	APR	01	(13,257,206)	6.25%	0.00506483	(88,500)
17	MAY	01	(11,681,842)	6.25%	0.00506483	(67,146)
18	JUN	01	(7,079,488)	6.25%	0.00506483	(59,167)
19	JUL	01	(1,410,520)	6.25%	0.00506483	(35,856)
20	AUG	01	6,894,646	6.25%	0.00506483	(7,144)
21	SEP	01	10,457,091	6.25%	0.00506483	34,920
22	OCT	01	18,867,874	6.25%	0.00506483	52,963
23	NOV	01	24,798,681	6.25%	0.00506483	95,563
24	DEC	01	27,288,514	6.25%	0.00506483	125,601
25	JAN	02	36,840,245	4.39%	0.00358673	97,875
26	FEB	02	37,781,528	4.39%	0.00358673	-
27	MAR	02	37,815,090	4.39%	0.00358673	-
28	APR	02	38,985,470	4.39%	0.00358673	-
29	MAY	02	38,800,942	4.39%	0.00358673	-
30	JUN	02	38,801,286	4.39%	0.00358673	-
31	JUL	02	38,801,528	4.39%	0.00358673	-
32	AUG	02	38,801,838	4.39%	0.00358673	-
33	SEP	02	38,364,161	4.39%	0.00358673	-
34	OCT	02	38,733,634	4.39%	0.00358673	-
35	NOV	02	39,578,833	4.39%	0.00358673	-
36	DEC	02	39,583,629	4.39%	0.00358673	-
37	TOTAL RECON PERIOD					**(1,546,341)**

TEXAS-NEW MEXICO POWER COMPANY
TOTAL TEXAS
FUEL OVER/(UNDER) RECOVERIES
FOR THE PERIOD JANUARY 2002 TO JUNE 2004

LINE NO.	MON	YR	TOTAL RECONCILABLE FUEL COSTS ($)	ADJUSTMENT FOR DISALLOWED COSTS ($)	ADJUSTED ELIGIBLE MONTHLY FUEL COSTS ($)	FUEL FACTOR REVENUE ($)	ADJUSTED FUEL OVER/ (UNDER) RECOVERY ($)	ADJUSTED CUMULATIVE FUEL COST OVER/(UNDER) RECOVERY ($)	CUMULATIVE INTEREST ACCRUAL BALANCES ($)	CUMULATIVE OVER/(UNDER) FUEL COST AND INTEREST RECOVERY ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Begining Balance per Exhibit RJK-3 Line 25								**43,123,340**	**(6,283,095)**	**36,840,245**
26	FEB	02	(942,236)		(942,236)	(953)	941,283	44,064,623	(6,150,959)	37,913,664
27	MAR	02	(29,524)		(29,524)	4,038	33,562	44,098,185	(6,014,973)	38,083,212
28	APR	02	(1,170,516)		(1,170,516)	(136)	1,170,380	45,268,565	(5,878,379)	39,390,186
29	MAY	02	185,110		185,110	582	(184,528)	45,084,037	(5,737,097)	39,346,940
30	JUN	02	66		66	410	344	45,084,381	(5,595,970)	39,488,411
31	JUL	02	-		-	242	242	45,084,623	(5,454,336)	39,630,287
32	AUG	02	-		-	310	310	45,084,933	(5,312,193)	39,772,740
33	SEP	02	436,838		436,838	(839)	(437,677)	44,647,256	(5,169,539)	39,477,717
34	OCT	02	(369,648)		(369,648)	(175)	369,473	45,016,729	(5,027,943)	39,988,786
35	NOV	02	(845,677)		(845,677)	(478)	845,199	45,861,928	(4,884,514)	40,977,414
36	DEC	02	(4,659)		(4,659)	137	4,796	45,866,724	(4,737,539)	41,129,185
37	JAN	03	-	-	-	-	-	45,866,724	(4,676,686)	41,190,038
38	FEB	03	-	-	-	-	-	45,866,724	(4,615,743)	41,250,981
39	MAR	03	-	-	-	-	-	45,866,724	(4,554,709)	41,312,015
40	APR	03	-	-	-	-	-	45,866,724	(4,493,585)	41,373,139
41	MAY	03	-	-	-	-	-	45,866,724	(4,432,371)	41,434,353
42	JUN	03	-	-	-	-	-	45,866,724	(4,371,066)	41,495,658
43	JUL	03	-	-	-	-	-	45,866,724	(4,309,670)	41,557,054
44	AUG	03	-	-	-	-	-	45,866,724	(4,248,184)	41,618,540
45	SEP	03	-	-	-	-	-	45,866,724	(4,186,607)	41,680,117
46	OCT	03	-	-	-	-	-	45,866,724	(4,124,938)	41,741,786
47	NOV	03	-	-	-	-	-	45,866,724	(4,063,178)	41,803,546
48	DEC	03	-	-	-	-	-	45,866,724	(4,001,327)	41,865,397
49	JAN	04	BALANCE JANUARY 15		-	-	-	45,866,724	(3,981,681)	41,885,043
50		04	-	-	-	-	-	45,866,724	(3,960,725)	41,905,999
51	FEB	04	-	-	-	-	-	45,866,724	(3,920,084)	41,946,640
52	MAR	04	-	-	-	-	-	45,866,724	(3,879,404)	41,987,320
53	APR	04	-	-	-	-	-	45,866,724	(3,838,684)	42,028,040
54	MAY	04	-	-	-	-	-	45,866,724	(3,797,925)	42,068,799
55	JUN	04	-	-	-	-	-	45,866,724	(3,757,126)	42,109,598
56	TOTAL TRUE-UP PERIOD		(2,740,246)	-	(2,740,246)	3,138	**2,743,384**	45,866,724	(3,757,126)	**42,109,598**

TEXAS-NEW MEXICO POWER COMPANY
TOTAL TEXAS
FUEL OVER/(UNDER) RECOVERIES
FOR THE TRUE-UP PERIOD JANUARY 2002 TO JUNE 2004

				INTEREST CALCULATION		
LINE NO.	MON	YR	CUMULATIVE OVER/(UNDER) FUEL COST AND INTEREST RECOVERY ($)	APPROVED ANNUAL INTEREST RATE	EFFECTIVE INTEREST FACTOR FOR ANNUAL COMPOUNDING	INTEREST ON PREVIOUS MONTH'S OVER/(UNDER) FUEL RECOVERY AND INTEREST BALANCE ($)
	(k)	(l)	(m)	(n)	(o)	(p)
26	FEB	02	37,913,664	4.39%	0.00358673	132,136
27	MAR	02	38,083,212	4.39%	0.00358673	135,986
28	APR	02	39,390,186	4.39%	0.00358673	136,594
29	MAY	02	39,346,940	4.39%	0.00358673	141,282
30	JUN	02	39,488,411	4.39%	0.00358673	141,127
31	JUL	02	39,630,287	4.39%	0.00358673	141,634
32	AUG	02	39,772,740	4.39%	0.00358673	142,143
33	SEP	02	39,477,717	4.39%	0.00358673	142,654
34	OCT	02	39,988,786	4.39%	0.00358673	141,596
35	NOV	02	40,977,414	4.39%	0.00358673	143,429
36	DEC	02	41,129,185	4.39%	0.00358673	146,975
37	JAN	03	41,190,038	1.79%	0.00147957	60,853
38	FEB	03	41,250,981	1.79%	0.00147957	60,943
39	MAR	03	41,312,015	1.79%	0.00147957	61,034
40	APR	03	41,373,139	1.79%	0.00147957	61,124
41	MAY	03	41,434,353	1.79%	0.00147957	61,214
42	JUN	03	41,495,658	1.79%	0.00147957	61,305
43	JUL	03	41,557,054	1.79%	0.00147957	61,396
44	AUG	03	41,618,540	1.79%	0.00147957	61,486
45	SEP	03	41,680,117	1.79%	0.00147957	61,577
46	OCT	03	41,741,786	1.79%	0.00147957	61,669
47	NOV	03	41,803,546	1.79%	0.00147957	61,760
48	DEC	03	41,865,397	1.79%	0.00147957	61,851
49	JAN	04	41,885,043	1.17%	0.00096981	19,646
50		04	41,905,999	1.17%	0.00096981	20,956
51	FEB	04	41,946,640	1.17%	0.00096981	40,641
52	MAR	04	41,987,320	1.17%	0.00096981	40,680
53	APR	04	42,028,040	1.17%	0.00096981	40,720
54	MAY	04	42,068,799	1.17%	0.00096981	40,759
55	JUN	04	42,109,598	1.17%	0.00096981	40,799
56	TOTAL TRUE-UP PERIOD					**2,525,969**